IDAHO POWER CO
Form 10-Q
May 08, 2008

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

(Mark One)

X QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2008

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

IDACORP, Inc.:

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

Idaho Power Company:

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

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

Number of shares of Common Stock outstanding as of March 31, 2008:

IDACORP, Inc.: 45,235,601

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

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

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

COMMONLY USED TERMS

Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
CAMP	-	Comprehensive Aquifer Management Plan
DSM	-	Demand Side Management
EIS	-	Environmental impact statement
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch, 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., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IWRB	-	Idaho Water Resource Board
LGAR	-	Large growth adjustment rate
maf	-	Million acre feet
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
Moody's	-	Moody's Investors Service

MW	-	Megawatt
MWh	-	Megawatt-hour
NEPA	-	National Environmental Policy Act of 1996
O & M	-	Operations and Maintenance
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
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

TABLE OF CONTENTS

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 March 31, 2008	2007
	(thousands of dollars except for per share amounts)	
Operating Revenues:		
Electric utility:		
General business	$ 167,313	$ 137,251
Off-system sales	33,363	57,838
Other revenues	12,120	10,839
Total electric utility revenues	212,796	205,928
Other	644	783
Total operating revenues	213,440	206,711
Operating Expenses:		
Electric utility:		
Purchased power	45,299	50,817
Fuel expense	37,237	30,913
Power cost adjustment	(17,744)	(21,536)
Other operations and maintenance	68,927	67,827
Demand-side management	3,364	2,115
Depreciation	25,750	25,290
Taxes other than income taxes	4,803	4,918
Total electric utility expenses	167,636	160,344
Other expense	1,048	2,588
Total operating expenses	168,684	162,932
Operating Income (Loss):		
Electric utility	45,160	45,584
Other	(404)	(1,805)
Total operating income	44,756	43,779
Other Income	4,417	5,389
Losses of Unconsolidated Equity-Method Investments	(4,036)	(1,326)
Other Expense	365	3,212
Interest Expense:		
Interest on long-term debt	16,876	13,548
Other interest	596	1,604
Total interest expense	17,472	15,152
Income Before Income Taxes	27,300	29,478
Income Tax Expense	5,584	4,898
Income from Continuing Operations	21,716	24,580
Income from Discontinued Operations, net of tax	-	67
Net Income	$ 21,716	$ 24,647
Weighted Average Common Shares Outstanding - Basic (000's)	44,847	43,687

Weighted Average Common Shares Outstanding - Diluted (000's)		45,004	43,820
Earnings Per Share of Common Stock (basic and diluted):			
Earnings per share from Continuing Operations	$	0.48	$ 0.56
Earnings per share from Discontinued Operations		-	-
Earnings Per Share of Common Stock	$	0.48	$ 0.56
Dividends Paid Per Share of Common Stock	$	0.30	$ 0.30

The accompanying notes are an integral part of these statements.

1

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

		March 31, 2008	December 31, 2007
Assets		(thousands of dollars)	
Current Assets:			
Cash and cash equivalents	$	7,404	$ 7,966
Receivables:			
Customer		72,173	69,160
Allowance for uncollectible accounts		(7,426)	(7,505)
Employee notes		2,171	2,128
Other		7,517	10,957
Accrued unbilled revenues		31,742	36,314
Materials and supplies (at average cost)		48,450	43,270
Fuel stock (at average cost)		15,930	17,268
Prepayments		7,749	9,371
Deferred income taxes		24,897	25,672
Refundable income tax deposit		46,257	46,083
Other		7,050	6,023
Total current assets		263,914	266,707
Investments		205,452	201,085
Property, Plant and Equipment:			
Utility plant in service		3,870,414	3,796,339
Accumulated provision for depreciation		(1,461,953)	(1,468,832)
Utility plant in service - net		2,408,461	2,327,507
Construction work in progress		206,114	257,590
Utility plant held for future use		6,455	3,366
Other property, net of accumulated depreciation		27,939	28,089
Property, plant and equipment - net		2,648,969	2,616,552
Other Assets:			

American Falls and Milner water rights	27,113	29,501
Company-owned life insurance	30,795	30,842
Regulatory assets	473,146	449,668
Long-term receivables (net of allowance of $1,878)	3,361	3,583
Employee notes	2,328	2,325
Other	54,386	53,045
Total other assets	591,129	568,964
Total	$ 3,709,464	$ 3,653,308

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

Liabilities and Shareholders' Equity		**March 31, 2008**	**December 31, 2007**
		(thousands of dollars)	
Current Liabilities:			
Current maturities of long-term debt	$	11,328	$ 11,456
Notes payable		243,509	186,445
Accounts payable		58,536	85,116
Taxes accrued		2,994	8,492
Interest accrued		27,976	18,913
Uncertain tax positions		27,187	26,764
Other		42,392	38,129
Total current liabilities		413,922	375,315
Other Liabilities:			
Deferred income taxes		479,589	466,182
Regulatory liabilities		275,425	274,204
Other		167,751	173,412
Total other liabilities		922,765	913,798
Long-Term Debt		1,155,290	1,156,880
Commitments and Contingencies (Note 6)			
Shareholders' Equity:			
Common stock, no par value (shares authorized 120,000,000; 45,236,415 and 45,063,107 shares issued, respectively)		678,724	675,774
Retained earnings		545,921	537,699
Accumulated other comprehensive loss		(7,155)	(6,156)
Treasury stock (814 and 380 shares at cost, respectively)		(3)	(2)
Total shareholders' equity		1,217,487	1,207,315
Total	$	3,709,464	$ 3,653,308

The accompanying notes are an integral part of these statements.

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

	Three months ended March 31,	
	2008	2007
	(thousands of dollars)	
Operating Activities:		
Net income	$ 21,716	$ 24,647
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	30,777	30,287
Deferred income taxes and investment tax credits	12,617	7,580
Changes in regulatory assets and liabilities	(20,466)	(19,002)
Non-cash pension expense	93	2,880
Undistributed (earnings) losses of subsidiaries	931	(1,566)
Gain on sale of assets	-	(1,604)
Other non-cash adjustments to net income	27	(365)
Change in:		
Accounts receivable and prepayments	1,811	602
Accounts payable and other accrued liabilities	(29,869)	(46,132)
Taxes accrued	(5,843)	593
Other current assets	729	4,869
Other current liabilities	12,227	17,165
Other assets	(1,122)	(1,388)
Other liabilities	(2,711)	2,455
Net cash provided by operating activities	20,917	21,021
Investing Activities:		
Additions to property, plant and equipment	(52,863)	(49,601)
Proceeds from the sale of IDACOMM	-	7,283
Investments in affordable housing	(8,487)	300
Investments in unconsolidated affiliates	(5,000)	(350)
Purchase of available-for-sale securities	-	(24,349)
Proceeds from the sale of available-for-sale securities	-	25,296
Purchase of held-to-maturity securities	-	(400)
Maturity of held-to-maturity securities	1,780	530
Other assets	(531)	481
Net cash used in investing activities	(65,101)	(40,810)
Financing Activities:		
Retirement of long-term debt	(1,779)	(2,696)
Dividends on common stock	(13,475)	(13,131)
Net change in short-term borrowings	57,063	27,427
Issuance of common stock	2,213	2,234

Acquisition of treasury stock		(269)		(338)
Other assets		(131)		(38)
Net cash provided by financing activities		43,622		13,458
Net decrease in cash and cash equivalents		(562)		(6,331)
Cash and cash equivalents at beginning of the period		7,966		9,892
Cash and cash equivalents at end of the period	$	7,404	$	3,561
Supplemental Disclosure of Cash Flow Information:				
Cash paid during the period for:				
Income taxes	$	-	$	21
Interest (net of amount capitalized)	$	7,934	$	7,511
Non-cash investing activities				
Additions to property, plant and equipment in accounts payable	$	16,350	$	6,657

The accompanying notes are an integral part of these statements.

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

		Three Months Ended March 31,		
		2008		**2007**
		(thousands of dollars)		
Net Income	$	21,716	$	24,647
Other Comprehensive Income (Loss):				
Unrealized gains (losses) on securities:				
Net Unrealized holding losses arising during the period, net of tax of ($708) and ($121)		(1,102)		(189)
Net Reclassification adjustment for gains included in net income, net of tax of $0 and ($561)		-		(874)
Net unrealized losses		(1,102)		(1,063)
Unfunded pension liability adjustment, net of tax of $67 and $72		103		113
Total Comprehensive Income	$	20,717	$	23,697

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three Months Ended March 31, 2008	2007
	(thousands of dollars)	
Operating Revenues:		
General business	$ 167,313	$ 137,251
Off-system sales	33,363	57,838
Other revenues	12,120	10,839
Total operating revenues	212,796	205,928
Operating Expenses:		
Operation:		
Purchased power	45,299	50,817
Fuel expense	37,237	30,913
Power cost adjustment	(17,744)	(21,536)
Other	54,654	52,206
Demand-side management	3,364	2,115
Maintenance	14,273	15,621
Depreciation	25,750	25,290
Taxes other than income taxes	4,803	4,918
Total operating expenses	167,636	160,344
Income from Operations	45,160	45,584
Other Income (Expense):		
Allowance for equity funds used during construction	896	1,404
(Losses) earnings of unconsolidated equity-method investments	(796)	1,535
Other income	3,449	3,703
Other expense	(688)	(2,874)
Total other income	2,861	3,768
Interest Charges:		
Interest on long-term debt	16,543	13,084
Other interest	1,894	2,173
Allowance for borrowed funds used during construction	(1,938)	(1,539)
Total interest charges	16,499	13,718
Income Before Income Taxes	31,522	35,634
Income Tax Expense	10,251	12,303
Net Income	$ 21,271	$ 23,331

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

Assets	March 31, 2008	December 31, 2007
	(thousands of dollars)	
Electric Plant:		
In service (at original cost)	$ 3,870,414	$ 3,796,339
Accumulated provision for depreciation	(1,461,953)	(1,468,832)
In service - net	2,408,461	2,327,507
Construction work in progress	206,114	257,590
Held for future use	6,455	3,366
Electric plant - net	2,621,030	2,588,463
Investments and Other Property	107,643	105,074
Current Assets:		
Cash and cash equivalents	5,306	5,347
Receivables:		
Customer	65,129	62,122
Allowance for uncollectible accounts	(1,226)	(1,305)
Notes	449	517
Employee notes	2,171	2,128
Other	4,298	7,605
Accrued unbilled revenues	31,742	36,314
Materials and supplies (at average cost)	48,450	43,270
Fuel stock (at average cost)	15,930	17,268
Prepayments	7,437	9,120
Deferred income taxes	3,848	4,074
Refundable income tax deposit	44,474	44,316
Other	2,284	1,067
Total current assets	230,292	231,843
Deferred Debits:		
American Falls and Milner water rights	27,113	29,501
Company-owned life insurance	30,795	30,842
Regulatory assets	473,146	449,668
Employee notes	2,328	2,325
Other	52,988	51,800
Total deferred debits	586,370	564,136
Total	$ 3,545,335	$ 3,489,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

Capitalization and Liabilities	March 31, 2008	December 31, 2007
	(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	581,758	581,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	450,059	442,300
Accumulated other comprehensive loss	(7,155)	(6,156)
Total common stock equity	1,120,442	1,113,682
Long-term debt	1,140,506	1,141,508
Total capitalization	2,260,948	2,255,190
Current Liabilities:		
Long-term debt due within one year	1,064	1,064
Notes payable	186,150	136,585
Accounts payable	58,084	84,457
Notes and accounts payable to related parties	901	724
Taxes accrued	4,295	2,403
Interest accrued	27,687	18,761
Uncertain tax positions	27,187	26,764
Other	41,317	36,907
Total current liabilities	346,685	307,665
Deferred Credits:		
Deferred income taxes	501,768	488,768
Regulatory liabilities	275,425	274,204
Other	160,509	163,689
Total deferred credits	937,702	926,661
Commitments and Contingencies (Note 6)		
Total	$ 3,545,335	$ 3,489,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	March 31, 2008	%	December 31, 2007	%
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	581,758		581,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	450,059		442,300	
Accumulated other comprehensive loss	(7,155)		(6,156)	
Total common stock equity	1,120,442	50	1,113,682	49
Long-Term Debt:				
First mortgage bonds:				
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6 % Series due 2032	100,000		100,000	
5.50% Series due 2033	70,000		70,000	
5.50% Series due 2034	50,000		50,000	
5.875% Series due 2034	55,000		55,000	
5.30% Series due 2035	60,000		60,000	
6.30% Series due 2037	140,000		140,000	
6.25% Series due 2037	100,000		100,000	
Total first mortgage bonds	945,000		945,000	
Amount due within one year	-		-	
Net first mortgage bonds	945,000		945,000	
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	9,573		10,636	
Note guarantee due within one year	(1,064)		(1,064)	
Unamortized premium/discount - net	(3,348)		(3,409)	
Total long-term debt	1,140,506	50	1,141,508	51
Total Capitalization	$ 2,260,948	100	$ 2,255,190	100

The accompanying notes are an integral part of these statements.

