IDACORP INC
Form 10-Q
May 07, 2009

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q

(Mark One)

X QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2009
OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	I.R.S. Employer Identification Number
1-14465	IDACORP, Inc.	82-0505802
1-3198	Idaho Power Company	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	
	State of Incorporation: Idaho	
	Websites: www.idacorpinc.com, www.idahopower.com	

None
Former name, former address and former fiscal year, if changed since last report.

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes _X_ No ___

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).
Yes __ No ___

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act (check one):

IDACORP, Inc.:

Large accelerated filer X	Accelerated filer	Non-accelerated filer		Smaller reporting company

Idaho Power Company:

Large accelerated filer	Accelerated filer	Non-accelerated filer	X	Smaller reporting company

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).
Yes ___ No _X_

Number of shares of Common Stock outstanding as of March 31, 2009:

IDACORP, Inc.: 47,145,082
Idaho Power Company: 39,150,812, all held by IDACORP, Inc.

This combined Form 10-Q represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representations as to the information relating to IDACORP, Inc. s other operations.

Idaho Power Company meets the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q and is therefore filing this Form with the reduced disclosure format.

COMMONLY USED TERMS

AFUDC	-	Allowance for Funds Used During Construction
APCU	-	Annual Power Cost Update
Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
EIS	-	Environmental impact statement
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch Ratings, Inc.
GAAP	-	Generally Accepted Accounting Principles in the United States of America
HCC	-	Hells Canyon Complex
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCO	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
LGAR	-	Load growth adjustment rate
maf	-	Million acre feet
MD&A	-	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	-	Moody s Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NOx	-	Nitrogen Oxide
NWRFC	-	National Weather Service Northwest River Forecast Center

O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
RH BART	-	Regional Haze - Best Available Retrofit Technology
RFP	-	Request for Proposal
S&P	-	Standard & Poor s Ratings Services
SFAS	-	Statement of Financial Accounting Standards
SO_2	-	Sulfur Dioxide
SRBA	-	Snake River Basin Adjudication
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

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SAFE HARBOR STATEMENT

This Form 10-Q contains forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Part I, Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations - Forward-Looking Information. Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of the words anticipates, believes, estimates, expects, intends, plans, predicts, projec result, may continue and similar expressions.

PART I - FINANCIAL INFORMATION
Item 1. Financial Statements
IDACORP, Inc.
Condensed Consolidated Statements of Income
(unaudited)

	Three months ended March 31,	
	2009	**2008**
	(thousands of dollars except for per share amounts)	
Operating Revenues:		
Electric utility:		
General business	$ 187,927	$ 167,313
Off-system sales	28,530	33,363
Other revenues	11,572	12,120
Total electric utility revenues	228,029	212,796
Other	545	644
Total operating revenues	228,574	213,440
Operating Expenses:		
Electric utility:		
Purchased power	32,795	45,299
Fuel expense	39,133	37,237
Third-party transmission expense	906	497
Power cost adjustment	15,859	(17,744)
Other operations and maintenance	68,769	68,430
Energy efficiency programs	4,057	3,364
Gain on sale of emission allowances	(228)	-
Depreciation	25,963	25,750
Taxes other than income taxes	5,062	4,803
Total electric utility expenses	192,316	167,636
Other expense	624	1,048
Total operating expenses	192,940	168,684
Operating Income (Loss):		
Electric utility	35,713	45,160
Other	(79)	(404)
Total operating income	35,634	44,756
Other Income, Net	6,921	3,741
Income (Losses) of Unconsolidated Equity-Method Investments	402	(4,036)
Interest Expense:		
Interest on long-term debt	16,639	16,876

Other interest	836		596	
Total interest expense	17,475		17,472	
Income Before Income Taxes	25,482		26,989	
Income Tax Expense	6,796		5,584	
Net Income	18,686		21,405	
Adjustment for loss attributable to noncontrolling interests	198		311	
Net Income attributable to IDACORP, Inc.	$	18,884	$	21,716
Weighted Average Common Shares Outstanding - Basic (000 s)	46,831		44,953	
Weighted Average Common Shares Outstanding - Diluted (000 s)	46,876		45,047	
Earnings Per Share of Common Stock (basic and diluted):				
Earnings Attributable to IDACORP, Inc.	$	0.40	$	0.48
Dividends Paid Per Share of Common Stock	$	0.30	$	0.30

The accompanying notes are an integral part of these statements.

1

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

Assets	March 31, 2009 (thousands of dollars)	December 31, 2008
Current Assets:		
Cash and cash equivalents	$ 89,113	$ 8,828
Receivables:		
Customer	70,919	64,733
Allowance for uncollectible accounts	(1,482)	(1,724)
Other	15,099	10,439
Taxes receivable	9,710	18,111
Accrued unbilled revenues	35,751	43,934
Materials and supplies (at average cost)	52,778	50,121
Fuel stock (at average cost)	13,941	16,852
Prepayments	9,878	10,059
Deferred income taxes	14,792	37,550
Other	8,956	7,381
Total current assets	319,455	266,284
Investments	185,532	198,552
Property, Plant and Equipment:		
Utility plant in service	4,077,121	4,030,134
Accumulated provision for depreciation	(1,520,896)	(1,505,120)
Utility plant in service - net	2,556,225	2,525,014
Construction work in progress	186,662	207,662
Utility plant held for future use	6,653	6,318
Other property, net of accumulated depreciation	19,270	19,171
Property, plant and equipment - net	2,768,810	2,758,165
Other Assets:		
American Falls and Milner water rights	25,008	26,332
Company-owned life insurance	30,036	29,482
Regulatory assets	692,270	696,332
Long-term receivables (net of allowance of $2,478)	3,844	4,012
Other	44,723	43,686

Total other assets	795,881		799,844	
Total	$	4,069,678	$	4,022,845

The accompanying notes are an integral part of these statements.

2

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	March 31, 2009	December 31, 2008
Liabilities and Shareholders Equity	(thousands of dollars)	
Current Liabilities:		
Current maturities of long-term debt	$ 81,502	$ 86,528
Notes payable	150,700	151,250
Accounts payable	53,010	96,785
Interest accrued	24,054	16,727
Uncertain tax positions	4,509	4,119
Other	47,017	40,259
Total current liabilities	360,792	395,668
Other Liabilities:		
Deferred income taxes	511,281	515,719
Regulatory liabilities	282,440	276,266
Other	322,988	344,870
Total other liabilities	1,116,709	1,136,855
Long-Term Debt	1,279,504	1,183,451
Commitments and Contingencies		
Shareholders Equity:		
IDACORP, Inc. shareholders equity:		
Common stock, no par value (shares authorized 120,000,000; 47,161,034 and 46,929,203 shares issued, respectively)	731,756	729,576
Retained earnings	586,408	581,605
Accumulated other comprehensive loss	(9,458)	(8,707)
Treasury stock (15,952 and 9,022 shares at cost, respectively)	(20)	(37)
Total IDACORP, Inc. shareholders equity	1,308,686	1,302,437
Noncontrolling interest	3,987	4,434
Total shareholders equity	1,312,673	1,306,871
Total	$ 4,069,678	$ 4,022,845

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Condensed Consolidated Statements of Cash Flows
(unaudited)

	Three months ended March 31,	
	2009	**2008**
	(thousands of dollars)	
Operating Activities:		
Net income	$ 18,686	$ 21,405
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	31,169	30,777
Deferred income taxes and investment tax credits	14,675	12,617
Changes in regulatory assets and liabilities	16,405	(20,466)
Non-cash pension expense	697	93
Undistributed losses of subsidiaries	12	931
Gain on sale of assets	(382)	-
Other non-cash adjustments to net income	243	27
Excess tax benefit from share-based payment arrangements	(128)	-
Change in:		
Accounts receivable and prepayments	(8,119)	1,811
Accounts payable and other accrued liabilities	(41,655)	(29,869)
Taxes accrued	8,553	(5,843)
Other current assets	8,436	729
Other current liabilities	11,952	12,227
Other assets	(1,332)	(1,122)
Other liabilities	(14,859)	(2,400)
Net cash provided by operating activities	44,353	20,917
Investing Activities:		
Additions to property, plant and equipment	(49,592)	(52,863)
Proceeds from the sale of non-utility assets	250	-
Investments in affordable housing	(850)	(8,487)
Proceeds from the sale of emission allowances	2,341	-
Investments in unconsolidated affiliates	-	(5,000)
Proceeds from the sale of investments	4,845	-
Maturity of held-to-maturity securities	-	1,780
Other	2,385	(531)
Net cash used in investing activities	(40,621)	(65,101)
Financing Activities:		
Issuance of long-term debt	100,000	-

Retirement of long-term debt	(8,735)	(1,779)
Dividends on common stock	(14,353)	(13,475)
Net change in short-term borrowings	(550)	57,063
Issuance of common stock	2,469	2,213
Acquisition of treasury stock	(1,408)	(269)
Excess tax benefit from share-based payment arrangements	128	-
Other	(998)	(131)
Net cash provided by financing activities	76,553	43,622
Net increase (decrease) in cash and cash equivalents	80,285	(562)
Cash and cash equivalents at beginning of the period	8,828	7,966
Cash and cash equivalents at end of the period	$ 89,113	$ 7,404
Supplemental Disclosure of Cash Flow Information:		
Cash received during the period for:		
Income taxes refunded	$ 13,060	$ -
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 9,535	$ 7,934
Non-cash investing activities		
Additions to property, plant and equipment in accounts payable	$ 4,975	$ 16,350

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Three Months Ended March 31,			
	2009		2008	
	(thousands of dollars)			
Net Income	$	18,686	$	21,405
Other Comprehensive Income (Loss):				
Unrealized losses on securities:				
Net unrealized holding losses arising during the period, net of tax of ($570) and ($708)	(887)		(1,102)	
Unfunded pension liability adjustment, net of tax of $87 and $67	136		103	
Total Comprehensive Income	17,935		20,406	
Comprehensive loss attributable to noncontrolling interests	198		311	
Comprehensive Income attributable to IDACORP, Inc.	$	18,133	$	20,717

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three Months Ended March 31,			
	2009		2008	
	(thousands of dollars)			
Operating Revenues:				
General business	$	187,927	$	167,313
Off-system sales	28,530		33,363	
Other revenues	11,572		12,120	
Total operating revenues	228,029		212,796	
Operating Expenses:				
Operation:				
Purchased power	32,795		45,299	
Fuel expense	39,133		37,237	
Third-party transmission expense	906		497	
Power cost adjustment	15,859		(17,744)	
Other	52,312		54,157	
Energy efficiency programs	4,057		3,364	
Gain on sale of emission allowances	(228)		-	
Maintenance	16,457		14,273	
Depreciation	25,963		25,750	
Taxes other than income taxes	5,062		4,803	
Total operating expenses	192,316		167,636	
Income from Operations	35,713		45,160	
Other Income (Expense):				
Allowance for equity funds used during construction	764		896	
Earnings (losses) of unconsolidated equity-method investments	3,302		(796)	
Other income, net	6,297		2,761	
Total other income	10,363		2,861	
Interest Charges:				
Interest on long-term debt	16,567		16,543	
Other interest	1,578		1,894	
	(1,126)		(1,938)	

Allowance for borrowed funds used during construction				
Total interest charges	17,019		16,499	
Income Before Income Taxes	29,057		31,522	
Income Tax Expense	9,773		10,251	
Net Income	$	19,284	$	21,271

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

Assets	March 31, 2009	December 31, 2008
	(thousands of dollars)	
Electric Plant:		
In service (at original cost)	$ 4,077,121	$ 4,030,134
Accumulated provision for depreciation	(1,520,896)	(1,505,120)
In service - net	2,556,225	2,525,014
Construction work in progress	186,662	207,662
Held for future use	6,653	6,318
Electric plant - net	2,749,540	2,738,994
Investments and Other Property	103,713	106,057
Current Assets:		
Cash and cash equivalents	82,949	3,141
Receivables:		
Customer	70,919	64,433
Allowance for uncollectible accounts	(1,482)	(1,724)
Other	12,639	7,947
Taxes receivable	12,618	41,363
Accrued unbilled revenues	35,751	43,934
Materials and supplies (at average cost)	52,778	50,121
Fuel stock (at average cost)	13,941	16,852
Prepayments	9,618	9,865
Deferred income taxes	3,975	3,852
Other	8,089	4,968
Total current assets	301,795	244,752
Deferred Debits:		
American Falls and Milner water rights	25,008	26,332
Company-owned life insurance	30,036	29,482
Regulatory assets	692,270	696,332
Other	43,845	42,907
Total deferred debits	791,159	795,053
Total	$ 3,946,207	$ 3,884,856

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	March 31, 2009	December 31, 2008
Capitalization and Liabilities	**(thousands of dollars)**	
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	618,758	618,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	487,103	482,047
Accumulated other comprehensive loss	(9,458)	(8,707)
Total common stock equity	1,192,183	1,187,878
Long-term debt	1,279,504	1,180,691
Total capitalization	2,471,687	2,368,569
Current Liabilities:		
Long-term debt due within one year	81,064	81,064
Notes payable	102,550	112,850
Accounts payable	52,234	96,268
Notes and accounts payable to related parties	1,309	768
Interest accrued	24,052	16,675
Uncertain tax positions	4,509	4,119
Other	46,094	39,155
Total current liabilities	311,812	350,899
Deferred Credits:		
Deferred income taxes	559,807	547,159
Regulatory liabilities	282,440	276,266
Other	320,461	341,963
Total deferred credits	1,162,708	1,165,388
Commitments and Contingencies		
Total	$ 3,946,207	$ 3,884,856

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	March 31, 2009	**%**	**December 31, 2008**	**%**
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	618,758		618,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	487,103		482,047	
Accumulated other comprehensive loss	(9,458)		(8,707)	
Total common stock equity	1,192,183	48	1,187,878	50
Long-Term Debt:				
First mortgage bonds:				
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6.025% Series due 2018	120,000		120,000	
6.15% Series due 2019	100,000		-	
6 % Series due 2032	100,000		100,000	
5.50% Series due 2033	70,000		70,000	
5.50% Series due 2034	50,000		50,000	
5.875% Series due 2034	55,000		55,000	
5.30% Series due 2035	60,000		60,000	
6.30% Series due 2037	140,000		140,000	
6.25% Series due 2037	100,000		100,000	
Total first mortgage bonds	1,165,000		1,065,000	
Amount due within one year	(80,000)		(80,000)	
Net first mortgage bonds	1,085,000		985,000	
Pollution control revenue bonds:				
Variable Rate Series 2003 due 2024	49,800		49,800	
Variable Rate Series 2006 due 2026	116,300		116,300	
Variable Rate Series 2000 due 2027	4,360		4,360	
Total pollution control revenue bonds	170,460		170,460	

American Falls bond guarantee		19,885			19,885	
Milner Dam note guarantee		8,509			9,573	
Note guarantee due within one year		(1,064)			(1,064)	
Unamortized premium/discount - net		(3,286)			(3,163)	
Term Loan Credit Facility		166,100			166,100	
Purchase of pollution control revenue bonds		(166,100)			(166,100)	
Total long-term debt		1,279,504	52		1,180,691	50
Total Capitalization	$	2,471,687	100	$	2,368,569	100

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Cash Flows
(unaudited)

	Three months ended March 31, 2009	2008
	(thousands of dollars)	
Operating Activities:		
Net income	$ 19,284	$ 21,271
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	28,002	27,482
Deferred income taxes and investment tax credits	8,881	11,661
Changes in regulatory assets and liabilities	16,405	(20,466)
Non-cash pension expense	697	93
Undistributed losses of subsidiary	-	796
Gain on sale of assets	(382)	-
Other non-cash adjustments to net income	(1,000)	(979)
Change in:		
Accounts receivables and prepayments	(7,550)	2,002
Accounts payable	(42,182)	(29,513)
Taxes accrued	28,746	1,547
Other current assets	8,436	729
Other current liabilities	11,862	12,090
Other assets	(1,332)	(1,123)
Other liabilities	(14,809)	(2,096)
Net cash provided by operating activities	55,058	23,494
Investing Activities:		
Additions to utility plant	(49,592)	(52,863)
Proceeds from sale of emission allowances	2,341	-
Investments in unconsolidated affiliates	-	(5,000)
Other	(1,761)	(531)
Net cash used in investing activities	(49,012)	(58,394)
Financing Activities:		
Issuance of long-term debt	100,000	-
Retirement of long-term debt	(1,064)	(1,064)
Dividends on common stock	(14,228)	(13,512)
Net change in short term borrowings	(10,300)	49,565

Other	(646)	(130)
Net cash provided by financing activities	73,762	34,859
Net increase (decrease) in cash and cash equivalents	79,808	(41)
Cash and cash equivalents at beginning of the period	3,141	5,347
Cash and cash equivalents at end of the period	$ 82,949	$ 5,306
Supplemental Disclosure of Cash Flow Information:		
Cash received during the period for:		
Income taxes received from parent	$ 24,481	$ 1,755
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 9,150	$ 7,121
Non-cash investing activities:		
Additions to utility plant in accounts payable	$ 4,975	$ 16,350

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Three Months Ended March 31,	
	2009	**2008**
	(thousands of dollars)	
Net Income	$ 19,284	$ 21,271
Other Comprehensive Income (Loss):		
Unrealized losses on securities:		
Net unrealized holding losses arising during the period, net of tax of ($570) and ($708)	(887)	(1,102)
Unfunded pension liability adjustment, net of tax of $87 and $67	136	103
Total Comprehensive Income	$ 18,533	$ 20,272

The accompanying notes are an integral part of these statements.

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

This Quarterly Report on Form 10-Q is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (IPC). These Notes to the Condensed Consolidated Financial Statements apply to both IDACORP and IPC. However, IPC makes no representation as to the information relating to IDACORP s other operations.

Nature of Business
IDACORP is a holding company formed in 1998 whose principal operating subsidiary is IPC. IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides certain access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes certain record retention and reporting requirements on IDACORP.

IPC is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

IDACORP s other subsidiaries include:

- IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;
- Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and

IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

Principles of Consolidation
IDACORP s and IPC s condensed consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. All significant intercompany balances have been eliminated in consolidation. Investments in

subsidiaries that the companies do not control and investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

The entities that IDACORP and IPC consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West, and 50 percent by Environmental Energy Company (EEC). Marysville has approximately $25 million of assets, primarily a small hydroelectric plant, and approximately $17 million of intercompany long-term debt, which is eliminated in consolidation. For this joint venture, Ida-West is considered the primary beneficiary because the ownership of the intercompany note results in it absorbing a majority of the expected losses of the entity.

Through IFS, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These VIEs are historic rehabilitation and affordable housing developments in which IFS holds limited partnership interests ranging from five to 99 percent. These investments are not consolidated because IFS does not absorb a majority of the expected losses of these entities, either because of specific provisions in the partnership agreements or due to not owning a majority interest. These investments were acquired between 1996 and 2008, and are presented as Investments on IDACORP s condensed consolidated balance sheets. IFS s maximum exposure to loss in these developments is limited to its net carrying value, which was $73 million at March 31, 2009.

Financial Statements

In the opinion of IDACORP and IPC, the accompanying unaudited condensed consolidated financial statements contain all adjustments necessary to present fairly their consolidated financial positions as of March 31, 2009, and consolidated results of operations for the three months ended March 31, 2009, and 2008, and consolidated cash flows for the three months ended March 31, 2009, and 2008. These adjustments are of a normal and recurring nature. These financial statements do not contain the complete detail or footnote disclosure concerning accounting policies and other matters that would be included in full-year financial statements and should be read in conjunction with the audited consolidated financial statements included in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. The reclassifications that were made to prior year amounts are as follows:

Other expense was combined with the other income line in the IDACORP and IPC condensed consolidated statements of income to present information in a more condensed manner;

Third-party transmission expense was broken out from electric utility other operations and maintenance in the IDACORP condensed consolidated statements of income and from other operation in the IPC condensed consolidated statements of income as third-party transmission costs are now treated as a power supply cost in the PCA;

Employee notes current was combined with other current receivables in the IDACORP and IPC condensed consolidated balance sheets due to the employee notes becoming an immaterial balance; and

Employee notes long-term was combined with other non-current assets in the IDACORP and IPC condensed consolidated balance sheets due to the employee notes becoming an immaterial balance.

