IDAHO POWER CO
Form 10-Q
August 06, 2009

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

(Mark One)

X QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2009
OR

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

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

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

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

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

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

IDACORP, Inc.:

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

Idaho Power Company:

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

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

Number of shares of Common Stock outstanding as of June 30, 2009:

IDACORP, Inc.: 47,248,205
Idaho Power Company: 39,150,812, all held by IDACORP, Inc.

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

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

COMMONLY USED TERMS

AFUDC	-	Allowance for Funds Used During Construction
APCU	-	Annual Power Cost Update
Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
EIS	-	Environmental impact statement
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch Ratings, Inc.
GAAP	-	Generally Accepted Accounting Principles in the United States of America
HCC	-	Hells Canyon Complex

Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCO	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
LGAR	-	Load growth adjustment rate
maf	-	Million acre feet
MD&A	-	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	-	Moody s Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NOx	-	Nitrogen Oxide
NWRFC	-	National Weather Service Northwest River Forecast Center
O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
REC	-	Renewable Energy Certificate
RH BART	-	Regional Haze - Best Available Retrofit Technology
RFP	-	Request for Proposal
S&P	-	Standard & Poor s Ratings Services
SFAS	-	Statement of Financial Accounting Standards
SO_2	-	Sulfur Dioxide
SRBA	-	Snake River Basin Adjudication
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

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SAFE HARBOR STATEMENT

This Form 10-Q contains forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Part I, Item 2, Management s Discussion

and Analysis of Financial Condition and Results of Operations - Forward-Looking Information. Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of the words anticipates, believes, estimates, expects, intends, plans, predicts, projec
result, may continue and similar expressions.

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

	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
	(thousands of dollars except for per share amounts)			
Operating Revenues:				
Electric utility:				
General business	$ 198,215	$ 188,748	$ 386,142	$ 356,060
Off-system sales	26,667	25,641	55,198	59,004
Other revenues	17,636	14,556	29,207	26,676
Total electric utility revenues	242,518	228,945	470,547	441,740
Other	1,116	1,281	1,661	1,925
Total operating revenues	243,634	230,226	472,208	443,665
Operating Expenses:				
Electric utility:				
Purchased power	25,091	50,089	57,886	95,387
Fuel expense	24,475	28,681	63,608	65,918
Third-party transmission expense	1,776	1,903	2,682	2,399
Power cost adjustment	26,762	(829)	42,621	(18,573)
Other operations and maintenance	74,653	73,714	143,422	142,144
Energy efficiency programs	8,673	3,928	12,731	7,293
Gain on sale of emission allowances	(60)	(346)	(289)	(346)
Depreciation	26,832	26,617	52,795	52,367
Taxes other than income taxes	5,088	4,800	10,150	9,603
Total electric utility expenses	193,290	188,557	385,606	356,192
Other expense	872	1,140	1,495	2,187
Total operating expenses	194,162	189,697	387,101	358,379
Operating Income (Loss):				
Electric utility	49,228	40,388	84,941	85,548
Other	244	141	166	(262)
Total operating income	49,472	40,529	85,107	85,286
Other Income, net	4,058	4,302	10,979	8,044
Losses of Unconsolidated Equity-Method Investments	(2,620)	(3,278)	(2,218)	(7,314)
Interest Expense:				
Interest on long-term debt	18,282	15,744	34,922	32,621
Other interest expense, net of AFUDC	(117)	1,313	719	1,909
Total interest expense	18,165	17,057	35,641	34,530
Income Before Income Taxes	32,745	24,496	58,227	51,486
Income Tax Expense	5,175	6,941	11,970	12,526
Net Income	27,570	17,555	46,257	38,960

Adjustment for (income) loss attributable to noncontrolling interests	(95)	(40)	102	271
Net Income attributable to IDACORP, Inc.	$ 27,475	$ 17,515	$ 46,359	$ 39,231
Weighted Average Common Shares Outstanding - Basic (000 s)	46,958	45,052	46,895	45,003
Weighted Average Common Shares Outstanding - Diluted (000 s)	46,977	45,155	46,927	45,101
Earnings Per Share of Common Stock:				
Earnings Attributable to IDACORP, Inc.-Basic	$ 0.59	$ 0.39	$ 0.99	$ 0.87
Earnings Attributable to IDACORP, Inc.-Diluted	$ 0.58	$ 0.39	$ 0.99	$ 0.87
Dividends Paid Per Share of Common Stock	$ 0.30	$ 0.30	$ 0.60	$ 0.60