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

	Three months ended March 31, 2008	2007
	(thousands of dollars)	
Operating Activities:		
Net income	$ 21,271	$ 23,331
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	27,482	27,133
Deferred income taxes and investment tax credits	11,661	5,684
Changes in regulatory assets and liabilities	(20,466)	(19,002)
Non-cash pension expense	93	2,880
Undistributed (earnings) losses of subsidiary	796	(1,535)
Gain on sale of assets	-	(1,435)
Other non-cash adjustments to net income	(979)	(1,416)
Change in:		
Accounts receivables and prepayments	2,002	(3,464)
Accounts payable	(29,513)	(44,814)
Taxes accrued	1,547	10,897
Other current assets	729	4,794
Other current liabilities	12,090	16,974
Other assets	(1,123)	(1,390)
Other liabilities	(2,096)	2,908
Net cash provided by operating activities	23,494	21,545
Investing Activities:		
Additions to utility plant	(52,863)	(49,113)
Purchase of available-for-sale securities	-	(24,349)
Proceeds from the sale of available-for-sale securities	-	25,296
Investments in unconsolidated affiliate	(5,000)	(350)
Other assets	(531)	481
Net cash used in investing activities	(58,394)	(48,035)
Financing Activities:		
Retirement of long-term debt	(1,064)	(1,064)
Dividends on common stock	(13,512)	(13,094)
Net change in short term borrowings	49,565	39,900
Other assets	(130)	(40)
Net cash provided by financing activities	34,859	25,702
Net decrease in cash and cash equivalents	(41)	(788)
Cash and cash equivalents at beginning of the period	5,347	2,404
Cash and cash equivalents at end of the period	$ 5,306	$ 1,616
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Income taxes received from parent	$ 1,755	$ 937
Interest (net of amount capitalized)	$ 7,121	$ 6,260
Non-cash investing activities:		

Additions to utility plant in accounts payable	$ 16,350	$ 6,379

The accompanying notes are an integral part of these statements.

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

	Three Months Ended March 31,	
	2008	**2007**
	(thousands of dollars)	
Net Income	$ 21,271	$ 23,331
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net Unrealized holding losses arising during the period, net of tax of ($708) and ($121)	(1,102)	(189)
Net Reclassification adjustment for gains included in net income, net of tax of $0 and ($561)	-	(874)
Net unrealized losses	(1,102)	(1,063)
Unfunded pension liability adjustment, net of tax of $67 and $72	103	113
Total Comprehensive Income	$ 20,272	$ 22,381

The accompanying notes are an integral part of these statements.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

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

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

IDACORP's other subsidiaries include:

- IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;
- Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and
- IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

On February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. The results of operations and the sale of IDACOMM, Inc. are reported as discontinued operations. Discontinued operations are discussed in Note 9.

Principles of Consolidation
IDACORP's and IPC's condensed consolidated financial statements include the accounts of each company and their consolidated subsidiaries. IDACORP also consolidates two variable interest entities (VIEs) for which it is the primary beneficiary. All significant intercompany balances have been eliminated in consolidation. Investments in 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 2008. IFS' maximum exposure to loss in these developments was $83 million at March 31, 2008.

Financial Statements

In the opinion of IDACORP and IPC, the accompanying unaudited condensed consolidated financial statements contain all adjustments necessary to present fairly their consolidated financial positions as of March 31, 2008, and consolidated results of operations for the three months ended March 31, 2008, and 2007, and consolidated cash flows for the three months ended March 31, 2008, and 2007. These adjustments are of a normal and recurring nature. These financial statements do not contain the complete detail or footnote disclosure concerning accounting policies and other matters that would be included in full-year financial statements and should be read in conjunction with the audited consolidated financial statements included in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Reclassifications

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

Earnings Per Share

The following table presents the computation of IDACORP's basic and diluted earnings per share from continuing operations for the three months ended March 31, 2008 and 2007 (in thousands, except for per share amounts):

	Three months ended March 31,			
		2008		**2007**
Numerator:				
Income from continuing operations	$	21,716	$	24,580
Denominator:				
Weighted-average common shares outstanding - basic *		44,847		43,687
Effect of dilutive securities:				
Options		49		49
Restricted Stock		108		84
Weighted-average common shares outstanding - diluted		45,004		43,820
Basic and diluted earnings per share from continuing operations	$	0.48	$	0.56

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

The diluted EPS computation excluded 482,000 options for the three months ended March 31, 2008, because the options' exercise prices were greater than the average market price of the common stock during that period. For the same period in 2007, there were 488,000 options excluded from the diluted EPS computation for the same reason. In total, 818,232 options were outstanding at March 31, 2008, with expiration dates between 2010 and 2015.

New Accounting Pronouncements

SFAS 141(R): In December 2007 the FASB issued SFAS 141(R), "*Business Combinations (Revised December 2007).*" SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: 1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; 2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and 3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. IDACORP and IPC are currently evaluating the impact of SFAS 141(R).

SFAS 160: In December 2007 the FASB issued SFAS 160, *"Noncontrolling Interests in Consolidated Financial Statements*." Among other things, SFAS 160 establishes a standard for the way noncontrolling interests (also called minority interests) are presented in consolidated financial statements and standards for accounting for changes in ownership interests. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. An entity may not apply it before that date. IDACORP and IPC are currently evaluating the impact of SFAS 160.

SFAS 161: In March 2008, the FASB issued SFAS 161, "*Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No. 133.*" SFAS 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under

Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. IDACORP and IPC are currently evaluating the impact of SFAS 161.

2. INCOME TAXES:

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP's effective rate on continuing operations for the three months ended March 31, 2008, was 20.5 percent, compared to 16.6 percent for the three months ended March 31, 2007. IPC's effective tax rate for the three months ended March 31, 2008, was 32.5 percent, compared to 34.5 percent for the three months ended March 31, 2007. 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.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the three months ended March 31, 2008, IDACORP entered into the following transactions involving its common stock:

85,030 original issue shares were used for awards granted under the 2000 Long-Term Incentive and Compensation Plan.

16,149 original issue shares and 26,359 treasury shares were used for awards granted under the Restricted Stock Plan.

15,100 treasury shares were used for the annual stock grant to directors under the Non-Employee Directors Stock Compensation Plan.

72,129 original issue shares were issued under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan.

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

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At March 31, 2008, the maximum number of shares available under the LTICP and RSP were 1,559,248 and 66,250, 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 Three months ended March 31,	IPC Three months ended March 31,

	2008	2007	2008	2007
Compensation cost	$ 971	$ 1,051	$ 921	$ 544
Income tax benefit	$ 379	$ 411	$ 360	$ 213

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 three months of 2008 was $30.54.

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

The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for CEPS and TSR awards granted during the first three months of 2008 was $22.76.

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

4. FINANCING:

Credit Facilities

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

IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008 with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, N.A., as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans are due on March 31, 2009. IPC used the proceeds from the loans to effect the mandatory purchase on April 3, 2008 of the Pollution Control Bonds (as discussed below under "Long-Term Financing") and to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and/or the Term Loan Credit Agreement. The loans may be prepaid, but may not be reborrowed. At March 31, 2008, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings were as follows at March 31, 2008, and December 31, 2007 (in thousands of dollars):

	March 31, 2008			December 31, 2007		
	IPC	IDACORP	Total	IPC	IDACORP	Total
Balances outstanding	$ 186,150	$ 57,359	$ 243,509	$ 136,585	$ 49,860	$ 186,445
Weighted-avg. interest rate	4.06%	4.12%	4.07%	5.56%	5.45%	5.53%

Long-Term Financing

IDACORP has $629 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. IPC has in place a registration statement that can be used for the issuance of an aggregate principal amount of $350 million of first mortgage bonds (including medium-term notes) and unsecured debt.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to $350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H.

On April 3, 2008, IPC made a mandatory purchase of the $49.8 million Humboldt County, Nevada Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 and the $116.3 million Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006 (together, the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008.

5. REGULATORY MATTERS:

Idaho General Rate Case
On February 28, 2008, the IPUC approved a settlement of IPC's general rate case filed June 8, 2007. The IPUC's order approved an average increase of 5.2 percent in base rate, or approximately $32.1 million in revenues, effective March 1, 2008.

Danskin 1 Power Plant Application
The Danskin 1 plant, a simple cycle combustion turbine near Mountain Home, Idaho, began commercial operations on March 11, 2008. The combustion turbine can provide approximately 166 MW of capacity during summer load peaks and up to 200 MW in the winter. On March 7, 2008, IPC filed an application with the IPUC requesting to recover the costs associated with the construction of this new plant. The filing asks for a $9 million, or 1.4 percent, annual increase in revenues, by June 1, 2008. The IPUC is proceeding on this application under modified procedure and will take comments through May 13, 2008.

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

	March 31, 2008	December 31, 2007
Idaho PCA current year:		
Deferral for the 2008-2009 rate year *	$ 107,160	$ 85,732
Idaho PCA true-up awaiting recovery:		
Authorized in May 2007	4,862	6,591
Oregon:		
2001 deferral	2,402	2,993
2006 deferral	2,148	2,107
Total deferral	$ 116,572	$ 97,423

* The 2008-2009 PCA deferral balance is reduced by $17 million of emission allowance sales 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. The PCA tracks IPC's actual net power supply costs (fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

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

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

monthly, and interest is applied to the balance.

The PCA mechanism provides that for both the forecast and the true-up components, 90 percent of deviations in power supply costs are to be reflected in IPC's rates.

On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing indicated an increase of $89.0 million to the PCA component of customers' rates to a level that is $121.6 million above base rates based upon historical sharing percentages between customers and shareholders.

The PCA filing also contained a proposal to flow through to customers 100 percent of the deviation in power supply costs for the prospective year. This is a one-year proposal that impacts the 2008 forecast component of the current PCA and its later true-up and would reduce IPC's requested rate increase to $87.2 million. While the overall filing requests a rate increase, the forecast component is a customer benefit. The $1.8 million reduction reflects an additional ten percent of the benefit being passed on to customers. The PCA mechanism provides for sharing of benefits and costs at a ratio of 90 percent to customers and ten percent to shareholders. IPC requested this deviation from the customary sharing percentage for two reasons:

1) Approximately 62 average MW of energy from PURPA wind projects that IPC had expected to receive in 2008 will not be available because the associated projects requested extensions of their on-line dates. IPC recovers 100 percent of power purchases from PURPA projects but will need to replace this energy with market purchases; and

2) Pursuant to IPC's risk management policy, which was established in accordance with IPUC-approved risk management guidelines, IPC had committed to net purchases of nearly $51 million at the time of the PCA filing. Under the current sharing methodology, IPC will only recover 90 percent of these known costs. Because of the prescriptive nature of this risk management activity, IPC believes that 100 percent customer sharing is appropriate.

These anticipated cost increases would be included in the true-up component of IPC's 2009 PCA filing.

As discussed below in "Emission Allowances," the IPUC ordered on April 14, 2008 that $16.4 million of proceeds, including interest, from the sales of SO_2 emission allowances in 2007 be applied to help offset the PCA deferral balances incurred during the 2007-2008 PCA year. This order is not reflected in IPC's PCA filing, but it is expected to reduce the requested PCA increase to $70.8 million.

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 was net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates became effective June 1, 2007.

Idaho Load Growth Adjustment Rate (LGAR): On January 9, 2007, the IPUC issued an order resetting IPC's LGAR to $29.41 per MWh, effective April 1, 2007. The LGAR subtracts the cost of serving additional Idaho retail load from the net power supply costs IPC is allowed to include in its PCA. The order revised the LGAR from the original rate of $16.84 per MWh set when the PCA began in 1993. This amount was established as the projected additional variable energy costs attributable to load growth and was subtracted from each year's PCA expense. IPC had requested the use of the embedded cost of serving new load and a rate of $6.81 per MWh, but the IPUC in its order determined to use the projected marginal cost, which resulted in a higher LGAR. The LGAR is reset during a general rate case.

The general rate case settlement approved by the IPUC on February 28, 2008, (discussed above in "General Rate Case - Idaho") contained a provision to make a good faith effort to develop a mechanism to adjust or replace the current LGAR. As an interim solution, the parties agreed to use the LGAR of $62.79 per MWh recommended by the IPUC Staff, but to apply it to only 50 percent of the load growth beginning in March 2008.

Emission Allowances: During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $18.5 million. On April 14, 2008, the IPUC ordered that $16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that $0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and is reflected in the PCA rates in effect during the June 1, 2007, through May 31, 2008, PCA rate year.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" power supply expenses. In the last 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 awaiting an order from the OPUC.

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. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

The timing of 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 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. The PCAM 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 PCAM differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case. Settlement conferences were held and the interested parties reached an agreement. A joint stipulation was filed with the OPUC on March 14, 2008. The OPUC approved the stipulation on April 28, 2008.

In connection with this proceeding, on March 24, 2008, IPC submitted testimony to the OPUC to revise its previous calculation of its April 2008 through March 2009 net power supply costs (October Update) to conform to the methodology agreed to by the parties in the PCAM stipulation. IPC also submitted the second part of the mechanism (March Forecast), reflecting expected hydro conditions and forward prices for the April 2008 through March 2009 period. The expected power supply costs of $150 million represent an increase of approximately $23 million over the October Update.

If approved, the power supply cost update submitted by IPC, which comprises both the October Update and the March Forecast, would result in a $4.8 million, or 15.69 percent, increase in Oregon revenues. New rates are expected to be effective on June 1, 2008.