Earnings Per Share (EPS)

In January 2009, IDACORP adopted FASB Staff Position (FSP) EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method described in SFAS No. 128, *Earnings per Share.* Prior-period EPS data has been adjusted retrospectively. FSP EITF 03-6-1 did not have a material impact on IDACORP s or IPC s condensed consolidated financial statements.

The following table presents the computation of IDACORP s basic and diluted earnings per share from continuing operations for the three months ended March 31, 2009 and 2008 (in thousands, except for per share amounts):

	Three months ended March 31, 2009	2008
Numerator:		
Net income attributable to IDACORP, Inc.	$ 18,884	$ 21,716
Denominator:		
Weighted-average common shares outstanding - basic	46,831	44,953
Effect of dilutive securities:		
Options	13	49
Restricted Stock	32	45
Weighted-average common shares outstanding diluted	46,876	45,047
Basic and diluted earnings per share from continuing operations	$ 0.40	$ 0.48

The diluted EPS computation excluded 687,485 options for the three months ended March 31, 2009, because the options exercise prices were greater than the average market price of the common stock during that period. For the same period in 2008, there were 482,000 options excluded from the diluted EPS computation for the same reason. In total, 782,081 options were outstanding at March 31, 2009, with expiration dates between 2010 and 2015.

Adoption of SFAS 160

IDACORP and IPC adopted SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51,* on January 1, 2009. This guidance provides accounting and reporting standards for noncontrolling interests in a consolidated subsidiary (previously referred to as minority interests) and clarifies that noncontrolling interests should be reported as equity on the consolidated financial statements. As a result of adopting this guidance, IDACORP has disclosed in its financial statements the portion of equity and net income attributable to the noncontrolling interests in consolidated subsidiaries and has reclassified $4 million of noncontrolling interests from Other Liabilities to Shareholders Equity on the December 31, 2008, balance sheet. IPC does not have any noncontrolling interests. The adoption of this guidance modifies financial statements presentation, but does not impact financial statement results.

Shareholders Equity

The following table presents a reconciliation of the carrying amount of shareholders equity (in thousands):

	Attributable to IDACORP, Inc.	**Attributable to noncontrolling interests**	**Total**

Shareholders equity at January 1, 2009	$	1,302,437	$	4,434	$	1,306,871
Net income (loss)		18,884		(198)		18,686
Common stock dividends		(14,081)		-		(14,081)
Common stock issuances		2,792		-		2,792
Common stock acquired		(868)		-		(868)
Unrealized holding losses on securities		(887)		-		(887)
Unfunded pension liability adjustment		136		-		136
Other		273		(249)		24
Shareholders equity at March 31, 2009	$	1,308,686	$	3,987	$	1,312,673
Shareholders equity at January 1, 2008	$	1,207,315	$	4,478	$	1,211,793
Net income (loss)		21,716		(311)		21,405
Common stock dividends		(13,494)		-		(13,494)
Common stock issuances		2,310		-		2,310
Common stock acquired		(269)		-		(269)
Unrealized holding losses on securities		(1,102)		-		(1,102)
Unfunded pension liability adjustment		103		-		103
Other		908		(7)		901
Shareholders equity at March 31, 2008	$	1,217,487	$	4,160	$	1,221,647

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. Beginning in February 2009, the IPUC has provided for the current collection of AFUDC in base rates for a specific capital project, as discussed in Note 6, Regulatory Matters.

Revenues
Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense. Beginning in February 2009, IPC is collecting AFUDC in base rates for a specific capital project, as discussed in Note 6, Regulatory Matters. Cash collected is recorded as a regulatory liability.

New Accounting Pronouncements
FSP FAS 132(R)-1: In December 2008, the FASB issued FSP FAS 132(R)-1, *Employers Disclosures about Postretiement Benefit Plan Assets.* This standard will require companies to provide users of financial statements with an understanding of: a) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; b) the major categories of plan assets; c) the inputs and valuation techniques used to measure the fair value of plan assets; d) the effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and e) significant concentrations of risk within plan assets. FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. IDACORP and IPC do not expect the adoption of FSP FAS 132(R)-1 to have a material effect on their consolidated financial statements.

2. INCOME TAXES:

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP s effective tax rate for the three months ended March 31, 2009, was 26.5 percent, compared to 20.5 percent for the three months ended March 31, 2008. IPC s effective tax rate for the three months ended March 31, 2009, was 33.6 percent, compared to 32.5 percent for the three months ended March 31, 2008. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC s regulatory flow-through tax adjustments, and lower tax credits from IFS.

In March 2009, the U.S. Congress Joint Committee on Taxation (JCT) completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 Internal Revenue Service examination report. The JCT accepted both items without change. Also in March 2009, IDACORP received $1.9 million of interest related to its federal refund for 2005. IDACORP considered these matters effectively settled in 2008 and had recorded the related financial effects in its December 31, 2008 financial statements.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the three months ended March 31, 2009, IDACORP entered into the following transactions involving its common stock:

102,128 original issue shares and 24,948 treasury shares were used for awards granted under the 2000 Long-Term Incentive and Compensation Plan.

28,518 original issue shares and 22,550 treasury shares were used for awards granted under the Restricted Stock Plan.

12,936 treasury shares were used for the annual stock grant to directors under the Non-Employee Directors Stock Compensation Plan.

101,185 original issue shares were issued under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan.

IDACORP has three share-based compensation plans. IDACORP s employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP s long-term growth. IDACORP also has one non-employee plan, the Non-Employee Directors Stock Compensation Plan (DSP). The purpose of the DSP is to increase directors stock ownership through stock-based compensation.

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The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At March 31, 2009, the maximum number of shares available under the LTICP and RSP were 1,453,756 and 21,677, respectively.

The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC s employees (in thousands of dollars). No equity compensation costs have been capitalized:

	IDACORP Three months ended March 31,		**IPC Three months ended March 31,**	
	2009	**2008**	**2009**	**2008**
Compensation cost	$ 1,244	$ 971	$ 1,183	$ 921
Income tax benefit	$ 486	$ 379	$ 463	$ 360

Stock awards: Restricted stock awards have vesting periods of up to three years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and is charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for restricted stock awards granted during the first quarter of 2009 was $25.48.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and will be paid out only on shares that eventually vest.

The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for CEPS and TSR awards granted during the first quarter of 2009 was $19.50.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. The fair value of each option is amortized into compensation expense using graded-vesting. Stock options are not a significant component of share-based compensation awards under the LTICP.

4. LONG-TERM DEBT:

Long-Term Financing
IDACORP has approximately $588 million remaining on a shelf registration statement that can be used for the issuance of debt securities or common stock.

On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt. IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

On February 27, 2009, IFS repaid $7.2 million of its $8 million debt outstanding related to investments in affordable housing. The debt was scheduled to mature in November 2009 and May 2010.

Pollution Control Revenue Refunding Bonds

Two series of bonds have been issued for the benefit of IPC and are each supported by a financial guaranty insurance policy issued by Ambac Assurance Corporation (Ambac). The two series are the $116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds).

On April 3, 2008, IPC made a mandatory purchase of the Pollution Control Bonds. IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of Ambac s credit ratings deterioration. The Pollution Control Bonds remain outstanding and have not been retired or cancelled. IPC is the current holder of the bonds, but ultimately expects to remarket the bonds to investors. The maximum interest rate is 14 percent for the Sweetwater bonds and at specified rates capped at 12 percent for the Humboldt bonds.

The regularly scheduled principal and interest payments on the Pollution Control Bonds and principal and interest payments on the bonds upon mandatory redemption on determination of taxability are insured by financial guaranty insurance policies issued by Ambac Assurance Corporation.

Term Loan Credit Agreement

IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans were due on March 31, 2009 and could be prepaid but not reborrowed. IPC used $166.1 million of the proceeds from the loans to effect the mandatory purchase on April 3, 2008, of the Pollution Control Bonds (as discussed above under Pollution Control Revenue Refunding Bonds) and $3.9 million to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement.

On February 4, 2009, IPC entered into a new $170 million Term Loan Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent and lender, Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. The new Term Loan Credit Agreement replaces the above mentioned Term Loan Credit Agreement. The loans are due on February 3, 2010, but are subject to earlier payment if IPC remarkets the Pollution Control Bonds discussed above. The loans may be prepaid but may not be reborrowed.

The new Term Loan Credit Agreement is a short-term arrangement; however, $166.1 million was classified as long-term debt as allowed by SFAS No. 6 *Classification of Short-Term Obligations Expected to Be Refinanced*. IPC has the ability to refinance the loans on a long-term basis by utilizing its credit facility, provided that the aggregate of the commitments utilizing the credit facility and commercial paper outstanding does not exceed $300 million. The remaining $3.9 million of the loans is classified as short-term debt.

5. NOTES PAYABLE:

Credit Facilities

IDACORP has a $100 million credit facility and IPC has a $300 million credit facility, both of which expire on April 25, 2012. Commercial paper may be issued up to the amounts supported by the bank credit facilities. Under these facilities the companies pay a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody s and S&P.

At March 31, 2009, no loans were outstanding on either IDACORP s facility or IPC s facility.
At March 31, 2009, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings were as follows at March 31, 2009, and December 31, 2008 (in thousands of dollars):

	March 31, 2009			December 31, 2008		
	IPC	**IDACORP**	**Total**	**IPC**	**IDACORP**	**Total**
Commercial paper outstanding	$ 98,650	$ 48,150	$ 146,800	$ 108,950	$ 13,400	$ 122,350
Other short-term borrowings	3,900	-	3,900	3,900	25,000	28,900
Total	$ 102,550	$ 48,150	$ 150,700	$ 112,850	$ 38,400	$ 151,250
Weighted-avg. interest rate	1.52%	1.48%	1.50%	4.89%	4.29%	4.74%

6. REGULATORY MATTERS:

Idaho 2008 General Rate Case

On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent

On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four principal areas of the order and requested clarification of certain issues. On March 19, 2009, the IPUC issued an order which increased IPC s Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent. The rate increase authorized by the March 19, 2009, order was effective for most customer classes on March 21, 2009. The IPUC corrected errors relating to the calculation of test year payroll expense ($6 million) and certain operation and maintenance expenses ($0.5 million). The IPUC also clarified four issues in agreement with IPC s recommended clarifications and indicated that the changes approved in the order resulted in a load growth adjustment rate (LGAR) of $26.63 per MWh, effective February 1, 2009.

The IPUC denied reconsideration with respect to the refund of $3.3 million recovered by IPC from the FERC and the recovery of $0.9 million of employee purchasing card expenditures. In response to the denial of reconsideration of the FERC fees, on April 2, 2009, IPC filed an application with the IPUC for an accounting order approving amortization of the fees over a five year period beginning in October 2006 when IPC received the FERC credit. The IPUC approved IPC s requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, IPC recorded a charge of $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009 through the end of the amortization period on September 30, 2011.

The order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Deferred Net Power Supply Costs
IPC s deferred net power supply costs consisted of the following (in thousands of dollars):

	March 31, 2009		December 31, 2008	
Idaho PCA current year:				
Deferral for the 2009-2010 rate year	$	103,300	$	93,657
Idaho PCA true-up awaiting recovery:				
Authorized in May 2008		22,003		47,164
Oregon deferral:				
2001 Costs		1,065		1,663
2006 Costs		1,146		1,215
2008 Power cost adjustment mechanism		5,506		5,400
Total deferral	$	133,020	$	149,099

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC s actual net power supply costs (fuel, purchased power and third-party transmission expenses less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

A forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and

A true-up component, based on the difference between the previous year s actual net power supply costs and the previous year s forecast. This component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The true-up component is calculated monthly, and interest is applied to the balance.

Prior to February 1, 2009, the PCA mechanism provided that 90 percent of deviations in power supply costs were to be reflected in IPC s rates for both the forecast and the true-up components. Effective February 1, 2009, this sharing percentage is now 95 percent.

2009-2010 PCA: On April 15, 2009, IPC filed its 2009-2010 PCA with the IPUC with a requested effective date of June 1, 2009. The filing requests a $93.8 million increase to the PCA component of customers rates, an 11.4 percent overall increase to Idaho rates.

2008-2009 PCA: On May 30, 2008, the IPUC approved IPC s 2008-2009 PCA and an increase to then-existing revenues of $73.3 million, effective June 1, 2008, which resulted in an average rate increase to IPC s customers of 10.7 percent. The IPUC s order adopted an IPUC Staff proposal to use a forecast for power supply costs that equaled the amount in current base rates. The revenue increase is net of $16.5 million of gains from the 2007 sale of excess SO_2 emission allowances, including interest, which the IPUC ordered be applied against the PCA.

PCA Workshops: In its May 30, 2008, order approving IPC s 2008-2009 PCA, the IPUC directed IPC to set up workshops with the IPUC Staff and several of IPC s largest customers (together, the Parties) to address PCA-related issues not resolved in the PCA filing. Workshops were conducted in the fall and a settlement stipulation was filed with the IPUC and approved on January 9, 2009.

The following changes were effective as of February 1, 2009:

PCA sharing methodology of 95/5 - the PCA sharing methodology allocates the costs and benefits of net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.

LGAR - the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on a formula that, based on filed data from the 2008 general rate case, would have produced an LGAR of $28.14 per MWh. As discussed above under 2008 General Rate Case, the LGAR, effective February 1, 2009, is $26.63 per MWh.

Use of IPC s operation plan power supply cost forecast - the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year s true-up rate, beginning with the 2009-2010 PCA filing.

Inclusion of third-party transmission expense - transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these types of costs from levels included in base rates is now reflected in PCA computations.

Adjusted distribution of base net power supply costs - base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Oregon: Beginning in 2008, IPC has a power cost recovery mechanism in Oregon with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

The APCU allows IPC to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The APCU has two components: the October Update, where each October IPC calculates its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC files a forecast of its expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices. On June 1 of each year, rates are adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, IPC is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which IPC absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and IPC. However, a collection will occur only to the extent that it results in IPC s actual return on equity (ROE) for the year being no greater than 100 basis points below IPC s last authorized ROE. A refund will occur only to the extent that it results in IPC s actual ROE for that year being no less than 100 basis points above IPC s last authorized ROE. The PCAM rate is then added to or subtracted from the APCU rate, subject to certain statutory limitations discussed below, with new combined rates effective each June 1.

2009 APCU: On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC s base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.55 percent increase. IPC and the OPUC Staff reached a verbal agreement on the October Update.

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast results in a requested increase to Oregon revenues of 11.46 percent, or $3.9 million annually. A joint stipulation by IPC, the OPUC Staff and the Citizens Utility Board in support of IPC s requested increase was filed with the OPUC on May 4, 2009. When approved, the final 2009 APCU rates are expected to become effective on June 1, 2009.

2008 APCU: On May 20, 2008, the OPUC approved IPC s 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.69 percent, increase in Oregon revenues.

2008 PCAM: On February 27, 2009, IPC filed the true-up of its net power supply costs for the period January 1 through December 31, 2008, with the OPUC. The 2008 PCAM filing reflects a deviation of actual net power supply costs above the forecast for that period of $7.4 million. After the application of the deadband, the filing requests that $5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed below under 2007-2008 Excess Power Costs. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference is scheduled for May 14, 2009.

2007-2008 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the 8-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was determined that IPC should be allowed to defer excess net power supply costs of $5.5 million dollars for that period. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. IPC is awaiting an order from the OPUC on the stipulation.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year. On October 6, 2008, the OPUC issued an order clarifying that the PCAM is a deferral under the Oregon statute.

IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC. Full recovery of the 2001 deferral is expected in 2009. The 2006-2007 deferral of $1.1 million, the May

1-December 31, 2007 deferral of $5.5 million (if approved by the OPUC) and the $5 million 2008 PCAM balance will have to be recovered sequentially following the full recovery of the 2001 deferral.

Fixed Cost Adjustment Mechanism (FCA)

On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program for IPC s residential and small general service customers. The FCA is a rate mechanism designed to remove IPC s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC s revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. The pilot program began on January 1, 2007, and runs through 2009, with the first rate adjustment occurring on June 1, 2008, and subsequent rate adjustments occurring on June 1 of each year during its term.

IPC deferred $0.7 million of FCA net under-recovery of fixed costs during the first quarter of 2009.

On March 13, 2009, IPC filed an application requesting a $5.2 million rate increase under the FCA pilot program for the net under-recovery of fixed costs during 2008. The new rates are requested to be effective from June 1, 2009 through May 31, 2010. The application will proceed under modified procedure with comments due May 8, 2009.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of $2.4 million to be distributed to residential and small general service customer classes equally on an energy used basis during the June 1, 2008, through May 31, 2009, FCA revenue collection period.

Energy Efficiency Matters

Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in conservation, energy efficiency and demand response programs. Effective June 1, 2008, IPC collects 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers. On March 13, 2009, IPC filed an application with the IPUC requesting an increase in Rider funding to 4.75 percent of base revenues effective June 1, 2009. On April 10, 2009, the IPUC ordered that this filing be processed by modified procedure with comments due by May 1, 2009. Approval of this application would increase annual Rider funds to approximately $33 million.

Energy Efficiency Prudency Review: In the 2008 general rate case, IPC requested that the IPUC explicitly find that IPC s expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and would, therefore, no longer be subject to potential disallowance. The IPUC Staff recommended that the IPUC defer a prudency determination for these expenditures until IPC was able to provide a comprehensive evaluation package of its programs and efforts. IPC contended that sufficient information had already been provided to the IPUC Staff for review.

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. On March 6, 2009, the IPUC approved the stipulation, identifying $18.3 million as prudent, which included $14.3 million of Rider funding and $4.0 million of other funds.

On April 1, 2009, IPC filed an application with the IPUC seeking a prudency determination on the $14.7 million balance of Rider funds spent during 2002 through 2007. IPC has requested that this application be processed under modified procedure.

Depreciation Filings

On September 12, 2008, the IPUC approved a revision to IPC s depreciation rates, retroactive to August 1, 2008. The new rates are based on a settlement reached by IPC and the IPUC Staff, and result in an annual reduction of depreciation expense of $8.5 million ($7.9 million allocated to Idaho) based upon December 31, 2006, depreciable electric plant in service.

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million. The OPUC Staff has recently accepted IPC s settlement offer and a stipulation is expected to be filed by May 8, 2009. In the settlement offer, IPC proposed that the OPUC Staff not make adjustments to the depreciation rates adopted by the IPUC and also proposed to commit to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction.

On October 22, 2008, IPC filed an application with the FERC requesting that IPC s revised depreciation rates as approved by the IPUC also be accepted for use in future rate filings made with the FERC. The FERC approved IPC s application on December 3, 2008. The new depreciation accrual rates will be reflected in IPC s OATT rates beginning October 1, 2009.

Open Access Transmission Tariff (OATT)

On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on financial and operational data IPC is required to file annually with the FERC in its Form 1. The formula rate request included a rate of return on equity of 11.25 percent. IPC s filing was opposed by several affected parties. Effective June 1, 2006, the FERC accepted IPC s proposed new rates, subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced IPC s proposed new rates and, as a result, approximately $1.7 million collected in excess of the settlement rates between June 1, 2006, and July 31, 2007, was refunded with interest in August 2007. As part of the settlement agreement, the FERC established an authorized rate of return on equity of 10.7 percent.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which would have further reduced the new transmission rates. IPC, as well as the opposing parties, appealed the Initial Decision to the FERC. If implemented, the Initial Decision would have required IPC to make additional refunds, of approximately $5.4 million (including $0.4 million of interest) for the June 1, 2006, through December 31, 2008, period. IPC previously reserved this entire amount.

On January 15, 2009, the FERC issued an Order on Initial Decision (FERC Order), which upheld the Initial Decision of the ALJ in most respects, but modified the Initial Decision in one respect that is unfavorable to IPC. The decision required IPC to reduce its transmission service rates to FERC jurisdictional customers. Furthermore, IPC was required to make refunds to FERC jurisdictional transmission customers in the total amount of $13.3 million (including $1.1 million in interest) for the period since the new rates went into effect in June 2006. Based on the FERC Order IPC reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008, bringing the total reserve amount to $13.3 million. Prior to the FERC Order, the FERC jurisdictional transmission revenues (net of the $5 million reserve) recorded in the last seven months of 2006, all of 2007 and 2008 were $8.1 million, $13.3 million and $15.8 million, respectively. Under the FERC Order, the transmission revenues would have been $6.4 million in the last seven months of 2006, $11 million in 2007 and $12.6 million in 2008. Refunds were made on February 25, 2009.

