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 September 30, 2007

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 are large accelerated filers, accelerated filers, or non-accelerated filers.

IDACORP, Inc.:
Large accelerated filer __X__ Accelerated filer ____ Non-accelerated filer ______

Idaho Power Company:
Large accelerated filer ______ Accelerated filer ____ Non-accelerated filer __X__

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 September 30, 2007:

IDACORP, Inc.:	44,995,330
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.

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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

AFDC	-	Allowance for Funds Used During Construction
CAMP	-	Comprehensive Aquifer Management Plan
CEP	-	Continuous Equity Program
cfs	-	Cubic feet per second
DSM	-	Demand Side Management
EIS	-	Environmental Impact Statement
Energy Act	-	Energy Policy Act of 2005
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, Inc.
FPA	-	Federal Power Act
GAAP	-	Generally Accepted Accounting Principles in the United States of America
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDEQ	-	Idaho Department of Environmental Quality
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCO	-	Idaho Energy Resources Co.
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
ITI	-	IDACORP Technologies, Inc.
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
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
NEPA	-	National Environmental Policy Act of 1996
O & M	-	Operations and Maintenance
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Oregon Power Cost Adjustment Mechanism
PM&E	-	Protection, Mitigation and Enhancement
PURPA	-	Public Utility Regulatory Policies Act of 1978
RFC	-	National Weather Service’s Northwest River Forecast Center
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," "projects," "may result," "may continue" and similar expressions.

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

	Three months ended September 30,	
	2007	**2006**
	(thousands of dollars except for per share amounts)	
Operating Revenues:		
Electric utility:		
General business	$ 211,873	$ 179,411
Off-system sales	34,843	39,692
Other revenues	13,800	9,696
Total electric utility revenues	260,516	228,799
Other	947	1,733
Total operating revenues	261,463	230,532
Operating Expenses:		
Electric utility:		
Purchased power	110,108	98,926
Fuel expense	43,291	34,933
Power cost adjustment	(43,749)	(54,995)
Other operations and maintenance	69,154	62,395
Demand-side management	4,307	-
Gain on sale of emission allowances	(1,872)	(22)
Depreciation	25,967	25,289
Taxes other than income taxes	4,714	4,057
Total electric utility expenses	211,920	170,583
Other expense	1,613	3,293
Total operating expenses	213,533	173,876
Operating Income (Loss):		
Electric utility	48,596	58,216
Other	(666)	(1,560)
Total operating income	47,930	56,656
Other Income	4,616	4,431
Losses of Unconsolidated Equity-Method Investments	(380)	(444)
Other Expense	2,055	2,669
Interest Expense:		
Interest on long-term debt	15,862	14,241
Other interest	763	549
Total interest expense	16,625	14,790
Income Before Income Taxes	33,486	43,184
Income Tax Expense	4,555	10,692
Income from Continuing Operations	28,931	32,492
Income from Discontinued Operations, net of tax	-	11,497
Net Income	$ 28,931	$ 43,989
Weighted Average Common Shares Outstanding - Basic (000's)	44,417	42,678
Weighted Average Common Shares Outstanding - Diluted (000's)	44,543	42,863
Earnings Per Share of Common Stock (basic and diluted):		
Earnings per share from Continuing Operations	$ 0.65	$ 0.76
Earnings per share from Discontinued Operations	-	0.27
Earnings Per Share of Common Stock	$ 0.65	$ 1.03
Dividends Paid Per Share of Common Stock	$ 0.30	$ 0.30

The accompanying notes are an integral part of these statements.

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

	Nine months ended September 30,	
	2007	**2006**
Operating Revenues:	(thousands of dollars except for per share amounts)	
Electric utility:		
General business	$ 511,337	$ 500,803
Off-system sales	129,859	219,531
Other revenues	37,776	16,587
Total electric utility revenues	678,972	736,921
Other	2,976	4,586
Total operating revenues	681,948	741,507
Operating Expenses:		
Electric utility:		
Purchased power	241,393	229,659
Fuel expense	101,724	83,856
Power cost adjustment	(107,457)	(6,928)
Other operations and maintenance	215,870	193,909
Demand-side management	8,970	-
Gain on sale of emission allowances	(2,754)	(8,258)
Depreciation	76,870	74,471
Taxes other than income taxes	14,267	15,957
Total electric utility expenses	548,883	582,666
Other expense	4,782	10,157
Total operating expenses	553,665	592,823
Operating Income (Loss):		
Electric utility	130,089	154,255
Other	(1,806)	(5,571)
Total operating income	128,283	148,684
Other Income	13,867	14,181
Losses of Unconsolidated Equity-Method Investments	(3,257)	(2,703)
Other Expense	6,838	6,745
Interest Expense:		
Interest on long-term debt	43,306	42,525
Other interest	3,881	2,753
Total interest expense	47,187	45,278
Income Before Income Taxes	84,868	108,139
Income Tax Expense	12,891	26,019
Income from Continuing Operations	71,977	82,120
Income from Discontinued Operations, net of tax	67	7,201
Net Income	$ 72,044	$ 89,321
Weighted Average Common Shares Outstanding - Basic (000's)	43,947	42,569
Weighted Average Common Shares Outstanding - Diluted (000's)	44,080	42,710
Earnings Per Share of Common Stock:		
Earnings per share from Continuing Operations-Basic	$ 1.64	$ 1.93
Earnings per share from Discontinued Operations-Basic	-	0.17
Earnings Per Share of Common Stock-Basic	$ 1.64	$ 2.10
Earnings per share from Continuing Operations-Diluted	$ 1.63	$ 1.92
Earnings per share from Discontinued Operations-Diluted	-	0.17
Earnings Per Share of Common Stock-Diluted	$ 1.63	$ 2.09
Dividends Paid Per Share of Common Stock	$ 0.90	$ 0.90

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

Assets	September 30, 2007	December 31, 2006
	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 16,652	$ 9,892
Receivables:		
Customer	71,047	62,131
Allowance for uncollectible accounts	(7,469)	(7,168)
Employee notes	2,287	2,569
Other	9,279	11,855
Energy marketing assets	1,829	12,069
Accrued unbilled revenues	32,766	31,365
Materials and supplies (at average cost)	43,598	39,079
Fuel stock (at average cost)	19,013	15,174
Prepayments	10,385	9,308
Taxes receivable	12,063	-
Deferred income taxes	31,549	28,035
Regulatory assets	145	1,480
Refundable income tax deposit	44,903	44,903
Other	3,570	2,513
Assets held for sale	-	3,326
Total current assets	291,617	266,531
Investments	201,532	202,825
Property, Plant and Equipment:		
Utility plant in service	3,712,899	3,583,694
Accumulated provision for depreciation	(1,466,697)	(1,406,210)
Utility plant in service - net	2,246,202	2,177,484
Construction work in progress	277,006	210,094
Utility plant held for future use	3,137	2,810
Other property, net of accumulated depreciation	28,217	28,692
Property, plant and equipment - net	2,554,562	2,419,080
Other Assets:		
American Falls and Milner water rights	29,762	30,543
Company-owned life insurance	31,719	34,055
Regulatory assets	454,120	423,548
Long-term receivables (net of allowance of $1,878)	3,583	3,802
Employee notes	2,366	2,411
Other	43,387	41,259
Assets held for sale	-	21,076
Total other assets	564,937	556,694
Total	$ 3,612,648	$ 3,445,130

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2007	December 31, 2006
Liabilities and Shareholders' Equity	**(thousands of dollars)**	
Current Liabilities:		
Current maturities of long-term debt	$ 92,368	$ 95,125
Notes payable	144,813	129,000
Accounts payable	65,805	86,440
Energy marketing liabilities	1,973	13,532
Taxes accrued	-	47,402
Interest accrued	28,165	12,657
Other	51,390	23,572
Liabilities held for sale	-	2,606
Total current liabilities	384,514	410,334
Other Liabilities:		
Deferred income taxes	486,006	498,512
Regulatory liabilities	276,086	294,844
Other	196,656	179,836
Liabilities held for sale	-	8,773
Total other liabilities	958,748	981,965
Long-Term Debt	1,061,276	928,648
Commitments and Contingencies (Note 5)		
Shareholders' Equity:		
Common stock, no par value (shares authorized 120,000,000; 44,995,710 and 43,905,458 shares issued, respectively)	672,905	638,799
Retained earnings	540,824	493,363
Accumulated other comprehensive loss	(5,617)	(5,737)
Treasury stock (380 and 71,570 shares at cost, respectively)	(2)	(2,242)
Total shareholders' equity	1,208,110	1,124,183
Total	$ 3,612,648	$ 3,445,130

The accompanying notes are an integral part of these statements.

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

	Nine Months Ended September 30, 2007	2006
	(thousands of dollars)	
Operating Activities:		
Net income	$ 72,044	$ 89,321
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	91,286	90,928
Deferred income taxes and investment tax credits	29,224	(16,467)
Changes in regulatory assets and liabilities	(110,813)	6,111
Undistributed earnings of subsidiaries	(4,648)	(7,944)
Gain on sale of assets	(4,437)	(25,242)
Other non-cash adjustments to net income	5,679	(2,592)
Change in:		
Accounts receivable and prepayments	(9,703)	23,569
Accounts payable and other accrued liabilities	(19,981)	(14,252)
Taxes accrued	(15,079)	2,720
Other current assets	(9,685)	1,241
Other current liabilities	16,582	14,779
Other assets	758	889
Other liabilities	5,973	6,787
Net cash provided by operating activities	47,200	169,848
Investing Activities:		
Additions to property, plant and equipment	(203,067)	(168,185)
Proceeds from the sale of ITI	-	21,469
Proceeds from the sale of IDACOMM	7,283	-
Investments in affordable housing	300	-
Proceeds from the sale of emission allowances	19,846	11,323
Investments in unconsolidated affiliates	(4,925)	(15,370)
Purchase of available-for-sale securities	(24,349)	(14,358)
Proceeds from the sale of available-for-sale securities	26,110	16,404
Purchase of held-to-maturity securities	(3,116)	(2,730)
Maturity of held-to-maturity securities	3,267	4,647
Other assets	(187)	617
Net cash used in investing activities	(178,838)	(146,183)
Financing Activities:		
Issuance of long-term debt	140,000	-
Retirement of long-term debt	(9,978)	(10,993)
Dividends on common stock	(39,629)	(38,449)
Net change in short-term borrowings	15,813	(27,410)
Issuance of common stock	34,893	9,174
Acquisition of treasury stock	(346)	(213)
Other	(2,355)	236
Net cash provided by (used in) financing activities	138,398	(67,655)
Net increase (decrease) in cash and cash equivalents	6,760	(43,990)
Cash and cash equivalents at beginning of period	9,892	52,356
Cash and cash equivalents at end of period	$ 16,652	$ 8,366
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Income taxes	$ 3,815	$ 43,022
Interest (net of amount capitalized)	$ 36,080	$ 35,520
Non-cash investing activities		
Additions to property, plant and equipment in accounts payable	$ 6,374	$ 9,226

The accompanying notes are an integral part of these statements.

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

	Three Months Ended September 30,	
	2007	**2006**
	(thousands of dollars)	
Net Income	$ 28,931	$ 43,989
Other Comprehensive Income:		
Unrealized gains (losses) on securities:		
Unrealized holding gains arising during the period, net of tax of $148 and $673	231	1,141
Reclassification adjustment for gains included in net income, net of tax of ($31) and ($326)	(48)	(508)
Net unrealized gains	183	633
Unfunded pension liability adjustment, net of tax of $72 and $0	113	-
Total Comprehensive Income	$ 29,227	$ 44,622

The accompanying notes are an integral part of these statements.

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

	Nine Months Ended September 30,	
	2007	**2006**
	(thousands of dollars)	
Net Income	$ 72,044	$ 89,321
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Unrealized holding gains arising during the period, net of tax of $452 and $608	704	893
Reclassification adjustment for gains included in net income, net of tax of ($592) and ($1,057)	(922)	(1,646)
Net unrealized losses	(218)	(753)
Unfunded pension liability adjustment, net of tax of $217 and $0	338	-
Total Comprehensive Income	$ 72,164	$ 88,568

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three Months Ended September 30,	
	2007	**2006**
	(thousands of dollars)	
Operating Revenues:		
General business	$ 211,873	$ 179,411
Off-system sales	34,843	39,692
Other revenues	13,800	9,696
Total operating revenues	260,516	228,799
Operating Expenses:		
Operation:		
Purchased power	110,108	98,926
Fuel expense	43,291	34,933
Power cost adjustment	(43,749)	(54,995)
Other	54,625	46,999
Demand-side management	4,307	-
Gain on sale of emission allowances	(1,872)	(22)
Maintenance	14,529	15,396
Depreciation	25,967	25,289
Taxes other than income taxes	4,714	4,057
Total operating expenses	211,920	170,583
Income from Operations	48,596	58,216
Other Income (Expense):		
Allowance for equity funds used during construction	1,909	1,711
Earnings of unconsolidated equity-method investments	1,296	2,191
Other income	2,475	2,460
Other expense	(2,205)	(2,577)
Total other income	3,475	3,785
Interest Charges:		
Interest on long-term debt	15,386	13,548
Other interest	2,361	1,263
Allowance for borrowed funds used during construction	(2,063)	(998)
Total interest charges	15,684	13,813
Income Before Income Taxes	36,387	48,188
Income Tax Expense	12,279	17,799
Net Income	$ 24,108	$ 30,389

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(thousands of dollars)	
Operating Revenues:		
General business	$ 511,337	$ 500,803
Off-system sales	129,859	219,531
Other revenues	37,776	16,587
Total operating revenues	678,972	736,921
Operating Expenses:		
Operation:		
Purchased power	241,393	229,659
Fuel expense	101,724	83,856
Power cost adjustment	(107,457)	(6,928)
Other	162,073	143,079
Demand-side management	8,970	-
Gain on sale of emission allowances	(2,754)	(8,258)
Maintenance	53,797	50,830
Depreciation	76,870	74,471
Taxes other than income taxes	14,267	15,957
Total operating expenses	548,883	582,666
Income from Operations	130,089	154,255
Other Income (Expense):		
Allowance for equity funds used during construction	4,687	4,821
Earnings of unconsolidated equity-method investments	3,376	5,995
Other income	8,332	8,376
Other expense	(6,637)	(6,834)
Total other income	9,758	12,358
Interest Charges:		
Interest on long-term debt	41,857	40,479
Other interest	7,019	3,727
Allowance for borrowed funds used during construction	(5,517)	(2,784)
Total interest charges	43,359	41,422
Income Before Income Taxes	96,488	125,191
Income Tax Expense	32,885	48,169
Net Income	$ 63,603	$ 77,022

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2007	December 31, 2006
Assets	**(thousands of dollars)**	
Electric Plant:		
In service (at original cost)	$ 3,712,899	$ 3,583,694
Accumulated provision for depreciation	(1,466,697)	(1,406,210)
In service - net	2,246,202	2,177,484
Construction work in progress	277,006	210,094
Held for future use	3,137	2,810
Electric plant - net	2,526,345	2,390,388
Investments and Other Property	99,165	91,244
Current Assets:		
Cash and cash equivalents	4,935	2,404
Receivables:		
Customer	64,006	54,218
Allowance for uncollectible accounts	(1,269)	(968)
Notes	480	514
Employee notes	2,287	2,569
Other	5,722	10,592
Accrued unbilled revenues	32,766	31,365
Materials and supplies (at average cost)	43,598	39,078
Fuel stock (at average cost)	19,013	15,174
Prepayments	10,194	8,952
Deferred income taxes	4,147	-
Regulatory assets	144	1,480
Refundable income tax deposit	43,927	-
Other	599	-
Total current assets	230,549	165,378
Deferred Debits:		
American Falls and Milner water rights	29,762	30,543
Company-owned life insurance	31,719	34,055
Regulatory assets	454,120	423,548
Employee notes	2,366	2,411
Other	42,072	40,158
Total deferred debits	560,039	530,715
Total	$ 3,416,098	$ 3,177,725

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2007	December 31, 2006
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	530,758	530,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	443,023	404,076
Accumulated other comprehensive loss	(5,617)	(5,737)
Total common stock equity	1,063,944	1,024,877
Long-term debt	1,041,715	902,884
Total capitalization	2,105,659	1,927,761
Current Liabilities:		
Long-term debt due within one year	81,064	81,064
Notes payable	144,813	52,200
Accounts payable	65,224	85,714
Notes and accounts payable to related parties	726	1,111
Taxes accrued	2,381	41,688
Interest accrued	27,856	12,324
Deferred income taxes	-	17
Other	50,228	24,367
Total current liabilities	372,292	298,485
Deferred Credits:		
Deferred income taxes	475,258	489,234
Regulatory liabilities	276,086	294,844
Other	186,803	167,401
Total deferred credits	938,147	951,479
Commitments and Contingencies (Note 5)		
Total	$ 3,416,098	$ 3,177,725