Fixed Cost Adjustment Mechanism (FCA)
On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program. The FCA is a rate mechanism designed to remove a utility's disincentive to invest in energy efficiency programs. The FCA separates (or decouples) the recovery of fixed costs from the variable kilowatt-hour charge and, instead, links it to a set amount per customer. If IPC under-collects its fixed costs per customer as a result of reduced electrical use, it can collect the difference through a surcharge. If IPC over-collects its authorized fixed costs, customers are refunded through a credit. The FCA is only applicable to residential and small commercial customers. 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.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for expenses incurred in 2007. The application is currently pending with the IPUC. IPC accrued $0.9 million of FCA expense in the first quarter of 2008.

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. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of $11 million based upon 2004 test year data. The rates were accepted subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates and that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced the estimated annual revenue increase to approximately $8.2 million based on 2004 test year data. Approximately $1.7 million collected in excess of these new rates between June 1, 2006, and July 31, 2007, was refunded with interest to customers.

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. If the Initial Decision is implemented, IPC estimates that it would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $3.2 million for the June 1, 2006, through March 31, 2008, period. IPC has reserved this entire amount. 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. IPC is awaiting a final FERC order.

Idaho Pension Expense Order

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, *"Employers' Accounting for Pensions,"* as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. 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 was deferred to a regulatory asset beginning in the third quarter. In the first quarter of 2008, $2.0 million of pension expense was deferred. IPC did not request a carrying charge be applied to the deferral of the accrued SFAS 87 expense.

6. COMMITMENTS AND CONTINGENCIES:

Guarantees

IPC has agreed to guarantee the performance of one-third of the reclamation activities at Bridger Coal Company, of which IERCO owns a one-third interest. This guarantee, which is renewed each December, was $60 million at March 31, 2008. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying the 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

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

Reference is made to IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 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 (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 fully briefed and oral argument was held on April 10, 2007. On November 20, 2007, the Ninth Circuit affirmed the dismissal. On December 10, 2007, Wah Chang filed Petitions for Rehearing and Rehearing En Banc with the U.S. Court of Appeals for the Ninth Circuit, which were denied January 15, 2008. Because Wah Chang did not file a petition for certiorari seeking Supreme Court review before the expiration date of April 14, 2008, this matter is now concluded.

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. 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 February 3, 2004, the FERC directed the California Independent System Operator (Cal ISO) to provide status reports with respect to its progress in calculating refunds, fuel and emissions allowance offsets to refunds and interest. The process of performing the calculations has engaged the Cal ISO for more than four years. On March 18, 2008, the Cal ISO published its Fortieth Status Report and on March 25, 2008, it released the interest calculations it had completed as a result of revising market clearing prices as directed by the FERC. In its Fortieth Status Report, the Cal ISO stated its intention to consider interest and cost allocation questions for parties that had FERC-approved settlements when it had completed the basic calculation of interest for revised market clearing prices. A date has not yet been set for this aspect of the Cal ISO's calculations.

While the refund proceedings were pending before the FERC, the California Attorney General filed a complaint with the FERC against sellers in the wholesale power market, including IE and IPC, alleging that the FERC's market-based rate requirements violate the Federal Power Act (FPA), and, even if the market-based rate requirements were valid, that the quarterly transaction reports filed by sellers did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint sought refunds for an expanded time when compared to the basic refund proceeding. The FERC dismissed the complaint but on September 9, 2004, the Ninth Circuit concluded that although market-based tariffs are permissible under the FPA, the matter should be remanded to the FERC to consider whether the FERC should exercise remedial power (including some form of refunds) when a market participant failed to submit reports. On December 28, 2006, a number of sellers filed a certiorari petition to the U.S. Supreme Court. The Supreme Court declined to grant certiorari and the matter has now been remanded to the FERC. The settlement IE and IPC reached with the California Parties that was approved by the FERC on May 22, 2006, anticipated the possibility of the outcome of the appeals discussed above and resolved the settling parties' claims in the event of the expansion of all of the refund proceedings as the Ninth Circuit ordered.

On March 21, 2008, the FERC issued an order responding to the remand by Ninth Circuit. The FERC's order established hearing procedures to permit wholesale purchasers that made short-term market-based rate purchases through the Cal ISO and the California Power Exchange (CalPX), as well as those making spot market purchases of energy through the California Energy Resources Scheduling Division of the California Department of Water Resources from January 1, 2000 to October 1, 2000, to (i) present evidence that any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus caused its market-based rates to be unjust and unreasonable and (ii) permit sellers to present evidence to the contrary. Before formal hearing procedures commenced, the FERC directed that the matter be presented to a settlement judge to attempt to settle individual cases. The FERC's March 21, 2008 order expands the field of those who may present evidence in the case from the original complaint of the California Attorney General and also is more restrictive in terms of what must be proven to establish a case. On April 7, 2008, IE and IPC joined with a number of other parties that already had settled this proceeding with the California Attorney General and the other California Parties requesting that they be dismissed from the case. The California Attorney General and the other California Parties indicated their agreement to the dismissal. On April 15, 2008, the FERC issued an order dismissing parties that already had settled, including IE and IPC, from these remanded proceedings. If rehearing is sought and the FERC reverses the dismissal, IE and IPC intend to vigorously defend themselves, but are unable to predict the outcome of this matter.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Port of Seattle withdrew its petition for review in one of the three consolidated cases and filed its initial brief on February 29, 2008. Final briefs are due by August 31, 2008. A date for argument has not been set. IE and IPC are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings the FERC issued an order 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 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the "gaming" and "partnership" show cause orders. The FERC staff submitted a motion to the FERC to dismiss the "partnership" proceeding, which was approved by the FERC in an order issued on January 23, 2004. The "gaming" settlement was approved by the FERC on March 4, 2004.

Some parties have sought review of what they claim are the excessively narrow or excessively broad scope of the show cause orders, and the Ninth Circuit has consolidated those claims with the other matters and is holding them in abeyance. The Port of Seattle is the only party to appeal the orders of the FERC approving the gaming settlement. IPC is not able to predict when the appeal will be considered or the outcome of the judicial determination of these issues.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001 concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and the refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation 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 proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. The U.S. Supreme Court has granted certiorari in one of the cases, which has been briefed and argued before the Court. IE and IPC are unable to predict how the Supreme Court will rule, how the FERC might respond to any such decision or how any such decision might affect the outcome of the Pacific Northwest proceeding.

There are pending in 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 with respect to 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.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants. Plaintiffs allege that IPC's ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860's or before.

On May 31, 2007, the U.S. District Court granted the defendants' motion to dismiss stating that the plaintiffs' claims are barred by the finality provision of the Indian Claims Commission Act. Plaintiffs filed a motion for reconsideration which the District Court denied. On January 25, 2008, the District Court entered judgment in favor of IPC. Plaintiffs filed a Notice of Appeal to the Ninth Circuit. The parties are in the process of filing briefs on appeal. Oral argument on the appeal has not yet been scheduled. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on IPC's consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the U.S. District Court for the District of 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.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity permit status of this matter. The court has not yet ruled on these motions. On March 13, 2008, the District Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on the consolidated financial position, results of operations or cash flows.

Sierra Club Notice of Intent to File Suit - Boardman: On January 15, 2008, the Oregon Chapter of the Sierra Club, the Northwest Environmental Defense Center, Friends of the Columbia Gorge, Columbia Riverkeeper, and Hells Canyon Preservation Council (collectively, Sierra Club) provided a 60-day notice to Portland General Electric Company (PGE) of intent to file suit. Sierra Club alleges violations of opacity standards at the Boardman coal-fired power plant located in Morrow County, Oregon of which IPC owns ten percent. PGE owns 65 percent and is the operator of the plant. Sierra Club further alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE's construction and operation of the plant. The 60-day notice period expired on March 15, 2008, but Sierra Club has not yet commenced litigation. Sierra Club alleges thousands of opacity permit limit violations by PGE from and before 2003, and claims that it will seek a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, and civil penalties of up to $32,500 per day per violation. IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on the 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, 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 of Idaho, 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, providing for discovery during the objection period, and setting and scheduling a conference for December 18, 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. On December 18, 2007, the court held a status and scheduling conference in the consolidated proceedings. Subsequently, the court issued a scheduling order on December 20, 2007, with a trial scheduled to begin on February 2, 2009. In January 2008, the state and IPC filed cross motions for summary judgment on issues in the case. These motions were briefed and oral argument before the court was held on the motions on February 21, 2008.

On April 18, 2008, the court issued a Memorandum Decision and order on Cross-Motions for Summary Judgment upholding the Swan Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the IDWR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court will hold a status conference in the near future to discuss how to proceed with respect to this issue. IPC is unable to predict the outcome of the consolidated proceedings.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation 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. IPC believes that 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 U.S. District 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 15, 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. The U.S. Bureau of Reclamation filed answers in each of these cases on February 15, 2008. On March 4, 2008, the U.S. District Court for the District of Idaho entered a preliminary scheduling order, setting that case for trial on December 15, 2009. The action in the U.S. District Court of Federal Claims has not yet been set for trial. IPC is unable to predict the outcome of this litigation.

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. On March 28, 2008, the plaintiffs filed a First Amended Complaint and Demand for Jury Trial. The plaintiffs' First Amended Complaint asserts claims for negligence, negligence *per se*, nuisance, breach of contract, and fraud. The claims are based on allegations that from 1972 until May 25, 2005, IPC discharged "stray voltage" from its electrical facilities that caused physical harm and injury to the plaintiffs' dairy herd. Plaintiffs seek compensatory damages in excess of $10,000 to be proven at trial.

IPC has not responded to the First Amended Complaint. 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.

7. BENEFIT PLANS:

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

	Pension Plan		Deferred Compensation Plan		Postretirement Benefits	
	2008	2007	2008	2007	2008	2007
Service cost	$ 3,730	$ 3,803	$ 320	$ 352	$ 327	$ 379
Interest cost	6,596	6,114	667	593	880	895
Expected return on plan assets	(8,494)	(8,342)	-	-	(738)	(690)
Amortization of transition obligation	-	-	-	-	510	510
Amortization of prior service cost	163	163	48	43	(133)	(134)
Amortization of net loss	-	-	122	142	-	132
Net periodic benefit cost	$ 1,995	$ 1,738	$ 1,157	$ 1,130	$ 846	$ 1,092

IDACORP and IPC have not contributed and do not expect to contribute to their pension plan in 2008.

8. SEGMENT INFORMATION:

IDACORP's only reportable segment at March 31, 2008 is utility operations, for which the primary source of revenue is the regulated operations of IPC. IFS, which had previously been identified as a reportable segment, is now included in the "All Other" column. IDACOMM, which had previously been identified as a reportable segment, is now reported as discontinued operations (See Note 9).

IPC's regulated operations include the generation, transmission, distribution, purchase and sale of electricity. This segment also includes income from Bridger Coal Company, an unconsolidated joint venture also subject to regulation. Other operating segments are below the quantitative thresholds for reportable segments and are included in the "All Other" category. This category is comprised of IFS's investments in affordable housing developments and other tax-advantaged investments, Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of energy marketer IE, which wound down its operations in 2003, and IDACORP's holding company expenses.

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

	Utility Operations	All Other	Eliminations	Consolidated Total
Three months ended March 31, 2008:				
Revenues	$ 212,796	$ 644	$ -	$ 213,440
Income from continuing operations	21,271	445	-	21,716
Total assets at March 31, 2008	$ 3,545,335	$ 228,620	$ (64,491)	$ 3,709,464
Three months ended March 31, 2007:				
Revenues	$ 205,928	$ 783	$ -	$ 206,711
Income from continuing operations	23,331	1,249	-	24,580

9. DISCONTINUED OPERATIONS:

In the second quarter of 2006, IDACORP decided to seek a buyer for its telecommunications subsidiary IDACOMM. 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 IDACOMM 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 March 31, 2008	Three months ended March 31, 2007
Revenues	$ -	$ 1,278
Operating expenses	-	(1,309)
Other (expense)	-	(25)
Loss on disposal	-	(2,877)
Pre-tax losses	-	(2,933)
Income tax benefit	-	3,000
Income from discontinued operations	$ -	$ 67

10. FAIR VALUE MEASUREMENTS

IDACORP and IPC partially adopted the provisions of SFAS 157 *"Fair Value Measurements"* (SFAS 157) on January 1, 2008. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

FASB Staff Position 157-2 (FSP 157-2) delayed the implementation of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow additional time to consider the effect of implementation issues that have arisen, or that may arise, from the application of SFAS 157. In accordance with FSP 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations.

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

Financial assets and liabilities recorded on the Condensed Consolidated Balance Sheets are categorized as follows:

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

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

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

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

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

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

IDACORP's and IPC's Level 2 inputs are based on exchange traded products adjusted for location using corroborated, observable market data.