IPC filed a request for rehearing with the FERC on February 17, 2009. IPC believes that the treatment of the Legacy Agreements conflicts with precedent. The rehearing request asserts that the FERC order is in error by: (1) requiring IPC to include the contract demands associated with the Legacy Agreements in the OATT formula rate divisor rather than crediting the revenue from the Legacy Agreements against IPC s transmission revenue requirement; (2) concluding that IPC must include the contract demands associated with the Legacy Agreements rather than the customers coincident peak demands; (3) concluding that the transmission rate contained in one or more of the Legacy Agreements was not a discounted rate; (4) failing to consider the non-monetary benefits received by IPC from the Legacy Agreements; (5) concluding that the services provided under the Legacy Agreements are firm services and therefore should be handled for rate purposes in the same manner as firm services under the OATT; and (6) failing to affirm the rate treatment that has been used for the Legacy Agreements for approximately 30 years. On March 18, 2009, the FERC issued a tolling order that effectively relieves it from acting on the request for reconsideration for an indefinite time period. IPC cannot predict when the FERC will rule on the request for rehearing or the outcome of this matter.

On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The new rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. The impact of this rate decrease on IPC s revenues is dependent on transmission volume sold, which can be highly variable. New rates were effective October 1, 2008. IPC has adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009, order.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations

There have been no material changes in purchase obligations outside of the ordinary course of business since December 31, 2008 with the exception of the following:

IPC entered into a contract, effective January 1, 2009, to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. The contract is expected to total $133 million from 2009 to 2014.

IPC entered into two contracts with Siemens Energy, Inc. to purchase gas and steam turbine equipment and services for the Langley Gulch power plant. IPC estimates it will spend approximately $90 million on the contracts from 2009 through 2012.

Guarantees

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at March 31, 2009. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, Bridger Coal Company has the ability to add a per ton surcharge if it is determined that future liabilities exceed the trust s assets. At this time Bridger Coal Company and IPC expect that the fund will be sufficient to cover all such costs. Because of the existence of the fund and the ability to apply a per ton surcharge, the estimated fair value of this guarantee is minimal.

Legal Proceedings

From time to time IDACORP and IPC are parties to legal claims, actions and complaints in addition to those discussed below. Although they will vigorously defend against them, IDACORP and IPC are unable to predict with certainty whether or not they will ultimately be successful. However, based on the companies evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IDACORP s or IPC s consolidated financial positions, results of operations or cash flows.

Reference is made to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008, for a discussion of all material pending legal proceedings to which IDACORP and IPC and their subsidiaries are parties. The following discussion provides a summary of material developments that occurred in those proceedings during the period covered by this report and of any new material proceedings instituted during the period covered by this report.

Western Energy Proceedings at the FERC: Throughout this report, the term western energy situation is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices and blackouts in the western United States. High prices for electricity in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds. Some of these proceedings (the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are pending in the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the western energy situation, including the California refund proceeding, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters, except as otherwise stated below, or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC s order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

IE and other parties petitioned the Ninth Circuit for review of the FERC s orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed by potential refund payors, including IE, potential refund recipients and governmental agencies. These cases have been consolidated before the Ninth Circuit. Since the initiation of these cases, the Ninth Circuit has convened a series of case management proceedings to organize these complex cases, while identifying and severing discrete cases that can proceed to briefing and decision and staying action on all of the other consolidated cases.

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds. A number of public entities filed petitions for panel rehearing in June 2007 and certain marketers filed petitions for rehearing and rehearing en banc in November 2007. Those requests were denied by the Ninth Circuit on April 6, 2009. The Ninth Circuit issued a mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court s decision.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection and that request remains pending before the FERC. IE and IPC are unable to predict how or when the FERC might rule on the request for rehearing, but its effect is confined to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC settling matters encompassed by the California refund proceeding, as well as other FERC proceedings and investigations relating to the western energy matters, including IE s and IPC s cost filing and refund obligation. A number of other parties, representing a small minority of potential refund claims, chose to opt out of the settlement. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and

IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IPC and IE. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement. In addition, the California Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming (gaming) or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the partnership show cause proceeding against IPC. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by IPC.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000, through October 1, 2000, to enable it to review evidence of economic withholding of generation. IPC, along with more than 60 other market participants, responded to the FERC data requests. The FERC terminated its investigations as to IPC on May 12, 2004. Although California government agencies and California investor-owned utilities have appealed the FERC s termination of this investigation as to IPC and more than 30 other market participants, the claims regarding the conduct encompassed by these investigations were released by these parties in the California refund settlement discussed above. IE and IPC are unable to predict the outcome of these matters, but believe that the releases govern any potential claims that might arise and that this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

<u>Pacific Northwest Refund:</u> On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict *Mobile-Sierra* standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

On June 26, 2008, the U.S. Supreme Court issued a decision in Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), a case regarding a FERC decision not to require re-pricing of certain long-term contracts. In Snohomish, the Supreme Court revisited and clarified the *Mobile-Sierra* doctrine in the context of fixed-rate, forward power contracts. At issue was whether, and under what circumstances, the FERC could modify the rates in such contracts on the grounds that there was a dysfunctional market at the time the contracts were executed. In its decision, the Supreme Court disagreed with many of the conclusions reached in an earlier decision by the Ninth Circuit and upheld the application of the *Mobile-Sierra* doctrine even in cases in which it is alleged that the markets were dysfunctional. The Supreme Court nonetheless directed the return of the case to the

FERC to (i) consider whether the challenged rates in the case constituted an excessive burden on consumers either at the time the contracts were formed or during the term of the contracts relative to the rates that could have been obtained after elimination of the dysfunctional market and (ii) clarify whether it found the evidence inadequate to support a claim that one of the parties to a contract under consideration engaged in unlawful market manipulation that altered the playing field for the particular contract negotiations - that is, whether there was a causal connection between allegedly unlawful activity and the contract rate. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court s decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court. Paper hearings have since been held in abeyance while the FERC s mediation service meets with the parties to the remanded case.

This decision is expected to have general implications for contracts in the wholesale electric markets regulated by the FERC, and particular implications for forward power contracts in such markets. The Snohomish decision upholds the application of the *Mobile-Sierra* doctrine to fixed-rate, forward power contracts even in allegedly dysfunctional markets.

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IPC and IE have asserted the *Mobile-Sierra* doctrine in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market. IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how this decision will affect the outcome of the Pacific Northwest proceeding.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants. Plaintiffs allege that IPC s ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860 s or before.
On May 31, 2007, the U.S. District Court granted the defendants motion to dismiss stating that the plaintiffs claims are barred by the finality provision of the Indian Claims Commission Act. Plaintiffs filed a motion for reconsideration which the District Court denied. On January 25, 2008, the District Court entered judgment in favor of IPC. Plaintiffs filed a Notice of Appeal to the Ninth Circuit. The parties have filed briefs on appeal. Oral argument on the appeal is scheduled for June 2, 2009. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on IPC s consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal fired plant in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured by the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit Boardman: On September 30, 2008, the Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired power plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE s construction and operation of the plant. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs response to the motion was filed February 25, 2009, and PGE s reply was filed April 8, 2009. The State of Oregon filed an amicus brief on April 1, 2009, addressing the substantive positions set forth in PGE s December 5, 2008, motion to dismiss and the plaintiffs February 25, 2009, response to the motion. The amicus brief does not state a position on the merits of the motion to dismiss but corrects what it perceives to be erroneous statements of law made by the plaintiffs and PGE regarding Oregon air quality regulations concerning the Prevention of Significant Deterioration program that were approved by the Environmental Protection Agency and incorporated into Oregon s State Implementation Plan. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Snake River Basin Adjudication: IPC is engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC.

On March 25, 2009, IPC and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions discussed below. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters.

The settlement agreement resolves the pending litigation by clarifying that IPC s water rights in excess of minimum flows at its hydroelectric facilities between Milner Dam and Swan Falls Dam are subordinate to future upstream beneficial uses, including aquifer recharge. The agreement commits the State and IPC to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. It also recognizes that water management measures that enhance aquifer levels, springs and river flows, such as aquifer recharge projects, benefit both agricultural development and hydropower generation and deserve study to determine their economic potential, their impact on the environment and their impact on hydropower generation. These will be a part of the Comprehensive Aquifer Management Plan (CAMP), recently approved by the Idaho Water Resource Board, which includes limits on the amount of aquifer recharge. IPC is a member of the CAMP advisory committee.

On May 6, 2009, as part of the settlement, IPC, the Governor and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. The settlement agreement is now subject to approval by the SRBA court.

IPC has also filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the United States for the lost generation resulting from the reduced flows and a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On March 11, 2009, the court entered an order extending the discovery schedule requiring that discovery be completed and pre-trial motions filed by December 3, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy in Canyon County, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho against IDACORP and IPC. The plaintiffs complaint asserted claims for negligence, negligence *per se*, gross negligence, nuisance, and fraud. The claims were based on allegations that from 1972 until at least March 2005, IPC discharged stray voltage from its electrical facilities that caused physical harm and injury to the plaintiffs dairy herd. Plaintiffs sought compensatory damages of not less than $1 million. In April 2009, IDACORP and IPC settled the lawsuit with the plaintiffs; the settlement did not have a material effect on IDACORP or IPC.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an IPC distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes and damage or alleged fire related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of IPC s distribution poles and that high winds contributed to the fire and its resultant damage.

IPC has received notice of claims from a number of the homeowners and their insurers and is continuing its investigation of these claims. IPC is insured up to policy limits against liability for claims in excess of its self-insured retention. IPC has accrued a reserve for any loss that is probable and reasonably estimable, including insurance deductibles, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

8. BENEFIT PLANS:

The following table shows the components of net periodic benefit costs for the three months ended March 31 (in thousands of dollars):

	Pension Plan		Senior Management Security Plan		Postretirement Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	$ 4,205	$ 3,730	$ 402	$ 320	$ 332	$ 327
Interest cost	6,947	6,596	714	667	882	880
Expected return on plan assets	(6,088)	(8,494)	-	-	(528)	(738)
Amortization of transition obligation	-	-	-	-	510	510
Amortization of prior service cost	163	163	58	48	(134)	(133)
Amortization of net loss	2,120	-	165	122	190	-
Net periodic benefit cost	7,347	1,995	1,339	1,157	1,252	846
Costs not recognized due to the effects of regulation	(7,347)	(1,995)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	$ -	$ -	$ 1,339	$ 1,157	$ 1,252	$ 846

IDACORP and IPC have not contributed and are not required to contribute to their pension plan in 2009. In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009 in order to avoid required contributions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. IPC has elected to use asset smoothing. As IPC was below the required funding level as of January 1, 2009, IPC is required to make additional contributions to improve the funded status of the plan beginning in 2010. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated minimum required contributions would be approximately $45 million in 2010 and $33 million in each of 2011, 2012, and 2013. IPC may elect to make contributions earlier than the required dates to maximize potential benefits from tax filings, and expected regulatory filings related to the recovery of pension contributions. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

9. INVESTMENTS IN DEBT AND EQUITY SECURITIES:

Investments in debt and equity securities are accounted for in accordance with SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*. Those investments classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities mature in 2009 and 2010. In 2009, $4.8 million of investments in debt securities previously classified as held-to-maturity were sold to facilitate the early repayment of debt, and $4.1 million were reclassified to available for sale.

The following table summarizes investments in debt and equity securities (in thousands of dollars):

	March 31, 2009			December 31, 2008		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale - IPC	$ -	$ 1,457	$ 12,352	$ -	$ -	$ 14,451
Available-for-sale - IFS	21	7	4,102	-	-	-
Held-to-maturity - IFS	3	-	496	3	25	9,448

At the end of each reporting period, IDACORP and IPC analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At March 31, 2009, five available-for-sale securities were in an unrealized loss position. Four of these securities are investments in broadly diversified equity index funds used to fund IPC s Senior Management Security Plan (SMSP) and the fifth is a debt security held by IFS. IDACORP and IPC have not recognized any impairment losses in 2009 because management has determined that IDACORP and IPC have the intent and ability to hold the assets for a forecasted recovery.

The following table summarizes securities that were in an unrealized loss position at March 31, 2009, and December 31, 2008, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	Aggregate Related Fair Value	Aggregate Unrealized Loss	Aggregate Related Fair Value
2009:				
Available-for-sale equity securities (IPC)	$ 1,457	$ 12,352	$ -	$ -
Available-for-sale debt securities (IFS)	$ 7	$ 1,311	$ -	$ -
2008:				
Held-to-maturity debt securities (IFS)	$ -	$ -	$ 25	$ 3,975

The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	Three months ended March 31,	
	2009	2008
Proceeds from sales	$ 3,817	$ -
Gross realized gains from sales	12	-
Gross realized losses from sales	5	-

10. FAIR VALUE MEASUREMENTS:

The following tables present information about IDACORP s and IPC s assets and liabilities measured at fair value on a recurring basis as of March 31, 2009 (in thousands of dollars). IDACORP s and IPC 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.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
IDACORP				
Assets:				
Derivatives	$ 1,154	$ 1	$ -	$ 1,155

Money market funds	77,397	-	-	77,397
Trading securities: Equity securities	4,763	-	-	4,763
Available-for-sale securities:				
Equity securities	12,354	-	-	12,354
Available-for-sale securities:				
Debt securities	-	4,120	-	4,120
Liabilities:				
Derivatives	$ (921)	$ (5,212)	$ -	$ (6,133)
IPC				
Assets:				
Derivatives	$ 1,154	$ 1	$ -	$ 1,155
Money market funds	76,959	-	-	76,959
Trading securities: Equity securities	4,010	-	-	4,010
Available-for-sale securities:				
Equity securities	12,354	-	-	12,354
Liabilities:				
Derivatives	$ (921)	$ (5,212)	$ -	$ (6,133)

In accordance with SFAS 157, IDACORP and IPC have categorized their financial instruments, based on the priority of the inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument. Financial assets and liabilities recorded on the Condensed Consolidated Balance Sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that IDACORP and IPC has the ability to access.

Level 2: Financial assets and liabilities whose values are based on the following:

a) Quoted prices for similar assets or liabilities in active markets;

b) Quoted prices for identical or similar assets or liabilities in non-active markets;

c) Pricing models whose inputs are observable for substantially the full term of the asset or liability;

d) Pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

IDACORP and IPC Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data and quoted prices for similar assets in non-active markets.

Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management s own assumptions about the assumptions a market participant would use in pricing the asset or liability.

IPC s derivatives are contracts entered into as part of our management of loads and resources. Electricity swaps are valued on the Intercontinental Exchange with quoted prices in an active market. Natural gas derivative and diesel derivative valuations are performed using New York Mercantile Exchange (NYMEX) pricing, adjusted for basis location, which are also quoted under NYMEX. Trading securities consists of employee-directed investments held in a Rabbi Trust and are related to an executive deferred compensation plan. Available-for-sale securities are related to the SMSP and are held in a Rabbi Trust and are actively traded money market and equity funds with quoted prices in active markets.

The following tables present the carrying value and estimated fair value of other financial instruments that are not reported at fair value, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable and long-term debt are based upon discounted cash flow analyses.

	March 31, 2009	
	Carrying Amount	**Estimated Fair Value**
	(thousands of dollars)	
IDACORP		
Assets:		
Notes receivable	$ 2,503	$ 2,503
Debt Securities	498	497
Liabilities:		
Long-term debt	$ 1,198,193	$ 1,111,798
IPC		
Assets:		
Notes receivable	$ 175	$ 175
Liabilities:		
Long-term debt	$ 1,197,754	$ 1,111,337

11. SEGMENT INFORMATION:

IDACORP s only reportable segment is utility operations, for which the primary source of revenue is the regulated operations of IPC. IPC s regulated operations include the generation, transmission, distribution, purchase and sale of electricity. This segment also includes income from Bridger Coal Company, an unconsolidated joint venture also subject to regulation.

Other operating segments are below the quantitative thresholds for reportable segments and are included in the All Other category. This category is comprised of IFS s investments in affordable housing developments and historic rehabilitation projects, Ida-West s joint venture investments in small hydroelectric generation projects, the remaining activities of energy marketer IE, which wound down its operations in 2003, and IDACORP s holding company expenses.

The following table summarizes the segment information for IDACORP s utility operations and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars):

Utility	All	Consolidated

	Operations		Other		Eliminations		Total	
Three months ended March 31, 2009:								
Revenues	$	228,029	$	545	$	-	$	228,574
Income (loss) from continuing operations attributable to IDACORP, Inc.		19,284		(400)		-		18,884
Total assets at March 31, 2009	$	3,946,207	$	148,541	$	(25,070)	$	4,069,678
Three months ended March 31, 2008:								
Revenues	$	212,796	$	644	$	-	$	213,440
Income from continuing operations attributable to IDACORP, Inc.		21,271		445		-		21,716

12. DERIVATIVE INSTRUMENTS

On January 1, 2009, IDACORP and IPC adopted SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities- an amendment of FASB Statement No. 133.* SFAS 161 requires the following disclosures.

Commodity Price Risk
IPC is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is commodity price risk related to IPC s ongoing utility operations producing electricity to meet the demand of its retail customers. Physical and financial forward contracts for both electricity and fuel used to produce electricity are entered into to manage the price risk associated with meeting forecasted loads. The objective of IPC s energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability and make economic use of temporary surpluses that may develop.

SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, requires companies to recognize all derivative instruments as either assets or liabilities at fair value on the balance sheet. IPC s physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements with the exception of forward contracts for the purchase of natural gas for use at IPC s peaking natural gas generation facilities. Because of IPC s PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

As of March 31, 2009, IPC had the following outstanding derivative commodity forward contracts that were entered into for the purpose of economically hedging forecasted purchases and sales:

Commodity	**Number of Units**	
Electricity purchases	591,175	MWh
Electricity sales	272,400	MWh
Natural gas	82,500	MMBtu
Diesel	615,423	gallons

The following table presents the fair values and locations of derivatives not designated as hedging instruments recorded in the balance sheet at March 31, 2009 (in thousands of dollars):

	Asset Derivatives		**Liability Derivatives**	
	Balance Sheet	**Fair**	**Balance Sheet**	**Fair**
Commodity derivatives	**Location**	**Value**	**Location**	**Value**
Current:				

Financial swaps	Other current assets	$	1,542	Other current liabilities	$	3,419
Financial swaps	Other current liabilities		2,293	Other current assets		137
Forward contracts			-	Other current liabilities		5,212
Long term:						
Financial swaps	Other assets		127	Other liabilities		380
Financial swaps	Other liabilities		-	Other assets		67
Forward contracts	Other liabilities		1			-
Total		$	3,963		$	9,215

The following table presents the effect on income of derivatives not designated as hedging instruments under SFAS 133 for the quarter ended March 31, 2009 (in thousands of dollars):

Commodity derivatives	**Location of Gain/(Loss) Recognized in Income on Derivative**	**Amount of Gain/(Loss) Recognized in Income on Derivative [1]**	
Financial swaps	Purchased power	$	(756)

[1] Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or liabilities.

IPC records changes in fair value of its derivative contracts as either regulatory assets or liabilities. Settlement gains and losses on electricity swap contracts are recorded on the income statement in sales for resale or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in fuel inventory on the balance sheet.

Credit Risk

At March 31, 2009, IPC does not have material credit exposure from financial instruments, including derivatives. IPC monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. IPC manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits or letters of credit from counterparties or their affiliates, as deemed necessary. The majority of IPC s contracts are under the Western Systems Power Pool agreement that provides for adequate assurances if a counterparty has debt that is downgraded to below investment grade by at least one rating agency. IPC also requires North American Energy Standards Board contracts as necessary for physical gas transactions, and International Swaps and Derivatives Association, Inc. contracts as needed for financial transactions.