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	September 30, 2007	%	December 31, 2006	%
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	530,758		530,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	443,023		404,076	
Accumulated other comprehensive loss	(5,617)		(5,737)	
Total common stock equity	1,063,944	51	1,024,877	53
Long-Term Debt:				
First mortgage bonds:				
7.38% Series due 2007	80,000		80,000	
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 % 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		-	
Total first mortgage bonds	925,000		785,000	
Amount due within one year	(80,000)		(80,000)	
Net first mortgage bonds	845,000		705,000	
Pollution control revenue bonds:				
Variable Auction Rate Series 2003 due 2024	49,800		49,800	
Variable Auction 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	10,636		11,700	
Note guarantee due within one year	(1,064)		(1,064)	
Unamortized premium/discount - net	(3,202)		(3,097)	
Total long-term debt	1,041,715	49	902,884	47
Total Capitalization	$ 2,105,659	100	$ 1,927,761	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)

	Nine Months Ended September 30, 2007	2006
	(thousands of dollars)	
Operating Activities:		
Net income	$ 63,603	$ 77,022
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	82,244	77,596
Deferred income taxes and investment tax credits	26,926	(15,882)
Changes in regulatory assets and liabilities	(110,813)	6,111
Undistributed earnings of subsidiary	(3,376)	(5,995)
Gain on sale of assets	(4,268)	(10,979)
Other non-cash adjustments to net income	3,580	(4,760)
Change in:		
Accounts receivables and prepayments	(13,249)	2,552
Accounts payable	(18,565)	(13,889)
Taxes accrued	2,098	(4,076)
Other current assets	(9,760)	1,158
Other current liabilities	16,580	15,729
Other assets	710	923
Other liabilities	6,706	8,016
Net cash provided by operating activities	42,416	133,526
Investing Activities:		
Additions to utility plant	(202,555)	(166,309)
Purchase of available-for-sale securities	(24,349)	(14,358)
Proceeds from the sale of available-for-sale securities	26,110	16,404
Proceeds from the sale of emission allowances	19,846	11,323
Investments in unconsolidated affiliate	(4,925)	(15,370)
Refundable deposit for tax related liabilities	(43,927)	-
Other assets	(186)	525
Net cash used in investing activities	(229,986)	(167,785)
Financing Activities:		
Issuance of long-term debt	140,000	-
Retirement of long-term debt	(1,064)	-
Dividends on common stock	(39,791)	(38,289)
Net change in short term borrowings	92,613	27,190
Other assets	(1,379)	(14)
Other	(278)	443
Net cash provided by (used in) financing activities	190,101	(10,670)
Net increase (decrease) in cash and cash equivalents	2,531	(44,929)
Cash and cash equivalents at beginning of period	2,404	49,335
Cash and cash equivalents at end of period	$ 4,935	$ 4,406
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Income taxes paid to parent	$ 8,978	$ 70,037
Interest (net of amount capitalized)	$ 32,270	$ 33,717
Non-cash investing activities:		
Additions to utility plant in accounts payable	$ 6,374	$ 9,226

The accompanying notes are an integral part of these statements.

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

	Three Months Ended September 30,	
	2007	**2006**
	(thousands of dollars)	
Net Income	$ 24,108	$ 30,389
Other Comprehensive Income:		
Unrealized gains (losses) on securities:		
Unrealized holding gains arising during the period, net of tax of $148 and $673	231	1,141
Reclassification adjustment for gains included in net income, net of tax of ($31) and ($326)	(48)	(508)
Net unrealized gains	183	633
Unfunded pension liability adjustment, net of tax of $72 and $0	113	-
Total Comprehensive Income	$ 24,404	$ 31,022

The accompanying notes are an integral part of these statements.

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

	Nine Months Ended September 30,	
	2007	**2006**
	(thousands of dollars)	
Net Income	$ 63,603	$ 77,022
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Unrealized holding gains arising during the period, net of tax of $452 and $608	704	893
Reclassification adjustment for gains included in net income, net of tax of ($592) and ($1,057)	(922)	(1,646)
Net unrealized losses	(218)	(753)
Unfunded pension liability adjustment, net of tax of $217 and $0	338	-
Total Comprehensive Income	$ 63,723	$ 76,269

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 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., 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.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of IDACORP Technologies, Inc. (ITI) to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM, Inc. (IDACOMM) to American Fiber Systems, Inc. The results of operations of ITI and IDACOMM are reported as discontinued operations. See Note 9 for further discussion of discontinued operations.

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

Through IFS, IDACORP also holds significant 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 up to 99 percent. These investments were acquired between 1996 and 2006. IFS' maximum exposure to loss in these developments was $81 million at September 30, 2007.

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 September 30, 2007, and consolidated results of operations for the three and nine months ended September 30, 2007 and 2006, and consolidated cash flows for the nine months ended September 30, 2007 and 2006. 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 therefore they 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, 2006. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Earnings Per Share
The following table presents the computation of IDACORP's basic and diluted earnings per share from continuing operations for the three and nine months ended September 30, 2007 and 2006 (in thousands, except for per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Numerator:				
Income from continuing operations	$ 28,931	$ 32,492	$ 71,977	$ 82,120
Denominator:				
Weighted-average common shares outstanding - basic*	44,417	42,678	43,947	42,569
Effect of dilutive securities:				
Options	34	125	41	87
Restricted Stock	92	60	92	54
Weighted-average common shares outstanding – diluted	44,543	42,863	44,080	42,710
Basic earnings per share from continuing operations	$ 0.65	$ 0.76	$ 1.64	$ 1.93
Diluted earnings per share from continuing operations	$ 0.65	$ 0.76	$ 1.63	$ 1.92

*Weighted average shares outstanding excludes non-vested shares issued under stock compensation plans.

The diluted EPS computation excluded 486,800 and 487,200 common stock options for the three and nine months ended September 30, 2007, respectively, because the options' exercise prices were greater than the average market price of the common stock during those periods. For the same periods in 2006, there were 463,600 and 643,600 options excluded from the diluted EPS computation for the same reason. In total, 833,102 options were outstanding at September 30, 2007, with expiration dates between 2010 and 2015.

Reclassifications
Certain prior year amounts have been reclassified to conform to the current year presentation. Net income and shareholders' equity were not affected by these reclassifications.

New Accounting Pronouncements
SFAS 157: In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 157, "*Fair Value Measurements*" (SFAS 157), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. IDACORP and IPC are currently evaluating the impact of adopting SFAS 157 on their financial statements.

SFAS 159: In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115"* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS No. 115, *"Accounting for Certain Investments in Debt and Equity Securities,"* applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. IDACORP and IPC are currently evaluating the impact of SFAS 159 on their financial statements.

FSP FIN 39-1: In April 2007 the FASB issued FASB Staff Position No. FIN 39-1 (FSP FIN 39-1), "*Amendment of FASB Interpretation No. 39"* (FIN 39). FSP FIN 39-1 modifies FIN 39, "*Offsetting of Amounts Related to Certain Contracts*," and permits reporting entities to offset receivables or payables recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires disclosure of a reporting entity's accounting policy (to offset or not offset) as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. IDACORP and IPC are evaluating the application of FSP FIN 39-1 with respect to their assets and liabilities.

EITF Issue No. 06-11: In June 2007, the FASB ratified Emerging Issues Task Force Issue No. 06-11, *"Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*" (EITF 06-11), which requires income tax benefits from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified awards and outstanding equity share options to be recognized as an increase in additional paid-in capital and to be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF 06-11 will become effective for dividends declared in years beginning after September 15, 2007. The adoption of EITF 06-11 is not expected to have a material impact on IDACORP's or IPC's financial statements.

2. INCOME TAXES:

Income tax rate

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 nine months ended September 30, 2007, was 15.2 percent, compared to 24.1 percent for the nine months ended September 30, 2006. IPC's effective tax rate for the nine months ended September 30, 2007, was 34.1 percent, compared to 38.5 percent for the nine months ended September 30, 2006.

The differences in estimated annual effective tax rates are primarily due to the decrease in pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

FIN 48

IDACORP and IPC adopted FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*" (FIN 48) on January 1, 2007, as required. IPC recorded an increase of $15.1 million to opening retained earnings for the cumulative effect of adopting FIN 48.

IDACORP and IPC recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. FIN 48 allows companies to change their accounting policy election for interest and penalties upon adoption of the standard. IDACORP and IPC had classified interest as income taxes prior to the adoption of FIN 48. As of January 1, 2007, IPC had accrued interest of $6.5 million. The interest liability did not materially change as of September 30, 2007. No penalties are accrued.

As of January 1, 2007, IPC had total unrecognized tax benefits of $21.2 million. If recognized, the $21.2 million would affect IPC's effective tax rate. The amount of unrecognized tax benefits did not materially change as of September 30, 2007.

IPC is currently disputing the Internal Revenue Service's (IRS) disallowance of IPC's use of the simplified service cost method of uniform capitalization for tax years 2001-2003. The dispute is under review with the IRS Appeals Office, and it is reasonably possible that the matter will be resolved in 2007. Resolution would result in a decrease to IPC's unrecognized tax benefits of $17.4 million. As of September 30, 2007, the appeals conference had not been scheduled.

IDACORP and IPC are subject to examination by their major tax jurisdictions – U.S. federal and state of Idaho – for tax years 2004 through 2006. There are no income tax examinations currently in process.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the nine months ended September 30, 2007, IDACORP entered into the following transactions involving its common stock:

- 16,222 original issue shares and 75,256 treasury shares were used for awards pursuant to the 2000 Long-Term Incentive and Compensation Plan (LTICP).
- 11,736 treasury shares were used for the annual stock grant to directors under the Non-Employee Directors Stock Compensation Plan (DSP).
- A total of 192,693 original issue shares were issued under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan.
- 881,337 original issue shares were issued in at-the-market offerings at an average price of $32.32 per share under the Continuous Equity Program.

IDACORP has three share-based compensation plans. IDACORP's employee plans are the 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 DSP. The purpose of the DSP is to increase directors' stock ownership through stock-based compensation.

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 September 30, 2007, the maximum number of shares available under the LTICP and RSP were 1,606,555 and 108,595, 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):

	IDACORP		IPC	
	Nine months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Compensation cost	$ 2,099	$ 2,124	$ 1,461	$ 1,016
Income tax benefit	$ 821	$ 830	$ 571	$ 397

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four 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 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 nine months of 2007 was $35.18.

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. For unvested awards granted prior to 2006, dividends are paid to recipients at the same time they are paid to other common shareholders. Beginning with the 2006 awards, dividends are accrued and will be paid out only on shares that eventually vest.

The performance goals for the 2006 and 2007 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 nine months of 2007 was $25.82.

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. Upon adoption of SFAS 123(R) on January 1, 2006, the fair value of each option is amortized into compensation expense using graded vesting. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

4. FINANCING:

Long-term Financing
On June 22, 2007, IPC issued $140 million of its 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15, 2037. IPC used the net proceeds to pay down outstanding commercial paper.

On October 18, 2007, IPC issued $100 million of its 6.25% First Mortgage Bonds, Secured Medium-Term Notes, Series G, due October 15, 2037. IPC will use the net proceeds to retire $80 million of 7.38% First Mortgage Bonds due December 1, 2007 and to pay down outstanding commercial paper.

IDACORP entered into a Sales Agency Agreement, dated as of December 15, 2005, and an amendment thereto, dated as of October 31, 2007, with BNY Capital Markets, Inc. (BNYCMI) to issue and sell up to 2,500,000 shares of common stock from time to time through BNYCMI as agent. As of October 31, 2007, 1,417,855 shares had been sold. The amendment extended the time during which the remaining 1,082,145 shares of common stock may be sold to December 1, 2008.

Credit Facilities
On April 25, 2007, IDACORP entered into an Amended and Restated Credit Agreement (IDACORP Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P. Morgan Securities Inc., as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders. The IDACORP Facility amended and restated a $150 million five-year facility that would have expired on March 31, 2010.

The IDACORP Facility is a $100 million five-year credit agreement that terminates on April 25, 2012. The IDACORP Facility, which will be used for general corporate purposes and commercial paper backup, 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 September 30, 2007, no loans or commercial paper were outstanding on the IDACORP Facility.

On April 25, 2007, IPC entered into an Amended and Restated Credit Agreement (IPC Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P. Morgan Securities Inc., as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders. The IPC Facility amended and restated a $200 million five-year credit facility that would have expired on March 31, 2010.

The IPC Facility is a $300 million five-year credit agreement that terminates on April 25, 2012. The IPC Facility, which will be used for general corporate purposes and commercial paper backup, 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 September 30, 2007, no loans were outstanding on IPC's Facility and $145 million of commercial paper was outstanding.

At September 30, 2007, IPC had regulatory authority to incur up to $450 million of short-term indebtedness.

5. COMMITMENTS AND CONTINGENCIES:

Guarantees
IPC has agreed to guarantee one-third of the cost of 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 September 30, 2007. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs and expects that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

Legal Proceedings
Reference is made to IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2006, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007, 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.

Wah Chang: Wah Chang's appeal to the U.S. Court of Appeals for the Ninth Circuit of the February 11, 2005 dismissal of the case by the Honorable Robert H. Whaley, sitting by designation in the U.S. District Court for the Southern District of California, was orally argued on April 10, 2007. The matter now awaits decision by the Ninth Circuit. IDACORP, IPC and IE intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Western Energy Proceedings at the FERC:
California Refund: 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. That plan included the potential for orders 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, and therefore not in compliance with the Federal Power Act. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. 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, 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. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the Settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the Settlement. The FERC issued an order on October 5, 2006, denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC orders approving the Settlement. Initially, the Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it and stayed further action on the consolidated cases while the court's mediator and FERC representatives work on achieving settlements with other parties. On October 25, 2007, the court issued an order that lifted its stay as to the review of the Port of Seattle's petition of the FERC's orders approving the February 17, 2006 offer of settlement as well as Port of Seattle's petitions for review of orders approving the settlements of two other sellers. The court's order also established a consolidated briefing schedule for these three cases with initial briefs due by January 28, 2008 and final briefs due at the end of July 2008. A date for argument has not been set. IPC and IE are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review filed by Port of Seattle.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings, the FERC issued orders permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy crisis of 2000 and 2001. On June 25, 2003, the FERC ordered a large number of parties, including IPC, to show cause why certain trading practices did not constitute "gaming" or anomalous market behavior ("partnership") in violation of the California Independent System Operator and California Power Exchange Tariffs. On October 16, 2003, IPC reached agreement with the FERC Staff on the show cause orders. The "gaming" settlement was approved by the FERC on March 4, 2004. Originally, eight parties sought rehearing of the "gaming" settlement. The FERC approved the motion to dismiss the "partnership" proceeding on January 23, 2004.

On October 11, 2006, the FERC issued an order denying rehearing of its earlier approval of the "gaming" settlement. On October 24, 2006, the Port of Seattle, Washington appealed to the U.S. Court of Appeals for the Ninth Circuit FERC's denial of its request for rehearing of its order granting approval of the settlement of the gaming allegations against IE and IPC. On November 17, 2006, the Ninth Circuit consolidated the Port of Seattle's review petition with a large number of review petitions previously consolidated and has stayed further action on the consolidated cases while the court's mediator and FERC representatives work on achieving settlements with other parties. The Ninth Circuit establishment of a briefing schedule for the settlements discussed above does not apply to the "gaming" settlement.

In addition, a number of parties have petitioned the Ninth Circuit Court of Appeals contending that the scope of the show cause proceedings was too narrow, but those petitions have been stayed. IE and IPC are unable to predict the outcome of these matters.

Pacific Northwest Refund: On June 19, 2001, the FERC expanded its price mitigation plan for the California Wholesale electricity market discussed above under "California Refund" to the entire western electrically interconnected system. This expansion led to the Pacific Northwest Refund proceeding. On September 24, 2001, the FERC Administrative Law Judge submitted recommendations and findings to the FERC, finding that prices in the Pacific Northwest during the December 25, 2000, through June 20, 2001, time period should be governed by the Mobile-Sierra standard of public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive, and that no refunds should be allowed. The FERC declined to order refunds on June 25, 2003, and multiple parties then appealed to the Ninth Circuit Court of Appeals. IE and IPC were parties in the FERC proceeding and participated in the appeal. On August 24, 2007, the court filed an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The court's opinion instructed the FERC to consider whether evidence of market manipulation submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources in the proceeding. On September 18, 2007, the court extended until November 16, 2007 the time for filing petitions for rehearing to allow the parties time to assess settlement prospects and directed Senior Judge Edward Leavey of the Ninth Circuit to initiate mediation efforts. The stay also effectively defers the time frame in which the court's mandate to the FERC might be issued. On October 25, 2007, Powerex Corp. filed an unopposed motion to extend the date for seeking rehearing until December 17, 2007. IE and IPC are unable to predict the outcome of these matters. The Settlement in the California Refund proceeding resolves all claims the California Parties have against IE and IPC in the Pacific Northwest proceeding.