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

The following table presents information about IDACORP's and IPC's assets and liabilities measured at fair value on a recurring basis as of March 31, 2008 (in thousands of dollars). IDACORP's and IPC's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
IDACORP				
Assets:				
Derivatives	$ 451	$ 2,627	$ -	$ 3,078
Trading securities	7,541	-	-	7,541
Available-for-sale securities	20,428	-	-	20,428
Liabilities:				
Derivatives	$ 234	$ -	$ -	$ 234
IPC				
Assets:				
Derivatives	$ 451	$ 2,627	$ -	$ 3,078
Trading securities	5,977	-	-	5,977

Available-for-sale securities	20,428	-	-	20,428
Liabilities:				
Derivatives	$ 234	$ -	$ -	$ 234

IDACORP and IPC adopted the provisions of SFAS 159, *"The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115"* (SFAS 159) on January 1, 2008. SFAS 159 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 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. IDACORP and IPC did not elect the fair value option for any existing eligible items. However, IDACORP and IPC will continue to evaluate new items on a case-by-case basis for consideration of the fair value option.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the "Company") as of March 31, 2008, and the related condensed consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2008 and 2007. 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, 2007, 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 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No.* 109, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).* In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2007, 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
May 7, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary (the "Company") as of March 31, 2008, and the related condensed consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2008 and 2007. 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, 2007, 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 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No.* 109, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).* In our opinion, the information set forth in the accompanying condensed consolidated balance sheet and statement of capitalization as of December 31, 2007, 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
May 7, 2008

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., 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 February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. The results of operations of and the sale of IDACOMM, Inc. are reported as discontinued operations. Discontinued operations are discussed in Note 9 to IDACORP's and IPC's Condensed Consolidated Financial Statements.

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements of IDACORP and IPC, which present the financial position at March 31, 2008, and December 31, 2007, and the results of operations and cash flows for each company for the three-month periods ended March 31, 2008 and 2007. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2007, and should be read in conjunction with the discussion in that report.

FORWARD-LOOKING INFORMATION:

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, IDACORP and IPC are hereby filing cautionary statements identifying important factors that could cause actual results to differ materially from those projected in forward-looking statements, as such term is defined in the Reform Act, made by or on behalf of IDACORP or IPC in this Quarterly Report on Form 10-Q, in presentations, in response to questions or otherwise. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue" 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 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, and the Oregon Public Utility Commission 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 power supply costs, recovery of 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;

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

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

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

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

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

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

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

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

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

Impacts from the formation of a regional transmission organization or the development of another transmission group;

Population growth rates and other demographic patterns;

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

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;

Changes in interest rates or rates of inflation;

Performance of the stock market and changes in interest rates, which affect the amount of required contributions to pension plans, and the reported costs of providing pension and other postretirement benefits;

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

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

Homeland security, acts of war or terrorism;

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

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

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

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

EXECUTIVE OVERVIEW:

First quarter 2008 financial results
A summary of IDACORP's net income and earnings per diluted share is as follows:

	Three months ended March 31,	
	2008	**2007**
Net income	$ 21,716	$ 24,647
Average outstanding shares - diluted (000s)	45,004	43,820
Earnings per diluted share	$ 0.48	$ 0.56

The key factors affecting the change in IDACORP's net income for the first quarter of 2008 include (amounts shown are net of income taxes):

IPC's net income was $21.3 million in the first quarter of 2008, a decrease of $2 million as compared to the first quarter of 2007. The key factors affecting the change in IPC's net income include:

Increased retail sales contributed $5.9 million to general business revenue for the quarter. IPC's service territory had 15 percent more heating degree days as compared to the same period in 2007 and four percent more heating degree days than normal. IPC continues to experience customer growth, with the average number of general business customers increasing 9,166 compared to the first quarter of 2007, an increase of two percent.

Rate increases added $12.4 million to general business revenue for the quarter as compared to the same period last year. A PCA increase on June 1, 2007, increased rates by an average of 14.5 percent, or $11.8 million. In addition, a general rate increase of 5.2 percent became effective March 1, 2008, and increased general business revenue $0.6 million.

Increased net power supply costs (fuel and purchased power less off-system sales), net of the current PCA deferral decreased earnings by $17.7 million (including the effects of the LGAR described below) for the quarter as compared to the same period last year. During the first quarter of 2008, IPC experienced poor hydroelectric generating conditions that have carried over from 2007. IPC's hydroelectric generation decreased to 46 percent of total system generation for the quarter as compared to 51 percent in 2007.

The Load Growth Adjustment Rate (LGAR) mechanism, a component of the PCA, reduced earnings by $3.2 million. Most of the impact came in January and February as base loads and the rate were reset in March in connection with the general rate case.

Bridger Coal Company's results in the first quarter were $1.6 million below last year, primarily due to difficulties with its underground longwall mining operations in January and February 2008.

Increased interest charges, primarily due to increases in long-term debt balances and variable interest rates, reduced earnings $1.7 million.

IFS earnings decreased $1.1 million for the quarter. The reduction is primarily due to lower tax benefits from aging investments and lower earnings on variable rate instruments.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as one additional financial measure, electric utility margin, that is considered a "non-GAAP financial measure" under SEC rules. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated in accordance with GAAP. The most directly comparable GAAP financial measure to electric utility margin is operating income.

The presentation of electric utility margin is intended to supplement the information available to investors for evaluating IPC's operating performance. When viewed in conjunction with IPC's operating income, electric utility margin provides a more complete understanding of the factors and trends affecting IPC's business, and users can assess which information best suits their needs. However, this measure is not intended to replace operating income, or any other measure calculated in accordance with GAAP, as an indicator of operating performance.
IPC's management uses electric utility margin, in addition to GAAP measures, to determine whether IPC is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. Electric utility margin also provides both management and investors with a better understanding of the effects of regulatory mechanisms on IPC's operating income. The primary limitation associated with this measure is that IPC's electric utility margin may not be comparable to other companies' electric utility margins. However, management uses electric utility margin as an internal tool for evaluating and conducting the business, and is therefore unburdened by this limitation.

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

	Three months ended March 31,	
	2008	**2007**
General business revenue	$ 167,313	$ 137,251
PCA water deferral *	(5,965)	7,773
PCA amortization	(2,455)	3,203
Total	158,893	148,227
Power supply costs:		
Off-system sales	33,363	57,838
Purchased power	(45,299)	(50,817)
Fuel	(37,237)	(30,913)
PCA deferral net of PCA water deferral	26,164	10,560
Total	(23,009)	(13,332)
Third party transmission expense	(497)	(799)
Other revenues (excluding Demand Side Management (DSM))	8,756	8,724
Electric utility margin	$ 144,143	$ 142,820
Electric utility margin as a percentage of total general business revenue, PCA water deferral, and PCA amortization	91%	96%

* The PCA water deferral is the reversal of the forecasted difference between power supply costs embedded in base rates and
expected power supply costs established for the one-year time period of April through March that is included in general
business revenue.

The decline in electric utility margin as a percentage of total general business revenue, PCA water deferral and PCA amortization is a result of power supply costs increasing at a greater rate than general business revenue due to below normal hydroelectric generation. The $15.5 million increase in the PCA deferral reflects the combined net positive deferral of the increased net power supply expenses and an increase in the negative impacts of the LGAR mechanism.

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

	Three months ended March 31, 2008	Three months ended March 31, 2007
Electric utility margin	$ 144,143	$ 142,820
Other operations and maintenance		
(excluding third party transmission expense)	(68,430)	(67,028)
Depreciation	(25,750)	(25,290)
Taxes other than income taxes	(4,803)	(4,918)
Operating income - electric utility (GAAP)	$ 45,160	$ 45,584

Hydroelectric generating conditions
Below normal temperatures and winter precipitation resulted in below normal stream flow conditions that negatively impacted hydroelectric generation in the first quarter of 2008. More gradual snowmelt, combined with below normal Snake River system reservoir carryover from last year, also reduced the overall water available for hydroelectric generation. On May 7, 2008, the National Weather Service's Northwest River Forecast Center indicated that Brownlee reservoir inflow for April through July 2008 is expected to be 4.9 maf or 78 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.0 and 8.0 million MWh from its hydroelectric facilities in 2008, compared to 6.2 million MWh in 2007.

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 power supply costs.

Capital requirements
IPC's 2008-2010 construction program and related expenditures are subject to on-going review and are revised to include changes in the expected timing of expenditures, load growth, construction costs, location of generation sources, transmission capacity, adequacy of rate recovery and environmental concerns. As a result of this review, IPC has revised its planned 2008 capital expenditures and expects to spend between $270 and $290 million.

General rate case settlement
On February 28, 2008 the IPUC approved a settlement of IPC's general rate case filed in 2007. New rates, effective March 1, 2008, increased IPC's annual revenue by $32.1 million or 5.2 percent. The base rates for residential customers increased 4.7 percent, and the base rates for the other classes of customers increased 5.65 percent.

Power Cost Adjustment filing
On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing indicates an increase of $89.0 million to the PCA component of customers' rates to a level that is $121.6 million above base rates based upon historical sharing percentages between customers and shareholders.

The PCA filing also contained a proposal to flow through to customers 100 percent of the deviation in power supply costs for the prospective year. This is a one-year proposal that impacts the 2008 forecast component of the current PCA and its later true-up and would reduce IPC's requested rate increase to $87.2 million. While the overall filing requests a rate increase, the forecast component is a customer benefit. The $1.8 million reduction reflects an additional ten percent of the benefit being passed on to customers.

In addition, the IPUC ordered on April 14, 2008 that $16.4 million of proceeds, including interest, from the sales of SO_2 emission allowances in 2007 be applied to help offset the PCA deferral balances incurred during the 2007-2008 PCA year. This order is not reflected in IPC's PCA filing, but it is expected to reduce the requested PCA increase to

$70.8 million.

Danskin 1 Power Plant Application

On March 7, 2008, IPC filed an application with the IPUC requesting to recover the costs associated with the construction of its new natural gas-fired plant as discussed in "Regulatory Matters - Integrated Resource Plan - Peaking Resource." The filing asks for a $9 million, or 1.4 percent, annual increase in revenue by June 1, 2008. The IPUC is proceeding on this application under modified procedure and will take comments through May 13, 2008.

Water Management Issues

Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources. This includes active participation in the Snake River Basin Adjudication, a judicial action initiated in 1987 to determine the nature and extent of water use in the Snake River basin, judicial and administrative proceedings relating to the conjunctive management of ground and surface water rights, and management and planning processes intended to reverse declining trends in river, spring, and aquifer levels and address the long-term water resource needs of the state. On occasion, resolution of these water management issues involves litigation. IPC is involved in legal actions regarding not only its water rights but also the water rights of others. One such action, initiated in the Snake River Basin Adjudication, involves IPC's water rights at the Swan Falls project on the Snake River and several other upstream hydroelectric projects that are the subject of a 1984 agreement with the state of Idaho known as the Swan Falls Agreement.

On April 18, 2008, the court issued a Memorandum Decision and Order on Cross-Motions for Summary Judgment upholding the Swan Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the IDWR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court will hold a status conference in the near future to discuss how to proceed with respect to this issue. IPC is unable to predict the outcome of the consolidated proceedings.

IPC also has initiated legal action against the U.S. Bureau of Reclamation (USBR) over the interpretation and effect of a 1923 contract with the USBR on the operation of the American Falls Reservoir and the release of water from that reservoir to be used at IPC's downstream hydroelectric projects. Although IPC intends to continue vigorously defending its water rights and although none of the pending water management issues are expected to impact IPC's hydroelectric generation in the near term, IPC cannot predict the ultimate outcome of these matters or what effect they may have on its consolidated financial positions, results of operations or cash flows. IPC's ongoing participation in such issues will help ensure that water remains available over the long-term for use at IPC's hydroelectric projects on the Snake River.

For a complete discussion of water management issues see "LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues."

RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and IPC's earnings during the three months ended March 31, 2008. In this analysis, the first quarter results for 2008 are compared to the same period in 2007.

The following table presents the earnings (losses) for IDACORP and its subsidiaries:

	Three months ended March 31,	
	2008	**2007**
IPC - Utility operations	$ 21,271	$ 23,331
IDACORP Financial Services	801	1,862
Ida-West Energy	55	205

IDACORP Energy	(12)	(55)
Holding company	(399)	(763)
Discontinued operations	-	67
Total earnings	$ 21,716	$ 24,647
Average common shares outstanding (diluted)	45,004	43,820
Diluted earnings per share	$ 0.48	$ 0.56

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, river base flows, spring flows, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC's hydroelectric projects are reduced, IPC's hydroelectric generation is reduced. This results in less generation from IPC's resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased 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 guide 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.

Hydroelectric generation for the January through March 2008 period was 10 percent below the same period in 2007 and 28 percent below the 30 year average due to a combination of more gradual snowmelt, below normal rainfall and below normal Snake River system reservoir carryover from last year. Reservoir carry-over storage above Brownlee reservoir was near the record low due to below average April through July runoff in 2007 and near record low flows in the Snake River from several years of drought.

On May 7, 2008, the National Weather Service's Northwest River Forecast Center estimated that Brownlee reservoir inflow for April through July 2008 would be 4.9 million acre-feet (maf), or 78 percent of average, which would be up considerably from the 2007 April through July inflow of 2.8 maf, or 44 percent of average. Storage in selected federal reservoirs upstream of Brownlee, as of April 13, 2008, was 86 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.0 and 8.0 million MWh from its hydroelectric facilities in 2008, compared to 6.2 million MWh in 2007.