Credit-Contingent Features

Certain of IPC s derivative instruments contain provisions that require IPC s unsecured debt to maintain an investment grade credit rating from each of the major credit rating agencies. If IPC s unsecured debt 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 full overnight 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 on March 31, 2009, is $6.5 million. IPC has posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2009, IPC could have been required to post $5.7 million of cash collateral to its counterparties.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of IDACORP, Inc.
Boise, Idaho

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the Company) as of March 31, 2009, and the related condensed consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of IDACORP, Inc. and subsidiaries as of December 31, 2008, and the related consolidated statements of income, comprehensive income, shareholders equity, and cash flows for the year then ended prior to retrospective adjustment for the adoption of Financial Accounting Standards Board Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, (not presented herein); and in our report dated February 25, 2009, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. We also audited the adjustments described in Note 1 that were applied to retrospectively adjust the December 31, 2008, consolidated balance sheet of IDACORP, Inc. and subsidiaries (not presented herein). In our opinion, such adjustments are appropriate and have been properly applied to the previously issued consolidated balance sheet in deriving the accompanying retrospectively adjusted consolidated balance sheet as of December 31, 2008.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
May 6, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Idaho Power Company
Boise, Idaho

We have reviewed the accompanying condensed consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary (the Company) as of March 31, 2009, and the related condensed consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary as of December 31, 2008, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for the year then ended (not presented herein); and in our report dated February 25, 2009, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).* In our opinion, the information set forth in the accompanying condensed consolidated balance sheet and statement of capitalization as of December 31, 2008, is fairly stated, in all material respects, in relation to the consolidated balance sheet and statement of capitalization from which it has been derived.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
May 6, 2009

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollar amounts and megawatt-hours (MWh) are in thousands unless otherwise indicated.)

INTRODUCTION:

In Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, IPC) are discussed.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is IPC. IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides certain access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes certain record retention and reporting requirements on IDACORP.

IPC is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

IDACORP s other subsidiaries include:

IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;

Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and

IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements of IDACORP and IPC. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2008 and should be read in conjunction with the discussions in that report.

FORWARD-LOOKING INFORMATION:

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, IDACORP and IPC are hereby filing cautionary statements identifying important factors that could cause actual results to differ materially from those projected in forward-looking statements, as such term is defined in the Reform Act, made by or on behalf of IDACORP or IPC in this Quarterly Report on Form 10-Q, in presentations, in response to questions or otherwise. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance, often, but not always, through the use of words or phrases such as anticipates, believes, estimates, expects, intends, plans, predicts, projects, may result, may continue expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements involve estimates, assumptions and uncertainties and are qualified in their entirety by reference to, and are accompanied by, the following important factors, which are difficult to predict, contain uncertainties, are beyond IDACORP s or IPC s control and may cause actual results to differ materially from those contained in forward-looking statements:

The effect of regulatory decisions by the Idaho Public Utility Commission, the Oregon Public Utility Commission and the Federal Energy Regulatory Commission affecting our ability to recover costs and/or earn a reasonable rate of return including, but not limited to, the disallowance of costs that have been deferred;

Changes in and compliance with state and federal laws, policies and regulations, including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates;

Changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or other taxing jurisdiction;

Litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability;

Changes in and compliance with laws, regulations and policies including changes in law and compliance with environmental, natural resources, endangered species and safety laws, regulations and policies and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies;

Global climate change and regional weather variations affecting customer demand and hydroelectric generation;

Over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities;

Construction of power generation, transmission and distribution facilities, including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up;

Operation of power generating facilities including performance below expected levels, breakdown or failure of equipment, availability of transmission and fuel supply;

Changes in operating expenses and capital expenditures, including costs and availability of materials, fuel and commodities;

Blackouts or other disruptions of Idaho Power Company s transmission system or the western interconnected transmission system;

Population growth rates and other demographic patterns;

Market prices and demand for energy, including structural market changes;

Increases in uncollectible customer receivables;

Fluctuations in sources and uses of cash;

Results of financing efforts, including the ability to obtain financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets and other economic conditions;

Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;

Changes in interest rates or rates of inflation;

Performance of the stock market, interest rates, credit spreads and other financial market conditions, as well as changes in government regulations, which affect the amount and timing of required contributions to pension plans and the reported costs of providing pension and other postretirement benefits;

Increases in health care costs and the resulting effect on medical benefits paid for employees;

Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;

Homeland security, acts of war or terrorism;

Natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire;

Adoption of or changes in critical accounting policies or estimates; and

New accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

EXECUTIVE OVERVIEW:

First Quarter 2009 Financial Results
A summary of net income attributable to IDACORP, Inc. and earnings per diluted share is as follows:

	Three months ended March 31,			
	2009		**2008**	
Net income attributable to IDACORP, Inc.	$	18,884	$	21,716
Average outstanding shares - diluted (000s)		46,876		45,047
Earnings per diluted share	$	0.40	$	0.48

IPC s electric utility operating income declined $9.4 million primarily due to a May 2008 Idaho Public Utilities Commission (IPUC) Order that required IPC to change the method for recording base power supply costs which impacted the PCA expense levels during the first and second quarter 2008. As a result, PCA expenses in the first quarter of 2008 were approximately $6.4 million lower (thereby increasing earnings) than what would have been recorded had the orders been effective by the end of the first quarter 2008.

IPC s sales volumes decreased five percent due in part to weather-related factors and the decline in commercial and industrial sales quarter-over-quarter. The impact of this reduction is partially mitigated by the Load Growth Adjustment Rate (LGAR) and Fixed Cost Adjustment (FCA) Mechanisms, both of which were put in place to manage the impact of changes in sales volumes (PCA) and customer usage (FCA) as compared to the levels included in base rates.

Utility operating income was further impacted by the Idaho general rate case which required IPC to reverse part of the refund of the Federal Energy Regulatory Commission fees recognized in 2006 decreasing income $1.7 million. A reduction in the open access transmission rates also reduced operating income $1.7 million.

Partially offsetting these items was a $4.1 million improvement in earnings from Bridger Coal Company, which had experienced losses in the first quarter of 2008 primarily due to difficulties related to the longwall mining operation, a $2.2 million increase in Other Income from life insurance investments and a $1.6 million increase in interest income primarily related to a federal income tax refund.

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for the three months ended March 31, 2008 to March 31, 2009 (in thousands):

March 31, 2008 Net income attributable to IDACORP, Inc.		$ 21,716
Change in IPC Net Income:		
PCA allocation change	$ (6,400)	
FERC fees refund reversal	(1,707)	
Other revenue decrease due to lower OATT rate	(1,729)	
Increased income at Bridger Coal Company	4,097	
Life Insurance benefits	2,189	
Increased interest income	1,621	
Tax and Other	(58)	
Total Change in IPC Net Income		(1,987)
Decreased net income at IFS (shown net of tax)		(660)
Other net decreases (shown net of tax)		(185)
March 31, 2009 Net income attributable to IDACORP, Inc.		$ 18,884

Capital Requirements

Major Projects: IPC has several major projects in development. These projects are summarized here and are discussed further in LIQUIDITY AND CAPITAL RESOURCES - Capital Requirements - Major Projects.

Langley Gulch power plant (2012 baseload resource): On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). Langley Gulch will be a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs and is anticipated to be in operation by December 2012. IPC proposes to construct Langley Gulch in Payette County, approximately four miles south of New Plymouth, Idaho, commencing in summer 2010 at an estimated cost of $427 million.

Gateway West transmission project: IPC and PacifiCorp are jointly exploring the Gateway West Project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. The estimated cost range for IPC s share of the project is between $500 million and $600 million. The lines will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. This project is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements.

Boardman-Hemingway transmission project: IPC is also exploring alternatives for the construction of a 500-kV line between southwestern Idaho at the Hemingway substation and the Northwest at Boardman substation. Currently, IPC estimates construction costs of $600 million and IPC expects to seek partners for up to 50 percent of the project when construction commences. The Boardman-Hemingway Line will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. This project is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements.

Liquidity

Pension Plan: Financial market volatility and disruption caused a significant decline in the value of qualified pension assets. Current provisions of the Pension Protection Act and relief provisions of the Worker, Retiree, and Employer Recovery Act require that if a company is not 94 percent funded as of January 1, 2009, then, the company will need to make additional contributions to improve the funded status of the plan. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated minimum required contributions would be approximately $45 million in 2010 and $33 million in each of 2011, 2012, and 2013.

American Recovery and Reinvestment Act of 2009: The American Recovery and Reinvestment Act of 2009, enacted on February 17, 2009, provides tax and appropriation benefits to the utility industry. IPC is currently evaluating the impact of and opportunities under the Act.

Regulatory Matters

Idaho 2008 General Rate Case: On January 30, 2009, the IPUC issued its final order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On March 19, 2009, in response to IPC s request for reconsideration, the IPUC issued an order which increased IPC s Idaho revenue requirement by approximately $6.1 million to approximately $27 million. The request for reconsideration is discussed in more detail in REGULATORY MATTERS - Idaho Rate Cases - 2008 General Rate Case.

Idaho Ratemaking Treatment Act: This legislation allows the IPUC to authorize and pre-approve ratemaking treatment for qualified capital construction projects of IPC and other Idaho utilities. The legislation will become effective July 1, 2009, and provide greater assurance to capital markets of IPC s ability to recover costs for large projects authorized by the IPUC.

Idaho PCA: PCA workshops were conducted in the fall of 2008 and the resulting settlement stipulation became effective February 1, 2009. The stipulation includes, among other things, a change in the sharing percentage between customers and shareholders, the inclusion of third-party transmission expense in the PCA and a new LGAR rate. The stipulation is discussed in more detail in REGULATORY MATTERS - Deferred Net Power Supply Costs - PCA Workshops.

Integrated Resource Plan: IPC is currently preparing the 2009 IRP, which was originally expected to be completed in June 2009. In light of the economic changes since September 2008 and in response to the OPUC s desire for additional analysis regarding the Boardman to Hemingway Transmission Project, on April 24, 2009 IPC filed a request for an extension with the IPUC and OPUC to delay the filing of the 2009 IRP until December 2009.

OATT: Effective June 1, 2006, IPC s Open Access Transmission Tariff (OATT) was made a formula rate based on financial and operational data IPC is required to file annually with the FERC in its Form 1. On January 15, 2009, the FERC issued an unfavorable order affecting the way IPC calculates its OATT. The order required IPC to reduce its transmission service rates to FERC jurisdictional customers and make refunds in the total amount of $13.3 million (including $1.1 million in interest) for the period since June 2006, which IPC did on February 25, 2009. IPC has filed a request for rehearing with the FERC. On March 18, 2009, the FERC issued a tolling order that effectively relieves it from acting on the request for reconsideration for an indefinite period of time. The OATT is discussed in more detail in REGULATORY MATTERS - Federal Regulatory Matters - OATT.

Environmental Issues

IPC is actively tracking state, regional and federal developments in the climate change area and the related proposals for renewable portfolio standards. IPC is also monitoring changes in air quality standards, including possible changes in the National Ambient Air Quality Standards and the development of Maximum Achievable Control Technology standards for mercury emissions from coal-fired power plants. These issues are discussed in more detail in LEGAL AND ENVIRONMENTAL ISSUES Environmental Issues.

Idaho Water Management Issues: Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at IPC s hydroelectric projects on the Snake River. On March 25, 2009, IPC and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007 with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters. For a further discussion of water management issues see LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues.

2009 Operating and Financial Metrics Outlook

The outlook for key operating and financial metrics for 2009 is:

	2009 Estimates	
Key Operating & Financial Metrics	**Current**	**Previous**
IPC Operation & Maintenance Expense (Millions)	No change	\$280-\$290
IPC Capital Expenditures (Millions) (1)	No change	\$220-\$230
IPC Hydroelectric Generation (Million MWh) (2)	No change	6.5-8.5
Non-regulated Subsidiary Earnings and Holding Company Expenses (Millions)	No change	\$0.0-\$3.0
Effective Tax Rates:		
IPC	No change	31%-35%
Consolidated IDACORP	No change	24%-28%

(1) For the three-year period, 2009-2011, IPC expects to spend approximately \$780 - \$800 million. This amount includes expenditures for the siting and permitting of major transmission expansions for Boardman to Hemingway, Gateway West, Hemingway Station and the Hemingway Hubbard facilities, but excludes the costs for the Langley Gulch power plant. On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant. A decision from the IPUC is expected later this year. If the IPUC grants the CPCN, IPC expects to spend between \$45-\$50 million during 2009 on this project. IPC s estimate for construction of Langley Gulch power plant is \$427 million, including transmission interconnection costs.

(2) The projected range for annual hydroelectric generation is based on 2008-09 Snake River Basin snowpack at 91 percent of average on April 30 with reservoir levels approximately 108 percent above normal.

RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP s and IPC s earnings during the three months ended March 31, 2009. In this analysis, the first quarter results for 2009 are compared to the same period in 2008.

The following table presents net income (losses) for IDACORP and its subsidiaries:

	Three months ended March 31,	
	2009	2008
IPC - Utility operations	$ 19,284	$ 21,271
IDACORP Financial Services	141	801
Ida-West Energy	188	55
IDACORP Energy	(19)	(12)
Holding company	(710)	(399)
Net income attributable to IDACORP, Inc.	$ 18,884	$ 21,716
Average common shares outstanding (diluted)	46,876	45,047
Earnings per diluted share	$ 0.40	$ 0.48

Utility Operations

Operating environment: IPC is one of the nation s few investor-owned utilities with a predominantly hydroelectric generating base. Because of its reliance on hydroelectric generation, IPC s generation operations can be significantly affected by water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC s hydroelectric facilities, springtime snow pack run-off, river base flows, spring flows, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC s hydroelectric projects are reduced, IPC s hydroelectric generation is reduced. This results in less generation from IPC s resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased power supply costs. During high water years, increased off-system sales and the decreased need for purchased power reduce net power supply costs.

Operations plans are developed during the year to provide guidance for generation resource utilization and energy market activities (off-system sales and power purchases). The plans incorporate forecasts for generation unit availability, reservoir storage and stream flows, gas and coal prices, customer loads, energy market prices and other pertinent inputs. Consideration is given to when to use IPC s available resources to meet forecast loads and when to transact in the wholesale energy market. The allocation of hydroelectric generation between heavy load and light load hours or calendar periods is considered in development of the operating plans. This allocation is intended to utilize the flexibility of the hydroelectric system to shift generation to high value periods, while operating within the constraints imposed on the system. IPC s energy risk management policy, unit operating requirements and other obligations provide the framework for the plans.

Hydroelectric generation for the first quarter of 2009 was five percent below the same period in 2008 and 29 percent below the 30 year average due to a combination of below normal rainfall and near record low flows in the Snake River from several years of drought.

As of April 30, 2009, reservoir levels in selected federal reservoirs upstream of Brownlee were at 108 percent of average. The stream flow forecast released on April 30, 2009, by the NWRFC predicts that Brownlee reservoir inflow for April through July 2009 will be 5.0 million acre-feet (maf), or 80 percent of the NWRFC average, an increase over the 2008 April through July inflow of 4.4 maf, or 70 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.5 and 8.5 million MWh from its hydroelectric facilities in 2009, compared to 6.9 million MWh in 2008.

On December 30, 2008, IPC issued a request for proposals (RFP) seeking to acquire additional water through leases. Proposals were received in February 2009 and have been evaluated. IPC is currently negotiating possible leases for 2009. This action was taken in part to offset the impact of drought and changing water use patterns in southern Idaho and increase our ability to meet mid-summer electricity demands with lower cost hydroelectric generation. Acquiring water through lease also helps IPC improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex. IPC includes these costs in its annual PCA filing.

IPC s system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,214 MW, set on June 30, 2008. Although IPC was able to meet all of its load requirements during this period of increased demand, all available resources of IPC s system were fully committed during this and other similar heavy load periods. The all-time winter peak demand is 2,464 MW, set on January 24, 2008.

The following table presents IPC s power supply for the three month period ended March 31:

	MWh Hydroelectric Generation	Thermal Generation	Total System Generation	Purchased Power	Total
Three months ended:					
March 31, 2009	1,586	1,966	3,552	661	4,213
March 31, 2008	1,663	1,979	3,642	687	4,329

General business revenue: The following table presents IPC s general business revenues, MWh sales, average number of customers and Boise, Idaho weather conditions for the three months ended March 31:

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		Three months ended March 31,	
		2009	2008
Revenue			
	Residential	$ 106,447	$ 95,242
	Commercial	51,542	44,675
	Industrial	31,044	26,657
	Irrigation	571	739
	Deferred revenue related to Hells Canyon relicensing AFUDC	(1,677)	-
	Total	$ 187,927	$ 167,313
MWh			
	Residential	1,534	1,589
	Commercial	957	999
	Industrial	781	851
	Irrigation	7	11
	Total	3,279	3,450
Customers (average)			
	Residential	404,408	401,156
	Commercial	64,080	62,952
	Industrial	124	121
	Irrigation	18,533	18,139
	Total	487,145	482,368
Heating degree-days		2,532	2,680
Precipitation (inches)		2.33	2.70

Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. Normal heating degree-days for the first quarter are 2,574 and normal precipitation for the first quarter is 3.94 inches.

General business revenue increased $20.6 million for the quarter as compared to the same period in 2008. This increase is primarily attributable to the following factors:

Rates: Rate changes positively impacted general business revenue $29.9 million for the quarter. The PCA component of rates increased $16.9 million, and there was an increase of $12.9 million due to increases in retail base rates, including a general rate increase of 5.2 percent effective March 1, 2008, a 1.37 percent increase for the Danskin plant effective June 1, 2008, and a 3.1 percent general rate increase effective February 1, 2009.

Usage: Changes in usage decreased general business revenues $9.8 million for the quarter.

Customers: General business customer growth of 1.3 percent increased revenue $2.2 million for the quarter.

As part of the general rate case effective February 1, 2009, the IPUC allowed IPC to begin collecting Allowance for Funds Used During Construction (AFUDC) for relicensing costs at Hells Canyon Complex (HCC) even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. IPC expects to collect approximately $10 million annually, but must defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service. This deferral offset revenues by approximately $1.7 million in the first quarter of 2009.

Off-system sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The following table presents IPC s off-system sales for the three months ended March 31:

	Three months ended March 31,			
	2009		**2008**	
Revenue	$	28,530	$	33,363
MWh sold		577		518
Revenue per MWh	$	49.45	$	64.41

Off-system sales revenue declined $4.8 million in the first quarter of 2009. Electricity prices, which are closely linked to natural gas prices, declined 23 percent as demand decreased for both gas and electricity in the Northwest. This decrease was partially offset by an 11 percent increase in MWh sold due to lower system load.

Other revenues: The table below presents the components of other revenues for the three months ended March 31:

	Three months ended March 31, 2009	2008
Transmission services and property rental	$ 7,515	$ 8,756
Energy efficiency	4,057	3,364
Total	$ 11,572	$ 12,120

The decrease in transmission services and property rental reflects new OATT rates implemented in January 2009 and the OATT rate refund. For further discussion, please refer to REGULATORY MATTERS Federal Regulatory Matters - OATT.

An IPUC order allows IPC to record energy efficiency program expenditures as an operating expense with an offsetting amount recorded in other revenues, resulting in no net effect on earnings. Energy efficiency revenues and expenses were $4.1 million and $3.4 million in the first quarter of 2009 and 2008, respectively, reflecting increased program expenditures.

Purchased power: The following table presents IPC s purchased power expenses and volumes for the three months ended March 31:

	Three months ended March 31, 2009	2008
Purchased power expense	$ 32,795	$ 45,299
MWh purchased	661	687
Cost per MWh purchased	$ 49.61	$ 65.94

Purchased power expense decreased $13 million due to a decline of 4 percent in volumes purchased resulting from lower system load. Cost per MWh declined 25 percent as demand decreased for both electricity and gas in the Northwest.

Fuel expense: The following table presents IPC s fuel expenses and generation at its thermal generating plants for the three months ended March 31:

	Three months ended March 31,			
	2009		2008	
Fuel expense	$	39,133	$	37,237
Thermal MWh generated		1,966		1,978
Cost per MWh	$	19.90	$	18.83

Fuel expense increased $1.9 million primarily due to a 20 percent increase in fuel expense at the Jim Bridger plant caused by higher coal prices related to the continued transition to underground mining operations at Bridger Coal Company. These increases were partially offset by a 58 percent decrease in fuel expense at the gas turbine plants due to lower generation and lower gas prices.

PCA: PCA expense represents the effects of the Idaho PCA and Oregon PCAM deferrals of net power supply costs (fuel, purchased power and third party transmission expense less off-system sales). These mechanisms are discussed in more detail below in REGULATORY MATTERS - Deferred Net Power Supply Costs.