There are pending in the U.S. Court of Appeals for the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the Western energy matters of 2000 and 2001, including the California refund proceeding, the structure and content of the FERC's market-based rate regime, show cause orders respecting contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of 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 are unable to predict the outcome of any of these petitions for review.

Shareholder Lawsuit: On May 26, 2004 and June 22, 2004, two shareholder lawsuits were filed in the U.S. District Court for the District of Idaho against IDACORP and certain of its directors and officers. The lawsuits captioned Powell, et al. v. IDACORP, Inc., et al. and Shorthouse, et al. v. IDACORP, Inc., et al., raised largely similar allegations. The lawsuits were putative class actions brought on behalf of purchasers of IDACORP stock between February 1, 2002, and June 4, 2002.

On May 21, 2007, the U.S. District Court for the District of Idaho granted the defendants' motion to dismiss the amended complaint because it failed to satisfy the pleading requirements for loss causation. The court also denied the plaintiffs' request to further amend the complaint.

On June 19, 2007, the plaintiffs filed a notice of appeal from the District Court's judgment to the United States Court of Appeals for the Ninth Circuit. On October 1, 2007, the plaintiffs filed a motion for voluntary dismissal of their appeal, with prejudice, with both sides to assume their own costs. IDACORP and the other defendants did not offer or tender any consideration for this motion, nor did the defendants oppose the motion. The Ninth Circuit granted plaintiffs' motion on October 3, 2007 and the order dismissing the appeal was filed with the District Court on October 9, 2007. This action is now concluded.

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 1, 2006, the defendants filed an Answer to plaintiffs' First Amended Complaint denying all liability to the plaintiffs and asserting certain affirmative defenses including collateral estoppel and res judicata, preemption, impossibility and impracticability, failure to join all real and necessary parties, and various defenses based on untimeliness. On June 19, 2006, the defendants filed a motion to dismiss plaintiffs' First Amended Complaint, asserting, among other things, that the Court lacks subject matter jurisdiction and that plaintiffs failed to join an indispensable party (namely, the United States government). 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. On June 8, 2007, plaintiffs filed a motion for reconsideration. On June 25, 2007, the defendants filed an opposition to plaintiffs' motion for reconsideration and plaintiffs filed their reply to opposition to motion for reconsideration on July 9, 2007. The matter is now fully briefed and submitted to the District Court for decision. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter.

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 (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in 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 and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to $32,500 per day per violation and reimbursement of the plaintiff's costs of litigation, including reasonable attorney fees.

The U.S. District Court has set this matter for trial commencing in April 2008. Discovery in the matter is ongoing. In October 2007, the plaintiffs and defendant filed motions for summary judgment on the alleged opacity permit violations. IPC continues to monitor the status of this matter but is unable to predict its outcome and 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. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial

District, which has jurisdiction over SRBA matters (SRBA Court), then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

On May 10, 2007, in order to protect its claims and the availability of water for power purposes at its facilities, and in response to the claim of ownership filed by the State, IPC filed a complaint and petition for declaratory and injunctive relief regarding the status and nature of IPC's water rights and the respective rights and responsibilities of the parties under the Swan Falls Agreement.

In conjunction with the filing of the complaint and petition, IPC filed motions with the court to stay all pending proceedings involving the water rights of IPC and to consolidate those proceedings into a single action where all issues relating to the Swan Falls Agreement can be determined.

IPC alleged in the complaint, among other things, that contrary to the parties' belief at the time the Swan Falls Agreement was entered into in 1984, the Snake River basin above Swan Falls was over-appropriated and as a consequence there was not in 1984, and there currently is not, water available for new upstream uses over and above the minimum flows established by the Swan Falls Agreement; that because of this mutual mistake of fact relating to the over-appropriation of the basin, the Swan Falls Agreement should be reformed; that the State's December 22, 2006, claim of ownership to IPC's water rights should be denied; and that the Swan Falls Agreement did not subordinate IPC's water rights to aquifer recharge.

On May 30, 2007, the State filed motions to dismiss IPC's complaint and petition. These motions were briefed and, together with IPC's motions to stay and consolidate the proceedings, were argued before the Court on June 25, 2007.

On July 23, 2007, the court issued an Order granting in part and denying in part the State's motion to dismiss, consolidating the issues into a consolidated sub case before the court and providing for discovery during the objection period; a scheduling conference is set for December 17, 2007. In its Order, the court denied the majority of the State's motion to dismiss, refusing to dismiss the complaint and finding that the court has jurisdiction to hear and determine virtually all the issues raised by IPC's complaint that relate to IPC's water rights and the effect of the Swan Falls Agreement upon those water rights. This includes the issues of ownership, whether IPC's water rights are subordinated to recharge and how those water rights are to be administered relative to other water rights on the same or connected resources. The court did find that by virtue of a state statute the IDWR, and its director, could not be parties to the SRBA and therefore stayed IPC's claims against the IDWR and its director pending resolution of the issues to be litigated in the SRBA, or until further order of the court.

Consistent with IPC's motion to consolidate and stay the proceedings, the court consolidated all of the issues associated with IPC's water rights before the court and stayed that proceeding to allow other parties that may be affected by the litigation to file responses or intervene in the consolidated proceedings by December 5, 2007. IPC is unable to predict the outcome of the consolidated proceedings.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy near Wilder, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho (Canyon County) against IDACORP and IPC. The plaintiffs' complaint asserts claims for negligence, negligence *per se*, gross negligence, nuisance, and fraud. The claims are 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 seek compensatory damages of not less than $1 million.

Plaintiffs have not yet served their complaint on IDACORP or IPC. If the action is pursued by the plaintiffs, the companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

6. REGULATORY MATTERS:

Deferred (Accrued) Net Power Supply Costs

IPC's deferred (accrued) net power supply costs consisted of the following (in thousands of dollars):

	September 30, 2007	December 31, 2006
Idaho PCA current year:		
Accrual for the 2007-2008 rate year [1]	$ -	$ (3,484)
Deferral for the 2008-2009 rate year [2]	70,855	-
Idaho PCA true-up awaiting recovery (refund):		
Authorized May 2006	-	(11,689)
Authorized May 2007	8,135	-
Oregon deferral:		
2001 costs	3,498	6,670
2005 costs	-	2,889
Total deferral (accrual)	$ 82,488	$ (5,614)

[1] Includes $69 million of emission allowance sales to be credited to the customers during the 2007-2008 PCA year.

[2] Includes $17 million of emission allowance sales made in 2007.

Idaho: IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portion, is then included in the calculation of the next year's PCA.

On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then existing level, which was $46.8 million below base rates, to a level that is $30.7 million above those base rates. This $77.5 million increase is net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates were effective June 1, 2007.

On June 1, 2006, IPC implemented the 2006-2007 PCA, which reduced the PCA component of customers' rates from the then-existing level, which was recovering $76.7 million above then-existing base rates, to a level that was $46.8 million below those base rates, a decrease of approximately $123.5 million.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" power supply expenses. In the Oregon general rate case, "normal" power supply expenses were set at a negative number (meaning that under normal water conditions IPC should be able to sell enough surplus energy to pay for all fuel and purchased power expenses and still have revenue left over to offset other costs). IPC requested authorization to defer an estimated $5.7 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is currently responding to data requests generated by the filing.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. On April 25, 2007, a tentative settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. This amount is subject to approval by the OPUC. The settlement stipulation was filed with the OPUC for approval on October 24, 2007. The parties also agreed that IPC would file an application for an Oregon PCA mechanism.

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 per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Fixed Cost Adjustment Mechanism (FCA)

On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent of the volume of IPC's energy sales. This filing was a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The accounting for the FCA will be separate from the PCA. IPC proposed a three percent cap on any rate increase to be applied at the discretion of the IPUC.

IPC and the IPUC Staff agreed in concept to a three-year pilot beginning January 1, 2007, and a stipulation was filed on December 18, 2006. The stipulation called for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of demand side management (DSM) activities. The IPUC approved the stipulation on March 12, 2007. The pilot program began retroactively on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. IPC has accrued $1.7 million of FCA expense through the third quarter of 2007.

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 FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. The proposed rates would have produced an annual revenue increase for the FERC jurisdiction of approximately $13 million based on 2004 test year data. The FERC accepted IPC's rates, effective June 1, 2006, subject to adjustment to conform to SFAS 109 tax accounting requirements, which lowered the estimated annual revenues to approximately $11 million.

On August 8, 2007, the FERC approved a settlement agreement (Settlement Agreement) filed in June 2007 by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates and that were in existence before the implementation of OATT in 1996 (Legacy Agreements). The effect of this settlement approval was to reduce the estimated FERC jurisdictional annual revenue increase from $11 million to approximately $8.2 million based on 2004 test year data. The Settlement Agreement requires that amounts collected in excess of the new rates for the June 1, 2006 through July 31, 2007 period be refunded with interest to customers. These refunds totaled approximately $1.7 million and were paid in August 2007.

Hearings were held before the FERC in June 2007 regarding the treatment of the Legacy Agreements. IPC's position was that the revenue IPC receives under the Legacy Agreements should be credited against the total transmission revenue requirement attributed to OATT customers and that the contract demands of the Legacy Agreements should not be included in the load divisor of the rate formula. The intervenors in the proceeding took the position that such contract demands should be included in the load divisor, rather than being revenue credited.

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 is on file and publicly available at FERC Docket No. ER06-787. In the Initial Decision, the ALJ concluded that (i) the Legacy Agreements should be included in the load divisor of the rate formula and (ii) the revenue IPC receives under the Legacy Agreements should not be credited against the total transmission revenue requirement attributed to OATT customers. The ALJ further concluded that the amounts used in the rate formula should be the monthly coincident peak usages under the Legacy Agreements rather than the contract demands under the Legacy Agreements proposed by the FERC Staff and intervenors. IPC had argued that if the Legacy Agreements were to be reflected in the load divisor, rather than as a revenue credit, it should be at the level of monthly coincident peak usage, not at the level of the contract demands.

If the Initial Decision is implemented, IPC estimates that this ruling will reduce the estimated FERC jurisdictional annual revenue increase (based on 2004 test year data) by approximately $1.4 million (from approximately $8.2 million to $6.8 million).

The Initial Decision is subject to appeal to the FERC by all parties to the proceeding. On October 1, 2007, IPC along with other parties filed its Brief on Exceptions. Briefs were required to be submitted by October 1, 2007, with reply briefs due by October 21, 2007. If the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $1.7 million for the June 1, 2006 through July 31, 2007 period. IPC has reserved this entire amount. Amounts collected from August 1, 2007 through December 31, 2007 have been and will continue to be collected at the proposed rates, and amounts collected in excess of the final rates will be refunded with interest. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process.

Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current contributions being made to the plan. On March 20, 2007, IPC filed a request with the IPUC to clarify that IPC can consider future contributions made to the pension plan a recoverable cost of service. An order approving this application would not determine the methodology of recovery but would permit IPC to record a regulatory asset related to pension costs. On June 1, 2007, the IPUC issued its order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for accrued 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. IPC will begin deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million will be deferred to a regulatory asset beginning in the third quarter. IPC did not request a carrying charge to be applied to the deferral of the accrued SFAS 87 expense.

7. SEGMENT INFORMATION:

IDACORP has identified two reportable segments: utility operations and IFS. ITI and IDACOMM, which had previously been identified as reportable segments, are now reported as discontinued operations (see Note 9).

The utility operations segment's primary sources of revenue are 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 IERCO, a wholly-owned subsidiary of IPC that is also subject to regulation and is a one-third owner of Bridger Coal Company, an unconsolidated joint venture. The IFS segment represents that subsidiary's investments in affordable housing developments and historic rehabilitation projects. Operating segments not included above are below the quantitative thresholds for reportable segments and are included in the "All Other" category. This category is comprised of 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.

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

	Utility Operations	IFS	All Other	Eliminations	Consolidated Total
Three months ended September 30, 2007:					
Revenues	$ 260,516	$ 295	$ 652	$ -	$ 261,463
Income from continuing operations	24,108	1,752	3,071	-	28,931
Three months ended September 30, 2006:					
Revenues	$ 228,799	$ 339	$ 1,394	$ -	$ 230,532
Income (loss) from continuing operations	30,389	2,116	(13)	-	32,492
Total assets at September 30, 2007	$ 3,416,098	$ 126,617	$ 144,052	$ (74,119)	$ 3,612,648
Nine months ended September 30, 2007:					
Revenues	$ 678,972	$ 900	$ 2,076	$ -	$ 681,948
Income from continuing operations	63,603	5,374	3,000	-	71,977
Nine months ended September 30, 2006:					
Revenues	$ 736,921	$ 1,038	$ 3,548	$ -	$ 741,507
Income (loss) from continuing operations	77,022	6,347	(1,249)	-	82,120

8. BENEFIT PLANS:

The following table shows the components of net periodic benefit costs for the three months ended September 30 (in thousands of dollars):

	Pension Plan		Deferred Compensation Plan		Postretirement Benefits	
	2007	2006	2007	2006	2007	2006
Service cost	$ 3,803	$ 3,334	$ 352	$ 368	$ 268	$ 345
Interest cost	6,114	5,145	593	582	844	809
Expected return on plan assets	(8,347)	(7,097)	-	-	(702)	(596)
Amortization of transition obligation	-	-	-	-	510	482
Amortization of prior service cost	163	153	43	61	(133)	(126)
Amortization of net loss	-	29	142	211	38	192
Net periodic benefit cost	$ 1,733	$ 1,564	$ 1,130	$ 1,222	$ 825	$ 1,106

The following table shows the components of net periodic benefit costs for the nine months ended September 30 (in thousands of dollars):

	Pension Plan		Deferred Compensation Plan		Postretirement Benefits	
	2007	2006	2007	2006	2007	2006
Service cost	$ 11,409	$ 10,857	$ 1,056	$ 1,105	$ 1,026	$ 1,097
Interest cost	18,343	16,755	1,779	1,745	2,634	2,569
Expected return on plan assets	(25,040)	(23,113)	-	-	(2,082)	(1,892)
Amortization of net obligation at transition	-	-	-	-	1,530	1,530
Amortization of prior service cost	488	498	130	184	(401)	(401)
Amortization of net loss	-	97	425	633	302	609
Net periodic benefit cost	$ 5,200	$ 5,094	$ 3,390	$ 3,667	$ 3,009	$ 3,512

IDACORP and IPC have not contributed and do not expect to contribute to their pension plan in 2007.

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9. DISCONTINUED OPERATIONS:

In the second quarter of 2006, IDACORP decided to seek buyers for its fuel cell technology subsidiary ITI and its telecommunications subsidiary IDACOMM. IDACORP had been reviewing strategic alternatives for ITI and IDACOMM in order to focus on its core utility business. The planned disposals of these businesses met the criteria established for reporting them as assets held for sale as defined by SFAS 144. SFAS 144 requires that a long-lived asset classified as held for sale be measured at the lower of its carrying amount or fair value, less costs to sell, and requires the holder to cease depreciation and amortization. Based on an analysis of the fair value of each subsidiary, no adjustments to the carrying values were required for the year ended December 31, 2006.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. IDACORP recorded a gain of $11.5 million, net of tax, from this transaction.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

The operating results of these businesses have been separately classified and reported as discontinued operations on IDACORP's condensed consolidated statements of income. A summary of discontinued operations is as follows (in thousands of dollars):

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues	$ -	$ 2,036	$ 1,278	$ 10,740
Operating expenses	-	(2,969)	(1,309)	(18,416)
Other expense	-	(61)	(25)	(128)
Gain (loss) on disposal	-	14,476	(2,877)	14,476
Pre-tax income (losses)	-	13,482	(2,933)	6,672
Income tax (expense) benefit	-	(1,985)	3,000	529
Income from discontinued operations	$ -	$ 11,497	$ 67	$ 7,201

The assets and liabilities of IDACOMM were classified as held for sale on IDACORP's condensed consolidated balance sheet at December 31, 2006. A summary of the components of assets and liabilities held for sale is as follows (in thousands of dollars):

	December 31, 2006
Assets	
Current assets	$ 3,326
Property and investments	20,789
Other assets	287
Total assets	$ 24,402
Liabilities	
Current liabilities	$ 2,606
Other liabilities	8,773
Total liabilities	$ 11,379

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 September 30, 2007, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2007 and 2006, and of cash flows for the nine-month periods ended September 30, 2007 and 2006. 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, 2006, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated February 28, 2007, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of 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 as of December 31, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
October 30, 2007

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 September 30, 2007, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2007 and 2006, and of cash flows for the nine-month periods ended September 30, 2007 and 2006. 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, 2006, 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 28, 2007, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of 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, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet and statement of capitalization from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
October 30, 2007

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.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM, Inc. (IDACOMM) as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144. IDACORP's condensed consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 9 to IDACORP's and IPC's Condensed Consolidated Financial Statements and later in the MD&A.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2006, and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007, and June 30, 2007, and should be read in conjunction with the discussions in those reports.