IPC's system load is dual peaking, with the larger peak demand occurring in the summer. IPC's record system peak of 3,193 MW occurred on July 13, 2007. The all-time winter peak demand is 2,464 MW set on January 24, 2008. The previous hourly system winter peak of 2,459 MW was set in 1998.

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

	MWh				
	Hydroelectric Generation	Thermal Generation	Total System Generation	Purchased Power	Total
Three months ended:					
March 31, 2008	1,663	1,979	3,642	687	4,329
March 31, 2007	1,846	1,747	3,593	975	4,568

IPC's modeled median annual hydroelectric generation is 8.5 million MWh, based on hydrologic conditions for the period 1928 through 2006 and adjusted to reflect the current level of water resource development.

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

	Three months ended March 31, 2008	2007
Revenue		
Residential	$ 95,242	$ 78,582
Commercial	44,675	36,208
Industrial	26,657	22,099
Irrigation	739	362
Total	$ 167,313	$ 137,251
MWh		
Residential	1,589	1,464
Commercial	999	943
Industrial	851	871
Irrigation	11	5
Total	3,450	3,283
Customers (average)		
Residential	401,156	394,464
Commercial	62,952	60,747
Industrial	121	126
Irrigation	18,139	17,865
Total	482,368	473,202
Heating degree-days	2,680	2,336
Precipitation (inches)	2.70	1.78

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 $30.1 million for the quarter, as compared to the same period in 2007. This increase is primarily attributable to three factors: 1) the effects of rate changes for the current year, 2) increased customer usage, and 3) continued customer growth.

Rates: Adjustments to rates had a $21.3 million positive impact on general business revenue for the quarter. Rates were positively impacted by a PCA average rate increase of 14.5 percent effective June 1, 2007, and a general rate increase of 5.2 percent effective March 1, 2008.

Usage: General business revenue increased $6.7 million for the quarter due to an increase in residential and commercial usage due to colder weather.

Customers: Moderate growth in customer count in IPC's service territory increased revenue $2.1 million for the quarter as compared to the same period in 2007.

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

	Three months ended March 31, 2008	2007
Revenue	$ 33,363	$ 57,838
MWh sold	518	964
Revenue per MWh	$ 64.41	$ 59.97

37

Poor stream flow conditions decreased hydroelectric generation and electricity available for surplus sales. Total MWh sold in the first quarter of 2008 decreased 46 percent as compared to the same period last year, while the overall price per MWh increased seven percent. More gradual snowmelt, below normal rainfall, and below normal Snake River system reservoir carryover from last year reduced the overall water available for hydroelectric generation.

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

	Three months ended March 31,	
	2008	**2007**
Transmission services and property rental	$ 9,512	$ 9,268
DSM	3,364	2,115
Provision for rate refund	(756)	(544)
Total	$ 12,120	$ 10,839

An IPUC order allows IPC to record DSM program expenditures as an operating expense with an offsetting amount recorded in other revenues, resulting in no net effect on earnings. For the first quarter of 2008, IPC recorded $3.4 million related to DSM activities in other revenues, an increase of $1.2 million over same period last year, which reflects increased program expenditures.

The provision for rate refund is related to the Open Access Transmission Tariff discussed in "Regulatory Matters - Open Access Transmission Tariff (OATT)."

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

	Three months ended March 31,	
	2008	**2007**
Purchased power expense	$ 45,299	$ 50,817
MWh purchased	687	975
Cost per MWh purchased	$ 65.94	$ 52.13

For the quarter, IPC experienced a price increase of 26 percent as compared to the same period last year, which was offset by a decrease in volume purchased of 29 percent. The increase in prices was due to reduced regional generation caused by a combination of more gradual snowmelt, below normal rainfall and below normal Snake River system reservoir carryover from last year, and reduced overall water available for hydro generation. The volume decrease for the quarter was the result of conforming to IPC's 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 months ended March 31:

	Three months ended March 31, 2008	Three months ended March 31, 2007
Fuel expense	$ 37,237	$ 30,913
Thermal MWh generated	1,978	1,747
Cost per MWh	$ 18.83	$ 17.70

The increase in fuel expense is due to a 13 percent increase in MWh volume for the quarter as compared to the same period last year. The Jim Bridger and Valmy plants increased their volume 11 percent and 16 percent, respectively. Gas usage at the Bennett Mountain and Danskin facilities also contributed to the increase; energy generation volumes at these plants more than tripled from 11,643 MWh to 40,913 MWh, increasing gas costs $1.7 million for the quarter. Bennett Mountain and Danskin facilities use natural gas which is a higher priced resource than coal.

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

Weak hydroelectric generating conditions and lower surplus sales increased 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 resulted in the deferral of costs for recovery in subsequent rate years. As the deferred costs are recovered in rates, the deferred balances are amortized. In the first quarter of 2008, IPC amortized an under collection of the prior year balance. In 2007, IPC amortized an over collection of the prior year balance. The following table presents the components of PCA expense for the three months ended March 31:

	Three months ended March 31,	
	2008	**2007**
Current year power supply cost deferral	$ (20,199)	$ (18,333)
Amortization of prior year authorized balances	2,455	(3,203)
Total power cost adjustment	$ (17,744)	$ (21,536)

The 2007 general rate case, which became effective March 1, 2008, changed the monthly distribution of net power supply expenses by allocating significantly more power supply costs to the third quarter and less to the first and second quarters. IPC has reserved $8.5 million against the first quarter PCA deferral because it is IPC's belief that the monthly distribution of net power supply expenses will ultimately take on a more moderate seasonal shape. The reserve is not expected to have a material impact on annual results. An IPUC decision related to the reserve should be made by the end of May 2008 and may reduce the amount of the June 1, 2008, PCA rate adjustment.

Other operations and maintenance expenses: Other operations and maintenance expenses increased $1.1 million for the quarter as compared to 2007. The increase was primarily attributable to an increase in overhead line expense of $1.1 million, an increase in outside services of $0.8 million, and an increase of $0.4 million due to restricted stock plan expenses. The total increase was partially offset by a decrease of $2.8 million in thermal O&M. At the Valmy plant, planned and unplanned outage costs of $1.8 million occurred in the first quarter of 2007. In 2008, planned outages will not take place until the second quarter of 2008. The Bridger plant expenses decreased $1.0 million due to incentive charges and diesel inventory start-up charges in 2007 that have not recurred in 2008.

Non-utility operations

IFS: IFS' earnings decreased from $1.9 million in the first quarter of 2007 to $0.8 million in the first quarter of 2008, a decrease of $1.1 million. 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 made $8.5 million in new investments and generated $4.0 million of tax credits in the first quarter of 2008. IFS expects to make future investments in line with the ongoing needs of IDACORP.

Discontinued Operations: On February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. In the second quarter of 2006, IDACORP management designated the operations of IDACOMM as assets held for sale, as defined by SFAS 144. The operations of this entity are presented as discontinued operations in IDACORP's financial statements. Discontinued operations had no impact on earnings in the first quarter of 2008.

Interest Expense

Interest charges increased $2.3 million, due primarily to a $3.5 million increase in interest on long-term debt related to increases in long-term debt balances and variable interest rates. This increase was offset by a $0.5 million reduction in non-utility interest and a $0.4 million change in the allowance for funds used during construction.

Income Taxes

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP's effective rate on continuing operations for the three months ended March 31, 2008, was 20.5 percent, compared to 16.6 percent for the three months ended March 31, 2007. IPC's effective tax rate for the three months ended March 31, 2008, was 32.5 percent, compared to 34.5 percent for the three months ended March 31, 2007. 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 three months ended March 31, 2008, were $21 million and $23 million, respectively. IDACORP's operating cash flow remained approximately the same when compared to 2007 and IPC's operating cash flow increased approximately $2 million.

Investing cash flows
IDACORP's and IPC's investing cash outflows were $65 million and $58 million, respectively. Utility construction at IPC accounted for substantially all of its cash outflows. Additionally, IDACORP made an $8.5 million investment in affordable housing through its subsidiary, IFS.

Financing cash flows
IDACORP's and IPC's financing cash inflows were $44 million and $35 million, respectively. Both amounts represent additional short-term borrowings, partially offset by dividends paid of $14 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 from 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. The absence of cash flows from these discontinued operations has positively impacted liquidity and capital resources in periods subsequent to the sale.

Financing Programs
IDACORP's consolidated capital structure consisted of common equity of 46 percent and debt of 54 percent at March 31, 2008.

Shelf Registrations: IDACORP currently has $629 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. IPC has in place a registration statement that can be used for the issuance of an aggregate principal amount of $350 million of first mortgage bonds (including medium-term notes) and unsecured debt.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to $350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H.

Credit facilities: IDACORP's credit facility is a $100 million five-year credit agreement that terminates on April 25, 2012. IDACORP's credit facility, which is used for general corporate purposes and commercial paper 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 credit facility to $150 million and to request one-year extensions of the then existing termination date. At March 31, 2008, no loans were outstanding on IDACORP's facility and $57 million of commercial paper was outstanding. At May 7, 2008, $59 million of commercial paper was outstanding.

IPC's credit facility is a $300 million five-year credit agreement that terminates on April 25, 2012. IPC's credit facility, which is 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 credit facility to $450 million and to request one-year extensions of the then existing termination date. At March 31, 2008, no loans were outstanding on IPC's facility and $186 million of commercial paper was outstanding. At May 7, 2008, $201 million of commercial paper was outstanding.

IDACORP's credit facility and IPC's credit facility both contain covenants 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 March 31, 2008, the leverage ratios for IDACORP and IPC were both 54 percent. At March 31, 2008, IDACORP was in compliance with all other covenants of its credit facility and IPC was in compliance with all other covenants of its credit facility.

Term Loan Credit Agreement: IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, N.A., as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans are due on March 31, 2009. The loans may be prepaid but may not be reborrowed.

IPC used the proceeds to effect a mandatory purchase on April 3, 2008, of the pollution control bonds (as discussed below in "Pollution Control Revenue Refunding Bonds"), and to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and/or the Term Loan Credit Agreement.

IPC has regulatory authority to incur up to $450 million of short-term indebtedness.

Pollution Control Revenue Refunding Bonds: On April 3, 2008, IPC made a mandatory purchase of the $49.8 million Humboldt County, Nevada Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 and the $116.3 million Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006 (together, the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the pollution control bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode. IPC is the current holder of the bonds, but expects to remarket the bonds to investors before March 31, 2009.

Contractual obligations

There have been no material changes in contractual obligations, outside of the ordinary course of business, since December 31, 2007.

Credit ratings

On March 24, 2008, Fitch announced that it revised its rating outlook to negative from stable for IDACORP and IPC, while affirming the existing ratings for both companies. Fitch affirmed its BBB Issuer Default Rating (IDR) on

IDACORP and IPC, its F2 short-term IDR rating on IDACORP and IPC, it's A- rating on IPC's senior secured debt, its BBB+ rating on IPC's senior unsecured debt and its F2 ratings on IDACORP's and IPC's commercial paper.

Fitch stated that the outlook revision primarily reflects weakening underlying credit metrics due to IPC's inability under its power cost adjustment mechanism to fully recover higher thermal generation production and purchase power costs in rates. Fitch also cited below normal water conditions in six of the last seven years and the appearance that 2008 could extend that trend. Fitch stated that this dynamic in concert with a relatively large capital investment program and timing differences between when those costs are incurred and reflected in rates appear likely to result in earnings, cash flow and credit metrics more consistent with low "BBB" creditworthiness.

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	F2	F2
Credit Facility	None	None	Baa 1	Baa 2	None	None
Rating Outlook	Stable	Stable	Stable	Stable	Negative	Negative

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

Capital requirements

IDACORP's internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2008 through 2010, where capital requirements are defined as utility construction expenditures, excluding Allowance for Funds Used During Construction, plus other regulated and non-regulated investments. This excludes mandatory or optional principal payments on debt obligations. As discussed in IDACORP's Annual Report on Form 10-K for the year ended December 31, 2007, 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.

REGULATORY MATTERS:

Idaho General Rate Cases

On March 28, 2008, IPC filed a notice of intent with the IPUC to file a general rate case on or after June 1, 2008. The notice of intent provides IPC with a 60-day window, beginning June 1, 2008, in which it is permitted to file a new general rate case.

On June 8, 2007, IPC filed an application with the IPUC in order to begin recovery of its capital investments and higher operating costs. IPC filed its case based upon a 2007 forecast test year, a first for IPC in the Idaho jurisdiction. IPC filed a settlement stipulation with the IPUC on January 23, 2008, that included an average annual increase of 5.2 percent (approximately $32.1 million annually). On February 28, 2008, the IPUC approved the stipulation as filed. New rates were effective March 1, 2008. The base rates for residential customers increased by 4.7 percent, and the base rates for the other classes of customers increased by 5.65 percent. Neither an overall rate of return nor a return on equity was specified in the settlement. The currently authorized rate of return remains at 8.1 percent.

The parties to the proceeding also agreed in the settlement to make a good faith effort to develop a mechanism to adjust or replace the current LGAR of $29.41 per MWh. As an interim solution, the parties have agreed to use the LGAR of $62.79 per MWh recommended by the IPUC Staff on December 10, 2007, but to apply it to only 50 percent of the load growth beginning in March 2008.

