AVISTA Corp.

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PUBLIC SERVICE COMMISSION

April 20, 2012

Leroy Beeby
Public Service Commission
State of Montana
1701 Prospect Avenue
Helena, MT 59620

Dear Mr. Beeby,

Enclosed you will find Avista Corporation's 2011 Annual Electric Report.

Please address all inquiries regarding this filing to John Wilcox at (509) 495-4171 or john.wilcox@avistacorp.com.

Sincerely,

John F. Wilcox

John F. Wilcox
External Reporting Analyst

Enclosure

YEAR ENDING 12/31/2011

ANNUAL REPORT
OF

AVISTA CORPORATION

ELECTRIC UTILITY

RECEIVED BY
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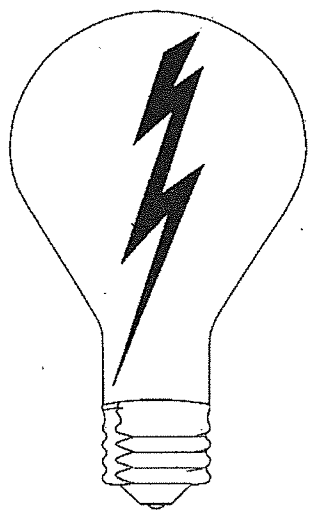
COMMISSION



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

REVISED - 2005

IDENTIFICATION

Year: **2011**

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	$145,166.00
2	Kristianne Blake	P. O. Box 28338, Spokane, WA 99208	$176,355.00
3	Donald C. Burke (1)	16 Ivy Court, Langhorne, PA 19047	$64,834.00
4	Roy Lewis Eiguren (2)	712 Warm Springs Ave, Boise, ID 83712	$21,667.00
5	Rick R. Holley (3)	999 Third Ave., Suite 4300, Seattle, WA 98104	$58,834.00
6	John F. Kelly	142 Isla Dorada Blvd. Coral Gables, FL 33143	$180,776.00
7	Rebecca A. Klein	611 S. Congress Ave. Ste 125 Austin, TX 78704	$134,333.00
8	Michael L. Noel	11960 Six Shooter Rd., Prescott, AZ 86305	$137,000.00
9	Marc F. Racicot	28013 Swan Cove Dr. Bigfork, MT 59911	$128,000.00
10	Heidi B. Stanley	PO Box 8650, Spokane, WA 99203	$135,500.00
11	R. John Taylor	P. O. Box 538, Lewiston, ID 83501	$155,019.00
12	Scott L. Morris (4)	1411 E. Mission Ave., Spokane, WA 99202	(2)
13			
14	(1) Mr. Burke was appointed as director effective August 1, 2011.		
15	(2) Mr. Eiguren resigned from the board of directors effective February 5, 2011.		
16	(3) Mr. Holley was appointed as director effective August 1, 2011.		
17	(4) Mr. Morris is the Chairman of the Board, President and Chief Executive Officer of Avista Corp.		
18			
19			
20			

Company Name: **Avista Corporation** **SCHEDULE 3**

Officers

Year: 2011

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 Customer Solutions	Utility Operations	Don F. Kopczynski
24			
25			
26	Vice President and Chief	Strategic Planning	Roger D. Woodworth
27	Strategy Officer		
28			
29			
30	Vice President and Chief Counsel for	Legal/Regulatory	David J. Meyer
31	Regulatory and Governmental Affairs		
32			
33	Vice President of Energy Delivery	Transmission and	Jason R. Thackston
34		Distribution	
35			
36	Vice President and Chief Information	Information	James M. Kensok
37	Officer	Technology	
38			
39	Vice President of Energy Resources	Resource	Richard L. Storro
40		Management	
41			
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CORPORATE STRUCTURE

Year: 2011

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1				
2	Avista Capital, Inc.	Parent company to the	$9,971,326	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	Ecova, Inc. (formerly known as	Provider of utility bill processing, payment and information		
9	Advantage IQ, Inc.)	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, LLC	Commercial office and retail leasing.		
20				
21	Steam Plant Brew Pub LLC	Restaurant operations.		
22				
23	Avista Ventures, Inc.	Inactive.		
24				
25	Avista Development, Inc.	Non-operating company which maintains an investment portfolio		
26		of real estate and other investments.		
27				
28	Pentzer Corporation	Parent of Bay Area Manufacturing and Pentzer Venture Holdings.		
29				
30	Bay Area Manufacturing	Holding Company. Parent of Advanced Manufacturing and		
31		Development, Inc.		
32				
33	Pentzer Venture Holdings	Inactive.		
34				
35	Advanced Manufacturing	Performs custom sheet metal manufacturing of electronic		
36	and Devlopment, Inc.	enclosures. Has a wood products division.		
37				
38	Spokane Energy, LLC	Marketing of energy.		
39				
40				
41	Avista Northwest Resources, LLC	Formed in 2009 to own an interest in a venture fund		
42				
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49				
50	**TOTAL**		9,971,326	

Company Name: Avista Corporation

SCHEDULE 5

CORPORATE ALLOCATIONS

Year: 2011

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1						
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3						
4	Not applicable					
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34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2011

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
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32	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

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	Spokane Energy LLC	Electric capacity payment	Negotiated contract	1,800,000		
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32	**TOTAL**			1,800,000		

MONTANA UTILITY INCOME STATEMENT

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	29,636	38,304	29.25%
2				
3	Operating Expenses			
4	401 Operation Expenses	25,206,373	26,261,416	4.19%
5	402 Maintenance Expense	6,164,297	8,351,626	35.48%
6	403 Depreciation Expense	12,872,752	13,288,026	3.23%
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	7,735,122	8,146,733	5.32%
12	409.1 Income Taxes - Federal	none/n.a.	none/n.a.	#VALUE!
13	- Other	201,175	358,569	78.24%
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**	52,179,719	56,406,370	8.10%
21	**NET UTILITY OPERATING INCOME**	(52,150,083)	(56,368,066)	-8.09%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	6,346	10,754	69.46%
3	442 Commercial & Industrial - Small	1,391	2,359	69.59%
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	21,899	25,191	15.03%
9				
10	**TOTAL Sales to Ultimate Consumers**	29,636	38,304	29.25%
11	447 Sales for Resale			
12				
13	**TOTAL Sales of Electricity**	29,636	38,304	29.25%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	**TOTAL Revenue Net of Provision for Refunds**	29,636	38,304	29.25%
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			
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues			
24				
25	**TOTAL Other Operating Revenues**			
26	**Total Electric Operating Revenues**	29,636	38,304	29.25%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	180,662	190,834	5.63%
6	501 Fuel	17,475,416	18,818,373	7.68%
7	502 Steam Expenses	3,677,996	3,593,901	-2.29%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	37,137	93,372	151.43%
11	506 Miscellaneous Steam Power Expenses	2,060,904	1,858,634	-9.81%
12	507 Rents	15,498	32,398	109.05%
13				
14	TOTAL Operation - Steam	23,447,613	24,587,512	4.86%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	323,810	396,605	22.48%
18	511 Maintenance of Structures	476,268	681,596	43.11%
19	512 Maintenance of Boiler Plant	3,142,265	4,605,356	46.56%
20	513 Maintenance of Electric Plant	392,594	655,211	66.89%
21	514 Maintenance of Miscellaneous Steam Plant	340,421	679,172	99.51%
22				
23	TOTAL Maintenance - Steam	4,675,358	7,017,940	50.10%
24				
25	**TOTAL Steam Power Production Expenses**	28,122,971	31,605,452	12.38%
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: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering	115,030	99,117	-13.83%
5	536 Water for Power			
6	537 Hydraulic Expenses	6,211	83,708	1247.74%
7	538 Electric Expenses	1,192,827	1,136,449	-4.73%
8	539 Miscellaneous Hydraulic Power Gen. Expenses	280,202	179,186	-36.05%
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic	1,594,270	1,498,460	-6.01%
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering	55,878	104,342	86.73%
15	542 Maintenance of Structures	232,209	130,319	-43.88%
16	543 Maint. of Reservoirs, Dams & Waterways	451,694	114,602	-74.63%
17	544 Maintenance of Electric Plant	411,518	314,641	-23.54%
18	545 Maintenance of Miscellaneous Hydro Plant	(50,770)	74,512	246.76%
19				
20	TOTAL Maintenance - Hydraulic	1,100,529	738,416	-32.90%
21				
22	**TOTAL Hydraulic Power Production Expenses**	2,694,799	2,236,876	-16.99%
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**	30,817,770	33,842,328	9.81%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	11,709	11,354	-3.03%
4	561	Load Dispatching	28,395	27,088	-4.60%
5	562	Station Expenses	2,406	2,065	-14.17%
6	563	Overhead Line Expenses	14,660	52,797	260.14%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others			
9	566	Miscellaneous Transmission Expenses			
10	567	Rents	86,240	81,739	-5.22%
11					
12		TOTAL Operation - Transmission	143,410	175,043	22.06%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	45,497	50,180	10.29%
15	569	Maintenance of Structures	279	2,653	850.90%
16	570	Maintenance of Station Equipment	23,565	17,021	-27.77%
17	571	Maintenance of Overhead Lines	308,358	514,909	66.98%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	377,699	584,763	54.82%
22					
23		**TOTAL Transmission Expenses**	521,109	759,806	45.81%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering			
28	581	Load Dispatching			
29	582	Station Expenses			
30	583	Overhead Line Expenses			
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			
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**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	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	49	379	673.47%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	240		-100.00%
42	930.2 Miscellaneous General Expenses	20,791	22	-99.89%
43	931 Rents			
44				
45	TOTAL Operation - Admin. & General	21,080	401	-98.10%
46	Maintenance			
47	935 Maintenance of General Plant	10,711	10,507	-1.90%
48				
49	**TOTAL Administrative & General Expenses**	31,791	10,908	-65.69%
50				
51	**TOTAL Operation & Maintenance Expenses**	31,370,670	34,613,042	10.34%