The following table presents the components of the PCA for the three months ended March 31:

		Three months ended March 31,		
		2009		**2008**
Current year power supply cost deferral	$	(10,407)	$	(20,199)
Amortization of prior year authorized balances		26,266		2,455
Total power cost adjustment	$	15,859	$	(17,744)

The $33.6 million increase in 2009 PCA expense is primarily due to a $23.8 million increase in the amortization of the prior year authorized balances. In both years, net power supply costs were higher than the amounts estimated in the annual PCA forecast, resulting in the deferral of costs for recovery in subsequent rate years. As the deferred costs are being recovered in rates, the deferred balances are amortized.

The current year deferral is $9.8 million lower primarily due to a May 2008 IPUC Order that required IPC to change the method for recording base power supply costs which impacted the PCA expense levels during the first and second quarter 2008. As a result, PCA expenses in the first quarter of 2008 were approximately $6 million lower (thereby increasing earnings) than what would have been recorded had the orders been effective by the end of the first quarter 2008.

Other operations and maintenance expenses: Other operations and maintenance expense increased $0.3 million due to an increase of $2.2 million in payroll-related expenses and an accrual of $1.7 million for a FERC fees refund. Partially offsetting these increases was a decrease of $2.3 million from the fixed cost adjustment mechanism, and a $1.3 million decrease in outside services due to budget reductions in 2009.

Non-utility Operations

IFS: IFS contributed $0.1 million and $0.8 million to net income in the first quarter of 2009 and 2008, respectively, principally from the generation of federal income tax credits and accelerated tax depreciation benefits related to its investments in affordable housing and historic rehabilitation developments.

IFS made $0.8 million in new investments in the first quarter of 2009 and generated tax credits of $2.0 million and $2.7 million during the first quarters of 2009 and 2008, respectively. IFS will continue to review new legislation for opportunities for investment that will be commensurate with the ongoing needs of IDACORP.

Income Taxes

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP s effective rate on continuing operations for the three months ended March 31, 2009, was 26.5 percent, compared to 20.5 percent for the three months ended March 31, 2008. IPC s effective tax rate for the three months ended March 31, 2009, was 33.6 percent, compared to 32.5 percent for the three months ended March 31, 2008. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC s regulatory flow-through tax adjustments, and lower tax credits from IFS.

In March 2009, the U.S. Congress Joint Committee on Taxation (JCT) completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 Internal Revenue Service examination report. The JCT accepted both items without change. Also in March 2009, IDACORP received $1.9 million of interest related to its federal refund for 2005. IDACORP considered these matters effectively settled in 2008 and had recorded the related financial effects in its December 31, 2008, financial statements.

LIQUIDITY AND CAPITAL RESOURCES:

Operating Cash Flows

IDACORP s and IPC s operating cash inflows for the quarter ended March 31, 2009 were $44 million and $55 million, respectively. These amounts were an increase of $23 million and $32 million, respectively, compared to the quarter ended March 31, 2008. The following are significant items that affected operating cash flows in 2009:

The increases in IDACORP s and IPC s operating cash inflows were primarily the result of a $24 million increase in the collection of previously deferred net power supply costs as compared to 2008.

Income tax refunds increased $13 million and $23 million for IDACORP and IPC, respectively compared to 2008, due to the settlement of the 2005 Internal Revenue Service examination.

Inflows were partially offset by the refund of $13 million to transmission customers upon a final order from the FERC on IPC s OATT. The OATT is further discussed in REGULATORY MATTERS - Federal Regulatory Matters - OATT.

IDACORP s operating cash flows are driven principally by IPC. General business revenues and the costs to supply power to general business customers have the greatest impact on IPC s operating cash flows, and are subject to risks and uncertainties relating to weather and water conditions and IPC s ability to obtain rate relief to cover its operating costs and provide a return on investment.

Investing Cash Flows

IDACORP s and IPC s investing cash outflows were $41 million and $49 million, respectively for the quarter ended March 31, 2009. Investing cash outflows are primarily the result of IPC s utility construction. The outflows were partially offset by $5 million received from the sale of investments held by IFS and $2 million in proceeds from the sale of emission allowances by IPC.

Financing Cash Flows

IDACORP s and IPC s financing cash inflows for the quarter ended March 31, 2009 were $77 million and $74 million, respectively, compared to $44 million and $35 million, respectively, for the quarter ended March 31, 2008. On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. The $100 million inflow was partially offset by dividends paid of $14 million and the repayment of $7 million of notes by IFS.

Economic Environment

IDACORP and IPC continue to perform assessments to determine the impact on IDACORP s and IPC s financial position, if any, of recent market developments, including the bankruptcy and restructuring or merging of certain financial institutions. Despite the turmoil in the global credit markets, IDACORP and IPC continue to have access to the capital markets and have been able to generate funds internally and externally to meet capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan because IDACORP and IPC rely on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by internally generated funds. IDACORP and IPC expect that operating cash flows, together with the revolving credit facilities and other external financing, will be adequate to meet their operating and capital needs, although there can be no assurance that continued or increased volatility and disruption in the global capital and credit markets will not restrict either company s ability to access these markets on commercially acceptable terms or at all.

Financing Programs

IDACORP s consolidated capital structure consisted of common equity of 46 percent and debt of 54 percent at March 31, 2009. IPC s consolidated capital structure consisted of common equity of 45 percent and debt of 55 percent at March 31, 2009.

Shelf Registrations: IDACORP has approximately $588 million remaining on a shelf registration statement that can be used for the issuance of debt securities and common stock. On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt. IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

Credit Facilities: The following table outlines available liquidity.

	March 31, 2009		December 31, 2008	
	IDACORP	**IPC**	**IDACORP**	**IPC**
Revolving credit facility	$ 100,000	$ 300,000	$ 100,000	$ 300,000
Commercial paper outstanding	(48,150)	(98,650)	(13,400)	(108,950)
Floating rate draw	-	-	(25,000)	-
Identified for other use [1]	-	(24,245)	-	(24,245)
Net balance available	$ 51,850	$ 177,105	$ 61,600	$ 166,805

[1] Port of Morrow and American Falls bonds that holders may put to IPC.

IDACORP s credit facility is a $100 million five-year credit agreement that terminates on April 25, 2012. IDACORP s credit facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million. IDACORP has the right to request an increase in the aggregate principal amount of the IDACORP Facility to $150 million and to request one-year extensions of the then existing termination date. At March 31, 2009, no loans were outstanding on IDACORP s credit facility and $48 million of commercial paper was outstanding. At May 4, 2009, no loans and $46 million of commercial paper was outstanding.

IPC s credit facility is a $300 million five-year credit agreement that terminates on April 25, 2012. IPC s credit facility, which will be used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IPC has the right to request an increase in the aggregate principal amount of the IPC Facility to $450 million and to request one-year extensions of the then existing termination date. At March 31, 2009, no loans were outstanding on IPC s credit facility and $99 million of commercial paper was outstanding. At May 4, 2009, no loans and $36 million of commercial paper was outstanding.

Term Loan Credit Agreement: IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans were due on March 31, 2009 and could be prepaid but not reborrowed. IPC used $166.1 million of the proceeds from the loans to effect the mandatory purchase on April 3, 2008, of the Pollution Control Bonds (as discussed below under Pollution Control Revenue Refunding Bonds) and $3.9 million to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement.

IPC entered into a new $170 million Term Loan Credit Agreement, dated as of February 4, 2009, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on February 4, 2009, in an aggregate principal amount of $170 million. The loans are due on February 3, 2010, but are subject to earlier payment if IPC remarkets the pollution control revenue refunding bonds discussed below. The loans may be prepaid but not reborrowed. The new Term Loan Credit Agreement replaces the above mentioned Term Loan Credit Agreement.

Without additional approval from the Idaho Public Utilities Commission, the Public Utility Commission of Oregon and the Public Service Commission of Wyoming, the aggregate amount of borrowings by IPC under the Term Loan Credit Agreement together with any other short-term borrowings at any one time outstanding may not exceed $450 million.

Debt Covenants: The IDACORP credit facility, the IPC credit facility and the Term Loan Credit Agreement each contain covenants requiring the company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At March 31, 2009, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively. At March 31, 2009, IDACORP and IPC were each in compliance with all other covenants in their respective credit facilities and the Term Loan Credit Agreement. Reference is made to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008 for a discussion of additional debt covenants.

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Pollution Control Revenue Refunding Bonds: Two series of bonds have been issued for the benefit of IPC and are each supported by a financial guaranty insurance policy issued by Ambac Assurance Corporation (Ambac). The two series are the $116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds).

On April 3, 2008, IPC made a mandatory purchase of the Pollution Control Bonds. IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of Ambac s credit ratings deterioration. The Pollution Control Bonds remain outstanding and have not been retired or cancelled. IPC is the current holder of the bonds, but ultimately expects to remarket the bonds to investors. The maximum interest rate is 14 percent for the Sweetwater bonds and at specified rates capped at 12 percent for the Humboldt bonds.

Credit Ratings

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table outlines the current S&P, Moody s and Fitch Ratings, Inc. (Fitch) ratings of IDACORP s and IPC s securities:

	S&P		**Moody s**		**Fitch**	
	IPC	**IDACORP**	**IPC**	**IDACORP**	**IPC**	**IDACORP**
Corporate Credit Rating	BBB	BBB	Baa 1	Baa 2	None	None
Senior Secured Debt	A-	None	A3	None	A-	None
Senior Unsecured Debt	BBB	BBB-	Baa 1	Baa 2	BBB+	BBB
Short-Term Tax-Exempt Debt	BBB-/A-2	None	Baa 1/ VMIG-2	None	None	None
Commercial Paper	A-2	A-2	P-2	P-2	F-2	F-2
Credit Facility	None	None	Baa 1	Baa 2	None	None
Rating Outlook	Stable	Stable	Negative	Negative	Negative	Negative

These security ratings reflect the views of the rating agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

IPC is experiencing a cycle of heavy infrastructure investment needed to address expected customer growth, peak demand growth, reliability, and aging plant and equipment. IPC s aging hydroelectric and thermal facilities require continuing upgrades and component replacement. In addition, costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. IPC must also add to its transmission system and distribution facilities to provide new service and to maintain reliability. As a result, IPC expects to spend between $780 and $800 million for construction related activities from 2009 to 2011, excluding construction of the Langley Gulch power plant. While internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2009 through 2011, IDACORP and IPC do not expect to need to access the equity capital markets during 2009, except for issuances under dividend reinvestment and employee-related plans. IDACORP and IPC expect to continue financing capital requirements with internally generated funds and externally financed capital.

The following table presents IPC s estimated cash requirements for construction, excluding AFUDC, for 2009 through 2011 (in millions of dollars):

	2009		2010-2011	
Ongoing Capital Expenditures	$	150-155	$	400-410
Advanced Metering Infrastructure (AMI)		20-22		40-50
Major Projects excluding Langley Gulch (detailed below)		50-53		95-105
Minimum Transmission for Baseload Resource		-		20-25
Total	$	220-230	$	555-590

Major Projects:

Langley Gulch Power Plant (2012 Baseload Resource): On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant. Langley Gulch will be a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs and is anticipated to be in operation by December 2012. IPC proposes to construct Langley Gulch in Payette County, approximately four miles south of New Plymouth, Idaho, commencing in summer 2010. The plant would connect to existing transmission lines.

The need for a baseload generating resource was identified in IPC s 2004 and 2006 Integrated Resource Plan (IRP) and the 2008 plan update. Langley Gulch was selected as the result of a competitive Request for Proposal (RFP) process IPC issued in April 2008. Proposals received from independent power supply developers were compared to each other and to an IPC-owned and operated CCCT. An independent consultant assisted IPC with the evaluation process, which considered price and non-price attributes of the responses to the RFP. Langley Gulch was identified as the preferred resource due to location, operating flexibility and lower cost.

IPC s estimate for construction of Langley Gulch is $427 million, including transmission interconnection costs. IPC s application requests that amounts incurred in excess of the estimate would be included in rates only if the IPUC agreed the additional amounts were prudent and should be included in rates. Should the CPCN be granted by the IPUC, it is expected that IPC would spend between $45 and $50 million during 2009 on the project. The CPCN is expected to be issued in the third quarter of 2009. For the project, IPC entered into two equipment supply contracts with Siemens Energy, Inc. (Siemens) a gas turbine purchase agreement dated December 19, 2008, and a steam turbine purchase agreement dated February 11, 2009. IPC has paid approximately $9 million to Siemens Energy to reserve the turbine equipment purchases under the contracts, with no further payment required before September 2009. IPC expects that it will spend approximately $90 million on the contracts. The two contracts have similar terms. Each contract requires: IPC pay a fixed price for the equipment; Siemens to guarantee delivery of the equipment to the site by specific dates that will accommodate the project schedule, or incur liquidated damages; Siemens to guarantee that the equipment will meet specified performance and emission standards, or incur liquidated damages; Siemens to warrant for a period of time that the equipment is free from defects; and Siemens to provide certain technical field assistance and consultation services under the contracts. The contracts are assignable by IPC with the consent of Siemens (which consent may not be unreasonably withheld). IPC also has the right to cancel the contracts at any time by paying specified cancellation charges.

IPC s purchase of the gas turbine under the gas turbine purchase agreement is subject to IPC (1) receiving the CPCN from the IPUC by September 1, 2009, (2) receiving IPC board approval for the expenditure of funds for Langley Gulch by September 1, 2009, and (3) providing satisfactory evidence to Siemens that IPC has sufficient financial resources available to it to meet its purchase payment obligations under the gas turbine purchase agreement. IPC expects to be able to meet these conditions. However, in the event IPC does not meet the conditions, or if for any other reason IPC does not wish to proceed with the purchase of the gas turbine under the gas turbine purchase agreement, IPC may terminate the agreement. Upon such termination IPC would be required to pay a cancellation fee to Siemens, based on a percentage of the total purchase price of the gas turbine. The cancellation fee percentage increases monthly from 20 percent on July 1, 2009 to 100 percent on or after September 1, 2010, including a cancellation fee of 35 percent on September 1, 2009. The steam turbine purchase agreement does not contain the purchase conditions set forth in the gas turbine purchase agreement. IPC has the right to terminate the steam turbine purchase agreement at any time upon paying a cancellation fee to Siemens based on a percentage of the total purchase price of the steam turbine. The steam turbine purchase agreement cancellation fee percentage increases monthly from 10 percent on February 1, 2009 to 100 percent on or after May 1, 2011, including a cancellation fee of 15 percent on September 1, 2009.

In its application, IPC requested that the IPUC include in its order one of two alternative ratemaking mechanisms: (1) authorization for IPC to annually include construction work in progress in rate base for all or a portion of the construction expenditures or (2) a commitment for the IPUC to apply specific ratemaking parameters for project costs and investment that IPC can rely upon when Langley Gulch is completed, including (a) acceptance of the reasonableness of costs up to the cost estimate, (b) commencement of cost recovery upon commercial operation and (c) agreement that the return on equity on Langley Gulch would be the same as is in effect when Langley Gulch is placed in service. IPC also requested that the IPUC authorize it to recover its prudently expended fuel costs through the PCA mechanism.

Hemingway Station: Construction of a new 500-kV station named Hemingway is expected to address growth, capacity and operating constraints to ensure reliable service to our network and native load customers while meeting mandatory regulatory reliability requirements. The station was originally part of the Gateway West Project but the timing of this addition was accelerated to 2010 to help meet forecast deficits and improve reliability. Cost estimates for the project, including rights-of-way, permitting and substation interconnections, are included in the above table and total approximately $52 million.

Hemingway-Hubbard Transmission Line: As part of the Hemingway Station Project, the Hemingway-Hubbard transmission line is expected to provide power to the Treasure Valley in southwest Idaho by 2010. The Hemingway-Hubbard line will consist of a new 230-kV double circuit transmission line and convert an existing 138-kV transmission line to 230-kV. Cost estimates for the project are included in the above table and total approximately $25 million.

Boardman-Hemingway Line: The Boardman-Hemingway Line is a proposed 500 kV transmission project between a substation near Boardman, Oregon and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. This line will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. This project is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. The initial project phase estimate of $50 million will be funded by IPC and includes the engineering, environmental review, permitting and rights-of-way. On March 9, 2009, IPC initiated a community advisory process to engage the public in a final route selection in compliance with the National Environmental Policy Act and Energy Facility Siting Council requirements. Cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table. Cost estimates for the project (including initial phase project estimate and construction costs of the line) are approximately $600 million. IPC expects to seek partners for up to 50 percent of the project when construction commences. Current estimates for the project in-service date have been delayed from 2013 to 2015 subject to siting, permitting and regulatory approvals. Construction costs are currently not included in IPC s 2009 to 2011 forecast.

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. This project will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. It is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC s share of the initial phase of engineering, environmental review, permitting and rights-of-way is approximately $40 million and cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table. Construction costs are currently not included in our 2009 to 2011 forecast. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires.

Other capital requirements: IDACORP s non-regulated capital expenditures are expected to be $15 million in 2009 and $5 million for 2010. These expenditures primarily relate to IFS s tax structured investments.

The credit and financial markets have experienced volatility and disruption. As a result, IPC and IDACORP have reduced or delayed many capital expenditures relating to customer growth and other non-critical projects. Additionally, hiring restrictions have been implemented and are expected to slow the growth of operation and maintenance spending in 2009.

Contractual Obligations

There have been no material changes in contractual obligations outside of the ordinary course of business since December 31, 2008 with the exception of the following:

IPC entered into a contract, effective January 1, 2009, to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. The contract is expected to total $133 million from 2009 to 2014.

On February 4, 2009, IPC entered into a Term Loan Credit Agreement in the amount of $170 million. The loans are due February 3, 2010. Additional details relating to the loans are discussed above under Financing Programs Term Loan Credit Agreement.

On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019.

IPC entered into two contracts with Siemens Energy, Inc. to purchase gas and steam turbine equipment for Langley Gulch. IPC estimates it will spend approximately $90 million on the contracts from 2009 through 2012. The contracts are discussed above in Capital Requirements Major Projects Langley Gulch Power Plant (2012 Baseload Resource).

Pension Plan

IDACORP and IPC have not contributed and do not expect to contribute to their pension plan in 2009. In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009 in order to avoid required contributions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. IPC has elected to use asset smoothing. As IPC was below the required funding level as of January 1, 2009, IPC is required to make additional contributions to improve the funded status of the plan beginning in 2010. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated minimum required contributions would be approximately $45 million in 2010 and $33 million in each of 2011, 2012, and 2013. IPC may elect to make contributions earlier than the required dates to maximize potential benefits from tax filings, and expected regulatory filings related to the recovery of pension contributions. Additional legislative or regulatory measures, as well as fluctuations in investment market conditions, may impact these funding requirements.

REGULATORY MATTERS:

Idaho Rate Cases

2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent.

On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four principal areas of the order and requested clarification of certain issues. On March 19, 2009, the IPUC issued an order that increased IPC s Idaho revenue requirement by an additional $6.1 million, to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent. The rate increase authorized by the March 19, 2009, order was effective for most customer classes on March 21, 2009. The IPUC corrected errors relating to the calculation of test year payroll expense ($6 million) and certain operation and maintenance expenses ($0.5 million). The IPUC also clarified four issues in agreement with IPC s recommended clarifications and indicated that the changes approved in the order resulted in a load growth adjustment rate (LGAR) of $26.63 per MWh, effective February 1, 2009.

The IPUC denied reconsideration with respect to a refund of $3.3 million received by IPC from the FERC and the recovery of $0.9 million of employee purchasing card expenditures. In response to the denial of reconsideration of the FERC fees, on April 2, 2009, IPC filed an application with the IPUC for an accounting order approving amortization of the fees over a five year period beginning in October 2006 when IPC received the FERC credit. The IPUC approved IPC s requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, IPC recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period on September 30, 2011.

The order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Langley Gulch (2012 Baseload Resource)
On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). Six parties have filed to intervene in the proceeding. Hearings have been set for July 14, 2009. Please see further discussion in LIQUIDITY AND CAPITAL RESOURCES - Major Projects - Langley Gulch Power Plant (2012 Baseload Resource).

Idaho Ratemaking Treatment Act Senate Bill 1123: Senate Bill 1123 was signed into law on April 9, 2009, and becomes effective on July 1, 2009. This legislation establishes an additional voluntary process for consideration of utility capital expenditures, whereby the IPUC may authorize and pre-approve ratemaking treatment for qualified capital construction projects of IPC and other Idaho utilities. The bill expands the IPUC s ability to shape the resources in a utility s portfolio before construction of, or commitment to, such a resource and it also provides additional surety to capital markets that utility expenditures are prudent and pose less risk of financial loss due to a guaranteed rate of return.