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" or similar 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

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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:

- Changes in and compliance with governmental policies, including new interpretations of existing policies, and regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission, the Oregon Public Utility Commission, and the Internal Revenue Service with respect to allowed rates of return, industry and rate structure, day-to-day business operations, acquisition and disposal of assets and facilities, operation and construction of plant facilities, provision of transmission services, relicensing of hydroelectric projects, recovery of purchased power expenses, recovery of other capital investments, present or prospective wholesale and retail competition, including but not limited to retail wheeling and transmission costs, and other refund proceedings;
- Changes arising from the Energy Policy Act of 2005;
- 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 environmental, endangered species and safety laws and policies;
- Weather variations affecting hydroelectric generating conditions and customer energy usage;
- Over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities;
- Construction of power generating, transmission and distribution facilities including an inability to obtain required governmental permits and approvals, and risks related to contracting, construction and start-up;
- Operation of power generating facilities including breakdown or failure of equipment, performance below expected levels, competition, fuel supply, including availability, transportation and prices, and availability of transmission;
- Blackouts or other disruptions of Idaho Power Company's or the western interconnected transmission systems;
- Impacts from the potential formation of a regional transmission organization or the development of another transmission group;
- Population growth rates and demographic patterns;
- Market demand and prices for energy, including structural market changes;
- Changes in operating expenses and capital expenditures, including costs and availability of materials and commodities, and fluctuations in sources and uses of cash;
- Results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by factors such as credit ratings and general economic conditions;
- Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;
- Homeland security, natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire, acts of war or terrorism;
- Market conditions that could affect the operations and prospects of IDACORP's subsidiaries or their competitors;
- Increasing health care costs and the resulting effect on medical benefits paid for employees;
- Performance of the stock market and the changing interest rate environment, which affect the amount of required contributions to pension plans, as well as the reported costs of providing pension and other postretirement benefits;
- Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;
- Changes in tax rates or policies, interest rates or rates of inflation;
- 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:

Third Quarter and Year-to-Date 2007 Financial Results

A summary of IDACORP's net income and earnings per diluted share is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Net income	$ 28,931	$ 43,989	$ 72,044	$ 89,321
Weighted average common shares outstanding – diluted (000's)	44,543	42,863	44,080	42,710
Earnings per diluted share	$ 0.65	$ 1.03	$ 1.63	$ 2.09

The key factors affecting the change in IDACORP's net income for the third quarter and year-to-date 2007 include (amounts shown are net of income taxes):

- Income from discontinued operations declined $11.5 million for the quarter and $7.1 million year-to-date. On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. See Note 9 to the IDACORP, Inc. and Idaho Power Company notes to condensed consolidated financial statements for more information on the transactions.
- Earnings at the holding company improved $3.1 million and $4.6 million for the third quarter and year-to-date 2007. The year-to-date improvement reflects a reduction in operating expenses and the effect of intra-period tax allocations recorded at the holding company. These intra-period tax allocations will reverse in the fourth quarter of 2007.
- IFS contributed $1.8 million to earnings in the third quarter and $5.4 million for 2007 year-to-date, a decrease of $0.4 million and $1.0 million, respectively, compared to the same periods in 2006.
- IPC's net income and contribution to earnings per diluted share decreased as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Net income	$ 24,108	$ 30,389	$ 63,603	$ 77,022
IDACORP Weighted average common shares outstanding – diluted (000's)	44,543	42,863	44,080	42,710
Earnings per diluted share	$ 0.54	$ 0.71	$ 1.44	$ 1.80

The key factors affecting the decrease in IPC's net income for the third quarter and year-to-date 2007 include (amounts shown are net of income taxes):

- Increased retail sales contributed $3.2 million and $11.9 million to electric utility margin (see "Non-GAAP Financial Measures" below for a calculation of electric utility margin) for the third quarter and year-to-date 2007, respectively. Warmer and drier conditions in 2007 led to higher irrigation loads as compared to the prior year. IPC continued to experience moderate customer growth, with the average number of general business customers increasing 11,585 and 12,744 for the third quarter and year-to-date 2007 compared to the same periods in 2006, an increase of 2.5 percent and 2.8 percent, respectively.
- Increased costs to supply power, net of rate adjustments, reduced electric utility margin by $6.4 million and $12.5 million for the third quarter and year-to-date 2007, respectively. Poor hydroelectric generating conditions in 2007 increased IPC's reliance on typically more expensive thermal generation and purchased power, and reduced wholesale sales. IPC's hydroelectric generation contributed only 41 percent and 48 percent of total system generation for the third

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quarter and year-to-date 2007, respectively, as compared to 47 percent and 60 percent for the same periods in 2006.

- Increases in Other O&M expenses reduced earnings by $4.1 million and $14.4 million for the third quarter and year-to-date 2007, respectively, compared to the same periods in 2006. The quarter increase is primarily the result of increases in third-party transmission costs (included in electric utility margin) and regulatory commission expenses. The year-to-date increase is primarily the result of increases in third-party transmission costs, regulatory commission expenses, maintenance expenses for IPC's coal-fired generation facilities, hydroelectric license and inspection costs, and the Fixed Cost Adjustment accrual which began in 2007.
- Gain on sales of excess SO_2 emission allowances was $1.1 million and $1.7 million for the third quarter and year-to-date 2007, respectively, compared to $0.0 million and $5.0 million for the same periods in 2006.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as one other financial measure, electric utility margin, that is considered a "non-GAAP financial measure" as defined in accordance with SEC rules. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. This non-GAAP financial measure reflects an additional way of viewing an aspect of IPC's operations that, when viewed with IPC's GAAP results and the accompanying reconciliation to electric utility operating income, the corresponding GAAP financial measure, may provide a more complete understanding of factors and trends affecting IPC's business. Management uses this measure, in addition to GAAP measures, in evaluating the performance and outlook of IPC, and therefore believes investors should have similar data when making decisions. Electric utility margin is used by IPC to help determine whether IPC is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. Electric utility margin helps management understand the regulatory portions of business and the effects of regulatory mechanisms. The primary limitation associated with the use of this non-GAAP measure is that IPC's electric utility margin measure may not be comparable to other companies' electric utility margin measure. When evaluating and conducting business, management is not burdened with the limitations of the non-GAAP financial measure since the limitations pertain primarily to comparisons outside IPC. For external users, the non-GAAP financial measure provides additional information to IPC's GAAP disclosures and users can assess which information best suits their needs. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

The calculations of IPC's electric utility margin are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
General business revenue	$ 211,873	$ 179,411	$ 511,337	$ 500,803
PCA amortization	(3,238)	3,779	2,504	(571)
Other revenues amortization				
Irrigation load reduction	-	118	-	(5,400)
Rate case tax settlement	-	100	-	(4,745)
Adjusted general business revenue	208,635	183,408	513,841	490,087
Power supply costs:				
Sales for resale	34,843	39,692	129,859	219,531
Purchased power	(110,108)	(98,926)	(241,393)	(229,659)
Fuel	(43,291)	(34,933)	(101,724)	(83,856)
PCA deferral	46,987	51,216	104,953	7,499
Net power supply costs	(71,569)	(42,951)	(108,305)	(86,485)
Third party transmission expense	(4,851)	(2,874)	(9,383)	(6,583)
Other revenues (excluding DSM)	9,493	9,478	28,806	26,732
Electric utility margin	$ 141,708	$ 147,061	$ 424,959	$ 423,751

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The following reconciles electric utility margin to electric utility operating income (GAAP):

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Electric utility margin	$ 141,708	$ 147,061	$ 424,959	$ 423,751
Other operations and maintenance (excluding third party transmission expense)	(64,303)	(59,521)	(206,487)	(187,326)
Gain on sale of emission allowances	1,872	22	2,754	8,258
Depreciation	(25,967)	(25,289)	(76,870)	(74,471)
Taxes other than income taxes	(4,714)	(4,057)	(14,267)	(15,957)
Operating income – electric utility (GAAP)	$ 48,596	$ 58,216	$ 130,089	$ 154,255

Hydroelectric generating conditions

Significantly below normal winter precipitation and stream flow conditions has resulted in below average hydroelectric generation through September 2007 of 4.9 million MWh compared to 7.7 million MWh for the same period in 2006. On August 1, 2007, the National Weather Service's Northwest River Forecast Center (RFC) reported that Brownlee reservoir inflow for April through July 2007 was 2.8 maf, or just 44 percent of the RFC average. As of October 21, 2007, storage in selected federal reservoirs upstream of Brownlee was 55 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.0 and 6.5 million MWh from its hydroelectric facilities in 2007, compared to 9.2 million MWh in 2006.

Because of its reliance on hydroelectric generation, IPC's operations can be significantly affected by weather 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, 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 net power supply costs.

Power Cost Adjustment

On June 1, 2007, IPC implemented its annual Power Cost Adjustment (PCA), which results in a $77.5 million, or 14.5 percent on average, increase in the rates of Idaho customers. The increase in rates is a direct result of significantly below normal winter precipitation and deteriorated stream flow conditions during the first half of 2007. In years where water is plentiful and IPC can fully utilize its extensive hydroelectric system, power production costs are lower and IPC can pass those benefits to its customers in the form of rate reductions. In years when water is in short supply, as it was this past winter, the higher costs of supplying power by other means are shared with IPC's customers.

General Rate Case filing

On June 8, 2007, IPC filed an application with the IPUC requesting an average base rate increase of 10.35 percent for its Idaho customers. Base rates primarily reflect IPC's cost of providing electrical service to its customers, including equipment and infrastructure. IPC's proposal would increase revenues $63.9 million annually and allow IPC to begin recovery of its capital investments and higher operating costs. The application included a requested return on equity of 11.5 percent and an overall rate of return of 8.561 percent. IPC had requested that the rate increase become effective by January 2008; however, on October 19, the procedural schedule for the case was extended for six weeks by mutual consent of the parties. The extension allows other parties to the case to review IPC's third quarter results before filing their testimony. IPUC Staff and intervenor testimony will be filed by December 10, 2007. Hearings are scheduled in January. Any rate change is now expected to become effective by February 2008.

Capital requirements

IPC is experiencing a cycle of heavy infrastructure investment to address customer energy, capacity and reliability needs and aging plant and equipment. IPC's aging hydroelectric and thermal generation facilities require upgrades and component replacement. In addition, costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Continuing load growth also requires that IPC add to its transmission system and distribution facilities to provide new service and to maintain reliability. Planned expenditures include distribution lines for new and existing customers and several high-voltage transmission lines.

July 2007 high temperatures

IPC's service territory experienced record-setting high temperatures during July 2007. Due to these weather conditions and continued customer growth, IPC set three new all-time system peaks between July 5 and July 13, 2007, with the highest, 3,193 MW, being set on July 13, 2007. The previous hourly system peak of 3,084 MW was set in 2006. Although IPC was able to meet all of its load requirements during these periods of increased demand, all available resources of IPC's system were fully committed during several heavy load periods. The record-setting temperatures also contributed to numerous wildfires throughout IPC's service area. Although the wildfires damaged or destroyed several distribution and transmission structures, the wildfires did not have a material impact to earnings in the third quarter or year-to-date 2007.

IPC/PacifiCorp (MidAmerican) Memorandum of Understanding

IPC and PacifiCorp are jointly exploring a project, called the Gateway West Project, to build two 500-kV lines between the Jim Bridger plant and Boise. The lines would be designed to increase electrical transmission capacity across southern Idaho in response to increasing customer demand and growth. If built, it is expected that the majority of the project would be completed between 2012 and 2014, depending on the timing of rights of way acquisition, siting and permitting, and construction sequencing. IPC estimates that its share of project costs would be between $800 million and $1.2 billion.

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 GAAP. 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, 2006, and have not changed materially from that discussion.

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 and nine months ended September 30, 2007. In this analysis, the results for 2007 are compared to the same period in 2006.

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The following table presents the earnings (losses) for IDACORP's operating segments as well as the holding company:

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Continuing operations:				
IPC - Utility operations	$ 24,108	$ 30,389	$ 63,603	$ 77,022
IDACORP Financial Services	1,752	2,116	5,374	6,347
Ida-West Energy	993	1,079	2,034	2,441
IDACORP Energy	2	(54)	(75)	(166)
Holding Company	2,076	(1,038)	1,041	(3,524)
Income from continuing operations	28,931	32,492	71,977	82,120
Income from discontinued operations	-	11,497	67	7,201
Net income	$ 28,931	$ 43,989	$ 72,044	$ 89,321
Average common shares outstanding (diluted)	44,543	42,863	44,080	42,710
Diluted earnings per share:				
Income from continuing operations	$ 0.65	$ 0.76	$ 1.63	$ 1.92
Income from discontinued operations	$ -	$ 0.27	$ -	$ 0.17
Diluted earnings per share	$ 0.65	$ 1.03	$ 1.63	$ 2.09

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 weather 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, 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 typically more expensive 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 net 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 the 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.

The following table presents IPC's power supply for the three and nine month periods ended September 30:

	MWh				
	Hydroelectric Generation	**Thermal Generation**	**Total system Generation**	**Purchased Power**	**Total**
Three months ended:					
September 30, 2007	1,499	2,133	3,632	1,693	5,325
September 30, 2006	1,821	2,082	3,903	1,427	5,330
Nine months ended:					
September 30, 2007	4,884	5,341	10,225	4,195	14,420
September 30, 2006	7,687	5,020	12,707	4,130	16,837

Significantly below normal winter precipitation and stream flow conditions have resulted in below average hydroelectric generation through September 2007 of 4.9 million MWh compared to 7.7 million MWh for the same nine month period in 2006. On August 1, 2007, the RFC reported that Brownlee reservoir inflow for April through July 2007 was 2.8 maf, or just 44 percent of the RFC average. As of October 21, 2007, storage in selected federal reservoirs upstream of Brownlee was 55 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.0 and 6.5 million MWh from its hydroelectric facilities in 2007, compared to 9.2 million MWh in 2006.

IPC's system load peaks in the summer and winter, with the larger peak demand occurring in the summer. IPC's record system peak of 3,193 MW occurred on July 13, 2007. Although IPC was able to meet system load requirements, all available resources of IPC's system were fully committed during several heavy load periods.

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 and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenue				
Residential	$ 83,066	$ 72,550	$ 224,534	$ 224,992
Commercial	50,481	41,700	126,671	125,241
Industrial	28,875	24,055	74,269	80,947
Irrigation	49,451	41,106	85,863	69,623
Total	$ 211,873	$ 179,411	$ 511,337	$ 500,803
MWh				
Residential	1,301	1,249	3,832	3,689
Commercial	1,077	1,009	2,959	2,794
Industrial	869	875	2,576	2,597
Irrigation	1,042	987	1,862	1,593
Total	4,289	4,120	11,229	10,673
Customers (average)				
Residential	398,322	389,379	396,357	386,122
Commercial	61,939	59,202	61,321	58,727
Industrial	127	131	127	132
Irrigation	18,128	18,219	18,014	18,093
Total	478,516	466,931	475,819	463,074
Heating degree-days	100	114	3,009	3,115
Cooling degree-days	1,001	940	1,286	1,209
Precipitation (inches)	0.71	0.42	4.72	8.62

Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when customers 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.

General business revenue increased $32.5 million and $10.5 million for the third quarter and year-to-date 2007, respectively, primarily attributable to three factors: 1) the effects of the base and PCA rate changes for the current and prior years; 2) higher customer usage; and 3) continued customer growth.

- **Rates:** Rates had a positive impact on general business revenue of $24.6 million in the third quarter 2007 as compared to the same period in the prior year primarily due to a PCA average rate increase of 14.5 percent effective June 1, 2007. Rates negatively impacted general business revenue by $16.6 million year-to-date 2007 as compared to the same period in the prior year. A PCA reduction on June 1, 2006, decreased rates by an average of 19.3 percent but was moderated

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by a base rate increase of 3.2 percent on June 1, 2006 and the new PCA increase averaging 14.5 percent effective June 1, 2007. Revenues for year-to-date 2006 also included $10 million related to a rate case tax settlement and an irrigation load reduction rate adjustment, both of which were recovered from June 2005 to May 2006 (with a corresponding reduction to other revenues).