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	June 30, 2009		**December 31, 2008**	
Assets	**(thousands of dollars)**			
Current Assets:				
Cash and cash equivalents	$	16,002	$	8,828
Receivables:				
Customer	70,777		64,733	
Allowance for uncollectible accounts	(1,247)		(1,724)	
Other	14,226		10,439	
Taxes receivable	99		18,111	
Accrued unbilled revenues	48,265		43,934	
Materials and supplies (at average cost)	51,251		50,121	
	23,331		16,852	

Fuel stock (at average cost)				
Prepayments	9,493		10,059	
Deferred income taxes	14,731		37,550	
Other	8,602		7,381	
Total current assets	255,530		266,284	
Investments	193,548		198,552	
Property, Plant and Equipment:				
Utility plant in service	4,107,992		4,030,134	
Accumulated provision for depreciation	(1,540,469)		(1,505,120)	
Utility plant in service - net	2,567,523		2,525,014	
Construction work in progress	201,155		207,662	
Utility plant held for future use	6,653		6,318	
Other property, net of accumulated depreciation	19,157		19,171	
Property, plant and equipment - net	2,794,488		2,758,165	
Other Assets:				
American Falls and Milner water rights	24,747		26,332	
Company-owned life insurance	28,812		29,482	
Regulatory assets	693,366		696,332	
Long-term receivables (net of allowance of $1,684 and $2,478)	5,204		4,012	
Other	46,981		43,686	
Total other assets	799,110		799,844	
Total	$	4,042,676	$	4,022,845

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	June 30, 2009	December 31, 2008
Liabilities and Shareholders Equity	**(thousands of dollars)**	
Current Liabilities:		
Current maturities of long-term debt	$ 83,502	$ 86,528
Notes payable	79,099	151,250
Accounts payable	66,038	96,785
Interest accrued	17,919	16,727
Other	44,069	44,378
Total current liabilities	290,627	395,668
Other Liabilities:		
Deferred income taxes	512,978	515,719
Regulatory liabilities	292,378	276,266
Other	332,626	344,870
Total other liabilities	1,137,982	1,136,855
Long-Term Debt	1,283,570	1,183,451
Commitments and Contingencies		
Shareholders Equity:		
IDACORP, Inc. shareholders equity:		
Common stock, no par value (shares authorized 120,000,000; 47,264,189 and 46,929,203 shares issued, respectively)	734,880	729,576
Retained earnings	599,735	581,605
Accumulated other comprehensive loss	(8,179)	(8,707)
Treasury stock (15,984 and 9,022 shares at cost, respectively)	(21)	(37)
Total IDACORP, Inc. shareholders equity	1,326,415	1,302,437
Noncontrolling interest	4,082	4,434
Total shareholders equity	1,330,497	1,306,871
Total	$ 4,042,676	$ 4,022,845

The accompanying notes are an integral part of these statements.

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

	Six months ended June 30,	
	2009	**2008**
Operating Activities:	**(thousands of dollars)**	
Net income	$ 46,257	$ 38,960
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	55,434	57,050
Deferred income taxes and investment tax credits	7,548	16,777
Changes in regulatory assets and liabilities	38,358	(24,824)
Non-cash pension expense	2,209	1,274
Losses of equity method investments	2,218	7,314
Distributions from equity method investments	7,710	-
Gain on sale of assets	(412)	(3,382)
Other non-cash adjustments to net income	(358)	748
Change in:		
Accounts receivable and prepayments	(8,869)	1,967
Accounts payable and other accrued liabilities	(28,293)	(13,462)
Taxes accrued	18,155	(5,255)
Other current assets	(11,940)	(25,921)
Other current liabilities	(1,464)	3,655