MONTANA TAXES OTHER THAN INCOME

Year: 2011

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	7,070	(386)	-105.46%
5	Motor Vehicle Tax	4,675	1,350	-71.12%
6	KWH Tax	1,113,818	1,213,272	8.93%
7	Property Taxes	6,605,137	6,929,490	4.91%
8	Public Commission Tax	1,293	44	-96.60%
9	Colstrip Generation Tax	3,129	2,963	-5.31%
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51	**TOTAL MT Taxes Other Than Income**	7,735,122	8,146,733	5.32%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2011

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts allocated to Montana are not significant.				
2	Aecom Inc.	engineering	555,365		
3	Alcan Cable	construction consulting	492,018		
4	All Surface Roofing and Waterproofing Inc.	roofing services	335,043		
5	Booz & Company Inc	consulting	2,329,432		
6	Bouten Construction Company	construction consulting	1,041,977		
7	Columbia Grid	transmission planning	324,184		
8	Deloitte & Touche LLP	audit	1,520,546		
9	Dewey & Leboeuf LLP	legal	324,698		
10	Dinero Solutions, LLC	consulting IT	952,547		
11	EFACEC Advanced Control Systems	construction consulting	309,625		
12	Electrical Consultants, Inc.	construction consulting	466,223		
13	ERMCO	construction consulting	4,429,691		
14	Garco Construction Inc	construction consulting	1,970,836		
15	G&W Electric	construction consulting	2,534,980		
16	Hanna & Associates Inc	consulting	364,184		
17	Hickey Brothers Fisheries LLC	consulting fish passage	318,369		
18	Intellitect	water monitoring	661,246		
19	Interior Solutions, Inc.	office design	466,291		
20	ITRON Inc	consulting IT	962,405		
21	Jaco Construction Inc	construction consulting	472,515		
22	Land Expressions	landscape architecture	1,249,067		
23	McKinstry Essention Inc	construction consulting	4,154,980		
24	Northwest Hydraulic Consultants	consulting	370,250		
25	Northwest Steel Fab	engineering	257,814		
26	Paine Hamblen Coffin Brooke	legal	799,717		
27	Osmose Utilities Services Inc.	engineering	263,756		
28	Pro Building Systems	construction consulting	293,598		
29	Project Corps LLC	consulting	310,555		
30	Regulas Integrated Solutions LLC	consulting	259,991		
31	Science Applications International Corporation	engineering	324,481		
32	Scope Services Inc.	construction consulting	271,355		
33	Tilton Excavation LLC	construction services	380,596		
34	US Fish & Wildlife Service	consulting	312,667		
35	Western Electricity	consulting	546,341		
36	Wesco Distribution Inc.	construction consulting	410,106		
37	Other amounts less than $250,000		20,026,900		
38					
39	**TOTAL Payments for Services**		51,064,349		

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2011

	Description	Total Company	Montana	% Montana
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3	NONE			
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50	**TOTAL Contributions**			

Pension Costs

Year: 2011

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	409,942	358,047	-12.66%
8	Service cost	12,835	11,203	-12.72%
9	Interest Cost	22,873	22,037	-3.65%
10	Plan participants' contributions			
11	Amendments	400		-100.00%
12	Actuarial Gain	41,366	35,521	-14.13%
13	Benefits paid	(19,267)	(16,866)	12.46%
14	Expenses paid			
15	Benefit obligation at end of year	468,149	409,942	-12.43%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	306,712	272,732	-11.08%
18	Actual return on plan assets	14,705	29,846	102.96%
19	Acquisition			
20	Employer contribution	26,000	21,000	-19.23%
21	Benefits paid	(19,267)	(16,866)	12.46%
22	Expenses paid			
23	Fair value of plan assets at end of year	328,150	306,712	-6.53%
24	**Funded Status**	(139,999)	(103,230)	26.26%
25	Unrecognized net actuarial loss	184,066	142,179	-22.76%
26	Unrecognized prior service cost	665	1,140	71.43%
27	Unrecognized net transition obligation/(asset)			
28	Prepaid (accrued) benefit cost	44,732	40,089	-10.38%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.05%	5.70%	12.87%
32	Expected return on plan assets	7.40%	7.75%	4.73%
33	Rate of compensation increase	4.87%	4.72%	-3.08%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	12,835	11,203	-12.72%
37	Interest cost	22,873	22,037	-3.65%
38	Expected return on plan assets	(23,115)	(21,381)	7.50%
39	Transition (asset)/obligation recognition	400		
40	Amortization of prior service cost	475	650	36.84%
41	Recognized net actuarial loss	7,889	6,798	-13.83%
42	Net periodic benefit cost	21,357	19,307	-9.60%
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	2,742	2,674	-2.48%
50	Not Covered by the Plan			
51	Active	1,459	1,396	-4.32%
52	Retired	1,004	1,008	0.40%
53	Deferred Vested Terminated	279	270	-3.23%

Other Post Employment Benefits (OPEBS)

Year: 2011

	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	4.98%	5.50%	10.44%
8	Expected return on plan assets	7.00%	7.75%	10.71%
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	60,339	39,560	-34.44%
20	Service cost	1,805	684	-62.11%
21	Interest Cost	4,126	2,624	-36.40%
22	Plan participants' contributions	450	367	-18.44%
23	Amendments			
24	Actuarial Gain	42,476	21,657	-49.01%
25	Benefits paid	(4,466)	(4,553)	-1.95%
26	Expenses paid			
27	Benefit obligation at end of year	104,730	60,339	-42.39%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	22,875	20,394	-10.85%
30	Actual return on plan assets	(420)	2,481	690.71%
31	Acquisition			
32	Employer contribution			
33	Benefits paid			
34	Expenses paid			
35	Fair value of plan assets at end of year	22,455	22,875	1.87%
36	**Funded Status**	(82,275)	(37,464)	54.46%
37	Unrecognized net actuarial loss	76,187	35,149	-53.86%
38	Unrecognized prior service cost	(1,005)	(1,154)	-14.83%
39	Prepaid (accrued) benefit cost	(7,093)	(3,469)	51.09%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	1,805	684	-62.11%
42	Interest cost	4,126	2,624	-36.40%
43	Expected return on plan assets	(1,601)	(1,581)	1.25%
44	Amortization of prior service cost	356	356	
45	Recognized net actuarial loss	3,458	1,379	-60.12%
46	Net periodic benefit cost	8,144	3,462	-57.49%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA	104,730	60,339	-42.39%
49	Amount Funded through 401(h)			
50	Amount Funded through Other ___________			
51	TOTAL	104,730	60,339	-42.39%
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL	104,730	60,339	-42.39%

Other Post Employment Benefits (OPEBS) Continued

Year: 2011

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	2,278	2,206	-3.16%
3	Not Covered by the Plan			
4	Active	1,459	1,398	-4.18%
5	Retired	819	808	-1.34%
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							
2							
3							
4							
5							
6							
7							
8							
9							
10							

Company Name: Avista Corporation

SCHEDULE 17

Year: 2011

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	662,307	537,363	2,295,876	3,495,546	3,245,967	8%
2	M. T. Thies Senior Vice President and Chief Financial Officer	341,153	184,530	419,679	945,362	854,760	11%
3	M.M. Durkin Senior Vice President General Counsel and Chief Compliance Officer	288,655	156,133	465,917	910,705	830,451	10%
4	K.S. Feltes Senior Vice President and Corporate Secretary	253,654	137,201	570,593	961,448	864,018	11%
5	D.P. Vermillion Senior Vice President	304,039	164,455	645,817	1,114,311	996,337	12%

Other compensation includes stock-based awards and the change in pension and non-qualified deferred compensation.