- **Usage:** Sales growth of $5.0 million and $18.2 million for the third quarter and year-to-date 2007, respectively, resulted from higher usage in 2007 as compared to the same periods in the prior year. Higher irrigation, industrial, residential, and commercial use accounted for the increase. Irrigation revenue is up due to drier than normal conditions in the summer of 2007 as compared to 2006. Residential, industrial and commercial usage was positively impacted by warmer weather conditions during the summer months.
- **Customers:** Moderate growth in customer count in IPC's service territory increased revenue $2.9 million and $8.9 million for the third quarter and year-to-date 2007, respectively. The residential, commercial, industrial and irrigation customer bases increased or (decreased) from the prior year as follows:

Customer Base	Quarter Change %	Annual Change %
Residential	2.3	2.7
Commercial	4.3	4.1
Industrial	(2.8)	(3.9)
Irrigation	(0.5)	(0.4)
Overall weighted total	2.5	2.8

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 and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Revenue	$ 34,843	$ 39,692	$ 129,859	$ 219,531
MWh sold	620	790	2,110	5,077
Revenue per MWh	$ 56.20	$ 50.22	$ 61.54	$ 43.24

Deteriorated stream flow conditions for the quarter and year-to-date significantly decreased hydroelectric generation and electricity available for surplus sales. Revenue declines from lower sales volumes were moderated by higher prices. Prior year prices were lower because of abundant energy supplies in the region. Beginning in 2007, IPC is utilizing financial hedge instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to conforming to IPC's energy risk management policy, managing IPC's energy portfolio to meet customer load, and reacting to changes in market conditions to minimize net power supply costs.

Other revenues: The following table presents the components of other revenues for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Transmission services and property rental	$ 9,215	$ 10,210	$ 29,499	$ 27,639
DSM revenues	4,307	-	8,970	-
Rate case tax settlement	-	100	-	(4,745)
Irrigation load reduction	-	118	-	(5,400)
Provision for rate refund	278	(732)	(693)	(907)
Total	$ 13,800	$ 9,696	$ 37,776	$ 16,587

Beginning in January 2007, a new IPUC accounting order became effective for the treatment of IPC's DSM expenses. DSM costs are recorded in Other operations and maintenance expenses and are offset by the same amount recorded in Other revenues resulting in no net effect on earnings. See "Other operations and maintenance expenses."

Other revenues remained relatively flat and increased $12.2 million (excluding $4.3 million and $9.0 million of DSM revenue) as compared to the third quarter and year-to-date 2006, respectively. For the quarter, a $1.0 million decrease in transmission services and property rental, primarily due to a reduction in wheeling revenues, was offset by a $1.0 million change in the provision for rate refund. The fluctuation in the provision for rate refund was due primarily to a true up of the liability because of an agreement with intervenors, and a judge's decision on the applicable rate. The year-to-date increase is primarily due to a $10.1 million increase from the completed amortization of tax settlement and irrigation lost revenue accruals. From June 2005 to May 2006 IPC was collecting and recording in general business revenues, with a corresponding reduction to Other revenues, amounts related to a 2003 Idaho general rate case tax settlement and amounts related to an irrigation load reduction program. Revenues for the rate case tax settlement were accrued from September 2004 to May 2005. Higher wheeling revenues also contributed $2.5 million to the increase in year-to-date Other revenues.

Purchased power: The following table presents IPC's purchased power for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Purchases	$ 110,108	$ 98,926	$ 241,393	$ 229,659
MWh purchased	1,693	1,427	4,195	4,130
Cost per MWh purchased	$ 65.04	$ 69.33	$ 57.54	$ 55.61

The MWhs purchased for the quarter were up compared to the same period last year due to less water available for hydroelectric generation and record peak loads during July and August. The cost per MWh purchased was down from last year due to forward purchases made in late 2005 for the summer of 2006, as required by the risk management policy, which turned out to be high priced compared to actual market prices during the summer of 2006. Despite market prices being higher in 2007 due to poor hydrologic conditions, they were lower than for the 2006 forward purchases. The year-to-date increase is due to more wholesale energy purchases required compared to 2006 due to less water available for hydroelectric generation and record peak loads during July and August. Beginning in 2007, IPC is utilizing financial hedge instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to conforming to IPC's energy risk management policy, managing IPC's energy portfolio to meet customer load, and reacting to changes in market conditions to minimize net power supply costs.

Fuel expense: The following table presents IPC's fuel expenses and generation at its thermal generating plants for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Fuel expense	$ 43,291	$ 34,933	$ 101,724	$ 83,856
Thermal MWh generated	2,133	2,082	5,341	5,020
Cost per MWh	$ 20.30	$ 16.78	$ 19.05	$ 16.70

Fuel expense increased in large part due to increased utilization of gas-fired resources, a result of poor hydroelectric generating conditions. Gas usage at the Bennett Mountain facility was a major component of the increase. Bennett Mountain comprised six percent and three percent of thermal generation for the third quarter and year-to-date 2007, respectively, as compared to one percent in both the third quarter and year-to-date 2006. Fuel costs for Bennett Mountain were $9.4 million and $13.6 million in the third quarter and year-to-date 2007, respectively, as compared to $1.1 million and $3.1 million for the third quarter and year-to-date 2006.

PCA: PCA expense represents the effects of IPC's PCA regulatory mechanism in Idaho and Oregon deferrals of net power supply costs, which are discussed in more detail below in "REGULATORY MATTERS - Deferred (Accrued) Net Power Supply Costs."

In the third quarter of 2007, lower off-system sales, coupled with increased coal and natural gas utilization, caused a significant increase in net power supply costs (fuel and purchased power less off-system sales) over the amounts in the annual PCA forecast. This increase in net power supply costs was largely a result of deteriorated hydroelectric generating conditions in 2007, resulting in the deferral of costs which will be recovered in subsequent rate years. As the deferred costs are recovered in rates, the deferred balances are amortized.

The following table presents the components of PCA expense for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Current year power supply cost deferral	$ (46,987)	$ (51,216)	$ (104,953)	$ (7,499)
Amortization of prior year authorized balances	3,238	(3,779)	(2,504)	571
Total power cost adjustment	$ (43,749)	$ (54,995)	$ (107,457)	$ (6,928)

Other operations and maintenance expenses: Other operations and maintenance expenses increased $6.8 million, or ten percent, and $22.0 million, or eleven percent, (excluding $4.3 million and $9 million of DSM costs) as compared to the third quarter and year-to-date 2006, respectively. The increase was attributable to the following factors:

- Regulatory commission expenses increased $4.2 million, and $4.6 million, as compared to the third quarter and year-to-date 2006, respectively. In August 2006, FERC fee accruals of $3 million were reversed after a favorable lawsuit judgment;
- Transmission O&M expenses increased $2.2 million, and $3.4 million, as compared to the third quarter and year-to-date 2006, respectively, due to higher third party transmission costs;
- Thermal O&M expenses increased $3.2 million, as compared to year-to-date 2006. While much of this increase was due to a planned increase in maintenance activity, the increase also occurred due to unanticipated overhaul costs during the annual outages in the first half of the year;
- Hydroelectric O&M expenses increased $2.2 million as compared to year-to-date 2006 due to the booking of American Falls bond principal amortization that resumed in the fourth quarter of 2006, additional FERC hydro license compliance costs, FERC required inspection costs, and general labor cost increases; and
- The FCA accrual, which began in 2007, was $1.7 million year-to-date.

Demand-side management: Beginning in January 2007, a new IPUC accounting order became effective for the treatment of IPC's DSM expenses. DSM costs were recorded in Other operations and maintenance expenses and were offset by the same amount recorded in Other revenues, resulting in no net effect on earnings.

IPC's DSM programs provide opportunities for all customer classes to balance their energy needs with best-practice energy usage to minimize consumption while realizing the benefits of reliable electrical service. IPC's 2006 IRP laid the groundwork for the planning and implementation of future programs, including the addition of three new DSM programs. In addition to the DSM programs identified in the 2006 IRP, IPC has also continued to pursue other customer-focused DSM initiatives, including conservation programs and educational opportunities.

Gain on the sale of emission allowances: Gain on sale of emission allowances increased $1.9 million and decreased $5.5 million as compared to the third quarter and year-to-date 2006, respectively. The quarter increase is due to a lack of sales of excess SO_2 emission allowances in the third quarter of 2006. The year-to-date change is due to recording the gain on the sale of 78,000 SO_2 emission allowances in 2006 as compared to 35,000 in the same period of 2007.

Non-utility operations

IFS: IFS contributed $1.8 million and $5.4 million in the third quarter and year-to-date 2007, respectively, a decrease of $0.4 million and $1.0 million from the same periods in 2006. IFS' income is derived 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 generated $3.6 million and $10.9 million of tax credits in the third quarter of 2007 and year-to-date 2007, respectively. There were no additional investments in affordable housing for the third quarter or year-to-date 2007.

Discontinued Operations: In the second quarter of 2006, IDACORP management designated the operations of ITI and IDACOMM as assets held for sale, as defined by SFAS 144. The operations of these entities are presented as discontinued operations in IDACORP's financial statements.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. The following is a summary of the discontinued operations for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues	$ -	$ 2,036	$ 1,278	$ 10,740
Operating expenses	-	(2,969)	(1,309)	(18,416)
Other expense	-	(61)	(25)	(128)
Gain (loss) on disposal	-	14,476	(2,877)	14,476
Pre-tax income (losses)	-	13,482	(2,933)	6,672
Income tax (expense) benefit	-	(1,985)	3,000	529
Income from discontinued operations	$ -	$ 11,497	$ 67	$ 7,201

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 nine months ended September 30, 2007, was 15.2 percent, compared to 24.1 percent for the nine months ended September 30, 2006. IPC's effective tax rate for the nine months ended September 30, 2007, was 34.1 percent, compared to 38.5 percent for the nine months ended September 30, 2006.

The differences in estimated annual effective tax rates are primarily due to the decrease in pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

LIQUIDITY AND CAPITAL RESOURCES:

Operating cash flows
IDACORP's and IPC's operating cash flows for the nine months ended September 30, 2007, were $47 million, and $42 million, respectively. Compared to 2006, operating cash flows decreased approximately $123 million and $91 million for IDACORP and IPC, respectively. The decreases are primarily the result of power supply costs deferred for future recovery under IPC's PCA mechanism, partially offset by decreased income tax payments of $39 million and $61 million for IDACORP and IPC, respectively.

Investing cash flows

IDACORP's and IPC's investing cash outflows for the nine months ended September 30, 2007, were $179 million and $230 million, respectively, compared to $146 million and $168 million, respectively, for the nine months ended September 30, 2006. Utility construction at IPC accounted for the majority of its cash outflows. For IDACORP, IPC's investing outflows were partially offset by $7 million cash received from the sale of IDACOMM in 2007. Cash inflows from emission allowance sales were $20 million and $11 million in 2007 and 2006, respectively.

Financing cash flows

IDACORP's and IPC's financing cash inflows for the nine months ended September 30, 2007, were $138 million and $190 million, respectively, compared to cash outflows of $68 million and $11 million, respectively, for the nine months ended September 30, 2006. The increases in financing cash flows are due to the issuance of $140 million of first mortgage bonds at IPC and common stock issuances at IDACORP, and the fluctuations in short-term debt.

> **Debt issuances:** On June 22, 2007, IPC issued $140 million of its 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15, 2037. IPC used the net proceeds to pay down outstanding commercial paper, which had increased to $164 million in June 2007 because of capital expenditures and reduced operating cash flows.
>
> On October 18, 2007, IPC issued $100 million of its 6.25% First Mortgage Bonds, Secured Medium-Term Notes, Series G, due October 15, 2037. IPC will use the net proceeds to retire $80 million of 7.38% First Mortgage Bonds due December 1, 2007, and to pay down outstanding commercial paper.
>
> **Equity Issuances:** From June to September 2007, IDACORP received $28.5 million from the issuance of 881,337 shares of common stock under its Continuous Equity Program (CEP). The average price of these issuances was $32.32.
>
> Under IDACORP's dividend reinvestment and stock purchase plan and employee savings plan, IDACORP issued 192,693 common shares for proceeds of $6.2 million.

Discontinued operations

Cash flows from discontinued operations are included with the cash flows from continuing operations in IDACORP's Consolidated Statements of Cash Flows. The cash flows of IDACORP's discontinued operations have reduced net cash provided by operating activities and increased net cash used in investing activities, except for the cash received in February 2007 from the sale of IDACOMM and in July 2006 from the sale of ITI. The absence of cash flows from these discontinued operations is expected to positively impact liquidity and capital resources in future periods.

Capital requirements

IDACORP's internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2007 through 2009, where capital requirements are defined as utility construction expenditures, excluding Allowance for Funds Used During Construction (AFDC), plus other regulated and non-regulated investments. This excludes mandatory or optional principal payments on debt obligations. As discussed in IDACORP's 2006 Form 10-K, IDACORP may fund capital requirements with a combination of internally generated funds, the use of revolving credit facilities and the issuance of long-term debt and equity.

Long-term Financing

IPC has fully utilized the existing registration statement capacity for first mortgage bonds. The IPC Board of Directors has authorized the registration of an additional $350 million in first mortgage bonds and other debt securities.

Credit Facilities

On April 25, 2007, IDACORP entered into an Amended and Restated Credit Agreement (IDACORP Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P.

Morgan Securities Inc., as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders. The IDACORP Facility amended and restated a $150 million five-year facility that would have expired on March 31, 2010.

The IDACORP Facility is a $100 million five-year credit agreement that terminates on April 25, 2012. The IDACORP Facility, which will be used for general corporate purposes and commercial paper backup, 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 September 30, 2007, no loans were outstanding on IDACORP's Facility and no commercial paper was outstanding. As of October 29, 2007, no commercial paper was outstanding.

On April 25, 2007, IPC entered into an Amended and Restated Credit Agreement (IPC Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P. Morgan Securities Inc., as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders. The IPC Facility amended and restated a $200 million five-year credit facility that would have expired on March 31, 2010.

The IPC Facility is a $300 million five-year credit agreement that terminates on April 25, 2012. The IPC Facility, which will be used for general corporate purposes and commercial paper backup, 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 September 30, 2007, no loans were outstanding on IPC's Facility and $145 million of commercial paper was outstanding. As of October 29, 2007, commercial paper outstanding was $93 million.

The IDACORP Facility and the IPC Facility both contain a covenant requiring each 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 September 30, 2007, the leverage ratios for IDACORP and IPC were 52 and 54 percent, respectively. At September 30, 2007, IDACORP was in compliance with all other covenants of the IDACORP Facility and IPC was in compliance with all other covenants of the IPC Facility. See IDACORP's and IPC's Current Report on Form 8-K filed on May 1, 2007, for a discussion of the terms of the IDACORP Facility and the IPC Facility.

Contractual obligations
There have been no material changes in contractual obligations, outside of the ordinary course of business, since December 31, 2006, except for power purchase agreements entered into by IPC with Telocaset Wind Power Partners, LLC, and Raft River Energy I, LLC. The agreement with Telocaset Wind Power Partners, LLC, was approved by the IPUC on February 27, 2007 the agreement with Raft River Energy I, LLC, has been filed with the IPUC and is pending approval. These commitments will result in an increase to our contractual obligations previously disclosed in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2006, for periods beyond fiscal year 2007. Purchased power and transmission agreements are expected to increase $16 million in fiscal year 2008, an aggregate $43 million in fiscal years 2009 and 2010, an aggregate $46 million in fiscal years 2011 and 2012, and $487 million thereafter. These contracts are discussed more fully in "REGULATORY MATTERS – Integrated Resource Plan." The adoption of FIN 48, effective January 1, 2007, was not material to IDACORP's or IPC's contractual obligations. Under FIN 48, certain liabilities related to uncertain tax positions have been recognized. See Note 2 to IDACORP's and IPC's Condensed Consolidated Financial Statements for a discussion of FIN 48.

Credit ratings
On September 6, 2007, S&P announced that it had modified the criteria related to assigning ratings on first mortgage bonds (senior secured debt) that are higher than a company's corporate credit rating. As a result, IPC's senior secured debt ratings improved from A- to A. All other S&P credit ratings for IDACORP and IPC remain unchanged.

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 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 (prelim)	BBB (prelim)	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	Negative	Negative	Stable	Stable	Stable	Stable

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.

LEGAL AND ENVIRONMENTAL ISSUES:

Legal and Other Proceedings
Reference is made to IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2006, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007, 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.

Wah Chang: Wah Chang's appeal to the U.S. Court of Appeals for the Ninth Circuit of the February 11, 2005, dismissal of the case by the Honorable Robert H. Whaley, sitting by designation in the U.S. District Court for the Southern District of California, was orally argued on April 10, 2007. The matter now awaits decision by the Ninth Circuit. IDACORP, IPC and IE intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Western Energy Proceedings at the FERC:

California Refund: 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. That plan included the potential for orders directing electricity sellers into California from October 2, 2000 through June 20, 2001 to refund the portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable, and therefore not in compliance with the Federal Power Act. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. 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, 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. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the Settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the Settlement. The FERC issued an order on October 5, 2006, denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC orders approving the Settlement. Initially, the Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it and stayed further action on the consolidated cases while the court's mediator and FERC representatives work on achieving settlements with other parties. On October 25, 2007, the court issued an order that lifted its stay as to the review of the Port of Seattle's petition of the FERC's orders approving the February 17, 2006 offer of settlement as well as Port of Seattle's petitions for review of orders approving the settlements of two other sellers. The court's order also established a consolidated briefing schedule for these three cases with initial briefs due by January 28, 2008 and final briefs due at the end of July 2008. A date for argument has not been set. IPC and IE are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review filed by Port of Seattle.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings, the FERC issued orders permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy crisis of 2000 and 2001. On June 25, 2003, the FERC ordered a large number of parties, including IPC, to show cause why certain trading practices did not constitute "gaming" or anomalous market behavior ("partnership") in violation of the California Independent System Operator and California Power Exchange Tariffs. On October 16, 2003, IPC reached agreement with the FERC Staff on the show cause orders. The "gaming" settlement was approved by the FERC on March 4, 2004. Originally, eight parties sought rehearing of the "gaming" settlement. The FERC approved the motion to dismiss the "partnership" proceeding on January 23, 2004.