Other assets	(1,831)	459
Other liabilities	(14,090)	(1,861)
Net cash provided by operating activities	110,632	53,499
Investing Activities:		
Additions to property, plant and equipment	(100,271)	(125,373)
Proceeds from the sale of non-utility assets	2,250	5,690
Investments in affordable housing	(6,174)	(8,486)
Proceeds from the sale of emission allowances	2,341	833
Investments in unconsolidated affiliates	-	(8,725)
Proceeds from the sale of investments	8,965	-
Purchase of held-to-maturity securities	-	(965)
Maturity of held-to-maturity securities	-	2,735
Withdrawal of refundable deposit for tax related liabilities	-	20,000
Other	(3,319)	(1,524)
Net cash used in investing activities	(96,208)	(115,815)
Financing Activities:		
Increase in term loans	-	170,000
Issuance of long-term debt	100,000	-
Retirement of long-term debt	(8,735)	(6,317)
Purchase of pollution control revenue bonds	-	(166,100)
Dividends on common stock	(28,230)	(26,985)
Net change in short-term borrowings	(72,151)	89,076
Issuance of common stock	4,927	4,295
Acquisition of treasury stock	(1,408)	(281)
Other	(1,653)	(414)
Net cash provided by (used in) financing activities	(7,250)	63,274
Net increase in cash and cash equivalents	7,174	958
Cash and cash equivalents at beginning of the period	8,828	7,966
Cash and cash equivalents at end of the period	$ 16,002	$ 8,924
Supplemental Disclosure of Cash Flow Information:		
Cash paid (refunded) during the period for:		
Income taxes	$ (11,785)	$ 5
Interest (net of amount capitalized)	$ 32,956	$ 33,824
Non-cash investing activities		
Additions to property, plant and equipment in accounts payable	$ 5,578	$ 9,960
Investments in affordable housing	$ 6,000	$ -

The accompanying notes are an integral part of these statements.

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

Three months ended

	June 30, 2009	2008
	(thousands of dollars)	
Net Income	$ 27,570	$ 17,555
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $734 and ($181)	1,143	(281)
Unfunded pension liability adjustment, net of tax of $87 and $67	136	103
Total Comprehensive Income	28,849	17,377
Comprehensive income attributable to noncontrolling interests	(95)	(40)
Comprehensive Income attributable to IDACORP, Inc.	$ 28,754	$ 17,337

The accompanying notes are an integral part of these statements.

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

	Six months ended June 30, 2009	2008
	(thousands of dollars)	
Net Income	$ 46,257	$ 38,960
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $164 and ($888)	256	(1,384)
Unfunded pension liability adjustment, net of tax of $174 and $133	272	207
Total Comprehensive Income	46,785	37,783
Comprehensive loss attributable to noncontrolling interests	102	271
Comprehensive Income attributable to IDACORP, Inc.	$ 46,887	$ 38,054

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2009	**2008**	**2009**	**2008**
	(thousands of dollars)			
Operating Revenues:				
General business	$ 198,215	$ 188,748	$ 386,142	$ 356,060
Off-system sales	26,667	25,641	55,198	59,004
Other revenues	17,636	14,556	29,207	26,676
Total operating revenues	242,518	228,945	470,547	441,740
Operating Expenses:				
Operation:				
Purchased power	25,091	50,089	57,886	95,387
Fuel expense	24,475	28,681	63,608	65,918
Third-party transmission expense	1,776	1,903	2,682	2,399
Power cost adjustment	26,762	(829)	42,621	(18,573)
Other	54,613	53,575	106,925	107,732
Energy efficiency programs	8,673	3,928	12,731	7,293
Gain on sale of emission allowances	(60)	(346)	(289)	(346)
Maintenance	20,040	20,139	36,497	34,412
Depreciation	26,832	26,617	52,795	52,367
Taxes other than income taxes	5,088	4,800	10,150	9,603
Total operating expenses	193,290	188,557	385,606	356,192

Income from Operations	49,228	40,388	84,941	85,548
Other Income (Expense):				
Allowance for equity funds used during construction	1,734	232	2,498	1,129
Earnings (losses) of unconsolidated equity-method investments	(649)	(1,070)	2,653	(1,866)
Other income, net	1,648	3,839	7,944	6,599
Total other income	2,733	3,001	13,095	5,862
Interest Charges:				
Interest on long-term debt	18,268	15,409	34,835	31,952
Other interest	1,350	2,252	2,929	4,146
Allowance for borrowed funds used during construction	(1,658)	(1,479)	(2,785)	(3,417)
Total interest charges	17,960	16,182	34,979	32,681
Income Before Income Taxes	34,001	27,207	63,057	58,729
Income Tax Expense	7,675	9,479	17,447	19,730
Net Income	$ 26,326	$ 17,728	$ 45,610	$ 38,999