BALANCE SHEET

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	3,678,969,028	3,871,949,346	-5%
4	101.1 Property Under Capital Leases	7,203,329	7,203,329	
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use	2,218,041	4,764,240	-53%
8	106 Completed Constr. Not Classified - Electric			
9	107 Construction Work in Progress - Electric	60,766,153	78,182,229	-22%
10	108 (Less) Accumulated Depreciation	(1,238,948,043)	(1,305,984,420)	5%
11	111 (Less) Accumulated Amortization	(24,281,139)	(27,227,740)	11%
12	114 Electric Plant Acquisition Adjustments	22,027,941		#DIV/0!
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(21,600,847)		#DIV/0!
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	2,486,354,463	2,628,886,984	-5%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	5,403,010	6,021,869	-10%
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(908,291)	(915,043)	1%
20	123 Investments in Associated Companies	12,047,000	12,047,000	
21	123.1 Investments in Subsidiary Companies	77,733,569	71,971,368	8%
22	124 Other Investments	21,346,633	18,889,385	13%
23	128 Other Special Funds	12,397,507	13,288,292	-7%
	Long-Term Derivative Instruments	15,260,734	184,929	8152%
24	**TOTAL Other Property & Investments**	143,280,162	121,487,800	18%
25				
26	**Current & Accrued Assets**			
27	131 Cash	1,722,379	945,496	82%
28	132-134 Special Deposits	7,981,895	22,215,906	-64%
29	135 Working Funds	762,784	861,010	-11%
30	136 Temporary Cash Investments	17,455,810	60,913	28557%
31	141 Notes Receivable	226,712	283,666	-20%
32	142 Customer Accounts Receivable	197,906,612	173,557,636	14%
33	143 Other Accounts Receivable	8,919,486	7,943,467	12%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(3,846,839)	(4,498,489)	14%
35	145 Notes Receivable - Associated Companies			
36	146 Accounts Receivable - Associated Companies	211,095	29,252	622%
37	151 Fuel Stock	6,288,853	4,248,389	48%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	23,335,143	21,746,205	7%
41	155 Merchandise			
42	156 Other Material & Supplies			
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed			
	164 Gas Storage	17,242,935	23,609,470	-27%
45	165 Prepayments	10,754,149	16,554,560	-35%
46	171 Interest & Dividends Receivable		85,059	-100%
47	172 Rents Receivable	1,488,593	1,568,627	-5%
48	174 Miscellaneous Current & Accrued Assets	213,064	254,324	-16%
	176 Derivative Instruments Assets - Hedges	18,095,937	1,356,071	1234%
49	Long-Term Derivative Instruments	(15,260,734)	(184,929)	-8152%
50	**TOTAL Current & Accrued Assets**	293,497,874	270,636,633	8%

BALANCE SHEET

Year: 2011

	Account Number & Title		This Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	12,854,887	14,332,877	-10%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	182.3	Other Regulatory Assets	429,832,794	524,250,326	
10	183	Prelim. Survey & Investigation Charges	3,946,461	4,180,937	-6%
11	184	Clearing Accounts			
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	17,414,947	34,001,379	-49%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	25,454,075	23,830,734	7%
17	190	Accumulated Deferred Income Taxes	119,988,041	153,408,420	-22%
	191	Unrecovered Purchased Gas Costs	(22,074,296)	(12,140,283)	
18		**TOTAL Deferred Debits**	587,416,909	741,864,390	-21%
19					
20		**TOTAL Assets & Other Debits**	3,510,549,408	3,762,875,807	-7%

	Account Title		This Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	805,656,943	832,413,930	-3%
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	15,798,128	11,686,949	35%
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	6,137,359	11,086,810	-45%
33	215	Appropriated Retained Earnings	326,861,303	364,536,285	-10%
34	216	Unappropriated Retained Earnings	(24,343,433)	(28,386,302)	14%
35	217	(Less) Reacquired Capital Stock			
	219	Accumulated Other Comprehensive Income	(4,325,953)	(5,636,826)	
36		**TOTAL Proprietary Capital**	1,125,784,347	1,185,700,846	-5%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	1,098,148,636	1,257,171,208	-13%
41	222	(Less) Reacquired Bonds		(83,700,000)	100%
42	223	Advances from Associated Companies	51,547,000	51,547,000	
43	224	Other Long Term Debt			
44	225	Unamortized Premium on Long Term Debt	222,084	213,200	4%
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(2,013,529)	(1,838,814)	-10%
46		**TOTAL Long Term Debt**	1,147,904,191	1,223,392,594	-6%

Company Name: Avista Corporation

BALANCE SHEET

Year: 2011

	Account Number & Title		This 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	4,974,661	4,749,777	5%
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	2,684,975	3,235,000	-17%
9	228.3	Accumulated Provision for Pensions & Benefits	161,188,441	246,176,609	-35%
10	228.4	Accumulated Misc. Operating Provisions			
11		Long-Term Derivative Instruments	31,037,217	43,172,136	-28%
	230	Asset Retirement Obligations	3,887,409	3,512,818	
12		**TOTAL Other Noncurrent Liabilities**	203,772,703	300,846,340	-32%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	110,000,000	61,000,000	80%
17	232	Accounts Payable	121,798,025	98,160,779	24%
18	233	Notes Payable to Associated Companies	7,374,317	1,866,383	295%
19	234	Accounts Payable to Associated Companies	866,285	709,883	22%
20	235	Customer Deposits	7,958,557	8,868,640	-10%
21	236	Taxes Accrued	(397,450)	8,292,344	-105%
22	237	Interest Accrued	11,290,059	11,797,709	-4%
23	238	Dividends Declared			
24	241	Tax Collections Payable	32,330	104,101	-69%
25	242	Miscellaneous Current & Accrued Liabilities	52,383,017	55,333,088	-5%
26	243	Obligations Under Cap. Leases - Current	195,575	224,884	-13%
27	245	Derivative Instrument Liabilities - Hedges	82,526,148	130,248,787	-37%
28		Long-Term Derivative Instruments	(31,037,216)	(43,172,136)	28%
29		**TOTAL Current & Accrued Liabilities**	362,989,647	333,434,462	9%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,089,208	947,213	15%
34	253	Other Deferred Credits	17,050,733	10,400,886	64%
35	254	Other Regulatory Liabilities	31,545,561	26,584,147	19%
36	255	Accumulated Deferred Investment Tax Credits	7,842,362	20,939,852	-63%
37	257	Unamortized Gain on Reacquired Debt	2,655,731	2,484,655	7%
38	281-283	Accumulated Deferred Income Taxes	609,914,925	658,144,812	-7%
39		**TOTAL Deferred Credits**	670,098,520	719,501,565	-7%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		3,510,549,408	3,762,875,807	-7%

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, except Spokane Energy, LLC (Spokane Energy). Avista Capital's subsidiaries include Ecova, Inc. (Ecova), formerly Advantage IQ, Inc. (Advantage IQ), a 79.2 percent owned subsidiary as of December 31, 2011. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America.

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 accounting principles generally accepted in the United States of America (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 accounting principles generally accepted in the United States of America (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 Federal Energy Regulatory Commission (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 primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Operating Revenues
Revenues related to the sale of energy are 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 the following amounts as of December 31 (dollars in thousands):

	2011	2010
Unbilled accounts receivable	$82,950	$84,073

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2011 and 2010.

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 as follows for the years ended December 31:

	2011	2010
Ratio of depreciation to average depreciable property	2.92%	2.84%

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

- electric thermal production - 33 years,
- hydroelectric production - 74 years,
- electric transmission - 51 years,
- electric distribution - 38 years, and
- natural gas distribution property - 49 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 the following amounts for the years ended December 31 (dollars in thousands):

	2011	2010
Utility taxes	$55,739	$49,953

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. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited against total interest expense in the Statements of Income. The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable 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 does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2011	2010
Effective AFUDC rate	7.91%	8.25% (1)

(1) Rate was effective from January 1, 2010 to November 30, 2010. Effective December 1, 2010, rate was changed to 7.91%.

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 from 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 and recorded over the requisite service period.

See Note 16 for further information.

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.

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. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Derivative Assets and Liabilities
Derivatives are recorded as either assets or liabilities on the Balance Sheets 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 Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (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. Regulatory assets are assessed regularly and are probable for recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are 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.

Fair Value Measurements
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. 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. See Note 14 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits
The Company prepares its financial statements in accordance with regulatory accounting practices 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.

Regulatory accounting practices require 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 regulatory accounting practices 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.

See Note 19 for further details of regulatory assets and liabilities.

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 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 that began 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 Washington 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.

Contingencies
The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

NOTE 2. NEW ACCOUNTING STANDARDS

In May 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU will require enhanced disclosures for fair value measurements, including quantitative sensitivity analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB's intent about the application of existing fair value measurement requirements. The Company will be required to adopt this ASU effective January 1, 2012. The Company does not expect that this ASU will have material impact on its financial condition, results of operations and cash flows.

NOTE 3. ECOVA ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova (formerly Advantage IQ) common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These rights were not exercised during July 2011. These redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion.

On December 31, 2010, Ecova acquired substantially all of the assets and liabilities of The Loyalton Group (Loyalton), a Minneapolis-based energy management firm providing energy procurement and price risk management solutions.