The parties also agreed to participate in a good faith discussion regarding a forecast test year methodology that balances the auditing concerns of the IPUC Staff and intervenors with IPC's need for timely rate relief.

On March 12, 2008, IPC, the IPUC Staff, and other parties to the recent general rate case conducted a workshop to discuss the appropriate approach to the development of a forecast test year. IPC described a method that would start with historical, regulatory-adjusted financial information that could be audited by the IPUC Staff and others. That information would be escalated under prescribed methods into the forecast test year for revenues, expenses and rate base. IPC would support the historical information, the adjustments, and the escalation methods as part of its general rate case filing. The parties to the workshop expressed general agreement to this approach and also agreed that no further workshops would be necessary. IPC will develop a 2008 test year using this method in anticipation of a general rate case filing later this year.

Danskin 1 Power Plant Application: On March 7, 2008, IPC filed an application with the IPUC requesting to recover the costs associated with the construction of its new natural gas-fired plant as discussed below in "Integrated Resource Plan - Peaking Resource." The filing asks for a $9 million, or 1.4 percent, annual increase in revenue, by June 1, 2008. The IPUC is proceeding on this application under modified procedure and will take comments through May 13, 2008.

Deferred Net Power Supply Costs
The following table presents the balances of deferred net power supply costs:

		March 31, 2008	December 31, 2007
Idaho PCA current year:			
	Deferral for the 2008-2009 rate year *	$ 107,160	$ 85,732
Idaho PCA true-up awaiting recovery:			
	Authorized in May 2007	4,862	6,591
Oregon deferral:			
	2001 costs	2,402	2,993
	2006 costs	2,148	2,107
	Total deferral	$ 116,572	$ 97,423

* The 2008-2009 PCA deferral balance is reduced by $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. The PCA tracks IPC's actual net power supply costs (fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

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

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

monthly, and interest is applied to the balance.

The PCA mechanism provides that for both the forecast and the true-up components, 90 percent of deviations in power supply costs are to be reflected in IPC's rates.

On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing indicated an increase of $89.0 million to the PCA component of customers' rates to a level that is $121.6 million above base rates based upon historical sharing percentages between customers and shareholders.

The PCA filing also contained a proposal to flow through to customers 100 percent of the deviation in power supply costs for the prospective year. This is a one-year proposal that impacts the 2008 forecast component of the current PCA and its later true-up and would reduce IPC's requested rate increase to $87.2 million. While the overall filing requests a rate increase, the forecast component is a customer benefit. The $1.8 million reduction reflects an additional ten percent of the benefit being passed on to customers. The PCA mechanism provides for sharing of benefits and costs at a ratio of 90 percent to customers and ten percent to shareholders. IPC requested this deviation from the customary sharing percentage for two reasons:

1) Approximately 62 average MW of energy from PURPA wind projects that IPC had expected to receive in 2008 will not be available because the associated projects requested extensions of their on-line dates. IPC recovers 100 percent of power purchases from PURPA projects but will need to replace this energy with market purchases; and
2) Pursuant to IPC's risk management policy, which was established in accordance with IPUC-approved risk management guidelines, IPC had committed to net purchases of nearly $51 million at the time of the PCA filing. Under the current sharing methodology, IPC will only recover 90 percent of these known costs. Because of the prescriptive nature of this risk management activity, IPC believes that 100 percent customer sharing is appropriate.

These anticipated cost increases would be included in the true-up component of IPC's 2009 PCA filing.

As discussed below in "Emission Allowances," the IPUC ordered on April 14, 2008 that $16.4 million of proceeds, including interest, from the sales of SO_2 emission allowances in 2007 be applied to help offset the PCA deferral balances incurred during the 2007-2008 PCA year. This order is not reflected in IPC's PCA filing, but it is expected to reduce the requested PCA increase to $70.8 million.

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 was net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates became effective June 1, 2007.

Idaho Load Growth Adjustment Rate (LGAR): On January 9, 2007, the IPUC issued an order resetting IPC's LGAR to $29.41 per MWh, effective April 1, 2007. The LGAR subtracts the cost of serving additional Idaho retail load from the net power supply costs IPC is allowed to include in its PCA. The order revised the LGAR from the original rate of $16.84 per MWh set when the PCA began in 1993. This amount was established as the projected additional variable energy costs attributable to load growth and was subtracted from each year's PCA expense. IPC had requested the use of the embedded cost of serving new load and a rate of $6.81 per MWh, but the IPUC in its order determined to use the projected marginal cost, which resulted in the higher LGAR. The LGAR is reset during a general rate case.

As discussed above in "Idaho General Rate Case," the IPUC-approved settlement stipulation reset the LGAR to $62.79 per MWh, but applies that rate to only 50 percent of the load growth beginning in March 2008. In the 2007 general rate, IPC filed normalized firm base load of 15.6 million MWh as compared with 14.8 million MWh in the 2005 general rate case. Because the LGAR is reset in general rate cases, IPC expects to update its filed base load on a more frequent basis during periods of high load growth and will update it in its 2008 general rate case.

Emission Allowances: During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $18.5 million. On April 14, 2008, the IPUC ordered that $16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that $0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and is reflected in PCA rates in effect during the June 1, 2007, through May 31, 2008, PCA rate year.

The bulk of IPC's accumulated excess emission allowances were sold during the 2005-2007 period. IPC has approximately 18,000 excess emission allowances currently and anticipates realizing a similar amount annually into the near future. Tighter emission restrictions are expected in the long term which may cause IPC to use more emission allowances for its own requirements and reduce the annual amount of excess emission allowances.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" 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 awaiting an order from the OPUC.

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. A settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

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.

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. The PCAM 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 PCAM differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case. Settlement conferences were held and the interested parties reached an agreement. A joint stipulation was filed with the OPUC on March 14, 2008. The OPUC approved the stipulation on April 28, 2008.

In connection with this proceeding, on March 24, 2008, IPC submitted testimony to the OPUC to revise its previous calculation of its April 2008 through March 2009 net power supply costs (October Update) to conform to the methodology agreed to by the parties in the PCAM stipulation. IPC also submitted the second part of the mechanism (March Forecast), reflecting expected hydro conditions and forward prices for the April 2008 through March 2009 period. The expected power supply costs of $150 million represent an increase of approximately $23 million over the October Update.

If approved, the power supply cost update submitted by IPC, which comprises both the October Update and the March Forecast, would result in a $4.8 million, or 15.69 percent, increase in Oregon revenues. New rates are expected to be effective on June 1, 2008.

Fixed Cost Adjustment Mechanism (FCA)
On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program. The FCA is a rate mechanism designed to remove a utility's disincentive to invest in energy efficiency programs. The FCA separates (or decouples) the recovery of fixed costs from the variable kilowatt-hour charge and, instead, links it to a set amount per customer. If IPC under-collects its fixed costs per customer as a result of reduced electrical use, it can collect the difference through a surcharge. If IPC over-collects its authorized fixed costs, customers are refunded through a credit. The FCA is only applicable to residential and small commercial customers. 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.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for expenses incurred in 2007. The application is currently pending with the IPUC. IPC accrued $0.9 million of FCA expense in the first quarter of 2008.

Idaho Energy Efficiency Rider

On March 14, 2008, IPC filed an application with the IPUC requesting an increase to its Energy Efficiency Rider (Rider). The Rider is the chief funding mechanism for IPC's investment in conservation, energy efficiency, and demand response programs. IPC proposed an increase from 1.5 percent of base revenues to 2.5 percent, or about $17 million, effective June 1, 2008. The application also seeks authorization to eliminate the current funding caps for residential and irrigation customers resulting in more equitable cost recovery between customer classes. IPC is also seeking authorization to utilize Rider funding to support customer programs aimed at the installation of small-scale renewable energy projects.

Idaho Depreciation Filing
On April 1, 2008, IPC filed an application with the IPUC for revised depreciation rates to be applied prospectively to depreciable plant in service. If approved, the requested rates would result in an annual reduction of depreciation expense of $6.7 million ($6.2 million allocated to Idaho) based upon December 31, 2006, depreciable plant in service. IPC is awaiting an accounting order from the IPUC.

Idaho Pension Expense Order
In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, *"Employers' Accounting for Pensions,"* as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. 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 was deferred to a regulatory asset beginning in the third quarter. In the first quarter of 2008, $2.0 million of pension expense was deferred. IPC did not request a carrying charge to be applied to the deferral of the accrued SFAS 87 expense.

Revised Statement of Policy and Code of Conduct
On April 21, 2008, the IPUC approved IPC's Revised Statement of Policy and Code of Conduct covering transactions between IPC and subsidiaries of IDACORP. The Code of Conduct is designed to prescribe conduct between IPC and an affiliate, avoid issues of self-dealing and provide a framework to determine if cost recovery for affiliate transactions should be included in rates.

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. At IPC's request, IPC representatives met with FERC personnel on October 18, 2007, to discuss several data responses that IPC had previously provided. In follow-up to that meeting, IPC had further discussions with and submitted additional materials to the FERC staff. In April 2008, the FERC advised IPC that it was no longer pursuing the investigation.

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. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of $11 million based upon 2004 test year data. The rates were accepted subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates and that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced the estimated annual revenue increase to approximately $8.2 million based on 2004 test year data. Approximately $1.7 million collected in excess of these new rates between June 1, 2006, and July 31, 2007, was refunded with interest to customers in August 2007.

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. If the Initial Decision is implemented, IPC estimates that it would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $3.2 million for the June 1, 2006, through March 31, 2008, period. IPC has reserved this entire amount. 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. IPC is awaiting a final FERC order.

Regional Transmission Organization (RTO) costs: On April 30, 2008, the FERC issued an order amending the OATT formula rate to recover $0.3 million of RTO formation costs deferred by IPC. The new rates will be effective May 1, 2008, and will allow IPC to recover the FERC-jurisdictional portion of deferred RTO costs over five years. The deferred amount will be added to rate base and amortized over five years. The impact on the OATT rate is an increase from $19.31 per kW-year to $19.73 per kW-year, or 2.2 percent.

Transmission Projects

The transmission projects discussed below will be used both by wholesale transmission customers and to serve native load consistent with IPC's OATT. These facilities will be subject to both the FERC and state public utility commission regulation and rate-making policies.

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West Project to build two 500-kV lines between the Jim Bridger plant in Wyoming and Boise. The lines would be designed to increase electrical transmission capacity across southern Idaho in response to increasing customer demand and growth, along with other transmission service requests. The regional planning report has been submitted to the Western Electricity Coordinating Council (WECC) for review as part of the ratings process. A review team has been established from members of the WECC to analyze the impact of the project on 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. Planning and project management personnel for both companies have begun the initial phases of this project. IPC and PacifiCorp have 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.

Hemingway-Boardman Line: Consistent with the 2006 IRP and requirements and requests of other transmission customers, IPC is exploring alternatives for the construction of a 500-kV line between southwestern Idaho and the Northwest. If built, this line could be in service as early as 2012. Several electric utilities, including IPC, have proposed development of a transmission station near Boardman, Oregon which would serve as the northwest terminal of the project. The Idaho terminal would be the proposed Hemingway Station located in the vicinity of Melba and Murphy, Idaho on the south side of the Snake River near Boise. IPC and a number of other utilities with proposed regional transmission projects in the Northwest have signed a letter agreeing to coordinate technical studies, which have begun. The regional planning report has been submitted to the WECC for review as part of the ratings process. Other planning and project management activities are underway. IPC has received inquiries about participating in this project from other parties.

Integrated Resource Plan

IPC' s 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. 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 to file a new IRP in June 2009. IPC continually evaluates the resource plan and adjusts it to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. Several items from the 2006 IRP have been updated, including:

Peaking Resource: The Danskin 1 plant, a simple cycle combustion turbine near Mountain Home, Idaho, began commercial operations on March 11, 2008. The combustion turbine can provide approximately 166 MW of capacity during summer load peaks and up to 200 MW during the winter.

Geothermal Agreement: On January 9, 2008, the IPUC approved a power purchase agreement 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 and two units at the Neal Hot Springs site located in eastern Oregon. The remaining 32.5 MW is not expected to meet the 2009 on-line date identified in the 2006 IRP.

Geothermal RFP: On January 22, 2008, IPC released an RFP for 50 to 100 MW of geothermal energy. While additional geothermal resources were not included in the 2006 IRP for this time frame, the development of PURPA wind and combined heat and power projects has been slower than anticipated. If competitively priced geothermal resources are available, they may help to meet future resource needs. Proposals were received on March 14, 2008, and are currently being evaluated.

Combined Heat and Power (CHP) RFP: The 2006 IRP included 50 MW of CHP coming on-line in 2010. CHP development at customers' facilities has not progressed as anticipated in the 2006 IRP. Since CHP development has been less than anticipated, IPC may release an RFP in late 2008.

2012 Baseload RFP: In light of the decision to no longer pursue a conventional coal resource in 2013 as identified in the 2006 IRP, on April 1, 2008 IPC issued an RFP for 250 to 600 MW of dispatchable, physically delivered firm or unit contingent energy to be acquired under power purchase agreements or tolling agreements. A tolling agreement is an arrangement where one party owns, operates and maintains the generating facility and the other party provides fuel, pays capacity charges and receives the contracted output from the project including energy, capacity and ancillary services. The timing of this addition was also accelerated to 2012 to meet forecast deficits not anticipated in the 2006 IRP. The RFP's range in quantity from 250 to 600 MW reflects uncertainty regarding the amount of potential new customer load that will actually materialize IPC expects to reach a final decision on RFP quantity in June 2008. IPC intends to submit a self-build proposal for a combined-cycle combustion turbine which will serve as a benchmark in the evaluation process. Proposals are due by October 17, 2008.