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	June 30, 2009	December 31, 2008
Assets	(thousands of dollars)	
Electric Plant:		

In service (at original cost)	$ 4,107,992	$ 4,030,134
Accumulated provision for depreciation	(1,540,469)	(1,505,120)
In service - net	2,567,523	2,525,014
Construction work in progress	201,155	207,662
Held for future use	6,653	6,318
Electric plant - net	2,775,331	2,738,994
Investments and Other Property	102,204	106,057
Current Assets:		
Cash and cash equivalents	11,523	3,141
Receivables:		
Customer	70,777	64,433
Allowance for uncollectible accounts	(1,247)	(1,724)
Other	12,375	7,947
Taxes receivable	7,013	41,363
Accrued unbilled revenues	48,265	43,934
Materials and supplies (at average cost)	51,251	50,121
Fuel stock (at average cost)	23,331	16,852
Prepayments	9,287	9,865
Deferred income taxes	3,914	3,852
Other	7,752	4,968
Total current assets	244,241	244,752
Deferred Debits:		
American Falls and Milner water rights	24,747	26,332
Company-owned life insurance	28,812	29,482
Regulatory assets	693,366	696,332
Other	46,148	42,907
Total deferred debits	793,073	795,053
Total	$ 3,914,849	$ 3,884,856

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	June 30, 2009	December 31, 2008
Capitalization and Liabilities	(thousands of dollars)	
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	618,758	618,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	499,281	482,047
Accumulated other comprehensive loss	(8,179)	(8,707)
Total common stock equity	1,205,640	1,187,878
Long-term debt	1,279,570	1,180,691
Total capitalization	2,485,210	2,368,569
Current Liabilities:		
Long-term debt due within one year	81,064	81,064
Notes payable	36,730	112,850
Accounts payable	64,014	96,268
Notes and accounts payable to related parties	1,238	768
Interest accrued	17,902	16,675
Other	43,305	43,274
Total current liabilities	244,253	350,899
Deferred Credits:		
Deferred income taxes	563,104	547,159
Regulatory liabilities	292,378	276,266
Other	329,904	341,963
Total deferred credits	1,185,386	1,165,388
Commitments and Contingencies		
Total	$ 3,914,849	$ 3,884,856

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	June 30, 2009	%	December 31, 2008	%
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	618,758		618,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	499,281		482,047	
Accumulated other comprehensive loss	(8,179)		(8,707)	
Total common stock equity	1,205,640	49	1,187,878	50
Long-Term Debt:				
First mortgage bonds:				
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6.025% Series due 2018	120,000		120,000	
6.15% Series Due 2019	100,000		-	
6 % Series due 2032	100,000		100,000	
5.50% Series due 2033	70,000		70,000	
5.50% Series due 2034	50,000		50,000	
5.875% Series due 2034	55,000		55,000	
5.30% Series due 2035	60,000		60,000	
6.30% Series due 2037	140,000		140,000	
6.25% Series due 2037	100,000		100,000	
Total first mortgage bonds	1,165,000		1,065,000	
Amount due within one year	(80,000)		(80,000)	
Net first mortgage bonds	1,085,000		985,000	
Pollution control revenue bonds:				
Variable Rate Series 2003 due 2024	49,800		49,800	
Variable Rate Series 2006 due 2026	116,300		116,300	
Variable Rate Series 2000 due 2027	4,360		4,360	
Total pollution control revenue bonds	170,460		170,460	
American Falls bond guarantee	19,885		19,885	
Milner Dam note guarantee	8,509		9,573	
Note guarantee due within one year	(1,064)		(1,064)	
Unamortized premium/discount - net	(3,220)		(3,163)	
Term Loan Credit Facility	166,100		166,100	
Purchase of pollution control revenue bonds	(166,100)		(166,100)	
Total long-term debt	1,279,570	51	1,180,691	50
Total Capitalization	$ 2,485,210	100	$ 2,368,569	100

The accompanying notes are an integral part of these statements.