In January 2011, Ecova acquired substantially all of the assets and liabilities of Building Knowledge Networks, LLC (BKN), a Seattle-based real-time building energy management services provider.

On November 30, 2011, Ecova acquired all of the capital stock of Prenova, Inc. (Prenova), an Atlanta-based energy management company.

In January 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company.

NOTE 4. 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 members of management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on 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 30 minutes up to multiple years.

Avista Corp. makes continuing projections of:

- electric loads at various points in time (ranging from 30 minutes 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 and fuel delivery capacity contracts.

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 including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. 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 natural gas supply requirements unhedged for purchase in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- optimization of interstate pipeline transportation capacity not needed to serve daily load, and
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2011 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
2012	1,021	2,181	39,547	78,575	613	1,398	4,261	71,913
2013	398	1,874	11,742	61,357	254	1,781	1,532	52,817
2014	366	30	5,562	22,328	286	737	1,050	8,900
2015	379	-	2,635	1,502	286	-	-	-
2016	367	-	910	227	287	-	-	-
Thereafter	949	-	-	-	730	-	-	-

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. Avista Corp. economically hedges a portion of the foreign currency risk by purchasing Canadian currency contracts 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. The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):

	2011	2010
Number of contracts	28	29
Notional amount (in United States dollars)	$7,033	$10,916
Notional amount (in Canadian dollars)	7,192	10,989
Derivatives amount	32	116

Interest Rate Swap Agreements

Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances. The following table summarizes the interest rate swaps that the Company has entered into as of December 31 (dollars in thousands):

	2011	2010
Number of contracts	3	2
Notional amount	$75,000	$50,000
Mandatory cash settlement date	July 2012	July 2012
Number of contracts	2	-
Notional amount	$85,000	-
Mandatory cash settlement date	June 2013	-
Derivative asset	-	127
Derivative liability	(18,895)	(53)

In September 2011, the Company cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds (see Note 11). Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2011 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument assets - Hedges	$ 32	$ -	$ 32
Interest rate contracts	Derivative instrument liabilities – Hedges	-	(16,253)	(16,253)
Interest rate contracts	Long-term portion of derivative instrument liabilities - Hedges	-	(2,642)	(2,642)
Commodity contracts	Derivative instrument assets current	1,618	(479)	1,139
Commodity contracts ...	Long-term portion of derivative assets	185	-	185
Commodity contracts	Derivative instrument liabilities current	40,090	(110,914)	(70,824)
Commodity contracts	Long-term portion of derivative instrument liabilities	44,308	(84,838)	(40,530)
Total derivative instruments recorded on the balance sheet		$86,233	$(215,126)	$(128,893)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2010 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument assets - Hedges	$ 116	$ -	$ 116
Interest rate contracts	Derivative instrument liabilities – Hedges	127	-	127
Interest rate contracts	Long-term portion of derivative instrument liabilities - Hedges	-	(53)	(53)
Commodity contracts	Derivative instrument assets current	6,293	(3,701)	2,592
Commodity contracts ...	Long-term portion of derivative assets	21,249	(5,988)	15,261
Commodity contracts	Derivative instrument liabilities current	5,934	(57,417)	(51,483)
Commodity contracts	Long-term portion of derivative instrument liabilities	1,386	(32,371)	(30,985)
Total derivative instruments recorded on the balance sheet		$35,105	$(99,530)	$(64,425)

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 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 mitigate capital requirements. As of December 31, 2011, the Company had cash deposited as collateral of $18.2 million and letters of credit of $18.8 million outstanding related to its energy derivative contracts.

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, 2011 was $154.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, the Company could be required to post $61.3 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. 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 such counterparty.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty 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 transactions on exchanges with fully collateralized clearing arrangements that significantly reduce 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 and natural gas utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, 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 because the counterparties may be similarly affected by changes in conditions.

The Company maintains margin agreements with certain counterparties and margin calls are periodically made and/or received. 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. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 5. 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 and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2011	2010
Utility plant in service	$342,539	$336,796
Accumulated depreciation	(225,746)	(219,770)

NOTE 6. 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):

	2011	2010
Asset retirement obligation at beginning of year	$3,887	$3,971
New liability recognized	-	19
Liability settled	(612)	(460)
Accretion expense	238	357
Asset retirement obligation at end of year	$3,513	$3,887

NOTE 7. 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, date of hire 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 $26 million in cash to the pension plan in 2011 and $21 million in 2010. The Company expects to contribute $44 million in cash to the pension plan in 2012.

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 (dollars in thousands):

	2012	2013	2014	2015	2016	Total 2017-2021
Expected benefit payments	$20,484	$21,899	$23,189	$24,759	$26,100	$154,146

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.

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 20 years, beginning in 1993.

The Company has 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 the employee's 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 total (dollars in thousands):

	2012	2013	2014	2015	2016	Total 2017-2021
Expected benefit payments	$5,277	$5,390	$5,523	$5,735	$5,946	$32,231

The Company expects to contribute $5.3 million to other postretirement benefit plans in 2012, 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, 2011 and 2010 and the components of net periodic benefit costs for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation as of beginning of year	$433,491	$378,235	$60,339	$39,560
Service cost	12,936	11,609	1,805	684
Interest cost	24,134	23,231	4,126	2,624
Actuarial loss	44,148	38,547	42,476	21,657
Transfer of accrued vacation	-	-	450	367
Benefits paid	(20,517)	(18,131)	(4,466)	(4,553)
Benefit obligation as of end of year	$494,192	$433,491	$104,730	$60,339
Change in plan assets:				
Fair value of plan assets as of beginning of year	$306,712	$272,732	$22,875	$20,394
Actual return on plan assets	14,705	29,846	(420)	2,481
Employer contributions	26,000	21,000	-	-
Benefits paid	(19,267)	(16,866)	-	-
Fair value of plan assets as of end of year	$328,150	$306,712	$22,455	$22,875
Funded status	$(166,042)	$(126,779)	$(82,275)	$(37,464)
Unrecognized net actuarial loss	192,883	149,819	76,187	35,149
Unrecognized prior service cost	665	1,140	(1,005)	(1,154)
Unrecognized net transition obligation	-	-	505	1,011
Prepaid (accrued) benefit cost	27,506	24,180	(6,588)	(2,458)
Additional liability	(193,548)	(150,959)	(75,687)	(35,006)
Accrued benefit liability	$(166,042)	$(126,779)	$(82,275)	$(37,464)
Accumulated pension benefit obligation	$429,135	$377,606	-	-
Accumulated postretirement benefit obligation:				
For retirees			$39,470	$27,921
For fully eligible employees			$29,597	$15,618
For other participants			$35,663	$16,800
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$ 328	$ 657
Unrecognized prior service cost	433	741	(653)	(750)
Unrecognized net actuarial loss	125,374	97,382	49,522	22,847
Total	125,807	98,123	49,197	22,754
Less regulatory asset	(119,360)	(92,570)	(49,873)	(23,981)
Accumulated other comprehensive loss (income)	$6,447	$5,553	$(676)	$(1,227)

Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	5.04%	5.69%	4.98%	5.50%
Discount rate for annual expense	5.68%	6.28%	5.53%	6.00%
Expected long-term return on plan assets	7.40%	7.75%	7.00%	7.75%
Rate of compensation increase	4.87%	4.72%		
Medical cost trend pre-age 65 – initial			7.50%	8.00%
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			8.00%	8.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2018	2015
	2011	2010	2011	2010
Components of net periodic benefit cost:				
Service cost	$12,936	$11,609	$1,805	$ 684
Interest cost	24,134	23,231	4,126	2,624
Expected return on plan assets	(23,115)	(21,381)	(1,601)	(1,581)
Transition obligation recognition	-	-	505	505
Amortization of prior service cost	475	650	(149)	(149)
Net loss recognition	9,493	7,189	3,458	1,379
Net periodic benefit cost	$23,923	$21,298	$8,144	$3,462

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 benefit plans 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 indicated in the table below:

	2011	2010
Equity securities	51%	51%
Debt securities	31%	31%
Real estate	5%	5%
Absolute return	10%	10%
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:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The market-related value of pension plan assets was determined as of December 31, 2011 and 2010.