Deferred Net Power Supply Costs

The following table presents the balances of deferred net power supply costs:

	March 31, 2009		December 31, 2008	
Idaho PCA current year:				
Deferral for the 2009-2010 rate year	$	103,300	$	93,657
Idaho PCA true-up awaiting recovery:				
Authorized in May 2008		22,003		47,164
Oregon deferral:				
2001 Costs		1,065		1,663
2006 Costs		1,146		1,215
2008 Power cost adjustment mechanism		5,506		5,400
Total deferral	$	133,020	$	149,099

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC s actual net power supply costs (fuel, purchased power and third party transmission expenses less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

A forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and

A true-up component, based on the difference between the previous year s actual net power supply costs and the previous year s forecast. This component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The true-up component is calculated monthly, and interest is applied to the balance.

Prior to February 1, 2009, the PCA mechanism provided that 90 percent of deviations in power supply costs were to be reflected in IPC s rates for both the forecast and the true-up components. Effective February 1, 2009, this sharing percentage is now 95 percent.

2009-2010 PCA: On April 15, 2009, IPC filed its 2009-2010 PCA with the IPUC with a requested effective date of June 1, 2009. The filing requests a $93.8 million increase to the PCA component of customers rates, an 11.4 percent overall increase to Idaho rates.

2008-2009 PCA: On May 30, 2008, the IPUC approved IPC s 2008-2009 PCA and an increase to then-existing revenues of $73.3 million, effective June 1, 2008, which resulted in an average rate increase to IPC s customers of 10.7 percent. The IPUC s order adopted an IPUC Staff proposal to use a forecast for power supply costs that equaled the amounts in current base rates. The revenue increase is net of $16.5 million of gains from the 2007 sale of excess SO_2 emission allowances, including interest, which the IPUC ordered be applied against the PCA.

PCA Workshops: In its May 30, 2008 order approving IPC s 2008-2009 PCA, the IPUC also directed IPC to set up workshops with the IPUC Staff and several of IPC s largest customers (together, the Parties) to address PCA-related issues not resolved in the PCA filing. Workshops were conducted in the fall, and a settlement stipulation was filed with the IPUC and approved on January 9, 2009.

The following changes were effective as of February 1, 2009:

PCA sharing methodology of 95/5 - the PCA sharing methodology allocates the costs and benefits of net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.

LGAR - the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on a formula that, based on filed data from the 2008 general rate case, would have produced an LGAR of $28.14 per MWh. As discussed above under   2008 General Rate Case,   the LGAR, effective February 1, 2009, is $26.63 per MWh.

Use of IPC s operation plan power supply cost forecast - the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year s   true-up   rate, beginning with the 2009-2010 PCA filing.

Inclusion of third-party transmission expense - transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these types of costs from levels included in base rates is now reflected in PCA computations.

Adjusted distribution of base net power supply costs - base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Oregon: Beginning in 2008, IPC has a power cost recovery mechanism in Oregon with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

The APCU allows IPC to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The APCU has two components: the October Update, where each October IPC calculates its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC files a forecast of its expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices. On June 1 of each year, rates are adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, IPC is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which IPC absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and IPC. However, a collection will occur only to the extent that it results in IPC s actual return on equity (ROE) for the year being no greater than 100 basis points below IPC s last authorized ROE. A refund will occur only to the extent that it results in IPC s actual ROE for that year being no less than 100 basis points above IPC s last authorized ROE. The PCAM rate is then added to or subtracted from the APCU rate, subject to certain statutory limitations discussed below, with new combined rates effective each June 1.

2009 APCU: On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC s base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.55 percent increase. IPC and the OPUC Staff have reached a verbal agreement on the October Update.

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast results in a requested increase to Oregon revenues of 11.46 percent, or $3.9 million annually. A joint stipulation by IPC, the OPUC Staff and the Citizens Utility Board in support of IPC s requested increase was filed with the OPUC on May 4, 2009. When approved, the final 2009 APCU rates are expected to become effective on June 1, 2009.

2008 APCU: On May 20, 2008, the OPUC approved IPC s 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.69 percent, increase in Oregon revenues.

2008 PCAM: On February 27, 2009, IPC filed the true-up of its net power supply costs for the period January 1 through December 31, 2008, with the OPUC. The 2008 PCAM filing reflects a deviation of actual net power supply costs above the forecast for that period of $7.4 million. After the application of the deadband, the filing requests that

$5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed to below under 2007-2008 Excess Power Costs. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference is scheduled for May 14, 2009.

2007-2008 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the 8-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was also determined that IPC should be allowed to defer excess net power supply costs of $5.5 million dollars for that period. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. IPC is awaiting an order from the OPUC on the stipulation.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year. On October 6, 2008, the OPUC issued an order clarifying that the PCAM is a deferral under the Oregon statute.

IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC. Full recovery of the 2001 deferral is expected in 2009. The 2006-2007 deferral of $1.1 million, the May 1-December 31, 2007 deferral of $5.5 million (if approved by the OPUC) and the $5 million 2008 PCAM balance will have to be recovered sequentially following the full recovery of the 2001 deferral.

Fixed Cost Adjustment Mechanism (FCA)
On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program for IPC s residential and small general service customers. The FCA is a rate mechanism designed to remove IPC s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC s revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. The pilot program began on January 1, 2007, and runs through 2009, with the first rate adjustment occurring on June 1, 2008, and subsequent rate adjustments occurring on June 1 of each year during its term. IPC deferred $0.7 million of FCA net under-recovery of fixed costs during the first quarter of 2009.

On March 13, 2009, IPC filed an application requesting a $5.2 million rate increase under the FCA pilot program for the net under-recovery of fixed costs during 2008. The new rates are requested to be effective from June 1, 2009 through May 31, 2010. The application will proceed under modified procedure with comments due May 8, 2009.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of $2.4 million to be distributed to residential and small general service customer classes equally on an energy used basis during the June 1, 2008, through May 31, 2009, FCA revenue collection period.

Energy Efficiency Matters
Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in conservation, energy efficiency and demand response programs. Effective June 1, 2008, IPC collects 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers. On March 13, 2009, IPC filed an

application with the IPUC requesting an increase in Rider funding to 4.75 percent of base revenues effective June 1, 2009. On April 10, 2009, the IPUC ordered that this filing be processed by modified procedure with comments due by May 1, 2009. Approval of this application would increase annual Rider funds to approximately $33 million.

Energy Efficiency Prudency Review: In the 2008 general rate case, IPC requested that the IPUC explicitly find that IPC s expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and would, therefore, no longer be subject to potential disallowance. The IPUC Staff recommended that the IPUC defer a prudency determination for these expenditures until IPC was able to provide a comprehensive evaluation package of its programs and efforts. IPC contended that sufficient information had already been provided to the IPUC Staff for review.

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. On March 6, 2009, the IPUC approved the stipulation, identifying $18.3 million as prudent, which included $14.3 million of Rider funding and $4.0 million of other funds.

On April 1, 2009, IPC filed an application with the IPUC seeking a prudency determination on the $14.7 million balance of Rider funds spent during 2002 through 2007. IPC has requested that this application be processed under modified procedure.

Commercial Demand Response: On March 2, 2009, IPC filed for approval of a voluntary Commercial Demand Response program for commercial and industrial customers larger than 200 kilowatts. IPC signed a five-year contract with a third-party aggregator, EnerNOC, to operate the program and make arrangements with IPC s customers to achieve peak reductions. This program will be dispatchable (meaning IPC will have flexibility to schedule peak reduction benefits during times of greatest need) and, in the next four years, is expected to increase to 50 MW of summer peak demand reduction availability by 2012. The anticipated cost of the program is approximately $12.2 million over its first five years. IPC is awaiting an order from the IPUC.

Irrigation Demand Response - Peak Rewards: On November 7, 2008, IPC filed a revised Irrigation Peak Rewards program design with the IPUC which was approved on January 14, 2009. The program is expected to provide an overall peak reduction of about 144 MW. Participating customers will receive a credit on their bills in exchange for allowing IPC, within specified parameters, to interrupt service to their irrigation pumps during certain peak hours in a six-week period in June and July. The anticipated cost of the irrigation program is $6.7 million in 2009 and is expected to increase to approximately $10.8 million in 2011.

Depreciation Filings

On September 12, 2008, the IPUC approved a revision to IPC s depreciation rates, retroactive to August 1, 2008. The new rates are based on a settlement reached by IPC and the IPUC Staff, and result in an annual reduction of depreciation expense of $8.5 million ($7.9 million allocated to Idaho) based upon December 31, 2006, depreciable electric plant in service.

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million. The OPUC Staff has recently accepted IPC s settlement offer and a stipulation is expected to be filed by May 8, 2009. In the settlement offer, IPC proposed that the OPUC Staff not make adjustments to the depreciation rates adopted by the IPUC and also proposed to commit to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction. IPC s request was filed in conjunction with the October 3, 2008, application discussed below in Advanced Metering Infrastructure (AMI).

On October 22, 2008, IPC filed an application with the FERC requesting that IPC s revised depreciation rates as approved by the IPUC also be accepted for use in future rate filings made with the FERC. The FERC approved IPC s application on December 3, 2008. The new depreciation accrual rates will be reflected in IPC s OATT rates beginning October 1, 2009.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In the future, the system will support enhancements to allow for time-variant rates, perform remote connects and disconnects, and collect system operations data enhancing outage management, reliability efforts and demand-side management options.

IPC filed AMI evaluation and deployment reports with the IPUC on May 1 and August 31, 2007, in compliance with an IPUC order. Consistent with the implementation plan contained in those reports, IPC entered into a number of contracts for materials and resources that allowed for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of its customers by the end of 2011. The executed contracts do not obligate IPC for any level of purchases and specifically allow IPC to cancel the contracts in the event that appropriate regulatory treatment regarding cost recovery is not granted.

Idaho: On August 5, 2008, IPC filed an application with the IPUC requesting a CPCN for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC approved IPC s application on February 12, 2009. In its application, IPC estimated the three-year investment in AMI to be $70.9 million. The 2009 revenue requirement impact of the AMI deployment was estimated to be $12.2 million. In an April 7, 2009, order, the IPUC clarified that IPC can expect, in the ordinary course of events, to include in rate base the prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million. The IPUC also clarified, as requested by IPC, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout IPC s service territory will eliminate or wholly offset the increase in IPC s revenue requirement caused by the authorized depreciation period.

On March 13, 2009, IPC filed an application with the IPUC for authority to increase its rates due to the inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and for those investments that will be made during a June 1, 2009, through May 31, 2010 test year. The filing requests an increase in IPC s annual revenues of $11.2 million and an effective date of June 1, 2009. The application will proceed under modified procedure with comments due by May 18, 2009.

Oregon: On October 3, 2008, IPC filed an application with the OPUC requesting authority to accelerate the depreciation and recovery of existing meters in the Oregon jurisdiction over an 18-month period beginning January 2009. The OPUC approved IPC s request on December 30, 2008. IPC s AMI deployment schedule calls for the replacement of the Oregon service-territory meters around October 2010. The existing meters will be fully depreciated prior to their removal from service. The filing estimated the balance of plant in service at December 31, 2008, attributable to the existing meters to be $1.4 million. The approval of this application results in an increase of $0.8 million for 2009 in both rates and depreciation expense. This increase will be partially offset by the request for revised depreciation rates filed in the same application and discussed above in Depreciation Filings, subject to true-up if the depreciation rates the OPUC ultimately approves differ from those that were approved by the IPUC.

Deferred Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the pension plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, *Employers Accounting for Pensions*, as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. IPC deferred $7.3 million of pension expense in the first quarter of 2009 and has deferred $17.9 million since the order became effective in 2007. IPC does not receive a carrying charge on the deferral balance.

Federal Regulatory Matters

The Bonneville Power Administration Residential Exchange Program: The Pacific Northwest Electric Power Planning and Conservation Act of 1980, through the Residential Exchange Program, has provided access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of the region s investor-owned utilities (IOUs). The program is administered by the Bonneville Power Administration (BPA). Pursuant to agreements between the BPA and IPC, benefits from the BPA were passed through to IPC s Idaho and Oregon residential and small farm customers in the form of electricity bill credits.

On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit ruled that the settlement agreements entered into between the BPA and the IOUs (including IPC) are inconsistent with the Northwest Power Act. On May 21, 2007, the BPA notified IPC and six other IOUs that it was immediately suspending the Residential Exchange Program payments that the utilities pass through to their residential and small farm customers in the form of electricity bill credits. IPC took action with both the IPUC and the OPUC to reduce the level of credit on its customers bills to zero, effective June 1, 2007.

Since that time IPC has been working with the other northwest IOUs and consumer-owned utilities, northwest state public utility commissions and the BPA to craft an agreement so that residential and small farm customers of IPC can resume sharing in the benefits of the federal Columbia River power system. However, the matter has yet to be resolved. The BPA has initiated several public processes, which ultimately will determine whether benefits will be restored to IPC customers. The most significant of these processes are the establishment of new residential purchase and sales agreements (RPSAs) and the WP-07 supplemental rate case. The RPSAs are intended to replace the settlement agreements invalidated by the court and to provide the structure through which benefits will be shared with the residential and small farm customers of IOUs. The WP-07 case addresses the calculation of overpayment (if any) of benefits to customers of the IOUs under the settlement agreements and whether those overpayments must be repaid by a reduction to future benefits.

The BPA issued a Final Record of Decision (ROD) on September 4, 2008, to establish new RPSAs and another ROD on September 22, 2008 in the WP-07 case. Together the RODs continue to reflect no residential exchange benefits for IPC s residential and small farm customers in the foreseeable future. IPC has filed petitions for review in the U.S. Court of Appeals for the Ninth Circuit challenging both RODs - the RPSAs on November 26, 2008, and the WP-07 case on December 16, 2008.

A mediation process within the Ninth Circuit Court was initiated in an attempt to settle Residential Exchange Program issues. Three meetings were held in February and March 2009 between the BPA, IOUs and consumer-owned utilities to determine if there is common ground for an overall settlement of the Residential Exchange Program. The mediation effort was unsuccessful, and briefing schedules are expected to be set.

IPC will continue its efforts to secure future benefits for its customers. Since these benefits were passed through to IPC s customers, the outcome of this matter is not expected to have an effect on IPC s financial condition or results of operations.

OATT: On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on financial and operational data IPC is required to file annually with the FERC in its Form 1. The formula rate request included a rate of return on equity of 11.25 percent. IPC s filing was opposed by several affected parties. Effective June 1, 2006, the FERC accepted IPC s proposed new rates, subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced IPC s proposed new rates and, as a result, approximately $1.7 million collected in excess of the settlement rates between June 1, 2006, and July 31, 2007, was refunded with interest in August 2007. As part of the settlement agreement, the FERC established an authorized rate of return on equity of 10.7 percent.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which would have further reduced the new transmission rates. IPC, as well as the opposing parties, appealed the Initial Decision to the FERC. If implemented, the Initial Decision would have required IPC to make additional refunds, of approximately $5.4 million (including $0.4 million of interest) for the June 1, 2006, through December 31, 2008, period. IPC previously reserved this entire amount.

On January 15, 2009, the FERC issued an Order on Initial Decision (FERC Order), which upheld the Initial Decision of the ALJ in most respects, but modified the Initial Decision in one respect that is unfavorable to IPC. The decision required IPC to reduce its transmission service rates to FERC jurisdictional customers. Furthermore, IPC was required to make refunds to FERC jurisdictional transmission customers in the total amount of $13.3 million (including $1.1 million in interest) for the period since the new rates went into effect in June 2006. Based on the FERC Order, IPC reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008, bringing the total reserve amount to $13.3 million. Prior to the FERC Order, the FERC jurisdictional transmission revenues (net of the $5 million reserve) recorded in the last seven months of 2006, all of 2007 and 2008 were $8.1 million, $13.3 million and $15.8 million, respectively. Under the FERC Order, the transmission revenues would have been $6.4 million in the last seven months of 2006, $11 million in 2007 and $12.6 million in 2008. Refunds were made on February 25, 2009.

IPC filed a request for rehearing with the FERC on February 17, 2009. IPC believes that the treatment of the Legacy Agreements conflicts with precedent. The rehearing request asserts that the FERC order is in error by: (1) requiring IPC to include the contract demands associated with the Legacy Agreements in the OATT formula rate divisor rather than crediting the revenue from the Legacy Agreements against IPC s transmission revenue requirement; (2) concluding that IPC must include the contract demands associated with the Legacy Agreements rather than the customers coincident peak demands; (3) concluding that the transmission rate contained in one or more of the Legacy Agreements was not a discounted rate; (4) failing to consider the non-monetary benefits received by IPC from the Legacy Agreements; (5) concluding that the services provided under the Legacy Agreements are firm services and therefore should be handled for rate purposes in the same manner as firm services under the OATT; and (6) failing to affirm the rate treatment that has been used for the Legacy Agreements for approximately 30 years. On March 18, 2009, the FERC issued a tolling order that effectively relieves it from acting on the request for reconsideration for an indefinite time period. IPC cannot predict when the FERC will rule on the request for rehearing or the outcome of this matter.

On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The new rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. The impact of this rate decrease on IPC s revenues is dependent on transmission volume sold, which can be highly variable. New rates were effective October 1, 2008. IPC has adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009, order.

FERC Compliance Program: The FERC issued Policy Statements on Enforcement in 2005 and 2008 and a Policy Statement on Compliance in 2008, which encourage companies to self-report to the FERC matters that constitute or may constitute violations of the Federal Power Act, the Natural Gas Act, the Natural Gas Policy Act and the requirements of FERC rules, regulations, orders and tariffs. The Policy Statements identify self-reporting as a factor the FERC will consider in determining the proper remedy for a violation and emphasize the role compliance programs play in identifying and correcting violations and in evaluating whether and the extent to which penalties may be imposed. IPC has implemented a compliance program to ensure that its operations conform to the FERC s requirements and to provide a means of identifying and if warranted, self-reporting on a regular basis any such matters to the FERC. IPC also self-reports matters relating to transmission reliability standards to the Western Electricity Coordinating Council (WECC). In 2007, FERC Order No. 693 approved mandatory reliability standards developed by the North American Electric Reliability Corporation. The WECC, a regional electric reliability organization, has responsibility for compliance and enforcement of these standards. As part of its compliance program, IPC has reported compliance issues relating to the FERC s Standards of Conduct and IPC s Open Access Transmission Tariff to the FERC, as well as matters relating to reliability standards to the WECC. Some of these matters have been resolved, while others are being reviewed by the FERC or the WECC. IPC is unable to predict what action if any the FERC will take with regard to the unresolved matters. IPC plans to continue its policy of using its compliance program to reduce potential violations and to self-report matters regularly to the FERC and the WECC.

Integrated Resource Plan

IPC s integrated resource planning process forecasts IPC s load and resource situation for the next twenty years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. The IRP is typically updated every two years, however with its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other Idaho utilities. To comply with this request IPC provided an update on the status of the IRP to both the IPUC and OPUC in June 2008. An IRP Addendum was also filed with the OPUC in February 2009, which specifically addressed the need for the Boardman to Hemingway Transmission Project. IPC is currently preparing the 2009 IRP, which was originally expected to be completed in June 2009. In light of the economic changes since September 2008 when IPC prepared the load forecast being used for the 2009 IRP, and in response to the OPUC s desire for additional analysis regarding the Boardman to Hemingway Transmission Project, on April 24, 2009, IPC filed a request for an extension with the IPUC and OPUC to delay the filing of the 2009 IRP until December 2009. If granted, this extension will allow IPC sufficient time to perform the requested analysis and incorporate an updated load forecast in the 2009 IRP.

During the time between resource plan filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. IPC continues to analyze and evaluate the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. Each of the sections below provides an update of items identified in the resource planning process.

For discussion of the 2012 Baseload Resource RFP, please see LIQUIDITY AND CAPITAL RESOURCES - Major Projects - Langley Gulch Power Plant (2012 Baseload Resource). For discussion of the Boardman to Hemingway Transmission Project, please see LIQUIDITY AND CAPITAL RESOURCES - Major Projects - Boardman Hemingway Line.

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Geothermal RFPs: In January 2008, IPC released an RFP for 50 to 100 MW of geothermal energy. Proposals were due in March 2008 and as the evaluation process proceeded, all but one of the respondents withdrew their proposals. IPC completed the RFP evaluation process on the remaining response, however it was not selected due to the economics and timing of the presented project.