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

	Six months ended June 30,	
	2009	**2008**
Operating Activities:	**(thousands of dollars)**	
Net income	$ 45,610	$ 38,999
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	55,030	56,650
Deferred income taxes and investment tax credits	3,354	16,050
Changes in regulatory assets and liabilities	38,358	(24,824)
Non-cash pension expense	2,209	1,274
(Earnings) losses of equity method investments	(2,653)	1,866
Distributions from equity method investments	7,460	-
Gain on sale of assets	(412)	(3,381)
Other non-cash adjustments to net income	(1,350)	(1,497)
Change in:		
Accounts receivables and prepayments	(8,665)	3,142
Accounts payable	(29,800)	(13,102)
Taxes accrued	34,350	9,650
Other current assets	(11,940)	(25,921)
Other current liabilities	(1,234)	3,650
Other assets	(1,831)	456
Other liabilities	(14,094)	(1,608)
Net cash provided by operating activities	114,392	61,404
Investing Activities:		
Additions to utility plant	(100,271)	(125,373)
Proceeds from the sale of non-utility assets	2,250	5,690
Proceeds from sale of emission allowances	2,341	833
Investments in unconsolidated affiliates	-	(8,725)
Withdrawal of refundable deposit for tax related liabilities	-	20,000
Other	(3,359)	(1,515)
Net cash used in investing activities	(99,039)	(109,090)
Financing Activities:		
Increase in term loans	-	170,000
Issuance of long-term debt	100,000	-
Retirement of long-term debt	(1,064)	(1,064)
Purchase of pollution control revenue bonds	-	(166,100)
Dividends on common stock	(28,376)	(27,084)
Net change in short term borrowings	(76,120)	73,764

Other	(1,411)	(413)
Net cash provided by (used in) financing activities	(6,971)	49,103
Net increase in cash and cash equivalents	8,382	1,417
Cash and cash equivalents at beginning of the period	3,141	5,347
Cash and cash equivalents at end of the period	$ 11,523	$ 6,764
Supplemental Disclosure of Cash Flow Information:		
Cash paid (received) during the period for:		
Income taxes received from parent	$ (18,286)	$ (6,996)
Interest (net of amount capitalized)	$ 32,380	$ 32,026
Non-cash investing activities:		
Additions to utility plant in accounts payable	$ 5,578	$ 9,960

The accompanying notes are an integral part of these statements.

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

	Three months ended June 30,	
	2009	**2008**
	(thousands of dollars)	
Net Income	$ 26,326	$ 17,728
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $734 and ($181)	1,143	(281)
Unfunded pension liability adjustment, net of tax of $87 and $67	136	103
Total Comprehensive Income	$ 27,605	$ 17,550

The accompanying notes are an integral part of these statements.

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

	Six months ended June 30,	
	2009	**2008**
	(thousands of dollars)	
Net Income	$ 45,610	$ 38,999
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $164 and ($888)	256	(1,384)
Unfunded pension liability adjustment, net of tax of $174 and $133	272	207
Total Comprehensive Income	$ 46,138	$ 37,822

The accompanying notes are an integral part of these statements.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

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

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

IDACORP s other subsidiaries include:

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

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

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

Principles of Consolidation

IDACORP s and IPC s condensed consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. All significant intercompany balances have been eliminated in consolidation. Investments in subsidiaries that the companies do not control and investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

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

Through IFS, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These VIEs are affordable housing and historic rehabilitation developments in which IFS holds limited partnership interests ranging from five to 99 percent. These investments are not consolidated because IFS does not absorb a majority of the expected losses of these entities, either because of specific provisions in the partnership agreements or due to not owning a majority interest. These investments were acquired between 1996 and 2009, and are presented as Investments on IDACORP s condensed consolidated balance sheets. IFS s maximum exposure to loss in these developments is limited to its net carrying value, which was $81 million at June 30, 2009.

Financial Statements

In the opinion of IDACORP and IPC, the accompanying unaudited condensed consolidated financial statements contain all adjustments necessary to present fairly their consolidated financial positions as of June 30, 2009, and consolidated results of operations for the three and six months ended June 30, 2009, and 2008, and consolidated cash flows for the six months ended June 30, 2009, and 2008. These adjustments are of a normal and recurring nature. These financial statements do not contain the complete detail or footnote disclosure concerning accounting policies and other matters that would be included in full-year financial statements and should be read in conjunction with the audited consolidated financial statements included in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Subsequent Events

In the preparation of these financial statements, IDACORP and IPC evaluate all subsequent events that provide additional evidence about conditions that existed at the date of the balance sheet. Subsequent events were evaluated through August 6, 2009, up to the time the financial statements were issued.