The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ -	$ 7,550	$ -	$ 7,550
Mutual funds:				
Fixed income securities	76,486	-	-	76,486
U.S. equity securities	102,790	-	-	102,790
International equity securities	52,241	-	-	52,241
Absolute return (1)	16,121	-	-	16,121
Commodities (2)	6,526	-	-	6,526
Common/collective trusts:				
Fixed income securities	-	27,774	-	27,774
U.S. equity securities	-	12,669	-	12,669
Real estate	-	-	8,598	8,598
Partnership/closely held investments:				
Absolute return (1)	-	-	16,587	16,587
Private equity funds (3)	-	-	808	808
Total	$254,164	$47,993	$25,993	$328,150

The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 335	$ -	$ -	$ 335
Mutual funds:				
Fixed income securities	96,026	-	-	96,026
U.S. equity securities	104,232	-	-	104,232
International equity securities	53,964	-	-	53,964
Absolute return (1)	12,662	-	-	12,662
Commodities (2)	7,133	-	-	7,133
Common/collective trusts:				
U.S. equity securities	-	13,653	-	13,653
Absolute return (1)	-	-	95	95
Real estate	-	-	423	423
Partnership/closely held investments:				
Absolute return (1)	-	-	16,917	16,917
Private equity funds (3)	-	-	1,272	1,272
Total	$274,352	$13,653	$18,707	$306,712

(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 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, 2011 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2011	$ 95	$ 423	$16,917	$1,272
Realized gains (losses)	(748)	22	-	373
Unrealized gains (losses)	746	1,098	(330)	(218)
Purchases (sales), net	(93)	7,055	-	(619)
Balance, as of December 31, 2011	$ -	$8,598	$16,587	$808

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, 2010 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2010	$844	$6,029	$15,794	$1,561
Realized gains (losses)	(233)	630	-	(148)
Unrealized gains (losses)	(193)	(160)	1,123	(48)
Purchases (sales), net	(323)	(6,076)	-	(93)
Balance, as of December 31, 2010	$ 95	$ 423	$16,917	$1,272

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 target asset allocation was 62 percent equity securities and 38 percent debt securities in 2011 and 2010.

The market-related value of other postretirement plan assets was determined as of December 31, 2011 and 2010. The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ -	$ 86	$ -	$ 86
Mutual funds:				
Fixed income securities	8,683	-	-	8,683
U.S. equity securities	7,278	-	-	7,278
International equity securities	4,766	-	-	4,766
U.S. equity securities	1,569	-	-	1,569
Other	73	-	-	73
Total	$22,369	$ 86	$ -	$22,455

The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 118	$ -	$ -	$ 118
Mutual funds:				
Fixed income securities	8,320	-	-	8,320
U.S. equity securities	6,986	-	-	6,986
International equity securities	5,572	-	-	5,572
U.S. equity securities	1,785	-	-	1,785
Other	94	-	-	94
Total	$22,875	$ -	$ -	$22,875

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, 2011 by $14.8 million and the service and interest cost by $0.8 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, 2011 by $12.3 million and the service and interest cost by $0.7 million.

The Company has a salary deferral 401(k) plans that is a defined contribution plan and cover substantially all employees. Employees can make contributions to their respective accounts in the plan on a pre-tax basis up to the maximum amount permitted by law. The Company matches a portion of the salary deferred by each participant according to the schedule in the plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2011	2010
Employer 401(k) matching contributions	$5,452	$4,797

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. There were deferred compensation assets and corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2011	2010
Deferred compensation assets and liabilities	$8,653	$9,285

NOTE 8. 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, 2011, the Company had $12.4 million of state tax credit carryforwards. State tax credits expire from 2015 to 2025. 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 completed an examination of the Company's 2008, 2009 or 2010 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2011 or 2010.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2011	2010
Regulatory assets for deferred income taxes	$84,576	$90,025

NOTE 9. 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 were as follows for the years ended December 31 (dollars in thousands):

	2011	2010
Utility power resources	$557,619	$649,408

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):

	2012	2013	2014	2015	2016	Thereafter	Total
Power resources..........	$218,599	$157,401	$139,180	$116,184	$111,698	$1,037,268	$1,780,330
Natural gas resources...	134,047	102,923	87,926	72,632	54,475	639,790	1,091,793
Total	$352,646	$260,324	$227,106	$188,816	$166,173	$1,677,058	$2,872,123

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 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 following table details future contractual commitments for these agreements (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Contractual obligations.....	$29,103	$30,346	$30,891	$28,392	$32,528	$246,503	$397,763

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. Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):

	2011	2010
PUD contract costs	$10,533	$8,287

Information as of December 31, 2011 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	$ 2,017	$ 887	$ -	2011
Douglas County PUD:						
Wells Project.......................	3.4%	28,000	2,456	876	3,613	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects................	3.3%	65,800	6,060	2,203	30,263	2055
Totals...........................		130,800	$10,533	$3,966	$33,876	

(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 2011. Debt service costs are included in annual costs.

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):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments	$3,337	$3,332	$3,305	$3,195	$3,106	$44,835	$61,110

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

NOTE 10. NOTES PAYABLE

In February 2011, Avista Corp. entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced its $320.0 million and $75.0 million committed lines of credit. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and revise the pricing terms.

The committed line of credit is secured by 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 agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2011, the Company was in compliance with this covenant.

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 December 31 (dollars in thousands):

	2011	2010
Balance outstanding at end of period	$61,000	$110,000
Letters of credit outstanding at end of period	$29,030	$ 27,126
Average interest rate at end of period	1.12%	0.57%

NOTE 11. BONDS

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

Maturity Year	Description	Interest Rate	2011	2010
2012	Secured Medium-Term Notes	7.37%	$ 7,000	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000
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
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	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 (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds (3)	4.45%	85,000	-
	Total secured long-term debt		1,263,700	1,178,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Settled interest rate swaps		(10,629)	(951)
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Total bonds		$1,173,471	$1,098,149

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(2) In December 2010, $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, (Avista Corporation Colstrip Project) due 2034, which had been held by Avista Corp. since 2009, were refunded by a new bond issue (Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, the bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(3) In December 2011, the Company issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041.

The following table details future long-term debt maturities including advances from associated companies (see Note 12) (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Debt maturities	$7,000	$50,000	$ -	$ -	$ -	$1,178,647	$1,235,647

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) 66-2/3 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. However, 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, 2011, property additions and retired bonds would have allowed the Company to issue $727.1 million in aggregate principal amount of additional First Mortgage Bonds.

See Note 10 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed line of credit agreement.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

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 distribution rates paid were as follows during the years ended December 31:

	2011	2010
Low distribution rate	1.13%	1.13%
High distribution rate..	1.40	1.41
Distribution rate at the end of the year	1.40	1.17

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 owns 100 percent of Avista Capital II and has solely and unconditionally 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 13. 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 as follows for the years ended December 31 (dollars in thousands):

	2011	2010
Rental expense..	$2,853	$2,885

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2011 were as follows (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments required.......	$1,412	$1,259	$1,260	$437	$131	$2,367	$6,866

NOTE 14. FAIR VALUE

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 (dollars in thousands):

	2011		2010	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds	$1,184,100	$1,369,763	$1,099,100	$1,139,765
Advances from associated companies	51,547	43,810	51,547	37,114

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

The fair value hierarchy 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.

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, 2011 and 2010 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ -	$80,571	$5,630	$(84,877)	$1,324
Foreign currency derivatives	-	32	-	-	32
Deferred compensation assets:					
Fixed income securities	2,116	-	-	-	2,116
Equity securities	5,252	-	-	-	5,252
Total	$7,368	$80,603	$5,630	$(84,877)	$8,724
Liabilities:					
Energy commodity derivatives	$ -	$177,743	$18,488	$(84,877)	$111,354
Interest rate swaps	-	18,895	-	-	18,895
Total	$ -	$196,638	$18,488	$(84,877)	$130,249

December 31, 2010					
Assets:					
Energy commodity derivatives	$ -	$15,124	$19,739	$(17,010)	$ 17,853
Interest rate swaps	-	127	-	-	127
Foreign currency derivatives	-	116	-	-	116
Deferred compensation assets:					
Fixed income securities	1,854	-	-	-	1,854
Equity securities	6,211	-	-	-	6,211
Total	$8,065	$15,367	$19,739	$(17,010)	$26,161
Liabilities:					
Energy commodity derivatives	$ -	$93,198	$6,280	$(17,010)	$82,468
Interest rate swaps	-	53	-	-	53
Total	$ -	$93,251	$6,280	$(17,010)	$82,521

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists.

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 4 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 $1.3 million as of December 31, 2011 and $1.2 million as of December 31, 2010.

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	
	2011	2010	2011	2010
Balance as of January 1	$19,739	$57,276	$(6,280)	$(7,806)
Total gains or losses (realized/unrealized):				
Included in net income	-	-	-	-
Included in other comprehensive income	-	-	-	-
Included in regulatory assets/liabilities (1)	(14,084)	(34,943)	(10,792)	1,209
Purchases	-	-	-	-
Issuance	-	-	-	-
Settlements	(25)	(2,594)	2,988	317
Transfers to other categories (2)	-	-	(4,404)	-
Ending balance as of December 31	$5,630	$19,739	$(18,488)	$(6,280)

(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.

(2) A derivative contract was reclassified from Level 2 to Level 3 during 2011 due to a particular unobservable input becoming more significant to the fair value measurement.

NOTE 15. 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 August 2010, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 3,087,500 shares of its common stock from time to time.

Shares issued under sales agency agreements were as follows in the years ended December 31:

	2011	2010
Shares issued under sales agency agreement	807,000	2,054,110

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2011 and 2010.