On October 11, 2006, the FERC issued an Order denying rehearing of its earlier approval of the "gaming" Settlement. On October 24, 2006, the Port of Seattle, Washington appealed to the U.S. Court of Appeals for the Ninth Circuit FERC's denial of its request for rehearing of its order granting approval of the settlement of the gaming allegations against IE and IPC. On November 17, 2006, the Ninth Circuit consolidated the Port of Seattle's review petition with a large number of review petitions previously consolidated and has stayed further action on the consolidated cases while the court's mediator and FERC representatives work on achieving settlements with other parties. The Ninth Circuit establishment of a briefing schedule for the settlements discussed above does not apply to the "gaming" settlement.

In addition, a number of parties have petitioned the Ninth Circuit Court of Appeals contending that the scope of the show cause proceedings was too narrow, but these petitions have been stayed. IE and IPC are unable to predict the outcome of these matters.

Pacific Northwest Refund: On June 19, 2001, the FERC expanded its price mitigation plan for the California Wholesale electricity market discussed above under "California Refund" to the entire western electrically interconnected system. This expansion led to the Pacific Northwest Refund proceeding. On September 24, 2001, the FERC Administrative Law Judge submitted recommendations and findings to the FERC finding that prices in the Pacific Northwest during the December 25, 2000 through June 20, 2001 time period should be governed by the Mobile-Sierra standard of public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that no refunds should be allowed. The FERC declined to order refunds on June 25, 2003 and multiple parties then appealed to the Ninth Circuit Court of Appeals. IE and IPC were parties in the FERC proceeding and are participating in the appeal. On August 24, 2007, the court filed an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The court's opinion instructed the FERC to consider whether evidence of market manipulation submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources in the proceeding. On September 18, 2007, the court extended until November 16, 2007 the time for filing petitions for rehearing to allow the parties time to assess settlement prospects and directed Senior Judge Edward Leavey of the Ninth Circuit to initiate mediation efforts. The stay also effectively defers the time in which the court's mandate to the FERC might be issued. On October 25, 2007, Powerex Corp. filed an unopposed motion to extend the date for seeking rehearing until December 17, 2007. IE and IPC are unable to predict the outcome of these matters. The Settlement in the California Refund proceeding resolves all claims the California Parties have against IE and IPC in the Pacific Northwest proceeding.

There are pending in the U.S. Court of Appeals for the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the Western energy matters of 2000 and 2001, including the California refund proceeding, the structure and content of the FERC's market-based rate regime, show cause orders respecting contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of 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 are unable to predict the outcome of any of these petitions for review.

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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 (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in 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 and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to $32,500 per day per violation and the plaintiff's costs of litigation, including reasonable attorney fees.

The U.S. District Court has set this matter for trial commencing in April 2008. Discovery in the matter is ongoing. In October 2007, the plaintiffs and defendant filed motions for summary judgment on the alleged opacity permit violations. IPC continues to monitor the status of this matter, but is unable to predict its outcome and is unable to estimate what effect this matter may have 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 in this MD&A and in Note 5 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.

Other Matters: The Bennett Mountain combustion turbine suffered a mechanical failure on July 11, 2006. IPC's investigation revealed that during construction a bolt was negligently installed by a third party. The bolt came loose, causing extensive mechanical damage. The plant was down from July 12, 2006, through September 6, 2006. Earlier this year, IPC received reimbursement for the bulk of the total repair costs from its insurance carrier and, with regards to the remaining repair costs, has since reached an agreement in principle with the third party which essentially makes IPC whole.

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, 2006, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

Idaho Water Management Issues: From 2000 through 2005, and year-to-date 2007, below normal precipitation and stream flows 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 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 Idaho Department of Water Resources (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 participate in these actions, as necessary, to protect its water rights.

IPC, together with other interested water users and state interests, also continues to explore and encourage the development of a long-term management plan that will protect the ESPA and the Snake River from further depletion. On February 14, 2007, the Idaho Water Resource Board (IWRB) presented the framework for an ESPA management plan to the Idaho Legislature recommending the development of a Comprehensive Aquifer Management Plan (CAMP). The proposed goal of the CAMP is to sustain the economic viability and social and environmental health of the ESPA by adaptively managing a balance between water use and supplies. The IWRB estimates that the development of the CAMP will take 16 months. Through House Concurrent Resolution 28 and House Bill 320, the Idaho Legislature appropriated funds and directed the IWRB to proceed with the development of the CAMP. Pursuant the IWRB recommendation in the CAMP Framework, an advisory committee has been established to make recommendations to the IWRB on the development of the CAMP. IPC sits on the CAMP advisory committee and will be working with the IWRB on the development of the CAMP.

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. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the court then adjudicates the claims and objections and enters a decree defining a party's water right. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

On May 10, 2007, in order to protect its claims and the availability of water for power purposes at its facilities, and in response to the claim of ownership filed by the State, IPC filed a complaint and petition for declaratory and injunctive relief regarding the status and nature of IPC's water rights and the respective rights and responsibilities of the parties under the Swan Falls Agreement. The complaint was filed in the Idaho District Court for the Fifth Judicial District, the court with jurisdiction over the SRBA, against the State of Idaho, the Governor, the Attorney General, the IDWR and the Director of the IDWR.

In conjunction with the filing of the complaint and petition, IPC filed motions with the court to stay all pending proceedings involving the water rights of IPC and to consolidate those proceedings into a single action where all issues relating to the Swan Falls Agreement can be determined.

IPC alleged in the complaint, among other things, that contrary to the parties' belief at the time the Swan Falls Agreement was entered into in 1984, the Snake River basin above Swan Falls was over-appropriated and as a consequence there was not in 1984, and there currently is not, water available for new upstream uses over and above the minimum flows established by the Swan Falls Agreement; that because of this mutual mistake of fact relating to the over-appropriation of the basin, the Swan Falls Agreement should be reformed; that the State's December 22, 2006, claim of ownership to IPC's water rights should be denied; and that the Swan Falls Agreement did not subordinate IPC's water rights to aquifer recharge.

On May 30, 2007, the State filed motions to dismiss IPC's complaint and petition. These motions were briefed and, together with IPC's motions to stay and consolidate the proceedings, were argued before the court on June 25, 2007.

On July 23, 2007, the court issued an Order granting in part and denying in part the State's motion to dismiss, consolidating the issues into a consolidated subcase before the court, and providing for discovery during the objection period; a scheduling conference is set for December 17, 2007. In its Order, the court denied the majority of the State's motion to dismiss, refusing to dismiss the complaint and finding that the court has jurisdiction to hear and determine virtually all the issues raised by IPC's complaint that relate to IPC's water rights and the effect of the Swan Falls Agreement upon those water rights. This includes the issues of ownership, whether IPC's water rights are subordinated to recharge and how those water rights are to be administered relative to other water rights on the same or connected resources. The court did find that by virtue of a state statute the IDWR, and its director, could not be parties to the SRBA and therefore stayed IPC's claims against the IDWR and its director pending resolution of the issues to be litigated in the SRBA, or until further order of the court.

Consistent with IPC's motion to consolidate and stay proceedings, the court consolidated all of the issues associated with IPC's water rights before the court and stayed that proceeding to allow other parties that may be affected by the litigation to file responses or intervene in the consolidated proceedings by December 5, 2007. IPC is unable to predict the outcome of the consolidated proceedings.

IPC has also recently filed two actions in the federal court, to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the U.S. on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the Reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. The U.S. has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, on October 15, 2007, IPC filed an action in the United States Court of Federal Claims in Washington, D.C. to recover damages from the U.S. for the lost generation resulting from the reduced flows. On October 16, 2007, IPC filed a second action in the United States District Court for the District of Idaho in Boise, Idaho, to compel the U.S. to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. IPC is unable to predict the outcome of this litigation.

Air Quality Issues: IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The coal-fired plants are: Jim Bridger (33 percent interest) located in Wyoming; Boardman (ten percent interest) located in Oregon; and North Valmy (50 percent interest) located in Nevada. The Clean Air Act establishes controls on the emissions from stationary sources like those owned by IPC in Idaho, Nevada, Oregon, and Wyoming. The Environmental Protection Agency (EPA) adopts many of the standards and regulations under the Clean Air Act while states have the primary responsibility for implementation and administration of these air quality programs. IPC continues to actively monitor, evaluate and work on air quality issues pertaining to the Clean Air Mercury Rule (CAMR), possible legislative amendment of the Clean Air Act, emerging greenhouse gas programs at the federal, regional and state levels, New Source Review permitting, National Ambient Air Quality Standards, and Regional Haze – Best Available Retrofit Technology (RH BART). Low nitrous oxide (NOx) burner technology and mercury continuous emission monitor installation are progressing at all three coal-fired power plants.

In December 2006, National Ambient Air Quality Standards for fine particulate matter adopted by EPA became effective. This new standard has been challenged by a number of groups in the U.S. Court of Appeals for the District of Columbia Circuit. All of the counties in Idaho, Nevada, Oregon, and Wyoming where IPC's power plants operate are currently designated as meeting attainment with federal air quality standards, including the new particulate matter standard. Nevertheless, under the new fine particulate standards, three years of data are being collected to determine the attainment status of all U.S. counties. The impact of these new standards will not be known until these data are collected, analyzed, and released to the public and the associated regulatory programs are promulgated and implemented.

The CAMR, issued by the EPA on March 15, 2005, limits mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will permanently cap utility mercury emissions. In response to the CAMR, the Idaho Department of Environmental Quality (IDEQ) proposed two new rules to the Idaho Environmental Quality Commission: a rule to opt out of the federal mercury cap-and-trade program, and a rule to prohibit the construction and operation of a coal-fired power plant in Idaho. In April 2006, the governor of Idaho signed House Bill 791, which placed a two year moratorium on applying for or issuance of permits, licenses or construction of certain coal-fired power plants in Idaho. The moratorium expires on April 7, 2008. During the 2007 Idaho state legislative session, the state did not reject the proposal to opt out of the cap-and-trade program, therefore accepting the opt out rule. IPC has no current plans impacted by the moratorium or opting out of the CAMR cap-and-trade program.

In accordance with new federal regional haze rules, the Wyoming Department of Environmental Quality (WDEQ) and Oregon Department of Environmental Quality (ODEQ) are conducting an assessment of emission sources pursuant to a RH BART process. 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 North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rules.

PacifiCorp submitted the RH BART application for the Jim Bridger plant in January 2007. The WDEQ is still evaluating the application. The plant is already in the process of installing the low NOx burners and scrubber upgrades that are proposed in the application.

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Portland General Electric (PGE) is completing the RH BART analysis for the Boardman plant. This analysis includes proposed emission control upgrades for the Boardman plant to comply with RH BART requirements. PGE is planning on submitting the report to the ODEQ by the end of 2007. Capital upgrade costs required to meet RH BART standards could vary significantly depending on the technology utilized. Because of the combined benefit of emission equipment that reduces multiple pollutants simultaneously, upgrade plans under consideration will also meet CAMR standards. Upgrade cost estimates to meet both standards range from $30 million to $62 million (IPC share). No commitments are in place at this time and the cost estimates are preliminary and subject to change. More detailed information will be available after the completion of the analysis for the Boardman plant and approval of the RH BART proposals by state and federal environmental regulators.

Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) regulations that would affect electric utilities. At the national level, numerous GHG bills have been introduced in the U.S. Senate and House of Representatives during 2006 and 2007. Debate continues in Congress on the direction and scope of U.S. policy on regulation of GHGs.

In the western U.S., the states of Arizona, California, New Mexico, Oregon, Utah and Washington, along with the provinces of British Columbia and Manitoba, Canada, have formed the Western Regional Climate Action Initiative (WCI). On August 22, 2007, the WCI partners released their regional goal to collectively reduce GHGs 15 percent below 2005 levels by 2020. The WCI partners have agreed to design a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to help achieve the goal. The states of Idaho, Nevada and Wyoming have not joined the WCI. It is possible that these and other states in which IPC operates or sells electricity into could join the WCI in the future.

California's governor signed an executive order in 2005 to reduce GHGs in that state to designated historical levels. On September 27, 2006, California's governor signed into law the Global Warming Solutions Act of 2006 which established GHG reduction goals and a framework for achieving these goals. On January 25, 2007, California enacted a GHG emission performance standard applicable to all electricity generated within the state or delivered from outside the state. Oregon passed the Global Warming Integration Act in June 2007 which, among other things, established the Oregon Global Warming Commission and state-wide GHG emission reduction goals. IPC will continue to monitor developments with respect to the implementation of this legislation; however, until the Oregon Global Warming Commission makes its recommendations and the associated regulatory programs are promulgated and implemented, it is not possible to determine the effect of this legislation on IPC's operations, particularly the Boardman facility. The Washington state legislature passed a bill in April 2007 setting climate pollution reduction and clean energy goals. Emission performance standards affecting electric utility contracts and power plant projects are included. Other regional and state GHG initiatives appear likely, although the states of Idaho, Nevada and Wyoming have not adopted GHG legislation. National, regional or state GHG requirements, if enacted and applicable, could result in significant costs to IPC to comply with restrictions on carbon dioxide or other GHG emissions.

Information about IDACORP's carbon dioxide emissions is included in the report *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States – 2004*. This report was released by the Ceres Investor Coalition, the Natural Resources Defense Council and the Public Service Enterprise Group Inc. in April 2006. The report lists IDACORP's 2004 carbon dioxide emissions at 1,222.0 lbs/MWh, as compared to the reported average for the 100 largest power producers of 1,341.8 lbs/MWh. IPC's carbon dioxide emissions on a lbs/MWh basis fluctuate with the amount of hydroelectric generation. Even during a low water year like 2004, IPC's emissions from electricity generation were below the average of the 100 largest power producers. During 2006, IPC's carbon dioxide emissions were approximately 917 lbs/MWh.

As part of IPC's resource planning protocol, the IRP process considers potential GHG emissions regulation and other environmental factors when evaluating potential portfolios. The 2006 IRP included a risk analysis of the costs associated with the regulation of carbon dioxide emissions by analyzing low, expected and high cases of $0, $14 and $50 respectively, per ton of carbon dioxide emitted. Environmental impacts have been and will continue to be integral components of IPC's resource decisions.

Due to escalating construction costs, the transmission cost associated with a remotely located resource, potential permitting issues, and continued uncertainty surrounding future GHG laws and regulations, IPC has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho. IPC will be adding 101 MW of wind generation in December, 2008 and 45.5 MW of geothermal generation in phases between 2007 and 2011.

New Source Review: EPA Region 8 began reviewing PacifiCorp operations, including the Jim Bridger plant, (of which IPC is a one-third owner), for compliance with New Source Review (NSR) and New Source Performance Standards (NSPS) through a Clean Air Act Section 114 information request sent in May 2003. PacifiCorp completed its phased response to the Section 114 request in February 2004 with the submission of a large volume of documents to the EPA relating to historical activities at Bridger and other PacifiCorp power plants. A number of utilities that have also been the subject of EPA NSR information requests have engaged in settlement negotiations with the EPA to resolve allegations of NSR and NSPS noncompliance. Prior settlements reached between the EPA and utility companies around the country to resolve these issues have resulted in commitments by the utility companies to install additional pollution control equipment and to pay civil penalties. IPC cannot predict the outcome of this matter at this time.

Climate Change: IPC’s substantial hydroelectric generation resources neither burn nor consume fossil fuels to produce electric energy to meet the needs of its customers. Given the debate concerning climate change, consensus is growing that broad steps should be taken in all sectors of the nation’s economy to carefully consider ways of limiting and/or reducing greenhouse gas emissions and mitigating climate change impacts while still providing necessary services in a cost-effective manner. IPC intends to continue to add renewable resources to its resource portfolio and will continue to monitor the climate change debate, current climate change research, and recently enacted as well as proposed legislation to identify the potential impacts of global climate change on all aspects of its business. Long-term climate change could significantly affect IPC’s business in a variety of ways, including but not limited to the following: (a) changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation; 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 global climate change on its business at this time.