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

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

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

Uncertain tax positions was combined with other current liabilities in IDACORP s and IPC s condensed consolidated balance sheets due to the uncertain tax positions becoming an immaterial balance.

Earnings Per Share (EPS)

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

The following table presents the computation of IDACORP s basic and diluted earnings per share for the three and six months ended June 30, 2009 and 2008 (in thousands, except for per share amounts):

	Three months ended	Six months ended

	June 30, 2009	2008	June 30, 2009	2008
Numerator:				
Net income attributable to IDACORP, Inc.	$ 27,475	$ 17,515	$ 46,359	$ 39,231
Denominator:				
Weighted-average common shares outstanding - basic	46,958	45,052	46,895	45,003
Effect of dilutive securities:				
Options	9	47	11	48
Restricted Stock	10	56	21	50
Weighted-average common shares outstanding diluted	46,977	45,155	46,927	45,101
Basic earnings per share	$ 0.59	$ 0.39	$ 0.99	$ 0.87
Diluted earnings per share	$ 0.58	$ 0.39	$ 0.99	$ 0.87

The diluted EPS computation excluded 685,581 and 686,533 options for the three and six months ended June 30, 2009, respectively, because the options exercise prices were greater than the average market price of the common stock during those periods. For the same periods last year, 482,000 options were excluded from the diluted EPS computation for the same reason. In total, 649,281 options were outstanding at June 30, 2009, with expiration dates between 2010 and 2015.

Adoption of SFAS 160

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

Shareholders Equity

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

	Attributable to IDACORP, Inc.	**Attributable to noncontrolling interests**	**Total**
Shareholders equity at January 1, 2009	$ 1,302,437	$ 4,434	$ 1,306,871
Net income (loss)	46,359	(102)	46,257
Common stock dividends	(28,230)	-	(28,230)

Common stock issuances		5,250		-		5,250
Common stock acquired		(869)		-		(869)
Unrealized holding gains on securities		256		-		256
Unfunded pension liability adjustment		272		-		272
Other		940		(250)		690
Shareholders equity at June 30, 2009	$	1,326,415	$	4,082	$	1,330,497
Shareholders equity at January 1, 2008	$	1,207,315	$	4,478	$	1,211,793
Net income (loss)		39,231		(271)		38,960
Common stock dividends		(27,081)		-		(27,081)
Common stock issuances		4,392		-		4,392
Common stock acquired		(280)		-		(280)
Unrealized holding losses on securities		(1,384)		-		(1,384)
Unfunded pension liability adjustment		207		-		207
Other		2,248		(7)		2,241
Shareholders equity at June 30, 2008	$	1,224,648	$	4,200	$	1,228,848

Allowance for Funds Used during Construction

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

Revenues

Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-end. IPC collects franchise fees and similar taxes related to energy

consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense. Beginning in February 2009, IPC is collecting AFUDC in base rates for a specific capital project, as discussed in Note 6, Regulatory Matters. Cash collected is recorded as a regulatory liability.

New Accounting Pronouncements

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

SFAS 166: In June 2009, the FASB issued SFAS 166, Accounting for Transfers of Financial Assets, which amends the derecognition guidance in SFAS 140, Accounting for Transfers and Servicing of Financial Assets and Derecognition of Liabilities. SFAS 166 addresses issues entities have encountered when applying SFAS 140 and addresses concerns expressed by the SEC, members of Congress, and financial statement users about the accounting and disclosures required by SFAS 140 in the wake of the subprime mortgage crisis and the deterioration in the global credit markets. For IDACORP and IPC, SFAS 166 is effective for financial asset transfers occurring on or after January 1, 2010 and early adoption is prohibited. IDACORP and IPC do not expect the adoption of SFAS 166 to have a material effect on their consolidated financial statements.

SFAS 167: In June 2009 the FASB issued SFAS 167, Amendments to FASB Interpretation No. 46(R), which amends the consolidation guidance that applies to VIEs. The amendments will significantly affect the overall consolidation analysis under Interpretation 46(R). SFAS 167 will require IDACORP and IPC to reconsider their previous FIN46(R) conclusions, including (1) whether an entity is a VIE, (2) whether the enterprise is the VIE s primary beneficiary, and (3) what type of financial statement disclosures are required. For IDACORP and IPC, SFAS 167 is effective as of January 1, 2010, and early adoption is prohibited. IDACORP and IPC are currently assessing the impact of SFAS 167 on their consolidated financial statements.