NOTE 16. 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 4.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2011, 0.2 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, 2011, 1.8 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 (included in other operating expenses) and income tax benefits in the Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2011	2010
Stock-based compensation expense	$5,756	$4,916
Income tax benefits	2,014	1,720

Stock Options

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

	2011	2010
Number of shares under stock options:		
Options outstanding at beginning of year	201,674	523,973
Options granted	-	-
Options exercised	(107,575)	(101,649)
Options canceled	(1,600)	(220,650)
Options outstanding and exercisable at end of year	92,499	201,674
Weighted average exercise price:		
Options exercised	$12.25	$11.51
Options canceled	$11.80	$22.60
Options outstanding and exercisable at end of year	$10.69	$11.53
Cash received from options exercised (in thousands)	$1,318	$2,179
Intrinsic value of options exercised (in thousands)	$1,279	$1,006
Intrinsic value of options outstanding (in thousands)	$1,393	$2,217

Information for options outstanding and exercisable as of December 31, 2011 is as follows:

Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17	80,499	$10.17	0.85
$12.41	6,000	12.41	1.35
$15.88	6,000	15.88	0.36
Total	92,499	$10.69	0.85

As of December 31, 2011 and 2010, 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, 2011 was 0.7 years. The following table summarizes restricted stock activity for the years ended December 31:

	2011	2010
Unvested shares at beginning of year	84,134	71,904
Shares granted	50,618	43,800
Shares cancelled	(431)	-
Shares vested	(40,839)	(31,570)
Unvested shares at end of year	93,482	84,134
Weighted average fair value at grant date	$23.06	$19.80
Unrecognized compensation expense at end of year (in thousands).	$932	$735
Intrinsic value, unvested shares at end of year (in thousands)	$2,407	$1,895
Intrinsic value, shares vested during the year (in thousands)	$934	$682

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 for grants prior to 2011 and 0 to 200 percent for 2011 grants 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 for grants prior to 2011 and 0 to 200 percent for shares granted in 2011. 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:

	2011	2010
Risk-free interest rate	1.2%	1.4%
Expected life, in years	3	3
Expected volatility	26.9%	27.8%
Dividend yield	4.7%	4.6%
Weighted average grant date fair value (per share)	$20.79	$15.30

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

The following summarizes performance share activity:

	2011	2010
Opening balance of unvested performance shares	325,700	300,601
Performance shares granted	184,600	168,700
Performance shares canceled	(2,177)	-
Performance shares vested	(156,778)	(143,601)
Ending balance of unvested performance shares	351,345	325,700
Intrinsic value of unvested performance shares (in thousands)	$9,047	$7,335
Unrecognized compensation expense (in thousands)	$2,991	$2,330

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2011 was 1.5 years. Unrecognized compensation expense as of December 31, 2011 will be recognized during 2012 and 2013. The following summarizes the impact of the market condition on the vested performance shares:

	2011	2010
Performance shares vested	156,778	143,601
Impact of market condition on shares vested	(15,678)	21,540
Shares of common stock earned	141,100	165,141
Intrinsic value of common stock earned (in thousands)	$3,633	$3,719

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, 2011 and 2010, the Company had recognized compensation expense and a liability of $1.0 million and $0.9 million related to the dividend component of performance share grants.

NOTE 17. 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 all such matters, 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, 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 in the Trading Investigation and order denying rehearing requests, the Company does not expect that this proceeding will have any material 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 effect on its financial condition, results of operations or cash flows.

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. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

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. The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of "who owes what to whom." The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of December 31, 2011, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the 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 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. A FERC hearing on that issue is scheduled to commence in April 2012. A May 2011 FERC order denied a motion filed by Avista Energy and Avista Corp. asking that the companies be dismissed from any further proceedings involving alleged tariff violations under FPA section 309. Avista Energy and Avista Corp. sought rehearing of that ruling in June 2011. As noted above, in Docket No. EL02-115, Avista Energy and Avista Corp. were absolved of any wrongdoing related to allegations of tariff violations during 2000 and 2001 and have argued that the doctrines of *res judicata* and collateral estoppel preclude relitigation of the same issues. The California AG, the CPUC, PG&E and SCE also filed for rehearing of the FERC's May 2011 order, arguing that it improperly denies them a market-wide remedy for the pre-refund period. They also filed a petition for review of the May 2011 order with the Ninth Circuit.

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 would result in a material loss. 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.

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. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order establishes an evidentiary, trial-type hearing before an ALJ, and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations. A procedural schedule in this docket has not yet been set.

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, are subject to potential claims in this proceeding, and if refunds are ordered by the FERC with regard to any particular contract, could be liable to make payments. 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. 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.

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. 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.

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 were given the opportunity 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 March 2010, the Presiding Administrative Law Judge (ALJ) granted the motions for summary disposition and found that a hearing was "unnecessary" because the California AG, CPUC, PG&E and SCE "failed to apply the appropriate test to determine market power during the relevant time period." The judge determined that "[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case." In May 2011, the FERC affirmed "in all respects" the ALJ's decision. In June 2011, the California AG, CPUC, PG&E and SCE filed for rehearing of that order.

Based on information currently known to the Company's management, and the ALJ's granting of Avista Corp. and Avista Energy's summary disposition motion, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project Complaint

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. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011, the court issued an order, which enforces the settlement agreement. The plaintiffs have subsequently appealed the court's decision. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows. Although the final resolution of this complaint remains uncertain, based on information currently known to the Company's management, the Company does not expect this complaint will have a material effect on its financial condition, results of operations or cash flows.

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 draft final RI/FS was submitted to the EPA in December 2011. The actual cleanup, if any, will not occur until the RI/FS is finalized and approved by the EPA. 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. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

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) are regulated under one 50-year FERC license issued in June 2009 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 license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene 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.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, the DOE filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company has until May 27, 2012 to develop mitigation strategies to address the low levels of dissolved oxygen. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully identified or approved by the DOE. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The EPA and the Idaho Department of Environmental Quality (Idaho DEQ) are preparing draft National Pollutant Discharge Elimination System permits and the 401 Water Quality Certifications for the Idaho dischargers, respectively, which once issued will be released for a 30-day public comment period.

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 implementing the license for the Spokane River Project.

Cabinet Gorge Total Dissolved Gas Abatement Plan

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) to the 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 provided for the possible opening and modification of 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 an addendum to the GSCP. The GSCP addendum abandons the concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of different options to abate TDG. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures and determined that two alternatives will be considered for continued development. Further analysis and review of these alternatives is expected to be completed through at least the middle of 2012. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help 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 led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. In 2009, the Company selected a contractor to design a permanent upstream passage facility at Cabinet Gorge. The Company anticipates that the design and cost estimates will be completed by the end of 2012 with construction taking place in 2013 and 2014.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by the DOE as "Aluminum Recycling – Trentwood." Operators of the UPR property maintained piles of aluminum "black dross," which can be designated as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer 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, Pentzer received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a RI/FS Work Plan in June 2010. At that time, UPR requested a contribution from Pentzer towards the cost of performing the RI/FS and also an access agreement to investigate the material deposited on the Pentzer property. Pentzer concluded an access agreement with UPR in October 2010. UPR completed the RI/FS during the fourth quarter of 2011. Based on information currently known to the Company's management, the Company does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

Injury from Overhead Electric Line (Munderloh v. Avista)

On March 4, 2010, the plaintiff and his wife filed a complaint against Avista Corp. in Spokane County Superior Court. Plaintiffs alleged that while the plaintiff was employed by a third party as a laborer at their construction site, he came into contact with Avista Corp.'s electric line, was injured and suffered economic and non-economic damages. Plaintiffs further alleged that Avista Corp. was at fault for failing to relocate the overhead electric line which it controlled and operated adjacent to the construction site. In January 2012, Avista Corp. and its insurance provider reached a settlement with the plaintiffs. Avista Corp. has expensed its share of the settlement (including legal fees) of $2 million (which was recorded in 2010 and 2011).

Damages from Fire in Stevens County, Washington

In August 2010, a fire in Stevens County, Washington occurred during a wind storm. The apparent cause of the fire may be a tree located outside of Avista Corp.'s right-of-way that came in contact with an electric line owned by Avista Corp. The fire area is a rural farm and timber landscape. The fire destroyed two residences and six outbuildings. The Company is not aware of any personal injuries resulting from the fire. Although no lawsuits have been filed, Avista Corp. has received several claims and it is possible that additional claims may be made and lawsuits may be filed against the Company. The Company has expensed its estimated liability for this matter, which was not material to its financial condition, results of operations or cash flows. Based on information currently known to the Company's management, the Company does not expect this complaint will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents 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 in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expired in April 2010. New agreements were reached in December 2010 (expiring in March 2014).

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 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 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 either have or have not agreed to a settlement as well as 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. For matters that affect Avista Corp.'s operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

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, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

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 adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated an adjudication in northern Idaho, which will ultimately include 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 and will continue to be a participant in these adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time.