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, 2007.

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

The relicensing costs are recorded and held in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $98 million and $4 million for HCC and Swan Falls, respectively, were included in construction work in progress at March 31, 2008.

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

Consistent with the requirements of The National Environmental Policy Act of 1969, as amended (NEPA), the FERC Staff prepared and issued on August 31, 2007, a final environmental impact statement (EIS) for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, the federal and state agencies, Native American tribes and the public about the environmental effects of IPC's proposed operation of the HCC. IPC is continuing to review the final EIS and expects to file comments on the final EIS with the FERC in 2008.

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

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 that each state certify that any discharge from the project complies with applicable state water quality standards. IPC filed supplemental information to the applications on February 1, 2008. IPC continues to work with the ODEQ and the IDEQ to ensure that state water quality standards will be met at the HCC so that the project can be appropriately certified.

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

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contains project-specific information and the results of environmental studies designed to determine project effects. Comments were received from the agencies and one Native American tribe and on February 19, 2008 a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. IPC expects to file a final license application with the FERC in June 2008.

Shoshone Falls Expansion: On August 17, 2006, IPC filed a license amendment application with the FERC, which would allow IPC to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. The license amendment is expected to be issued in 2008.

In conjunction with the license amendment application, IPC has filed a water rights application which is currently being reviewed by the IDWR.

LEGAL AND ENVIRONMENTAL ISSUES:

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

Reference is made to IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 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 (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 fully briefed and oral argument was held on April 10, 2007. On November 20, 2007, the Ninth Circuit affirmed the dismissal. On December 10, 2007, Wah Chang filed Petitions for Rehearing and Rehearing En Banc with the U.S. Court of Appeals for the Ninth Circuit, which were denied January 15, 2008. Because Wah Chang did not file a petition for certiorari to seek Supreme Court review by the expiration date of April 14, 2008, this matter is now concluded.

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. 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 February 3, 2004, the FERC directed the California Independent System Operator (Cal ISO) to provide status reports with respect to its progress in calculating refunds, fuel and emissions allowance offsets to refunds and interest. The process of performing the calculations has engaged the Cal ISO for more than four years. On March 18, 2008, the Cal ISO published its Fortieth Status Report and on March 25, 2008, it released the interest calculations it had completed as a result of revising market clearing prices as directed by the FERC. In its Fortieth Status Report, the Cal ISO stated its intention to consider interest and cost allocation questions for parties that had FERC-approved settlements when it had completed the basic calculation of interest for revised market clearing prices. A date has not yet been set for this aspect of the Cal ISO's calculations.

While the refund proceedings were pending before the FERC, the California Attorney General filed a complaint with the FERC against sellers in the wholesale power market, including IE and IPC, alleging that the FERC's market-based rate requirements violate the Federal Power Act (FPA), and, even if the market-based rate requirements were valid, that the quarterly transaction reports filed by sellers did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint sought refunds for an expanded time when compared to the basic refund proceeding. The FERC dismissed the complaint but on September 9, 2004, the Ninth Circuit concluded that although market-based tariffs are permissible under the FPA, the matter should be remanded to the FERC to consider whether the FERC should exercise remedial power (including some form of refunds) when a market participant failed to submit reports. On December 28, 2006, a number of sellers filed a certiorari petition to the U.S. Supreme Court. The Supreme Court declined to grant certiorari and the matter has now been remanded to the FERC. The settlement IE and IPC reached with the California Parties that was approved by the FERC on May 22, 2006 anticipated the possibility of the outcome of the appeals discussed above and resolved the settling parties' claims in the event of the expansion of all of the refund proceedings as the Ninth Circuit ordered.

On March 21, 2008, the FERC issued an order responding to the remand by Ninth Circuit. The FERC's order established hearing procedures to permit wholesale purchasers that made short-term market-based rate purchases through the Cal ISO and the California Power Exchange (CalPX), as well as those making spot market purchases of energy through the California Energy Resources Scheduling Division of the California Department of Water Resources from January 1, 2000 to October 1, 2000, to (i) present evidence that any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus caused its market-based rates to be unjust and unreasonable and (ii) permit sellers to present evidence to the contrary. Before formal hearing procedures commenced, the FERC directed that the matter be presented to a settlement judge to attempt to settle individual cases. The FERC's March 21, 2008 order expands the field of those who may present evidence in the case from the original complaint of the California Attorney General and also is more restrictive in terms of what must be proven to establish a case. On April 7, 2008, IE and IPC joined with a number of other parties that already had settled this proceeding with the California Attorney General and the other California Parties requesting that they be dismissed from the case. The California Attorney General and the other California Parties indicated their agreement to the dismissal. On April 15, 2008, the FERC issued an order dismissing parties that already had settled, including IE and IPC, from these remanded proceedings. If rehearing is sought and the FERC reverses the dismissal, IE and IPC intend to vigorously defend themselves, but are unable to predict the outcome of this matter.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Port of Seattle withdrew its petition for review in one of the three consolidated cases and filed its initial brief on February 29, 2008. Final briefs are due at the end of August 2008. A date for argument has not been set. IE and IPC are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings the FERC issued an order 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 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the "gaming" and "partnership" show cause orders. The FERC staff submitted a motion to the FERC to dismiss the "partnership" proceeding, which was approved by the FERC in an order issued on January 23, 2004. The "gaming" settlement was approved by the FERC on March 4, 2004.

Some parties have sought review of what they claim are the excessively narrow or excessively broad scope of the show cause orders, and the Ninth Circuit has consolidated those claims with the other matters and is holding them in abeyance. The Port of Seattle is the only party to appeal the orders of the FERC approving the gaming settlement. IPC is not able to predict when the appeal will be considered or the outcome of the judicial determination of these issues.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001, concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and the refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation 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 proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. The U.S. Supreme Court has granted certiorari in one of the cases, which has been briefed and argued before the Court. IE and IPC are unable to predict how the Supreme Court will rule, how the FERC might respond to any such decision or how any such decision might affect the outcome of the Pacific Northwest proceeding.

There are pending in 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 with respect to 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.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in U.S. District Court for the District of 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.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity permit status of this matter. The court has still not yet ruled on these motions. On March 13, 2008, the Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on the consolidated financial position, results of operations or cash flows.

Sierra Club Notice of Intent to File Suit - Boardman: On January 15, 2008, the Oregon Chapter of the Sierra Club, the Northwest Environmental Defense Center, Friends of the Columbia Gorge, Columbia Riverkeeper, and Hells Canyon Preservation Council (collectively, Sierra Club) provided a 60-day notice to Portland General Electric Company (PGE) of intent to file suit. Sierra Club alleges violations of opacity standards at the Boardman coal-fired power plant located in Morrow County, Oregon of which IPC owns ten percent. PGE owns 65 percent and is the operator of the plant. Sierra Club further alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE's construction and operation of the plant. The 60-day notice period expired on March 15, 2008, but the Sierra Club has not yet commenced litigation. Sierra Club alleges thousands of opacity permit limit violations by PGE from and before 2003, and claims that it will seek a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, and civil penalties of up to $32,500 per day per violation. IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on the consolidated financial position, results of operations or cash flows.

Other Legal Proceedings: IDACORP, IPC and/or IE are involved in lawsuits and legal proceedings in addition to those discussed above and in Note 6 to IDACORP's and IPC's Consolidated Financial Statements. Resolution of any of these matters will take time and the companies cannot predict the outcome of any of these proceedings. The companies believe that their reserves are adequate for these matters.

Environmental Issues

The section below summarizes and provides an update of environmental issues as discussed in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007.

Idaho Water Management Issues: From 2000 through 2005, and throughout 2007 and the first quarter of 2008, 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

2007 Idaho Legislature appropriated funds and directed the IWRB to proceed with the development of the CAMP. Pursuant to 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 Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, 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. 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, providing for discovery during the objection period, and setting a scheduling conference for December 18, 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. On December 18, 2007, the court held a status and scheduling conference in the consolidated proceedings. Subsequently, the court issued a scheduling order on December 20, 2007, with a trial scheduled to begin on February 2, 2009. In January 2008, the State of Idaho and IPC filed cross motions for summary judgment on issues in the case. These motions were briefed and oral argument before the court was held on the motions on February 21, 2008.

On April 18, 2008, the court issued a Memorandum Decision and Order on Cross-Motions for Summary Judgment upholding the Swan Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the ID WR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court will hold a status conference in the near future to discuss how to proceed with respect to this issue. IPC is unable to predict the outcome of the consolidated proceedings.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation 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. IPC believes that 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 U.S. District 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 15, 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. The U.S. Bureau of Reclamation filed answers in each of these cases on February 15, 2008. On March 4, 2008, the U.S. District Court for the District of Idaho entered a preliminary scheduling order, setting that case for trial on December 15, 2009. The action in the U.S. District Court of Federal Claims has not yet been set for trial. 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. 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 (NAAQS), and Regional Haze - Best Available Retrofit Technology (RH BART). Low nitrogen oxide (NO_x) burner technology and mercury continuous emission monitoring systems (mercury CEMS) installations are progressing at all three coal-fired power plants.

National Ambient Air Quality Standards: In March 2008, the EPA promulgated a final regulation which revised the 8-hour ozone NAAQS. For the primary (health-based) standard, the EPA lowered the standard from 0.08 parts per million (ppm) to 0.075 ppm. Under the EPA's final rule, states must make recommendations to the EPA by March 2009 for areas to be designated attainment, nonattainment and unclassifiable. It is possible that parties could challenge the EPA's decision. The impact of the new standard will not be known until data is collected, analyzed, and released to the public and the associated regulatory programs are promulgated and implemented.

Clean Air Mercury Rule: 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. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR and remanded it back to the EPA for reconsideration consistent with the court's interpretation of the Clean Air Act. On March 24, 2008, the EPA petitioned the U.S. Court of Appeals for the D.C. Circuit to reconsider its decision to overturn the CAMR. The impact of the court's decision will not be known until the judicial appeals process has been completed or until such time as the EPA develops a new regulation in response. It is possible that the D.C. Circuit's decision to remand the CAMR back to the EPA for reconsideration could result in changes to mercury rules or regulations adopted by the states in which IPC has partial ownership interests in coal-fired power plants. At this time, however, it is uncertain how state mercury rules or requirements might be affected and any resulting impacts to IPC.

Regional Haze - Best Available Retrofit Technology: In accordance with federal regional haze rules, the Wyoming Department of Environmental Quality and the Oregon Department of Environmental Quality 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 and Boardman plants. The two units at the North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. IPC continues to monitor RH BART processes at the Jim Bridger and Boardman plants.

Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) regulations and judicial decisions that would affect electric utilities. Such regulations could increase IPC's capital expenditures and operating costs and reduce earnings and cash flows. At the national level, numerous GHG bills were introduced in the U.S. Senate and House of Representatives during 2006 and 2007, including America's Climate Security Act of 2007 (S. 2191), which now awaits Senate floor action. The bill would impose an economy-wide cap on GHG emissions to reduce emissions 70 percent from 2005 levels by 2050. However, debate continues in Congress on the direction and scope of U.S. policy on regulation of GHGs.

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 or deliverer-based cap and trade program applicable to the electricity generation industry, to help achieve the goal. The type of regulatory program that the WCI plans to use to achieve reductions from the electricity generation industry is expected to be released in August 2008. The states of Idaho, Nevada and Wyoming have not joined the WCI. It is possible that these and other states in which IPC owns or operates fossil fuel-fired electricity generation facilities or sells electricity into could join the WCI in the future.

In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. Environmental Protection Agency,* a case involving the EPA's authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. The decision, combined with stimulus from state, regional and federal legislative and regulatory initiatives, judicial decisions and other factors may lead to a determination by the EPA to regulate carbon dioxide emissions from stationary sources, including electricity generators. On March 27, 2008, the EPA announced that it would issue an advanced notice of proposed rulemaking (ANPR) to solicit public input on whether GHG emissions should be regulated from stationary sources. The ANPR is expected to be released in the spring of 2008. On April 2, 2008, Attorneys General from 17 states filed suit in the U.S. Court of Appeals for the D.C. Circuit requesting the court to require the EPA to rule within 60 days on whether carbon dioxide is a danger to public health or welfare and, therefore, subject to regulation under the Clean Air Act. While the majority of current national, regional and state initiatives regarding GHG emissions contemplate market-based compliance programs, a determination by the EPA to regulate GHG emissions under the Clean Air Act could result in GHG emission limits on stationary sources that do not provide market-based compliance options such as cap-and-trade programs or emission offsets. IPC will continue to monitor developments with respect to the possible regulation of GHG emissions from stationary sources under the Clean Air Act.