REGULATORY MATTERS:

General Rate Cases

Idaho: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of approximately 10.35 percent for its Idaho customers in order to begin recovery of its capital investments and higher operating costs. IPC’s proposal would increase its revenues $63.9 million annually. The application included a requested return on equity of 11.5 percent and an overall rate of return of 8.561 percent. IPC filed its case based upon a 2007 forecast test year, a first for IPC in the Idaho jurisdiction. Since IPC’s last general rate case filing in 2005, IPC projects that it will have placed in service an additional $300 million of investment in its electrical system during 2006 and 2007. IPC also requested a $29.16 per MWh Load Growth Adjustment Rate (LGAR), which adjusts the power supply costs IPC is allowed to include in the PCA for differences between actual load and the load used in calculating base rates. The existing LGAR is $29.41 per MWh. The impact of the new LGAR on IPC will ultimately be determined by future load changes. By IPUC order, the LGAR is reset in general rate case proceedings. IPC had requested that the rate increase become effective by January 2008; however, on October 19, the procedural schedule for the case was extended for six weeks by mutual consent of the parties. The extension allows other parties to the case to review IPC’s third quarter results before filing their testimony. IPUC Staff and intervenor testimony will be filed by December 10, 2007. Hearings are scheduled in January. Any rate change is now expected to become effective by February 2008. IPC is unable to predict what relief the IPUC will grant.

Deferred (Accrued) Net Power Supply Costs

IPC's deferred (accrued) net power supply costs consisted of the following (in thousands of dollars):

	September 30, 2007	December 31, 2006
Idaho PCA current year:		
Accrual for the 2007-2008 rate year [1]	$ -	$ (3,484)
Deferral for the 2008-2009 rate year [2]	70,855	-
Idaho PCA true-up awaiting recovery (refund):		
Authorized May 2006	-	(11,689)
Authorized May 2007	8,135	-
Oregon deferral:		
2001 costs	3,498	6,670
2005 costs	-	2,889
Total deferral (accrual)	$ 82,488	$ (5,614)

[1] Includes $69 million of emission allowance sales to be credited to the customers during the 2007-2008 PCA year.

[2] Includes $17 million of emission allowance sales in 2007.

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portion, is then included in the calculation of the next year's PCA.

The true-up of the true-up portion of the PCA provides a tracking of the collection or the refund of true-up amounts. Each month, the collection or the refund of the true-up amount is quantified based upon the true-up portion of the PCA rate and the consumption of energy by customers. At the end of the PCA year, the total collection or refund is compared to the previously determined amount to be collected or refunded. Any difference between authorized amounts and amounts actually collected or refunded are then reflected in the following PCA year, which becomes the true-up of the true-up. Over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized.

On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then existing level, which was $46.8 million below base rates, to a level that is $30.7 million above those base rates. This $77.5 million increase is net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates were effective June 1, 2007.

On June 1, 2006, IPC implemented the 2006-2007 PCA, which reduced the PCA component of customers' rates from the then-existing level, which was recovering $76.7 million above then-existing base rates, to a level that was $46.8 million below those base rates, a decrease of approximately $123.5 million.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" power supply expenses. In the Oregon general rate case, "normal" power supply expenses were set at a negative number (meaning that under normal water conditions IPC should be able to sell enough surplus energy to pay for all fuel and purchased power expenses and still have revenue left over to offset other costs). IPC requested authorization to defer an estimated $5.7 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is currently responding to data requests generated by the filing.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2006, through April 30, 2007, in anticipation of higher than "normal" power supply expenses. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. Settlement discussions were held on April 25, 2007, and a tentative settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. This amount is subject to approval by the OPUC. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. On April 25, 2007, the parties agreed in principal to a settlement stipulation which would resolve the 2006-2007 deferral case. The stipulation was filed with the OPUC on October 24, 2007 for approval. Oregon PCA mechanism discussions are continuing under a separate docket.

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 per year. IPC is currently recovering through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Oregon Power Cost Adjustment Mechanism (PCAM)
On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost adjustment mechanism similar to the Idaho PCA. Oregon has a statutory requirement that limits IPC's ability to recover deferred net power supply costs to six percent per year. If the application is approved, it will allow IPC to recover excess net power supply costs or distribute benefits to customers in a more timely fashion than through the existing deferral process. The proposed mechanism differs from the Idaho PCA in that is reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case. A prehearing conference was held on October 4, 2007, and the first workshop was held on October 23, 2007. Settlement conferences are scheduled for November 5, 2007, and January 17, 2008, with a hearing tentatively set for March 5, 2008. It is expected that the PCAM will become effective in June 2008.

In connection with this proceeding, on October 29, 2007, IPC made a filing with the OPUC requesting that IPC's base net power supply costs be increased by $4.6 million for Oregon. In isolation, this would be an average 15 percent increase in rates; however, a yet to be filed forecast of net power supply costs would also be a component of future PCAM rates. If the OPUC approves the power cost adjustment mechanism, any changes in rates are not expected to be effective until June 2008.

Fixed Cost Adjustment Mechanism (FCA)
On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent of the volume of IPC's energy sales. This filing was a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The accounting for the FCA will be separate from the PCA. IPC proposed a three percent cap on any rate increase to be applied at the discretion of the IPUC.

IPC and the IPUC Staff agreed in concept to a three-year pilot beginning January 1, 2007, and a stipulation was filed on December 18, 2006. The stipulation called for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of DSM activities. The IPUC approved the stipulation on March 12, 2007. The pilot program began retroactively on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. IPC accrued $1.7 million of FCA expense through the third quarter of 2007.

Pension Expense
In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current contributions being made to the plan. On March 20, 2007, IPC filed a request with the IPUC to clarify that IPC can consider future contributions made to the pension plan a recoverable cost of service. An order approving this application would not determine the methodology of recovery but would permit IPC to record a regulatory asset related to pension costs. On June 1, 2007, the IPUC issued its order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for accrued 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. IPC will begin

deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million will be deferred to a regulatory asset beginning in the third quarter. IPC did not request a carrying charge to be applied to the deferral of the accrued SFAS 87 expense.

Wind Integration Costs

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), IPC is required to offer independent developers a power purchase contract based on a standard avoided cost rate for a qualifying facility with an output of 10 average megawatts (aMW) or less. Because a large number of wind project developers came to IPC requesting PURPA contracts in early 2005, IPC requested and the IPUC granted temporary relief from PURPA requirements until the impact of wind integration could be more fully studied. The IPUC granted this relief by temporarily reducing the PURPA cap of 10 aMW to 100 kW for PURPA wind projects.

On February 6, 2007, IPC filed with the IPUC a wind integration study report along with a petition requesting removal of the temporary restriction on the size of PURPA wind projects and adjustment of avoided cost rates to compensate for the increase in system costs due to wind variability. On March 15, 2007, and June 20, 2007, public workshops were held to present the results of the study, which were contested by wind developers and advocates of wind generation resources.

In an attempt to settle the case, IPC entered into a settlement stipulation with Renewable Northwest Project and the NW Energy Coalition on October 2, 2007. The settlement stipulation prescribes, among other things, a methodology for calculating a wind integration charge that will be applied to PURPA wind projects. The integration charge will be calculated as a percentage of the current 20-year, levelized, avoided cost rate, subject to a cap of $6.50/MWh. IPC is awaiting a ruling from the IPUC on this case which will ultimately determine the amount to be deducted from the avoided cost rate paid to PURPA wind projects.

Cassia Wind Farm Complaint

On September 13, 2006, Cassia Gulch Wind Park, LLC and Cassia Wind Farm, LLC (collectively Cassia) filed a complaint against IPC with the IPUC requesting the IPUC to determine that the cost responsibility for specified transmission system upgrades to meet contingency planning conditions should not be assigned to PURPA qualifying facilities connecting to the system, but rather should be rolled into IPC's plant-in-service rate base and recovered through rates to retail and transmission customers. The estimated costs of transmission system upgrades included in this complaint that relate to connecting Cassia to IPC's system are $60 million. Comments were filed in October and November 2006, and oral arguments were held in November 2006. On June 13, 2007, IPC and Cassia filed a Joint Motion to Dismiss the underlying complaint and to approve a related settlement stipulation. The IPUC approved the Joint Motion on August 29, 2007.

The key component of the stipulation is the concept of "redispatch." IPC's estimated cost of approximately $60 million to complete necessary transmission network upgrades was based on the assumption that the requesting projects in the transmission queue would not be dispatchable. Under the stipulation, Cassia agrees to install, at its expense, equipment and communication facilities necessary to reduce its energy output to a predetermined set-point within ten minutes of when IPC requests the reduction. Based on these provisions, the original estimate of $60 million decreases to approximately $11 million. Under the stipulation, IPC would fund 25 percent of any upgrade investment, which would be recoverable through rates, while the developer would fund 25 percent that is non-recoverable and 50 percent that is recoverable over time. The stipulation also addresses responsibility for network upgrade costs, sharing of network upgrade costs, refunds and interests on refunds and security for payment.

On October 15, 2007, the IPUC approved the application of this same cost allocation methodology to two PURPA qualifying projects that were not parties to the Cassia dispute and are in a different geographic region than the one impacted by the Cassia transmission upgrades. Although the IPUC did not in the Cassia proceeding approve broad application of the settlement to other projects, it did, in this case, determine that the circumstances were similar enough to warrant using the same cost allocation methodology.

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PURPA Avoided Cost Rate Computation

On September 10, 2007, IPC filed an application with the IPUC requesting modification to the method of computing avoided cost rates. These rates are used to set the price IPC pays to new PURPA projects over the lives of the purchase agreements. Specifically, IPC requested that the fuel cost component of the computation be revised from a three-year average natural gas price with a prescribed escalation factor to an average of the 20-year forecast of median natural gas prices as published by the Northwest Power and Conservation Council (NWPCC) for 2007. IPC believes that failing to recognize the non-linear shape of the NWPCC's 2007 forecast will cause the published rates to be much higher than they otherwise would be. IPC did not propose to adjust any of the non-fuel assumptions in the avoided cost rate computation.

AMI Report

IPC filed its Advanced Metering Infrastructure (AMI) Status Report with the IPUC on May 1, 2007, in compliance with an IPUC order. The report details IPC's resolution of the AMI-related issues identified in the December 2005 AMI Status Report. On August 31, 2007, IPC filed a supplemental report detailing its assessment of how it will proceed with AMI deployment. In the report IPC provided a summary of the financial analysis, a three-year AMI implementation plan beginning in late 2008, a discussion of cost recovery and identification of remaining issues.

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, provides access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of the region's investor-owned utilities. The program is administered by the Bonneville Power Administration (BPA). IPC entered into settlement agreements with the BPA which settled IPC's rights under the Residential Exchange Program for the fiscal year 2002-2006 rate period and for the fiscal year 2007-2011 rate period. Pursuant to these 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.

Several of the BPA's publicly owned and the direct-service industry customers filed lawsuits against the BPA with the United States Court of Appeals for the Ninth Circuit challenging certain aspects of the BPA's agreements with IPC, as well as those with other investor-owned utilities, and challenging the level of benefits previously paid to investor-owned utility customers. On May 3, 2007, the Ninth Circuit Court of Appeals ruled that the settlement agreements entered into between the BPA and the investor-owned utilities (including IPC) are inconsistent with the Northwest Power Act. On May 21, 2007, the BPA notified IPC and six other investor-owned utilities 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' bill to zero, effective June 1, 2007.

Since these benefits were passed through to IPC's customers, the outcome of this matter is not expected to have a significant effect on IPC's financial condition or results of operations. IPC is working, along with the other northwest investor-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.

FERC Investigation: On March 28, 2007, the FERC advised IPC that the FERC was commencing a preliminary, non-public investigation into the pricing and availability of transmission capacity into and out of IPC's IPCO point of delivery and transactions related to that transmission capacity during the period January 1, 2003, to present. Subsequently, the FERC made two data requests in connection with this investigation. IPC responded to those data requests between June and August 2007, and supplemented its response on July 27, 2007. At IPC's request, IPC representatives met with FERC personnel on October 18, 2007, to discuss several data responses that IPC had previously provided. IPC is now preparing responses to several additional questions asked by FERC personnel at that meeting. IPC is unable to predict the outcome of this investigation.

FERC Proceedings:

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 FERC Form 1 data.

The formula rate request included a rate of return on equity of 11.25 percent. The proposed rates would have produced an annual revenue increase for the FERC jurisdiction of approximately $13 million based on 2004 test year data. The FERC accepted IPC's rates, effective June 1, 2006, subject to adjustment to conform to SFAS 109 tax accounting requirements, which lowered the estimated annual revenues to approximately $11 million.

On August 8, 2007, the FERC approved a settlement agreement (Settlement Agreement) filed in June 2007 by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates and that were in existence before the implementation of OATT in 1996 (Legacy Agreements). The effect of this settlement approval was to reduce the estimated FERC jurisdictional annual revenue increase from $11 million to approximately $8.2 million based on 2004 test year data. The Settlement Agreement requires that amounts collected in excess of the new rates for the June 1, 2006 through July 31, 2007 period be refunded with interest to customers. These refunds totaled approximately $1.7 million and were paid in August 2007.

Hearings were held before the FERC in June 2007 regarding the treatment of the Legacy Agreements. IPC's position was that the revenue IPC receives under the Legacy Agreements should be credited against the total transmission revenue requirement attributed to OATT customers and that the contract demands of the Legacy Agreements should not be included in the load divisor of the rate formula. The intervenors in the proceeding took the position that such contract demands should be included in the load divisor, rather than being revenue credited.

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 is on file and publicly available at FERC Docket No. ER06-787. In the Initial Decision, the ALJ concluded that (i) the Legacy Agreements should be included in the load divisor of the rate formula and (ii) the revenue IPC receives under the Legacy Agreements should not be credited against the total transmission revenue requirement attributed to OATT customers. The ALJ further concluded that the amounts used in the rate formula should be the monthly coincident peak usages under the Legacy Agreements rather than the contract demands under the Legacy Agreements proposed by the FERC Staff and intervenors. IPC had argued that if the Legacy Agreements were to be reflected in the load divisor, rather than as a revenue credit, it should be at the level of monthly coincident peak usage, not at the level of the contract demands.

If the Initial Decision is implemented, IPC estimates that this ruling will reduce the estimated FERC jurisdictional annual revenue increase (based on 2004 test year data) by approximately $1.4 million (from approximately $8.2 million to $6.8 million).

The Initial Decision is subject to appeal to the FERC by all parties to the proceeding. On October 1, 2007, IPC along with other parties filed its Brief on Exceptions. Briefs were required to be submitted by October 1, 2007, with reply briefs due by October 21, 2007. If the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $1.7 million for the June 1, 2006 through July 31, 2007 period. IPC has reserved this entire amount. Amounts collected from August 1, 2007, through December 31, 2007 have been and will continue to be collected at the proposed rates, and amounts collected in excess of the final rates will be refunded with interest. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process.

<u>FERC Order 890:</u> In February 2007, the FERC issued Order No. 890 adopting a final rule designed to strengthen the pro forma OATT by providing greater consistency and increasing transparency. The FERC had stated in its Notice of Proposed Rulemaking leading to the final rule that "as a general matter, the purpose of this rulemaking is to strengthen the pro forma OATT to ensure that it achieves its original purpose - remedying undue discrimination - not to create new market structures." The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and to exempt intermittent generators, and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service, and generation re-dispatch.

As a transmission provider with an OATT on file with the FERC, IPC is required to comply with the requirements of the new rule. A major requirement of the new rule was to file a revised *pro forma* OATT on July 13, 2007. IPC also was required to file a revised Attachment C specifying the methodology to assess available transfer capability on September 11, 2007. IPC made the required FERC filings and is currently operating under the new tariff. IPC is also required to file an Attachment K to its tariff on December 7, 2007, which sets forth its coordinated, open and transparent planning process.

Certain details related to the rule remain to be determined prospectively, and thus it is difficult to make a precise determination of the overall effect of this new rule on IPC's transmission operations or wholesale marketing function. However, at least on a preliminary basis, the rule is not anticipated to have a significant impact on IPC's financial results. Nonetheless, the final rule includes a wide range of provisions addressing the provision of transmission services, and as the new tariff is implemented there is likely to be a significant impact on IPC's transmission operations, planning and wholesale marketing functions.