While the results of the geothermal RFP processes have been disappointing, IPC is continuing to work with project developers capable of delivering energy to its service area. IPC also continues to monitor developments in geothermal technology and is hopeful geothermal energy will become an economic and readily available resource for its customers.

Combined Heat and Power (CHP) RFP: The 2006 IRP included 50 MW of CHP coming on-line in 2010. In April 2008, IPC solicited its large industrial customers to determine the level of interest in CHP development. While the level of interest in CHP development has been less than anticipated in the 2006 IRP, IPC continues to work with parties to explore CHP development opportunities.

Relicensing of Hydroelectric Projects

IPC, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. IPC is actively pursuing the relicensing of the Hells Canyon Complex (HCC) and Swan Falls projects.

The relicensing costs are recorded and held in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $107 million and $4 million for HCC and Swan Falls, respectively, were included in construction work in progress at March 31, 2009.

The IPUC authorized IPC to include in rates approximately $6.8 million ($10.6 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. This became effective January 30, 2009, and in the first quarter IPC collected approximately $1.7 million. Collecting these amounts in current rates will reduce future rates related to obtaining the new license once the accumulated relicensing costs are placed in service. Further discussion is provided above in Idaho Rate Cases 2008 General Rate Case.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately two-thirds of IPC s hydroelectric generating capacity and 40 percent of its total generating capacity. In July 2003, IPC filed an application for a new license in anticipation of the July 2005 expiration of the then-existing license. IPC is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the new license is issued.

Consistent with the requirements of the National Environmental Policy Act of 1969, as amended (NEPA), the FERC Staff issued on August 31, 2007, a final environmental impact statement (EIS) for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes and the public about the environmental effects of IPC s proposed operation of the HCC. IPC is reviewing the final EIS and expects to file comments with the FERC in 2009.

In conjunction with the issuance of the final EIS, on September 13, 2007, the FERC requested formal consultation under the Endangered Species Act (ESA) with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) regarding the effect of HCC relicensing on several aquatic and terrestrial species listed as threatened under the ESA. However, formal consultation has not yet been initiated and NMFS and USFWS continue to gather and consider information relative to the effect of relicensing on relevant species. IPC continues to cooperate with the USFWS, the NMFS and the FERC in an effort to address ESA concerns.

Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, IPC has filed Water Quality Certification Applications, required under section 401 of the Clean Water Act, with the States of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. IPC continues to work with Idaho and Oregon to ensure that any discharges from the HCC will comply with the necessary state water quality standards so that appropriate water quality certifications can be issued for the project.

The FERC is expected to issue a license order for the HCC once the ESA consultation and the section 401 certification processes are completed.

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contained project-specific information and the results of environmental studies designed to determine project effects. Comments were received from the agencies and one Native American tribe and on February 19, 2008, a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. On June 26, 2008, IPC filed a final license application with the FERC. On July 9, 2008, in conformance with applicable regulations, the FERC issued a Notice of Application Tendered for Filing with the Commission, Soliciting Additional Study Requests, and Establishing Procedural Schedule for Relicensing and a Deadline for Submission of Final Amendments. Pursuant to that notice, state and federal resource agencies, Native American tribes or other interested parties were to file additional study requests with the FERC by August 26, 2008. Additional study requests were filed by the Shoshone-Bannock Tribes and the USFWS. IPC filed responses to these requests on September 26 and 29, 2008, respectively. The FERC is still considering the requests from the Shoshone-Bannock Tribes and the USFWS. On October 7, 2008, IPC received a request from the FERC to provide clarification and additional information on the Swan Falls license application. IPC submitted responses to this request on April 7, 2009. The FERC notified IPC on December 4, 2008, that the final license application had been officially accepted for filing. On January 9, 2009, the FERC issued a scoping document giving notice of scheduled scoping meetings, soliciting scoping comments and of its intent to prepare an Environmental Impact Statement (EIS) pursuant to the National Environmental Policy Act (NEPA). FERC held scoping meetings on February 10 and 11, 2009. On May 5, 2009, FERC issued Scoping Document 2 for the project, advising that based on the scoping meetings and comments received that staff will prepare an EIS, which the Commission will use to determine whether, and under what conditions, to issue a new hydropower license for the project. The FERC expects to complete the EIS in 2010.

Section 401 of the Clean Water Act requires that an applicant for a federal license to conduct an activity that results in any discharge to navigable waters must provide the licensing agency with a certification from the state in which the discharge occurs that the discharge will comply with applicable water quality standards. In conformance with that section, on June 6, 2008, IPC filed an application with the Idaho Department of Environmental Quality (IDEQ) for section 401 water quality certification. On April 1, 2009, the IDEQ issued public notice, seeking public comment on a draft section 401 certification for the project. No public comments were submitted and the IDEQ issued the section

401 certification on May 4, 2009.

Shoshone Falls Expansion: On August 17, 2006, IPC filed a license amendment application with the FERC, which would allow IPC to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. The license amendment is expected to be issued in 2009. In conjunction with the license amendment application, IPC has filed a water rights application which is currently being reviewed by the Idaho Department of Water Resources (IDWR).

LEGAL AND ENVIRONMENTAL ISSUES:

Western Energy Proceedings at the FERC: Throughout this report, the term western energy situation is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices and blackouts in the western United States. High prices for electricity in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds. Some of these proceedings (the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are pending in the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the western energy situation, including the California refund proceeding, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters, except as otherwise stated below, or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC s order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

IE and other parties petitioned the Ninth Circuit for review of the FERC s orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed by potential refund payors, including IE, potential refund recipients and governmental agencies. These cases have been consolidated before the Ninth Circuit. Since the initiation of these cases, the Ninth Circuit has convened a series of case management proceedings to organize these complex cases, while identifying and severing discrete cases that can proceed to briefing and decision and staying action on all of the other consolidated cases.

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds. A number of public entities filed petitions for panel rehearing in June 2007 and certain marketers filed petitions for rehearing and rehearing en banc in November 2007. Those requests were denied by the Ninth Circuit on April 6, 2009. The Ninth Circuit issued a mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court s decision.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection and that request remains pending before the FERC. IE and IPC are unable to predict how or when the FERC might rule on the request for rehearing, but its effect is confined to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC settling matters encompassed by the California refund proceeding, as well as other FERC proceedings and investigations relating to the western energy matters, including IE s and IPC s cost filing and refund obligation. A number of other parties, representing a small minority of potential refund claims, chose to opt out of the settlement. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IPC and IE. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement. In addition, the California Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

<u>Market Manipulation:</u> As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming (gaming) or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the partnership show cause proceeding against IPC. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by IPC.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000, through October 1, 2000, to enable it to review evidence of economic withholding of generation. IPC, along with more than 60 other market participants, responded to the FERC data requests. The FERC terminated its investigations as to IPC on May 12, 2004. Although California government agencies and California investor-owned utilities have appealed the FERC s termination of this investigation as to IPC and more than 30 other market participants, the claims regarding the conduct encompassed by these investigations were released by these parties in the California refund settlement discussed above. IE and IPC are unable to predict the outcome of these matters, but believe that the releases govern any potential claims that might arise and that this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict *Mobile-Sierra* standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

On June 26, 2008, the U.S. Supreme Court issued a decision in Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), a case regarding a FERC decision not to require re-pricing of certain long-term contracts. In Snohomish, the Supreme Court revisited and clarified the *Mobile-Sierra* doctrine in the context of fixed-rate, forward power contracts. At issue was whether, and under what circumstances, the FERC could modify the rates in such contracts on the grounds that there was a dysfunctional market at the time the contracts were executed. In its decision, the Supreme Court disagreed with many of the conclusions reached in an earlier decision by the Ninth Circuit and upheld the application of the *Mobile-Sierra* doctrine even in cases in which it is alleged that the markets were dysfunctional. The Supreme Court nonetheless directed the return of the case to the FERC to (i) consider whether the challenged rates in the case constituted an excessive burden on consumers either at the time the contracts were formed or during the term of the contracts relative to the rates that could have been obtained after elimination of the dysfunctional market and (ii) clarify whether it found the evidence inadequate to support a claim that one of the parties to a contract under consideration engaged in unlawful market manipulation that altered the playing field for the particular contract negotiations - that is, whether there was a causal connection between allegedly unlawful activity and the contract rate. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court s decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court. Paper hearings have since been held in abeyance while the FERC s mediation service meets with the parties to the remanded case.

This decision is expected to have general implications for contracts in the wholesale electric markets regulated by the FERC, and particular implications for forward power contracts in such markets. The Snohomish decision upholds the application of the *Mobile-Sierra* doctrine to fixed-rate, forward power contracts even in allegedly dysfunctional markets.

IPC and IE have asserted the *Mobile-Sierra* doctrine in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market. IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how this decision will affect the outcome of the Pacific Northwest proceeding.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured by the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit Boardman: On September 30, 2008, the Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired power plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE s construction and operation of the plant. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs response to the motion was filed February 25, 2009, and PGE s reply was filed April 8, 2009. The State of Oregon filed an amicus brief on April 1, 2009, addressing the substantive positions set forth in PGE s December 5, 2008, motion to dismiss and the plaintiffs February 25, 2009, response to the motion. The amicus brief does not state a position on the merits of the motion to dismiss but corrects what it perceives to be erroneous statements of law made by the plaintiffs and PGE regarding Oregon air quality regulations concerning the Prevention of Significant Deterioration program that were approved by the Environmental Protection Agency (EPA) and incorporated into Oregon s State Implementation Plan. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an IPC distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes and damage or alleged fire related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of IPC s distribution poles and that high winds contributed to the fire and its resultant damage.

IPC has received notice of claims from a number of the homeowners and their insurers and is continuing its investigation of these claims. IPC is insured up to policy limits against liability for claims in excess of its self-insured retention. IPC has accrued a reserve for any loss that is probable and reasonably estimable, including insurance deductibles, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Other Legal Proceedings: IDACORP, IPC and/or IE are involved in lawsuits and legal proceedings in addition to those discussed above and in Note 7 to IDACORP s and IPC s Consolidated Financial Statements. Resolution of any of these matters will take time and the companies cannot predict the outcome of any of these proceedings. The companies believe that their reserves are adequate for these matters.

Environmental Issues

The section below summarizes and provides an update of environmental issues as discussed in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008.

Global Climate Change: IPC is actively tracking state, regional and federal developments in the climate change area and the related proposals for renewable portfolio standards. IPC s substantial hydroelectric generation resources neither burn nor consume fossil fuels to produce electric energy to meet the needs of its customers. IPC intends to continue to add energy efficiency programs and renewable resources to its generation portfolio. As part of the ongoing 2009 IRP process, which includes involvement by and input from government, public and non-governmental organization stakeholders, IPC is reviewing forecast load growth, energy efficiency and demand response program performance, and proposed regulatory requirements including regulation of greenhouse gas (GHG) emissions and the adoption of a federal renewable electricity standard. Environmental impacts have been and will continue to be integral components of IPC s resource decisions.

On March 10, 2009, the EPA released a proposed mandatory GHG emissions reporting rule that would require reporting from large sources of GHG emissions. The EPA plans to use the emission information collected to assist it in making future climate policy decisions, including the potential future regulation of GHG emissions. The reporting rule is scheduled to be finalized by June 2009.

Congress is evaluating proposals that could lead to the adoption of a mandatory program to reduce GHG emissions through, for example, an economy-wide cap-and-trade program, a carbon tax or a combination of both. On March 31, 2009, Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) released their draft GHG cap-and-trade bill entitled the American Clean Energy and Security Act of 2009. In a public statement, the Obama administration indicated general support for the bill. In addition, states and regional initiatives (including the Western Climate Initiative) are considering regional market-based mechanisms to reduce GHG emissions. On April 17, 2009, the EPA proposed to make an endangerment finding for GHG emissions from mobile sources that could lead to the regulation of GHG emissions from mobile sources under the existing Clean Air Act. It is possible that the EPA could subsequently make a similar finding with respect to GHG emissions from stationary sources.

Information about IDACORP s CO_2 emissions is included in the report *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States 2008.* This report was released by the Ceres Investor Coalition, the Natural Resources Defense Council, the Public Service Enterprise Group Inc. and PG&E Corporation in May 2008. The report lists IDACORP s 2006 CO_2 emissions at 937.9 lbs/MWh (below the reported average for the 100 largest power producers of 1,343.6 lbs/MWh). IPC s CO_2 emissions on an lbs/MWh basis fluctuate with the amount of hydroelectric generation. In 2008, IPC s CO_2 emissions from IPC s electric power generation facilities were approximately 7.9 million tons, or 1,097 lbs/MWh (adjusted to reflect IPC s partial ownership in the Jim Bridger, Boardman and Valmy facilities). IPC intends to report additional information regarding GHG emissions to the Carbon Disclosure Project in May 2009.

Long-term climate change could significantly affect IPC s business in a variety of ways, including but not limited to: (a) changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation and extreme weather events could increase service interruptions, outages, and maintenance costs; and (b) legislative and/or regulatory developments related to climate change could affect plans and operations in various ways including placing restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general. IPC cannot, however, quantify the potential impact of climate change on its business at this time.

Renewable Electricity/Portfolio Standards: In early 2009, the Chairmen of both the House Committee on Energy and Commerce and the Senate Committee on Energy and Natural Resources proposed federal renewable electricity standard (RES) legislation. The House version, contained in Chairman Waxman s proposed American Clean Energy and Security Act of 2009, calls for 25 percent of a utility s electric energy generation to come from qualified renewable resources by 2025. The Senate version, contained in Chairman Bingaman s Majority RES Proposal, calls for 20 percent by 2021. Resources eligible to meet these standards include wind, solar, geothermal, biomass, landfill gas, ocean, and incremental hydropower (efficiency improvements or new capacity). Both proposals recognize the benefits of existing hydroelectric generation by allowing utilities to subtract generation from existing hydroelectric projects from their total sales base prior to calculating the percentage requirement.

In addition, IPC will be required to comply with a ten percent renewable energy portfolio standard (RPS) in Oregon beginning in 2025. No RPS requirement currently exists in Idaho. IPC continues to monitor proposed federal RPS legislation, which if passed could increase capital expenditures and operating costs and reduce earnings and cash flows.

IPC is currently purchasing energy from eight wind projects with a combined nameplate rating of 194.4 MW. IPC also has an additional 158 MW of wind generation under contract with CSPP (cogeneration and small power production) developers that have not yet been constructed. IPC continues to pursue additional geothermal and combined heat and power (CHP) generation resources with individual developers. Other renewable generation resources anticipated from future CSPP contracts include solar, biomass, CHP and additional wind projects.

Air Quality: IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. IPC continues to actively monitor, evaluate and work on air quality issues pertaining to federal and state mercury emission rules, possible legislative amendment of the Clean Air Act, New Source Review (NSR) permitting, National Ambient Air Quality Standards (NAAQS), and Regional Haze Best Available Retrofit Technology (RH BART). Installation of low nitrogen oxide (NOx) burner technology and over-fire air upgrades have been completed at the Valmy plant. The sulfur dioxide (SO_2) scrubber upgrade project has been completed on unit four at the Jim Bridger plant and scrubber upgrade projects on the other three units at the plant will occur over the next three years.

National Ambient Air Quality Standards: On February 24, 2009, the U.S. Court of Appeals for the District of Columbia Circuit remanded the EPA s revised NAAQS for particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard) to the EPA for reconsideration. The impact of this revised standard will not be known until the judicial appeals are completed and the associated regulatory programs are promulgated and implemented.

With respect to the EPA s March 2008 revisions to the 8-hour ozone NAAQS, on March 10, 2009, the EPA stated in a motion filed in the U.S. Court of Appeals for the District of Columbia Circuit that it intends to review the 8-hour ozone NAAQS primary (health-based) standard. The EPA also stated that it would make a determination within 180 days of its motion whether the standard should be modified.

Clean Air Mercury Rule: On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA s Clean Air Mercury Rule (CAMR) and remanded it back to the EPA for reconsideration consistent with the court s interpretation of the Clean Air Act. The EPA and an industry trade association subsequently filed requests with the U.S. Supreme Court to review the D.C. Circuit s decision. On February 6, 2009, the EPA filed a motion with the Supreme Court to withdraw its request and on February 23, 2009, the Supreme Court denied the industry trade association s request. The EPA simultaneously announced plans to develop maximum achievable control technology (MACT) standards for mercury emissions from coal-fired power plants. The new MACT standards could result in changes to the mercury reductions required by the states in which IPC has partial ownership interests in coal-fired power plants. IPC continues to monitor federal and state actions on mercury emissions. IPC is unable to predict at this time what actions the EPA or the other states may take in response to the court s decision or any resulting impacts to IPC.

Regional Haze Best Available Retrofit Technology: In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. The Wyoming Department of Environmental Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) are conducting an assessment of emission sources pursuant to a RH BART process. The states are also working on reasonable progress towards a long term strategy beyond BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

PacifiCorp submitted an RH BART application for the Jim Bridger plant in January 2007. The WDEQ is still evaluating the application and is expected to request public comment in 2009 on the draft RH BART State Implementation Plan (SIP) arising out of the application. Following public comment, the WDEQ will present the SIP to the Wyoming Environmental Quality Council for approval and submittal to the EPA. Legal challenges or appeals of the final SIP are possible. The plant is already in the process of installing low NOx burners and scrubber upgrades that are proposed in the application. Over the next four years, IPC s share of these upgrade expenditures is currently estimated at $24.3 million. IPC and PacifiCorp have been meeting with the WDEQ to discuss the potential for additional RH BART and reasonable progress requirements for the Jim Bridger plant. It is possible that additional capital expenditures would be required to satisfy these additional requirements; however, IPC is not able to quantify these expenditures at this time.

On August 20, 2008, the ODEQ issued a draft RH BART proposal for the Boardman plant that, if adopted, would require the installation of significant emission controls beginning in 2011. The pollution control requirements proposed by the ODEQ for RH BART and the long term strategy are estimated to cost approximately $59 million (IPC share). IPC s share of the cost to comply with the proposal would be approximately $38 million by 2014 with an additional $21 million by 2017. Installation of this pollution control equipment would require extended maintenance outages. On December 17, 2008, PGE proposed amendments to the ODEQ proposal, including an alternative of decommissioning the coal-fired unit at the Boardman plant subject to RH BART by the end of 2020 in lieu of installing SO_2 emissions controls by 2014. PGE also proposed including an alternative that would allow it to decommission the same unit in 2029 in lieu of installing additional NOx emission controls by 2017. The ODEQ has rescheduled the presentation of the proposed plan to the Oregon Environmental Quality Commission to the June 2009 commission meeting. PGE has indicated that the costs required pursuant to RH BART, together with any taxes, emission fees and other costs that may be imposed under future laws related to climate change could require an investment in excess of what the plant can economically support.

New Source Review: Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the New Source Review (NSR) permitting requirements and New Source Performance Standards (NSPS) of the federal Clean Air Act. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. The Obama administration has indicated an intention to continue this NSR enforcement initiative. In 2003, the EPA sent an information request to PacifiCorp, under section 114 of the Clean Air Act, requesting information relevant to NSR and NSPS compliance at its power plant operations, including the Jim Bridger plant (of which IPC is a one-third owner). PacifiCorp responded to this and another information request from the EPA. A number of utilities that have received section 114 information requests have engaged in negotiations with the EPA to address any allegations of non-compliance with NSR and NSPS requirements. In some cases, such negotiations have resulted in settlements requiring the payment of civil penalties, installation of additional pollution controls, the surrender of emission allowances, and the completion of supplemental environmental projects. IPC cannot predict the outcome of this matter at this time.

Idaho Water Management Issues: Since 2000 Idaho has experienced below normal precipitation and stream flows which have exacerbated a developing water shortage in Idaho, manifested by a number of water issues including declining Snake River base flows and declining levels in the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer that has been estimated to hold between 200 - 300 million acre feet (maf) of water. These issues are of interest to IPC because of their potential impacts on generation at IPC s hydroelectric projects.