NOTE 18. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. 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. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2011	2010
Information service contract payments	$13,038	$13,426

The majority of the costs are included in other operating expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.0 million in 2012, $10.5 million in 2013, $8.0 million in 2014, and $7.0 million in each of 2015, 2016 and 2017.

NOTE 19. 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 Energy Recovery Mechanism (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, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $12.9 million as of December 31, 2011.

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 Power Costs Adjustment (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. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory liability of $0.7 million as of December 31, 2011 and a regulatory asset of $18.3 million as of December 31, 2010.

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, 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 $12.1 million as of December 31, 2011 and $22.1 million as of December 31, 2010.

Washington General Rate Cases

In November 2010, the WUTC approved an all-party settlement stipulation in the Company's general rate case filed in March 2010. As agreed to in the settlement stipulation, electric rates for the Company's Washington customers increased by an average of 7.4 percent, which was designed to increase annual revenues by $29.5 million. Natural gas rates for the Company's Washington customers increased by an average of 2.9 percent, which was designed to increase annual revenues by $4.6 million. The new electric and natural gas rates became effective on December 1, 2010.

In December 2011, the WUTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for the Company's Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012.

As part of the settlement agreement, the Company agreed to not file a general rate case in Washington prior to April 1, 2012.

The settlement agreement also provides for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, the Company is deferring changes in maintenance costs related to its Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. The Company compares actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defers the difference. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, the Company deferred $0.5 million of maintenance costs in Washington.

Idaho General Rate Cases
In September 2010, the IPUC approved a settlement agreement in the Company's general rate case filed in March 2010. The new electric and natural gas rates became effective on October 1, 2010. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 9.3 percent, which was designed to increase annual revenues by $21.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The 2010 settlement agreement includes a rate mitigation plan under which the impact on customers of the new rates will be reduced by amortizing $11.1 million ($17.5 million when grossed up for income taxes and other revenue-related items) of previously deferred state income taxes over a two-year period as a credit to customers. While the Company's cash collections from customers will be reduced by this amortization during the two-year period, the mitigation plan will have no impact on the Company's net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the deferred state income tax balance is amortized.

In September 2011, the IPUC approved a settlement agreement in the Company's general rate case filed in July 2011. The new electric and natural gas rates became effective on October 1, 2011. As agreed to in the settlement agreement, base electric rates for the Company's Idaho customers increased by an average of 1.1 percent, which was designed to increase annual revenues by $2.8 million. Base natural gas rates for the Company's Idaho customers increased by an average of 1.6 percent, which was designed to increase annual revenues by $1.1 million.

As part of the settlement agreement, the Company agreed to not seek to make effective a change in base electric or natural gas rates prior to April 1, 2013, by means of a general rate case filing. This does not preclude the Company from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. The Company compares actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, the Company deferred $0.1 million of operation and maintenance costs in Idaho.

Oregon General Rate Cases
In March 2011, the OPUC approved an all-party settlement stipulation in the Company's general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for the Company's Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million will occur on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects upon a demonstration that such projects are complete and the costs were prudently incurred.

NOTE 20. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2011	2010
Cash paid for interest	$63,876	$68,638
Cash paid for income taxes	$16,631	$10,641

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	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	143,881	143,881	
7					
8		**TOTAL Intangible Plant**	6,366,329	6,366,329	
9					
10		**Production Plant**			
11					
12	Steam Production				
13					
14	310	Land & Land Rights	1,289,096	1,289,096	
15	311	Structures & Improvements	100,185,043	100,708,158	-1%
16	312	Boiler Plant Equipment	127,014,582	128,357,934	-1%
17	313	Engines & Engine Driven Generators		6,770	-100%
18	314	Turbogenerator Units	34,972,897	37,911,160	-8%
19	315	Accessory Electric Equipment	16,095,836	16,256,091	-1%
20	316	Miscellaneous Power Plant Equipment	13,051,248	13,298,287	-2%
21	317	Asset Retirement Costs	134,588	134,588	
22		**TOTAL Steam Production Plant**	292,743,290	297,962,084	-2%
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	43,434,224	-1%
38	331	Structures & Improvements	14,472,200	15,318,238	-6%
39	332	Reservoirs, Dams & Waterways	33,618,604	33,618,016	0%
40	333	Water Wheels, Turbines & Generators	75,262,908	80,790,665	-7%
41	334	Accessory Electric Equipment	14,201,209	14,201,209	
42	335	Miscellaneous Power Plant Equipment	3,398,617	3,398,617	
43	336	Roads, Railroads & Bridges	225,369	225,369	
44					
45		**TOTAL Hydraulic Production Plant**	184,047,254	190,986,338	-4%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	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**	476,790,544	488,948,422	-2%
17				
18	**Transmission Plant**			
19				
20	350 Land & Land Rights	1,163,893	1,356,392	-14%
21	352 Structures & Improvements	477,507	477,507	
22	353 Station Equipment	23,159,386	28,646,016	-19%
23	354 Towers & Fixtures	16,065,112	16,065,112	
24	355 Poles & Fixtures	7,226,665	7,226,665	
25	356 Overhead Conductors & Devices	15,792,122	15,791,654	0%
26	357 Underground Conduit			
27	358 Underground Conductors & Devices			
28	359 Roads & Trails	367,476	367,476	
29				
30	**TOTAL Transmission Plant**	64,252,161	69,930,822	-8%
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	34,907	34,907	
39	365 Overhead Conductors & Devices	10,038	10,038	
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**	215,190	215,190	

Company Name: Avista Corporation

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	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	202,052	213,676	-5%
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment	23,332	178,522	-87%
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	49,006	61,556	-20%
12	397 Communication Equipment	689,658	803,205	-14%
13	398 Miscellaneous Equipment		4,784	-100%
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	964,048	1,261,743	
17				
18	**TOTAL Electric Plant in Service**	548,588,272	566,722,506	

MONTANA DEPRECIATION SUMMARY

Year: 2011

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production	297,962,084	198,212,337	203,380,896	N/A
3	Nuclear Production				
4	Hydraulic Production	190,986,338	28,227,509	26,010,013	N/A
5	Other Production				
6	Transmission	69,930,822	21,487,098	23,280,713	N/A
7	Distribution	215,190	65,131	64,632	N/A
8	General		3,299,395	2,607,785	N/A
9	**TOTAL**	559,094,434	251,291,470	255,344,039	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	846,761	1,875,430	-55%
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)	2,059,775	2,216,970	-7%
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**	2,906,536	4,092,400	-29%

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: 2011

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	92,424,689	100,223,872	-8%
6	Depreciation	103,004,297	105,727,999	-3%
7	Amortization	(2,930,465)	28,936,761	-110%
8	Deferred Income Taxes - Net	36,084,184	21,115,803	71%
9	Investment Tax Credit Adjustments - Net	2,209,854	2,558,524	-14%
10	Change in Operating Receivables - Net	(11,666,672)	3,428,347	-440%
11	Change in Materials, Supplies & Inventories - Net	(11,466,814)	(2,737,133)	-319%
12	Change in Operating Payables & Accrued Liabilities - Net	(1,486,305)	(1,250,437)	-19%
13	Allowance for Funds Used During Construction (AFUDC)	(3,352,964)	(2,224,987)	-51%
14	Change in Other Assets & Liabilities - Net	(14,223,435)	(22,034,496)	35%
15	Other Operating Activities (explained on attached page)	(1,093,360)	(4,979,393)	78%
16	**Net Cash Provided by/(Used in) Operating Activities**	187,503,009	228,764,860	-18%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(206,800,158)	(240,025,802)	14%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	592,582		#DIV/0!
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	523,909		#DIV/0!
25	Disposition of Investments in and Advances to Affiliates		(5,482,493)	100%
26	Other Investing Activities (explained on attached page)	5,996,411	15,173,592	-60%
27	**Net Cash Provided by/(Used in) Investing Activities**	(199,687,256)	(230,334,703)	13%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	136,365,000	85,000,000	60%
32	Preferred Stock			
33	Common Stock	46,235,329	26,462,920	75%
34	Long-Term Debt to Affiliated Trusts			
35	Net Increase in Short-Term Debt	23,000,000		#DIV/0!
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(110,129,764)	(195,575)	-56211%
39	Preferred Stock			
40	Common Stock			
41	Long-Term Debt to Affiliated Trusts			
42	Net Decrease in Short-Term Debt		(49,000,000)	100%
43	Dividends on Preferred Stock			
44	Dividends on Common Stock	(55,682,173)	(63,736,957)	13%
45	Other Financing Activities (explained on attached page)	(11,626,275)	(15,034,097)	23%
46	**Net Cash Provided by (Used in) Financing Activities**	28,162,117	(16,503,709)	271%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	15,977,870	(18,073,552)	188%
49	**Cash and Cash Equivalents at Beginning of Year**	3,963,103	19,940,973	-80%
50	**Cash and Cash Equivalents at End of Year**	19,940,973	1,867,421	968%