SFAS 168: In June 2009 the FASB issued SFAS No. 168, The FASB Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles. The FASB Accounting Standards Codification will become the source of authoritative U.S. generally accepted accounting principles recognized by the FASB to be applied to nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP to SEC registrants. On the effective date of this statement, the Codification supersedes all then-existing non-SEC accounting and reporting standards and all other nongrandfathered, non-SEC accounting literature not included in the codification will become nonauthoritative. This statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. As SFAS 168 is not intended to change or alter existing GAAP, it will not impact IDACORP s or IPC s results of operations, cash flows or financial positions. The companies will adjust historical GAAP references in their third quarter 2009 Form 10-Q to reflect accounting guidance references included in the codification.

2. INCOME TAXES:

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP s effective tax rate for the six months ended June 30, 2009, was 20.5 percent, compared to 24.2 percent for the six months ended June 30, 2008. IPC s effective tax rate for the six months ended June 30, 2009, was 27.7 percent, compared to 33.6 percent for the six months ended June 30, 2008. The decrease in the 2009 estimated annual effective tax rates from 2008 was primarily due to an examination settlement, state bonus depreciation, and timing and amount of other regulatory flow-through tax adjustments at IPC. The decreases were partially offset by additional income tax expense from greater pre-tax earnings at IDACORP and IPC, and lower tax credits from IFS.

In April 2009, the State of Idaho adopted the federal bonus depreciation provisions enacted as part of the American Recovery and Reinvestment Act of 2009. IPC s regulatory tax accounting method allows for the flow-through of certain state tax adjustments, including accelerated depreciation. Due to the application of the bonus depreciation provision, IPC was able to reduce its income tax expense by $1.5 million as of June 30, 2009.

The Internal Revenue Service (IRS) completed its examination of IDACORP s 2006 tax year in May 2009. The 2006 examination report was submitted for U.S. Congress Joint Committee on Taxation (JCT) review in June. In July, the JCT completed its review and accepted the report without change. As of June 30, 2009, IDACORP considered all uncertain tax positions related to its 2006 tax year effectively settled and decreased IPC s liability for unrecognized tax benefits by $1.3 million.

In March 2009, the JCT completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 IRS examination report. The JCT accepted both items without change. IDACORP considered these matters effectively settled in 2008 and recorded the related financial effects in its December 31, 2008 financial statements.

The IRS began its examination of IDACORP s 2007-2008 tax years in July 2009. In May 2009, IDACORP formally entered the IRS Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. The 2007-2009 examinations are expected to be completed in 2010. IDACORP and IPC are unable to predict the outcome of these examinations.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the six months ended June 30, 2009, IDACORP entered into the following transactions involving its common stock:

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

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

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

204,340 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 June 30, 2009, the maximum number of shares available under the LTICP and RSP were 1,586,556 and 21,677, respectively.

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

	IDACORP Six months ended June 30,		**IPC Six months ended June 30,**	
	2009	**2008**	**2009**	**2008**
Compensation cost	$ 1,929	$ 2,289	$ 1,829	$ 2,160
Income tax benefit	$ 754	$ 895	$ 715	$ 845

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

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

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

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

4. LONG-TERM DEBT:

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

On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt in anticipation of utilizing short-term debt to repay its $80 million 7.20% First Mortgage Bonds which mature on December 1, 2009. IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

In February 2009, IFS repaid $7.2 million of debt related to investments in affordable housing. The debt was scheduled to mature in 2009 and 2010. On May 15, 2009, IFS issued a $6 million equity funding obligation to finance a portion of its $12 million investment in affordable housing. The obligation is scheduled to mature in 2010.

Pollution Control Revenue Refunding Bonds
On April 3, 2008, IPC made a mandatory purchase of two series of Pollution Control Revenue Refunding Bonds issued for the benefit of IPC, the $116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008.

This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of the financial guarantor s credit ratings deterioration. The Pollution Control Bonds remain outstanding and have not been retired or cancelled. IPC is the current holder of the bonds.

IPC has given notice, subject to rescission, to adjust the interest rate period of the Pollution Control Bonds from a weekly interest rate period to a term interest rate period effective August 20, 2009 in connection with the remarketing of the bonds to investors without the financial guaranty insurance policy.