As a result of declines in river flows, in 2003 several surface water users filed delivery calls with the IDWR, demanding that it manage ground water withdrawals pursuant to the prior appropriation doctrine of first in time is first in right and curtail junior ground water rights that are depleting the aquifer and affecting flows to senior surface water rights. These delivery calls have resulted in several administrative actions before the IDWR to enforce senior water rights as well as judicial actions before the state court challenging the constitutionality of state regulations used by the IDWR to conjunctively administer ground and surface water rights. Because IPC holds water rights that are dependent on the Snake River, spring flows and the overall condition of the ESPA, IPC continues to monitor and participate in these actions, as necessary, to protect its water rights.

One such action relates to the Milner hydroelectric project which is owned by the North Side Canal Company (NSCC) and the Twin Falls Canal Company (TFCC). NSCC and TFCC deliver water to and IPC operates the Milner project. NSCC and TFCC were issued a permit by IDWR for the hydropower project in the late 1980s, which subordinated the water right to all upstream consumptive uses except hydropower and groundwater recharge. However, on October 20, 2008, the IDWR issued a water right license for the project that subordinated the water right to groundwater recharge. On November 4, 2008, NSCC and TFCC filed a petition for hearing with the IDWR contesting the change in the subordination condition. The IDWR has appointed a hearing officer and granted the motions of several parties to intervene in the case. A hearing date has not been set on the petition. IPC is monitoring but is unable to predict the outcome of the administrative action.

IPC is also engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC.

On March 25, 2009, IPC and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions discussed below. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007 with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters.

The settlement agreement resolves the pending litigation by clarifying that IPC s water rights in excess of minimum flows at its hydroelectric facilities between Milner Dam and Swan Falls Dam are subordinate to future upstream beneficial uses, including aquifer recharge. The agreement commits the State and IPC to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. It also recognizes that water management measures that enhance aquifer levels, springs and river flows, such as aquifer recharge projects, benefit both agricultural development and hydropower generation and deserve study to determine their economic potential, their impact on the environment and their impact on hydropower generation. These will be a part of the Comprehensive Aquifer Management Plan (CAMP), recently approved by the Idaho Water Resource Board, which includes limits on the amount of aquifer recharge. IPC is a member of the CAMP advisory committee.

On May 6, 2009, as part of the settlement, IPC, the Governor and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. The settlement agreement is now subject to approval by the SRBA court.

IPC has also filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the United States for the lost generation resulting from the reduced flows and a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On March 11, 2009, the court entered an order extending the discovery schedule requiring that discovery be completed and pre-trial motions filed by December 3, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

OTHER MATTERS:

Southwest Intertie Project

On March 28, 2008, Great Basin Transmission, LLC (Great Basin) exercised its option to purchase the southern portion of the Southwest Intertie Project (SWIP), which consists principally of a federal permit for a specific transmission corridor in Nevada and Idaho and private rights-of-way in Idaho. This sale closed during the second quarter of 2008, and resulted in a net pre-tax gain of approximately $3 million. On December 30, 2008, IPC and Great Basin reached an agreement on the sale of the northern portion of the SWIP, which closed on March 31, 2009 and resulted in a pre-tax gain of $0.2 million.

Critical Accounting Policies and Estimates

IDACORP s and IPC s discussion and analysis of their financial condition and results of operations are based upon their condensed consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles. The preparation of these financial statements requires IDACORP and IPC to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, IDACORP and IPC evaluate these estimates including those estimates related to rate regulation, benefit costs, contingencies, litigation, impairment of assets, income taxes, unbilled revenue and bad debt. These estimates are based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances, and are the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. IDACORP and IPC, based on their ongoing reviews, make adjustments when facts and circumstances dictate.

IDACORP s and IPC s critical accounting policies are reviewed by the Audit Committee of the Board of Directors. These policies are discussed in more detail in the Annual Report on Form 10-K for the year ended December 31, 2008, and have not changed materially from that discussion.

Adopted Accounting Pronouncements

SFAS 141(R): On January 1, 2009, IDACORP and IPC adopted SFAS 141(R), *Business Combinations (Revised December 2007*). SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. In April 2009 the FASB issued FSP FAS 141(R)-1 *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies,* which further clarified the application of FAS 141(R). The adoption of SFAS 141(R), as amended, did not have a material impact on IDACORP s or IPC s consolidated financial statements.

SFAS 160: On January 1, 2009, IDACORP and IPC adopted SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements.* Among other things, SFAS 160 establishes a standard for the way noncontrolling interests (also called minority interests) are presented in consolidated financial statements and standards for accounting for changes in ownership interests. The adoption of SFAS 160, as reflected in IDACORP s and IPC s condensed consolidated financial statements, did not have a material impact and is discussed in more detail in Note 1 to the financial statements.

SFAS 161: On January 1, 2009, IDACORP and IPC adopted SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The adoption of SFAS 161 did not have a material impact on IDACORP s or IPC s consolidated financial statements.

SFAS 163: On January 1, 2009, IDACORP and IPC adopted SFAS 163, *Accounting for Financial Guarantee Insurance Contracts an interpretation of FASB Statement No. 60.* SFAS 163 is generally effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of SFAS 163 did not have an impact on IDACORP s or IPC s consolidated financial statements.

FSP FAS 142-3: On January 1, 2009, IDACORP and IPC adopted FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets.* FSP FAS 142-3 removes the requirement of SFAS 142, *Goodwill and Other Intangible Assets* for an entity to consider, when determining the useful life of an acquired intangible asset, whether the intangible asset can be renewed without substantial cost or material modifications to the existing terms and conditions associated with the intangible asset. FSP FAS 142-3 replaces the previous useful-life assessment criteria with a requirement that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal. The adoption of FSP FAS 142-3 did not have an impact on IDACORP S or IPC s consolidated financial statements.

Fair Value Measurement: In April 2009, the FASB issued three FSPs intended to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*, provides guidelines for making fair value measurements more consistent with the principles presented in FASB Statement No. 157, *Fair Value Measurements*. FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities.

FSP FAS 157-4 relates to determining fair values when there is no active market or where the price inputs being used represent distressed sales. It reaffirms what FAS 157 states is the objective of fair value measurement to reflect how much an asset would be sold for in an orderly transaction (as opposed to a distressed or forced transaction) at the date of the financial statements under current market conditions. Specifically, it reaffirms the need to use judgment to ascertain if a formerly active market has become inactive and in determining fair values when markets have become inactive.

FSP FAS 107-1 and APB 28-1 relate to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet of companies at fair value. Prior to issuing this FSP, fair values for these assets and liabilities were only disclosed once a year. The FSP now requires these disclosures on a quarterly basis, providing qualitative and quantitative information about fair value estimates for all those financial instruments not measured on the balance sheet at fair value.

FSP FAS 115-2 and FAS 124-2 on other-than-temporary impairments are intended to bring greater consistency to the timing of impairment recognition, and provide greater clarity to investors about the credit and noncredit components of impaired debt securities that are not expected to be sold. The measure of impairment in comprehensive income remains fair value. The FSP also requires increased and more timely disclosures sought by investors regarding expected cash flows, credit losses, and the aging of securities with unrealized losses.

The FSPs are effective for interim and annual periods ending after June 15, 2009, but entities may early adopt the FSPs for the interim and annual periods ending after March 15, 2009. IDACORP and IPC elected to adopt the FSPs for the interim period ending March 31, 2009. The adoption of the FSPs did not have a material effect on IPC s or IDACORP s consolidated financial statements.

New Accounting Pronouncements

See Note 1 to IDACORP s and IPC s Condensed Consolidated Financial Statements for a discussion of recently issued accounting pronouncements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments and derivative commodity instruments sensitive to changes in interest rates, commodity prices and equity prices that were held at March 31, 2009.

Interest Rate Risk
IDACORP and IPC manage interest expense and short- and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may be used to achieve the desired combination.

Variable Rate Debt: As of March 31, 2009, IDACORP and IPC had $264 million and $217 million, respectively, in net floating rate debt. Assuming no change in financial structure for either company, if variable interest rates were one percentage point higher than the rates in effect on March 31, 2009, interest rate expense would increase and pre-tax earnings would decrease by approximately $2.6 million for IDACORP and $2.2 million for IPC.

Fixed Rate Debt: As of March 31, 2009, IDACORP and IPC each had outstanding fixed rate debt of $1.2 billion. The fair market value of this debt was $1.1 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $89 million for IDACORP and IPC if interest rates were to decline by one percentage point from their March 31, 2009 levels.

Commodity Price Risk
Utility: IPC s commodity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2008. In a limited manner, IPC utilizes financial energy instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to securing adequate energy to meet utility load requirements in accordance with IPC s Risk Management Policy. This practice falls within the parameters of IPC s Risk Management Policy and these instruments are not used for trading purposes. These financial instruments are used in essentially the same manner as forward transactions to mitigate price risk but are considered derivative instruments under SFAS 133 and are therefore reported at fair value in IDACORP s and IPC s financial statements. Because of the PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities. Additional information regarding IPC s use of derivative instruments to manage commodity price risk can be found in Note 12 to IDACORP s and IPC s financial statements.

Credit Risk
Utility: IPC s credit risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2008. Additional information regarding credit risk relating to derivative instruments can be found in Note 12 to IDACORP s and IPC s financial statements.

Equity Price Risk
IDACORP s and IPC s equity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2008.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:
The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of March 31, 2009, have concluded that IDACORP s disclosure controls and procedures are effective.

IPC:
The Chief Executive Officer and the Chief Financial Officer of IPC, based on their evaluation of IPC s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of March 31, 2009, have concluded that IPC s disclosure controls and procedures are effective.

Changes in internal control over financial reporting:

There have been no changes in IDACORP s or IPC s internal control over financial reporting during the quarter ended March 31, 2009, that have materially affected, or are reasonably likely to materially affect, IDACORP s or IPC s internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Please refer to Note 7 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

ITEM 1A. RISK FACTORS

Idaho Power Company s risk management policy and programs relating to hedging power and gas exposures and counterparty creditworthiness may not always perform as intended, and we may suffer economic losses. Idaho Power Company actively manages the market risk inherent in its energy related activities and counterparty credit positions. We have policies and procedures that require us to monitor compliance with our risk management policies and programs, including verification of transactions, regular portfolio reporting of various risk management metrics and daily counterparty credit risk management measurement. However, actual hydroelectric and thermal generation, transmission availability and market prices may be significantly different from those originally planned for when we enter into our risk management positions. The high volatility of these items creates uncertainty in the appropriate amount of hedging activity to pursue. Forecasts of future loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power Company to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. Changes in market prices are also unpredictable and can at times result in Idaho Power Company s hedged positions performing less favorably than unhedged positions. In addition, Idaho Power Company s counterparty credit policies may not prevent counterparties from failing to perform, forcing the company to replace forward contracts with transactions in the open market. As a result, our risk management decisions may have significant impacts if actual events result in greater losses or costs in delivering energy to our customers and could negatively affect our financial condition, results of operations or cash flows.

National and regional economic conditions, in conjunction with increased rates, may reduce energy consumption, which may adversely affect revenues, earnings and future growth. The present economic recession and increased rates may reduce the amount of energy our customers consume, result in a loss of customers and reduce customer growth. A decrease in overall customer usage may adversely affect revenues, earnings, and future growth.

One or more of the banks participating in IDACORP, Inc. s and Idaho Power Company s credit facilities could default on their obligations to fund loans requested by the companies or could withdraw from participation in the credit facilities, which could negatively affect cash flows and the ability to meet capital requirements. IDACORP, Inc. and Idaho Power Company have $100 million and $300 million multi-year revolving credit facilities, respectively, with a group of lender banks that expire in April 2012. These facilities supplement operating cash flow and provide a primary source of liquidity. The facilities are also used as backup for commercial paper borrowings and are available for general corporate purposes. IDACORP, Inc. and Idaho Power Company are subject to the risk that one or more of the participating banks may default on their obligations to make loans under the credit facilities. IDACORP, Inc. and Idaho Power Company s inability to obtain loans under their respective credit facilities as needed could negatively affect cash flows and the ability to meet capital requirements.

IDACORP, Inc. and Idaho Power Company could be vulnerable to security breaches or other similar events that could disrupt their operations, require significant capital expenditures and/or result in claims against the companies. In the normal course of business, Idaho Power Company collects, processes and retains sensitive and confidential customer and proprietary information. Despite the security measures in place, Idaho Power Company s facilities and systems, and those of third-party service providers, could be vulnerable to security breaches or other similar events that could interrupt operations, resulting in a shutdown of service and expose Idaho Power Company to liability. In addition, Idaho Power Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches.

These additional Risk Factors should be read in conjunction with the Risk Factors included in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

As part of their compensation, each director of IDACORP and IPC who is not an employee received a grant of 1,848 shares of common stock, equal to $45,000, on March 2, 2009, except for C. Stephen Allred who was elected to the board on March 18, 2009, and received a pro-rated grant of 1,605 shares of common stock, equal to $37,500, on April 1, 2009. Directors may elect to defer receipt of their shares. The stock was issued without registration under the Securities Act of 1933 in reliance upon Section 4(2) of the Act.

Restrictions on Dividends:
A covenant under IDACORP s credit facility, IPC s credit facility and IPC s term loan credit agreement requires IDACORP and IPC to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. These agreements are discussed further in MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs.

IPC s Revised Code of Conduct approved by the IPUC on April 21, 2008, states that IPC will not pay any dividends to IDACORP that will reduce IPC s common equity capital below 35 percent of its total adjusted capital without IPUC approval.

IPC s ability to pay dividends on its common stock held by IDACORP and IDACORP s ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or IPC s Code of Conduct. At March 31, 2009, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively and IPC s common equity capital was 45 percent of its total adjusted capital. Based on these restrictions, IDACORP s and IPC s dividends were limited to $499 million and $404 million, respectively, at March 31, 2009.

IPC s articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. IPC has no preferred stock outstanding.

Issuer Purchases of Equity Securities:

IDACORP, Inc. Common Stock

Period	(a) Total Number of Shares Purchased 1	(b) Average Price Paid per Share		(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 January 31, 2009	20,926	$	29.19	-	-
February 1 February 28, 2009	30,486		25.48	-	-
March 1 March 31, 2009	857		23.36	-	-
Total	52,269	$	26.93	-	-

1 These shares were withheld for taxes upon vesting of restricted stock

ITEM 6. EXHIBITS

*Previously Filed and Incorporated Herein by Reference

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*2	Agreement and Plan of Exchange between IDACORP, Inc., and IPC dated as of February 2, 1998. File number 333-48031, Form S-4, filed on 3/16/98, as Exhibit 2.
*3.1	Restated Articles of Incorporation of IPC as filed with the Secretary of State of Idaho on June 30, 1989. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 4(a)(xiii).
*3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of IPC, as filed with the Secretary of State of Idaho on November 5, 1991. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(ii).
*3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of IPC, as filed with the Secretary of State of Idaho on June 30, 1993. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(iii).
*3.4	Articles of Amendment to Restated Articles of Incorporation of IPC, as filed with the Secretary of State of Idaho on June 15, 2000. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 3(a)(iii).
*3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on January 21, 2005. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 4.5.
*3.6	Articles of Amendment to Restated Articles of Incorporation of IPC, as amended, as filed with the Secretary of State of Idaho on November 19, 2007. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.3.
*3.7	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998. File number 33-56071-99, Post-Effective Amendment No. 1 to Form S-8, filed on 10/1/98, as Exhibit 3(d).
*3.8	Amended Bylaws of IPC, amended on November 15, 2007, and presently in effect. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.2.

*3.9	Articles of Incorporation of IDACORP, Inc. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.1.
*3.10	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.2.
*3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998. File number 333-00139-99, Post-Effective Amendment No. 1 to Form S-3, filed on 9/22/98, as Exhibit 3(b).
*3.12	Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect. File number 1-14456, Form 8-K, filed on 11/19/07, as Exhibit 3.1.
*4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between IPC and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees. File number 2-3413, as Exhibit B-2.
*4.2	IPC Supplemental Indentures to Mortgage and Deed of Trust: File number 1-MD, as Exhibit B-2-a, First, July 1, 1939 File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943 File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947 File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948 File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949 File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951 File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957 File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957 File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957 File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958 File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958 File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959 File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960 File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961 File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964 File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966 File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966 File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972 File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974 File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974 File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974 File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976 File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978 File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979 File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981 File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982 File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986 File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989 File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990

File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991
File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991
File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992
File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993
File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993
File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000
File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001
File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003
File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003
File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iii), Thirty-ninth, October 1, 2003
File number 1-3198, Form 8-K filed 5/10/05, as Exhibit 4, Fortieth, May 1, 2005.
File number 1-3198, Form 8-K filed 10/10/06, as Exhibit 4, Forty-first, October 1, 2006.
File number 1-3198, Form 8-K filed 6/4/07, as Exhibit 4, Forty-second, May 1, 2007.
File number 1-3198, Form 8-K filed 9/26/07, as Exhibit 4, Forty-third, September 1, 2007.
File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008.

*4.3 Instruments relating to IPC American Falls bond guarantee (see Exhibit 10.4). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).

*4.4 Agreement of IPC to furnish certain debt instruments. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(f).

*4.5 Agreement of IDACORP, Inc. to furnish certain debt instruments. File number 1-14465, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(c)(ii).

*4.6 Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 2(a)(iii).

*4.7 Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.1.

*4.8 First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.2.

*4.9 Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.

*10.1	Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).
*10.6	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10.13	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).

*10.151	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.15.
*10.161	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.16.
*10.17 1	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).
*10.18 1	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).
*10.19 1	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vii).
*10.20 1	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).
*10.21 1	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.21.
*10.221	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and IPC, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).
*10.231	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).
*10.241	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.24.
*10.25 1	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice

	president), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.25.
*10.261	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.26.
*10.271	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).
*10.281	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).
*10.291	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).
*10.301	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.30.
*10.311	IDACORP, Inc. Executive Incentive Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.31.
*10.321	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.32.
*10.331	IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.33.
*10.34	Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC s Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.35	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.36	

	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.37	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).
*10.38	Guaranty Agreement, dated February 10, 1992, between IPC and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).
*10.39	Power Purchase Agreement between IPC and PPL Montana, LLC, dated March 1, 2003 and Revised Confirmation Agreement dated May 9, 2003. File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 10(k).
*10.40	$100 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among IDACORP, Inc., various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-14465, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(l).
*10.41	$300 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among Idaho Power Company, various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(m).
*10.42	$170 Million Term Loan Credit Agreement, dated as of February 4, 2009, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.42.
*10.43	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.

*10.44	Power Purchase Agreement between IPC and PPL EnergyPlus, LLC, dated June 2, 2008. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2008, filed on 8/7/08, as Exhibit 10.46.
*10.45	Electric Service Agreement, dated September 17, 2008, between IPC and Hoku Materials, Inc. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2008, filed on 11/6/08, as Exhibit 10.47.
*10.46[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.46.
*10.471	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.47.
*10.481	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.48.
*10.491	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.49.
*10.501	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.50.
*10.511	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.51.
*10.521	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.52.
*10.531	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.53.
*10.541	Form of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.54.

*10.551	Form of Letter Agreement to Amend Outstanding IDACORP Financial Services, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.55.
*10.561	Form of Amendment to IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.56.
*10.571	Form of Termination of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.57.
10.58	Settlement Agreement, dated March 25, 2009, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34.
*10.59[1]	Exhibit A to the IDACORP, Inc. Executive Incentive Plan, as amended February 24, 2009. File number 1-14465, 1-3198, Form 8-K, filed on 3/2/09, as Exhibit 10.1.
*10.60[1]	Consulting Agreement, dated as of April 1, 2009, by and between Thomas R. Saldin and Idaho Power Company, including its parent IDACORP, Inc. and all subsidiaries and affiliates. File number 1-14465, 1-3198, Form 8-K, filed on 4/3/09, as Exhibit 10.1.
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.3	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
15	Letter Re: Unaudited Interim Financial Information
*21	Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on 2/28/08, as Exhibit 21.
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification.
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification.
31.3	IPC Rule 13a-14(a) CEO certification.
31.4	IPC Rule 13a-14(a) CFO certification.

32.1	IDACORP, Inc. Section 1350 CEO certification.
32.2	IDACORP, Inc. Section 1350 CFO certification.
32.3	IPC Section 1350 CEO certification.
32.4	IPC Section 1350 CFO certification.
99	Earnings press release for the first quarter 2009.

1 Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

IDACORP, Inc.
(Registrant)

Date	May 7, 2009	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	May 7, 2009	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date	May 7, 2009	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	May 7, 2009	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number

10.58	Settlement Agreement, dated March 25, 2009, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34.
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
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