Company Name: Avista Corp. SCHEDULE 23A

STATEMENT OF CASH FLOWS

Year: 2011

	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	(122,377)	-	
4				
5	Change in allowance for uncollectible receivables	136,069	651,650	-79%
6	Regulatory Gas Cost and Power Cost Adjustment	1,383,294	193,076	616%
7	Non-cash stock compensation	3,602,646	4,147,207	
8	Subsidiary earnings	(6,092,992)	(9,971,326)	39%
9	Total Line 15	(1,093,360)	(4,979,393)	78%
10				
11	**Line 26: Other Investing Activities**			
	Federal grant payments received	7,585,367	16,927,752	
	Changes in other property and investments	(1,588,956)	(1,754,160)	
12	Notes receivable	-	-	
13	Total Line 26	5,996,411	15,173,592	
10	**Line 45: Other Financing Activities**			
	Cash received (paid) in interest rate swap agreement	-	(10,557,000)	
11	Premiums paid for repurchase of debt	(10,710,164)	-	
12	Debt Issuance costs	(916,111)	(4,477,097)	
13	Total Line 45	(11,626,275)	(15,034,097)	

LONG TERM DEBT

Year: 2011

	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	43,000,000	8.87%	3,815,261	8.87%
4									
5	Pollution Control Bonds								
6									
7	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%
8	Colstrip 2010A PCRBs due 2032	12/15/10	10/1/32	66,700,000	66,700,000	66,700,000			
9	Colstrip 2010B PCRBs due 2034	12/15/10	3/1/34	17,000,000	17,000,000	17,000,000			
10	Reacquired Bonds Colstrip 2010A			(66,700,000)	(66,700,000)	(66,700,000)			
11	Reacquired Bonds Colstrip 2010B			(17,000,000)	(17,000,000)	(17,000,000)			
12									
13									
14	First Mortgage Bonds								
15	6.37% Issued June 1998	6/19/98	6/19/28	25,000,000	24,653,047	25,000,000	6.48%	1,618,863	6.48%
16	5.45% Issued November 2004	11/18/04	12/1/19	90,000,000	88,975,000	90,000,000	5.61%	5,047,001	5.61%
17	6.25% Issued Nov/Dec 2005	11/17/05	12/1/35	150,000,000	147,937,500	150,000,000	6.22%	9,332,891	6.22%
18	5.70% Issued Dec 2006	12/15/06	7/1/37	150,000,000	145,687,500	150,000,000	6.14%	9,216,608	6.14%
19	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%
20	5.125% Issued Sept 2009	9/22/09	4/1/22	250,000,000	257,701,222	250,000,000	4.91%	12,268,615	4.91%
21	1.69% Issued Dec. 2010	12/30/10	12/30/13	50,000,000	49,703,628	50,000,000	1.89%	945,329	1.89%
22	3.89% Issued Dec. 2010	12/20/10	12/20/20	52,000,000	45,350,468	52,000,000	5.58%	2,900,325	5.58%
23	5.55% Issued Dec. 2010	12/20/10	12/20/40	35,000,000	29,483,191	35,000,000	6.79%	2,375,362	6.79%
24	5.55% Issued Dec. 2011	12/14/11	12/14/41	85,000,000	73,760,229	85,000,000	5.34%	4,538,120	5.34%
25									
26	Junior Subordinated Debentures	6/3/97	6/1/37	51,547,000	36,828,822	51,547,000	0.99%	508,447	0.99%
27									
28									
29									
30									
31									
32	**TOTAL**			1,442,647,000	1,381,817,538	1,235,647,000		70,419,615	5.70%

Company Name: Avista Corporation

SCHEDULE 25

PREFERRED STOCK

Year: 2011

	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: 2011

		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	57,342,000	20.14	0.73	0.275		23.69	21.78	
9									
10	April								
11									
12	May								
13									
14	June	57,787,000	20.15	0.39	0.275		25.83	22.81	
15									
16	July								
17									
18	August								
19									
20	September	58,057,000	20.12	0.18	0.275		26.53	21.13	
21									
22	October								
23									
24	November								
25									
26	December	58,304,000	20.30	0.42	0.275		26.35	23.14	
27									
28									
29									
30									
31									
32	TOTAL Year End	58,423,000	20.30	1.72	1.1	36.05%	25.75		15.0

MONTANA EARNED RATE OF RETURN

Year: 2011

	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: 2011

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	566,723
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	4,092
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(255,344)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	315,471
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	38
18			
19	403 - 407	Depreciation & Amortization Expenses	13,288
20		Federal & State Income Taxes	359
21		Other Taxes	8,147
22		Other Operating Expenses	34,613
23		TOTAL Operating Expenses	56,406
24			
25		Net Operating Income	(56,368)
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	(56,368)
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	9
36		Commercial	1
37		Industrial	
38		Other	11
39			
40		**TOTAL NUMBER OF CUSTOMERS**	21
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	18,444
45		Average Annual Residential Cost per (Kwh) (Cents) *	6.48
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	99.57
48		Gross Plant per Customer	62,969

MONTANA CUSTOMER INFORMATION

Year: 2011

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, Montana		9	1	11	21
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**		9	1	11	21

Company Name: Avista Corporation

SCHEDULE 30

MONTANA EMPLOYEE COUNTS

Year: 2011

	Department	Year Beginning	Year End	Average
1				
2	Noxon Generating Station	28	35	32
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
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37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**	28	35	32

Company Name: Avista Corporation **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2011

	Project Description	Total Company	Total Montana
1			
2	Noxon Rapids Capital Projects Upgrades	11,760,903	11,760,903
3			
4	Clark Fork Improvement	4,714,201	4,714,201
5			
6	Other	837,777	837,777
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
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31			
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36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**	17,312,881	17,312,881

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2011

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	11	800	1669	1,238,294	297,020
2	Feb.	24	1900	1634	1,124,385	278,878
3	Mar.	1	1900	1439	1,049,047	227,575
4	Apr.	19	800	1295	1,127,384	363,789
5	May	3	800	1205	1,103,475	382,950
6	Jun.	28	1400	1290	1,065,344	361,988
7	Jul.	18	1700	1399	1,272,866	514,442
8	Aug.	25	1600	1535	1,063,916	247,363
9	Sep.	8	1700	1391	1,050,895	324,848
10	Oct.	26	800	1308	1,074,422	326,642
11	Nov.	16	800	1463	1,212,341	373,335
12	Dec.	12	1800	1536	1,323,022	386,060
13	**TOTAL**				13,705,391	4,084,890

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

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,723,844	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	9,035,133
4	Hydro - Conventional	4,534,293		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	723,596	for Resale	4,084,890
7	(Less) Energy for Pumping			
8	**NET Generation**	6,981,733	Non-Requirements Sales	
9	Purchases	6,724,582	for Resale	
10	Power Exchanges			
11	Received	543,343	Energy Furnished	
12	Delivered	(544,267)	Without Charge	
13	**NET Exchanges**	(924)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,322,223	Electric Utility	12,962
16	Delivered	(3,322,223)		
17	**NET Transmission Wheeling**		Total Energy Losses	572,406
18	Transmission by Others Losses			
19	**TOTAL**	13,705,391	**TOTAL**	13,705,391

SOURCES OF ELECTRIC SUPPLY

Year: 2011

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1					
2	Washington:				
3					
4	Thermal	Kettle Falls	Kettle Falls, WA	49	291,125
5	Hydro	Little Falls	Ford, WA	37	213,284
6	Hydro	Long Lake	Ford, WA	89	555,565
7	Hydro	Monroe Street	Spokane, WA	16	109,630
8	Hydro	Nine Mile	Spokane, WA	21	90,046
9	Hydro	Upper Falls	Spokane, WA	10	73,289
10	Combustion -				
11	Turbine	Northeast	Spokane, WA	15	289
12	Combustion -				
13	Turbine	Kettle Falls Bi-fuel	Kettle Falls, WA	8	1,375
14	Combustion -				
15	Turbine	Boulder Park	Spokane, WA	25	9,088
16					
17					
18	Idaho:				
19	Hydro	Cabinet Gorge	Clark Fork, ID	250	1,292,344
20	Hydro	Post Falls	Post Falls, ID	16	90,452
21	Combustion -				
22	Turbine	Rathdrum	Rathdrum, ID	87	7,784
23					
24					
25					
26	Montana:				
27	Thermal	Colstrip #3 and #4	Colstrip, MT	226	1,432,719
28	Hydro	Noxon	Thompson Falls, MT	408	2,109,683
29					
30	Oregon:				
31	Combustion -				
32	Turbine	Coyote Springs 2	Boardman, OR	305	705,060
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			1,562	6,981,733

Company Name: Avista Corporation

SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2011

	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							
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24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

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					

MONTANA CONSUMPTION AND REVENUES

Year: 2011

	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	$10,754	$6,346	166	133	9	8
2	Commercial - Small	2,359	1,391	28	21	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	25,191	21,899	334	327	11	11
12							
13	**TOTAL**	$38,304	$29,636	528	481	21	20