During 2007, IPC's carbon dioxide emissions from IPC's electric power generation facilities during 2007 were approximately 7.8 million tons, or 1,153 lbs/MWh (adjusted to reflect IPC's partial ownership in the Jim Bridger, Boardman and North Valmy facilities). At this time, IPC is unable to estimate the costs of compliance with potential national, regional or state GHG emissions reductions legislation or initiatives because these proposals are in the early stages of development and any final regulation, if adopted, could vary from current proposals. The actual impact of future regulation of GHG emissions on IPC's financial performance will depend on a number of factors, including but not limited to: (1) the geographic scope of any legislation or regulation (e.g., federal, regional, state); (2) the enactment date of the legislation or regulation and the compliance deadlines; (3) the type of any legislation or regulation (e.g., cap-and-trade, carbon tax, GHG emission limits); (4) the level of GHG reductions required and the year selected as a baseline for determining the amount or percentage of mandated GHG reductions; (5) the extent to which market-based compliance options are available; in any cap-and-trade program; (6) the extent to which a facility would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the price and availability of offsets in the secondary market and (7) the availability and cost of carbon control technology.

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

Renewable Portfolio Standards: Legislation to adopt a national renewable portfolio standard (RPS) has been introduced into but not yet adopted by Congress. IPC expects debate to continue on a national RPS and anticipates new developments in 2008. IPC is not currently subject to state RPS. It is possible that Idaho and other states in which IPC operates or sells power into could adopt RPS initiatives. IPC will continue to monitor RPS developments but cannot, at this time, predict the impacts of state and federal RPS legislation on its business.

OTHER MATTERS:

Southwest Intertie Project

IPC began developing the Southwest Intertie Project (SWIP) in 1988. IPC's investment consists predominantly of a federal permit for a specific transmission corridor in Nevada and Idaho and also private rights-of-way in Idaho. The SWIP rights-of-way extend from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada. In 2004 the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500kV transmission line within the rights-of-way before December 2009. On March 31, 2005, IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, that gave White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option could be exercised in part or as a whole.

On March 28, 2008, Great Basin Transmission, LLC (Great Basin), as successor in interest to White Pine, exercised its option to purchase the southern portion of the SWIP rights-of-way from IPC. This sale is expected to close during the second quarter of 2008, subject to customary closing conditions, and is expected to result in a net pre-tax gain to IPC of approximately $3 million. IPC and Great Basin also extended the term for exercise of the option on the northern portion of the SWIP rights-of-way from March 31, 2008, to December 31, 2008.

Critical Accounting Policies and Estimates

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

IDACORP's and IPC's critical accounting policies are reviewed by the Audit Committee of the Board of Directors. These policies are discussed in more detail in the Annual Report on Form 10-K for the year ended December 31, 2007, and have not changed materially from that discussion.

Adopted Accounting Pronouncements

SFAS 157: IDACORP and IPC partially adopted the provisions of SFAS 157 *"Fair Value Measurements"* (SFAS 157) on January 1, 2008. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. FASB Staff Position 157-2 (FSP 157-2) delayed the implementation of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow the FASB and constituents additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of SFAS 157. In accordance with FSP 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations. The adoption of SFAS 157 did not have a material effect on IDACORP's or IPC's financial statements.

SFAS 159: IDACORP and IPC adopted the provisions of SFAS 159, *"The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115"* (SFAS 159) on January 1, 2008. SFAS 159 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 115, *"Accounting for Certain Investments in Debt and Equity Securities,"* applies to all entities with available-for-sale and trading securities. IDACORP and IPC did not elect the fair value option for any existing eligible items, thus the adoption of SFAS 159 did not have a material effect on IDACORP's or IPC's financial statements.

FSP FIN 39-1: IDACORP and IPC adopted FASB Staff Position FIN 39-1 (FSP FIN 39-1), "*Amendment of FASB Interpretation No. 39"* (FIN 39) on January 1, 2008. 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. IDACORP and IPC have elected to offset these positions, which resulted in an immaterial net decrease to total assets and liabilities at March 31, 2008.

EITF Issue No. 06-11: IDACORP and IPC adopted Emerging Issues Task Force Issue No. 06-11, *"Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*" (EITF 06-11) on January 1, 2008. EITF 06-11 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. The adoption of EITF 06-11 did not have a material impact on IDACORP's or IPC's financial statements.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments and derivative commodity instruments sensitive to changes in interest rates, commodity prices and equity prices that were held at March 31, 2008.

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

Variable Rate Debt: As of March 31, 2008, IDACORP and IPC had $430 million and $374 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 March 31, 2008, interest expense for the year ending December 31, 2008, would increase and pre-tax earnings would decrease by approximately $4.3 million for IDACORP and $3.7 million for IPC.

Fixed Rate Debt: As of March 31, 2008, IDACORP and IPC had outstanding fixed rate debt of $980 million and $955 million, respectively. The fair market value of this debt was $952 million and $925 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 $89 million for IDACORP and $88 million for IPC if interest rates were to decline by one percentage point from their March 31, 2008 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, 2007. In a limited manner, IPC also utilizes financial energy instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to securing adequate energy to meet utility load requirements in accordance with IPC's Risk Management Policy. This practice falls within the parameters of IPC's Risk Management Policy and these instruments are not used for trading purposes. These financial instruments are used in essentially the same manner as forward transactions to mitigate price risk but are considered derivative instruments under SFAS 133 and are therefore reported at fair value in IDACORP's and IPC's financial statements. Because of the PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

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, 2007.

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, 2007.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:
The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of March 31, 2008, have concluded that IDACORP's disclosure controls and procedures are effective.

IPC:
The Chief Executive Officer and the Chief Financial Officer of IPC, based on their evaluation of IPC's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of March 31, 2008, have concluded that IPC's disclosure controls and procedures are effective.

Changes in internal control over financial reporting:

There have been no changes in IDACORP's or IPC's internal control over financial reporting during the quarter ended March 31, 2008, 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 6 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, 2007 have not changed materially.

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

As part of their compensation, each director of IDACORP and IPC who is not an employee received a grant of 1,510 shares of common stock, equal to $45,000, on March 3, 2008. The stock was issued without registration under the Securities Act of 1933 in reliance upon Section 4(2) of the Act.

Restrictions on Dividends:
Covenants under IDACORP's credit facility, IPC's credit facility and IPC's term loan credit agreement require 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. These agreements are discussed further in "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs."

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

IPC's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would cause their leverage ratios to exceed 65 percent or violate IPC's Code of Conduct. At March 31, 2008, the leverage ratios for IDACORP and IPC were 54 percent and 54 percent, respectively and IPC's common equity capital was 46 percent of its total adjusted capital.

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

Issuer Purchases of Equity Securities:

IDACORP, Inc. Common Stock

Period	**(a) Total Number of Shares Purchased 1**	**(b) Average Price Paid per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs**
January 1 - January 31, 2008	-$	-	-	-
February 1 - February 29, 2008	8,698	30.54	-	-
March 1 - March 31, 2008	109	32.11	-	-
Total	8,807	$ 30.56	-	-

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

ITEM 6. EXHIBITS

*Previously Filed and Incorporated Herein by Reference

*2	Agreement and Plan of Exchange between IDACORP, Inc., and IPC dated as of February 2, 1998. File number 333-48031, Form S-4, filed on 3/16/98, as Exhibit 2.
*3.1	Restated Articles of Incorporation of IPC as filed with the Secretary of State of Idaho on June 30, 1989. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 4(a)(xiii).
*3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of IPC, as filed with the Secretary of State of Idaho on November 5, 1991. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(ii).
*3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of IPC, as filed with the Secretary of State of Idaho on June 30, 1993. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(iii).
*3.4	Articles of Amendment to Restated Articles of Incorporation of IPC, as filed with the Secretary of State of Idaho on June 15, 2000. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 3(a)(iii).
*3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on January 21, 2005. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 4.5.
*3.6	Articles of Amendment to Restated Articles of Incorporation of IPC, as amended, as filed with the Secretary of State of Idaho on November 19, 2007. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.3.
*3.7	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998. File number 33-56071-99, Post-Effective Amendment No. 1 to Form S-8, filed on 10/1/98, as Exhibit 3(d).
*3.8	Amended Bylaws of IPC, amended on November 15, 2007, and presently in effect. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.2.
*3.9	Articles of Incorporation of IDACORP, Inc. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.1.
*3.10	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.2.
*3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998. File number 333-00139-99, Post-Effective Amendment No. 1 to Form S-3, filed on 9/22/98, as Exhibit 3(b).
*3.12	Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect. File number 1-14456, Form 8-K, filed

	on 11/19/07, as Exhibit 3.1.
*4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between IPC and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees. File number 2-3413, as Exhibit B-2.
*4.2	IPC Supplemental Indentures to Mortgage and Deed of Trust: File number 1-MD, as Exhibit B-2-a, First, July 1, 1939 File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943 File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947 File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948 File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949 File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951 File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957 File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957 File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957 File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958 File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958 File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959 File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960 File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961 File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964 File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966 File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966 File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972 File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974 File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974 File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974 File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976 File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978 File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979 File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981 File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982 File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986 File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989 File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990 File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991 File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991

	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iii), Thirty-ninth, October 1, 2003
	File number 1-3198, Form 8-K filed 5/10/05, as Exhibit 4, Fortieth, May 1, 2005.
	File number 1-3198, Form 8-K filed 10/10/06, as Exhibit 4, Forty-first, October 1, 2006.
	File number 1-3198, Form 8-K filed 6/4/07, as Exhibit 4, Forty-second, May 1, 2007.
	File number 1-3198, Form 8-K filed 9/26/07, as Exhibit 4, Forty-third, September 1, 2007.
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008.
*4.3	Instruments relating to IPC American Falls bond guarantee (see Exhibit 10.4). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).
*4.4	Agreement of IPC to furnish certain debt instruments. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(f).
*4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments. File number 1-14465, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(c)(ii).
*4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 2(a)(iii).
*4.7	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.
*4.8	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).
*4.9	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.

*4.10	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.
*4.11	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.
*10.1	Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).
*10.6	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10.13	

	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).
*10.151	Idaho Power Company Security Plan for Senior Management Employees I - a non-qualified, deferred compensation plan, amended and restated effective December 31, 2004, and as further amended March 14, 2007. File number 1-14465, 1-3198, Form 10-K for the year-ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.15.
*10.161	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).
*10.17 1	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).
*10.18 1	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).
*10.19 1	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on November 2, 2006, as Exhibit 10(h)(vii).
*10.20 1	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).
*10.211	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended and restated on November 15, 2007. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.21.
*10.221	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and IPC, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).
*10.231	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).
*10.241	Form of 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).
*10.251	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).
*10.261	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(xii).
*10.271	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).
*10.281	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).
*10.291	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).
*10.301	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (March 20, 2008). File number 1-14465, 1-3198, Form 8-K, filed on 3/26/08, as Exhibit 10.1.
*10.311	IDACORP, Inc. Executive Incentive Plan. File Number 1-14465, 1-3198, Form 8-K/A, filed on 2/27/08, as Exhibit 10.1.
*10.321	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, 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).
*10.331	IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.33.
*10.34	Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC's Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.35	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.36	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.37	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal

	Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).
*10.38	Guaranty Agreement, dated February 10, 1992, between IPC and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).
*10.39	Power Purchase Agreement between IPC and PPL Montana, LLC, dated March 1, 2003 and Revised Confirmation Agreement dated May 9, 2003. File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 10(k).
*10.40	$100 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among IDACORP, Inc., various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-14465, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(l).
*10.41	$300 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among Idaho Power Company, various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(m).
10.42	$170 Million Term Loan Credit Agreement, dated as of April 1, 2008, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders.
*10.43	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.
*10.441	IDACORP, Inc. Executive Incentive Plan NEO 2008 Award Opportunity Chart. File number 1-14465, 1-3198, Form 8-K/A, filed on 2/27/08, as Exhibit 10.2.
*10.451	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Performance Share Award Agreement (performance with two goals) NEO 2008 Award Opportunity Chart. File number 1-14465, 1-3198, Form 8-K, filed on 3/26/08, as Exhibit 10.2.
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.3	Statement Re: Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)

12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
12.5	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.6	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
15	Letter Re: Unaudited Interim Financial Information.
*21	Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 21.
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification.
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification.
31.3	IPC Rule 13a-14(a) CEO certification.
31.4	IPC Rule 13a-14(a) CFO certification.
32.1	IDACORP, Inc. Section 1350 CEO certification.
32.2	IDACORP, Inc. Section 1350 CFO certification.
32.3	IPC Section 1350 CEO certification.
32.4	IPC Section 1350 CFO certification.
99	Earnings press release for first quarter 2008.

1 Management contract or compensatory plan or arrangement

SIGNATURES

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

IDACORP, Inc.
(Registrant)

Date	May 8, 2008	By:	/s/ J. LaMont Keen

			J. LaMont Keen
			President and Chief Executive Officer
Date	May 8, 2008	By:	/s/ Darrel T. Anderson

Darrel T. Anderson
Senior Vice President - Administrative Services
and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date May 8, 2008 By: /s/ J. LaMont Keen

			J. LaMont Keen
			President and Chief Executive Officer
Date	May 8, 2008	By:	/s/ Darrel T. Anderson

Darrel T. Anderson
Senior Vice President - Administrative Services
and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	
10.42	$170 Million Term Loan Credit Agreement, dated as of April 1, 2008, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders.
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1 Management contract or compensatory plan or arrangement