<u>FERC Order 693:</u> Pursuant to section 215 of the Federal Power Act (FPA), on March 16, 2007, the FERC issued Order No. 693 in which it approved 83 of the 107 reliability standards proposed by the North American Electric Reliability Corporation (NERC). Previously, the FERC certified the NERC as the electric reliability organization responsible for developing and enforcing mandatory reliability standards. Collectively, the reliability standards define overall acceptable performance with regard to operation, planning and design of the North American Bulk-Power System. As the FERC recognized in Order No. 693, most of these reliability standards were already being adhered to on a voluntary basis. Compliance with these standards became mandatory and subject to the FERC's penalty authority in June 2007. Since then, additional reliability standards have been submitted, and will continue to be submitted, by the NERC to the FERC for approval. In July 2007, the FERC denied requests for rehearing of Order No. 693. IPC has reviewed all requirements, procedures and documentation to ensure compliance with these standards and submitted all necessary information by the effective date of June 18, 2007. IPC will also be required to certify its compliance with a subset of these standards (the WECC Actively Monitored Standards) by December 31, 2007, and be subject to compliance spot-checks beginning in 2008. The FERC's action is not expected to have a material impact on IPC's operations.

Northern Tier Transmission Group

IPC, along with four other transmission-owning entities covering all or parts of the transmission system in six western states, has formed the Northern Tier Transmission Group (NTTG). The goal of the group is to improve overall operation and expansion of the high-voltage transmission network. The group continues to make progress on four major initiatives: improving generation control performance (the first generation control became operational in March 2007); compliance with FERC Order 890 through cooperative efforts in developing process and information exchange; providing improved information on available transmission capacity; and conducting open, participatory transmission planning processes which will result in identifying specific transmission projects in 2007 and beyond. Several projects have been identified for the "fast-track" planning process and work has begun on engineering analysis. One of these projects is IPC's joint project with PacifiCorp (MidAmerican) to evaluate building two high voltage transmission lines as discussed below. Additionally, the NTTG is working on the process and documentation for its own compliance with FERC Order 890 for regional planning. Each utility will individually submit the resulting plan as a required attachment to its OATT filing due December 7, 2007.

IPC/PacifiCorp (MidAmerican) Memorandum of Understanding

IPC and PacifiCorp are jointly exploring a project, called the Gateway West Project, to build two 500-kV lines between the Jim Bridger plant and Boise. The lines would be designed to increase electrical transmission capacity across southern Idaho in response to increasing customer demand and growth. This project has been submitted to the Western Electricity Coordinating Council (WECC) for the first phase of the ratings process. A review team has been established from members of the WECC to analyze the impact of the project to the existing system. When the study is complete, necessary modifications will be made to the engineering design and the final rating will be obtained prior to the beginning of construction. Additionally, the planning and project management personnel for both companies have met to begin organizing the initial phases of this project. IPC and PacifiCorp are finalizing a cost sharing agreement for expenses associated with the analysis work of the initial phases. It is expected that the majority of the project would be completed between 2012 and 2014 depending on the timing of rights of way acquisition, siting and permitting, and construction sequencing. If the project is constructed, IPC estimates that its share of project costs would be between $800 million and $1.2 billion.

Idaho-Northwest Line
Consistent with the 2006 Integrated Resource Plan (IRP), IPC is exploring alternatives for the construction of a 500-kV line between southwestern Idaho and the Northwest. The location of this proposed line has not yet been determined. If built, this line could be in service as early as 2012.

Integrated Resource Plan
IPC filed its 2006 IRP with the IPUC in September 2006 and with the OPUC in October 2006. The 2006 IRP previewed IPC's load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions.

The IPUC accepted the 2006 IRP in March 2007. The OPUC acknowledged the 2006 IRP in September 2007 with the stipulation that IPC not commit to the construction of a 250-MW pulverized coal resource, identified to come on-line in 2013, until IPC presents an update of the 2006 IRP to the OPUC no later than June 2008. With its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other utilities. To comply with this request IPC intends to provide an update on the status of the 2006 IRP to both the IPUC and OPUC no later than June 2008 and file a new IRP in June 2009.

The near-term action plan in the 2006 IRP indicates initial commitments to the construction of a coal-fired base load resource would be necessary before the end of 2007 in order for a project to be on-line in 2013. In order to meet this schedule, IPC began screening and evaluating coal-fired resources in 2006. The results of this evaluation indicate construction costs have escalated substantially since resource cost estimates were prepared for the 2006 IRP. Due to escalating construction costs, the transmission cost associated with a remotely located resource, potential permitting issues, and continued uncertainty surrounding future GHG laws and regulations, IPC has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho. IPC continues to evaluate coal-fired resource opportunities, including expansion of its jointly-owned facilities, clean coal technologies and potential power purchase agreements for future energy needs.

Wind Agreement: In February 2007, the IPUC approved a Power Purchase Agreement with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW (nameplate) of wind generation from the Elkhorn Valley Wind Project located in eastern Oregon. The project is expected to be commercially operational in December 2007.

Geothermal Agreement: An RFP for geothermal-powered generation was released on June 2, 2006. IPC identified US Geothermal as the successful bidder in March 2007 based on a proposal to supply 45.5 MW of geothermal energy. IPC and US Geothermal have signed and submitted a Power Purchase Agreement for IPUC approval for 13 MW (nameplate generation) from the Raft River Geothermal Power Plant Unit #1 located in southern Idaho. This project began operating in October 2007. Contract negotiations for the remaining 32.5 MW will take place over the next several months and will include an additional unit at the Raft River site (on-line 2009) and two units at the Neal Hot Springs site located in eastern Oregon (on-line 2010 and 2011).

Relicensing of Hydroelectric Projects
The section below summarizes and provides an update of relicensing projects as discussed in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2006, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

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 and Swan Falls projects.

Hells Canyon Complex: The most significant ongoing relicensing effort is the Hells Canyon Complex (HCC), which provides approximately two-thirds of IPC's hydroelectric generating capacity and 40 percent of its total generating capacity. The current license for the HCC expired at the end of July 2005. Until the new multi-year license is issued, IPC operates the project under an annual license issued by the FERC. The license application was filed in July 2003 and accepted by the FERC for filing in December 2003. The

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FERC is now processing the application consistent with the requirements of the Federal Power Act (FPA), the National Environmental Policy Act of 1969, as amended (NEPA), the Energy Policy Act and other applicable federal laws.

Consistent with the requirements of NEPA, the FERC Staff has prepared an environmental impact statement (EIS) for the Hells Canyon project, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. On August 31, 2007, the FERC issued the final EIS for the HCC relicensing. The purpose of the final EIS is to inform the FERC, the federal and state agencies, Native American tribes and the public about the environmental effects of IPC's proposed operation of the HCC. The final EIS also considers reasonable alternatives to that proposed operation. In this latter context, the FERC Staff reviewed the comments and alternative proposals submitted by the agencies, tribes and the private interests and evaluated those alternatives as compared to measures proposed by IPC. The final EIS also contains a "Staff Alternative," reflecting those instances where some modification to IPC's proposal is deemed advisable by the Staff to address environmental impacts or concerns. The FERC will consider the findings and proposals contained in the final EIS, together with the other information and material filed in the relicensing proceeding, in the development of a license order for the HCC. IPC's initial review of the final EIS indicates that, in large measure, the findings and recommendations (the Staff Alternative) in the final EIS are consistent with the draft EIS issued by the FERC in July 2006 and that the final EIS generally accepts the science, analysis and the proposed measures contained in IPC's license application and supporting documents. IPC is continuing to review the final EIS and expects to file comments to the final EIS with the FERC by the end of 2007.

In conjunction with the issuance of the final EIS, on September 13, 2007, the FERC requested formal consultation with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) pursuant to section 7 of the Endangered Species Act (ESA) with regard to the effect of relicensing the HCC on several aquatic and terrestrial species listed as threatened under the ESA. IPC is cooperating with the USFWS, the NMFS and the FERC in an effort to address ESA concerns associated with the relicensing of the HCC. The FERC is not expected to issue a license order for the HCC until ESA consultation is completed.

On January 31, 2007, IPC filed Water Quality Certification Applications, under section 401 of the Clean Water Act (CWA), with the States of Oregon and Idaho. Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, section 401 of the CWA requires as a prerequisite to the licensing of the project by the FERC that each state certify that any discharge from the project complies with applicable state water quality standards. IPC is working with the Oregon Department of Environmental Quality and the Idaho Department of Environmental Quality to ensure that state water quality standards are met so that the project can be appropriately certified.

At September 30, 2007, $93 million of HCC relicensing costs were included in construction work in progress. The relicensing costs are recorded and will be held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On March 10, 2005, IPC issued a Formal Consultation Package (FCP) to natural resource agencies, Native American tribes and the public relating to environmental studies designed to determine project effects for the relicensing of the Swan Falls project. Based upon the results of those studies and the consultation with the agencies, tribes and the public, on September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contains project specific information and the results of the studies developed in the FCP. After the public review period ends in December 2007, IPC will review any comments received, and file a final license application with the FERC in June 2008.

At September 30, 2007, $3 million of Swan Falls project relicensing costs were included in construction work in progress. The relicensing costs are recorded and will be held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

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. In March 2007, IPC received from the FERC a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis, which provided for a 60-day comment period for interested entities. The FERC has advised IPC that it will reissue the draft EA before the end of 2007. The license amendment could be issued in early 2008.

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.

OTHER MATTERS:

Adopted Accounting Pronouncements

FIN 48: As discussed in Note 2 to IDACORP's and IPC's Condensed Consolidated Financial Statements, both companies adopted FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*" (FIN 48) on January 1, 2007, as required. IDACORP and IPC recorded an increase of $15.1 million to opening retained earnings for the cumulative effect of adopting FIN 48.

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 September 30, 2007.

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 September 30, 2007, IDACORP and IPC had $324 million and $333 million, respectively, in floating rate debt, net of temporary investments. Assuming no change in either company's financial structure, if variable interest rates were to average one percentage point higher than the average rate on September 30, 2007, interest expense for the year ending December 31, 2007, would increase and pre-tax earnings would decrease by approximately $3.2 million for IDACORP and $3.3 million for IPC.

Fixed Rate Debt: As of September 30, 2007, IDACORP and IPC had outstanding fixed rate debt of $967 million and $936 million, respectively. The fair market value of this debt was $943 million and $911 million, respectively. These instruments are fixed rate, and therefore do not expose IDACORP or IPC to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $80 million for IDACORP and $79 million for IPC if interest rates were to decline by one percentage point from their September 30, 2007 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, 2006. In a limited manner starting in 2007, IPC began utilizing 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 Energy Risk Management Policy. This practice falls within the parameters of IPC's Energy 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.

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, 2006.

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, 2006.

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 September 30, 2007, 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 September 30, 2007, 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 September 30, 2007, 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

Reference is made to Note 5 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

ITEM 1A. RISK FACTORS

The Risk Factors included in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2006 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 have not changed materially.

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

As part of her compensation, Judith Johansen, a non-employee director of IDACORP and IPC, received a grant of 916 shares of common stock, equal to $30,000, on September 20, 2007. 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 the IDACORP and IPC Credit Facilities requires IDACORP and IPC to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization of no more than 65 percent at the end of each fiscal quarter. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs - Credit Facilities." 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 cause their leverage ratios to exceed 65 percent. At September 30, 2007, the leverage ratios for IDACORP and IPC were 52 percent and 54 percent, respectively.

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.

ITEM 5. OTHER INFORMATION

On October 31, 2007, IDACORP entered into Amendment No. 1 to its Sales Agency Agreement with BNY Capital Markets, Inc. (BNYCMI), dated as of December 15, 2005, relating to the issuance and sale of up to 2,500,000 shares of IDACORP common stock from time to time in at the market offerings through BNYCMI as IDACORP's agent for such offer and sale. Under the terms of Amendment No. 1, IDACORP and BNYCMI extended the term of the Sales Agency Agreement's commitment period to terminate on the earliest of (1) the date on which BNYCMI shall have sold all the shares of IDACORP's common stock subject to the Sales Agency Agreement; (2) termination of the Sales Agency Agreement by either IDACORP or BNYCMI and (3) December 1, 2008. As of October 31, 2007, 1,082,145 shares of common stock remained available for offer and sale under the Sales Agency Agreement, as amended.

A copy of Amendment No. 1 to the Sales Agency Agreement is filed as Exhibit 1 hereto.

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ITEM 6. EXHIBITS

*Previously Filed and Incorporated Herein by Reference

1	Amendment No. 1, dated as of October 31, 2007, to Sales Agency Agreement, dated as of December 15, 2005, between IDACORP, Inc. and BNY Capital Markets, Inc.
*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(a)	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(a)(i)	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(a)(ii)	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(a)(iii)	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(a)(iv)	Articles of Amendment to Restated Articles of Incorporation of IPC, as amended, 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 3.3.
*3(b)	Amended Bylaws of IPC, amended on January 20, 2005, and presently in effect. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 3.2.
*3(c)	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(d)	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(d)(i)	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(d)(ii)	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(e)	Amended Bylaws of IDACORP, Inc., amended on January 20, 2005, and presently in effect. File number 1-14456, Form 8-K, filed on 1/26/05, as Exhibit 3.1.
*4(a)(i)	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(a)(ii)	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.

*4(b)	Instruments relating to IPC American Falls bond guarantee (see Exhibit 10(c)). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).
*4(c)(i)	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(c)(ii)	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(d)	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(e)	Rights Agreement, dated as of September 10, 1998, between IDACORP, Inc. and Wells Fargo Bank, N.A., as successor to The Bank of New York, as Rights Agent. File number 1-14465, Form 8-K, filed on 9/15/98, as Exhibit 4.
*4(f)	First Amendment to Rights Agreement, dated as of May 14, 2007, between IDACORP, Inc. and Wells Fargo Bank, N.A., as successor to The Bank of New York, as Rights Agent. File number 333-143404, Form S-8, filed on 5/31/07, as Exhibit 4(g).
*4(g)	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(h)	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(i)	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(a)	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(a)(i)	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10(a). File number 2-51762, as Exhibit 5(c).
*10(b)	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10(c)	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(d)	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(e)	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).

*10(e)(i)	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(e)(ii)	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10(e). File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10(e)(iii)	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10(e). File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10(e)(iv)	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10(e). File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).
*10(e)(v)	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10(e). File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10(e)(vi)	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10(e). File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10(f)	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(g)	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(h)(i) [1]	Idaho Power Company Security Plan for Senior Management Employees I - a non-qualified, deferred compensation plan, amended and restated effective December 31, 2004. 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)(i).
*10(h)(ii)[1]	Idaho Power Company Security Plan for Senior Management Employees II, a non-qualified, deferred compensation plan, effective January 1, 2005, 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)(xxxv).
10(h)(iii) [1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007.
*10(h)(iv) [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(h)(v) [1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on November 2, 2006, as Exhibit 10(h)(vii).
*10(h)(vi) [1]	The Revised 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(h)(vii) [1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended and restated on September 20, 2007.
*10(h)(viii)[1]	Form of Officer Indemnification Agreement for 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(h)(ix)[1]	Form of Director Indemnification Agreement for 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(h)(x)[1]	Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), 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)(x).
*10(h)(xi) [1]	Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), 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)(xi).
10(h)(xii) [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended and restated September 20, 2007.
*10(h)(xiii)[1]	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(h)(xiv)1	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(h)(xv)[1]	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(h)(xvi)[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (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)(xxiii).
*10(h)(xvii)[1]	IDACORP, Inc. Executive Incentive Plan. File Number 1-14465, 1-3198, Form 8-K, filed on 2/27/07, as Exhibit 10.1.
*10(h)(xviii)[1]	Idaho Power Company Executive Deferred Compensation Plan, 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)(xxxvi).
*10(h)(xix)[1]	IDACORP, Inc. and IPC 2007 Compensation for Non-Employee Directors of the Board of Directors. File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(h)(xix).

*10(i)	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(i)(i)	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10(i). File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10(i)(ii)	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10(i). File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10(j)	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(j)(i)	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(k)	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(l)	$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(m)	$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(n)	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/2006, as Exhibit 10.1.
12	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12(a)	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12(b)	Statement Re: Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
12(c)	Statement Re: Computation of Supplemental Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)

12(d)	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12 (e)	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, 2006, filed on 3/1/07 as Exhibit 21.
31(a)	IDACORP, Inc. Rule 13a-14(a) certification.
31(b)	IDACORP, Inc. Rule 13a-14(a) certification.
31(c)	IPC Rule 13a-14(a) certification.
31(d)	IPC Rule 13a-14(a) certification.
32(a)	IDACORP, Inc. Section 1350 certification.
32(b)	IPC Section 1350 certification.
99	Earnings press release for third quarter 2007.

[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	October 31, 2007	By:	*/s/ J. LaMont Keen* J. LaMont Keen President and Chief Executive Officer
Date	October 31, 2007	By:	*/s/ Darrel T. Anderson* Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date	October 31, 2007	By:	*/s/ J. LaMont Keen* J. LaMont Keen President and Chief Executive Officer
Date	October 31, 2007	By:	*/s/ Darrel T. Anderson* Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

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EXHIBIT INDEX

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1	Amendment No. 1, dated as of October 31, 2007, to Sales Agency Agreement, dated as of December 15, 2005, between IDACORP, Inc. and BNY Capital Markets, Inc.
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10(h)(vii)	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended and restated September 20, 2007.
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