Term Loan Credit Agreement

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

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

The new Term Loan Credit Agreement is a short-term arrangement; however, $166.1 million was classified as long-term debt as allowed by SFAS 6 Classification of Short-Term Obligations Expected to Be Refinanced. IPC has the ability to refinance the loans on a long-term basis by utilizing its credit facility, provided that the aggregate of the commitments utilizing the credit facility and commercial paper outstanding does not exceed $300 million. The remaining $3.9 million of the loans is classified as short-term debt.

5. NOTES PAYABLE:

Credit Facilities

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

At June 30, 2009, no loans were outstanding on either IDACORP s facility or IPC s facility. At June 30, 2009, IPC had regulatory authority to incur up to $450 million of short-term indebtedness.

Balances and interest rates of short-term borrowings were as follows at June 30, 2009, and December 31, 2008 (in thousands of dollars):

	June 30, 2009			December 31, 2008		
	IPC	**IDACORP**	**Total**	**IPC**	**IDACORP**	**Total**
Commercial paper outstanding	$ 32,830	$ 42,369	$ 75,199	$ 108,950	$ 13,400	$ 122,350
Other short-term borrowings	3,900	-	3,900	3,900	25,000	28,900
Total	$ 36,730	$ 42,369	$ 79,099	$ 112,850	$ 38,400	$ 151,250
Weighted-avg. interest rate	1.14%	1.09%	1.12%	4.89%	4.29%	4.74%

6. REGULATORY MATTERS:

Idaho 2008 General Rate Case
On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased IPC's Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

The IPUC denied reconsideration with respect to a refund of $3.3 million of fees recovered by IPC from the FERC. On April 2, 2009, IPC filed an application with the IPUC for an accounting order approving amortization of the fees over a five year period beginning October 2006 when IPC received the FERC credit. The IPUC approved IPC s requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, IPC recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period, September 2011. As the regulatory liability is amortized it will reduce electric utility other operations expense ratably over the remaining amortization period.

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Deferred (Accrued) Net Power Supply Costs

IPC s deferred (accrued) net power supply costs consisted of the following balances, including applicable carrying charges (in thousands of dollars):

	June 30, 2009	December 31, 2008
Idaho PCA current year:		
Deferral for the 2009-2010 rate year	$ -	$ 93,657
Accrual for the 2010-2011 rate year	(8,418)	-
Idaho PCA true-up awaiting recovery:		
Authorized in May 2008	-	47,164
Authorized in May 2009	101,719	-
Oregon deferral:		
2001 Costs	536	1,663
2006 Costs	2,369	1,215
2007 Costs	5,985	-
2008 Power cost adjustment mechanism	5,615	5,400
Total deferral	$ 107,806	$ 149,099

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

The annual adjustments are based on two components:

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

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

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

2009-2010 PCA: On April 15, 2009, IPC filed its 2009-2010 PCA with the IPUC with a requested effective date of June 1, 2009. The filing requested an increase to existing revenues of approximately $93.8 million or 11.4 percent. IPC subsequently provided its updated April operating plan, which reflected the need for increased revenues of $84.3 million or 10.2 percent.

The 2009-2010 PCA reflects a new methodology, approved by the IPUC on January 9, 2009 and discussed in PCA Workshops below that utilizes IPC s most recent operating plan to forecast power supply expenses rather than the previous method based on a forecast of Brownlee Reservoir inflow and a regression formula.

On May 29, 2009, the IPUC approved the 2009-2010 PCA of $84.3 million or 10.2 percent, effective June 1, 2009.

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

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

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

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

LGAR - the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on the formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.

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

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

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

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

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

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

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

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast resulted in a requested increase to Oregon revenues of 11.46 percent, or $3.9 million annually. A joint stipulation relating to the October Update and the March Forecast by IPC, the OPUC Staff and the Citizens Utility Board in support of IPC s requested increase was filed with the OPUC on May 4, 2009. On May 26, 2009, the OPUC issued its order adopting the stipulation and approving the rate increases set forth in the stipulation effective on June 1, 2009.

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

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

deadband, the filing requests that $5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed below under 2007-2008 Excess Power Costs. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference was held July 7, 2009. As a result of the conference, IPC will file updated testimony that reflects agreed upon changes to the calculation of the deferral.

2007-2008 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the eight-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was determined that IPC should be allowed to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for that period. The amount to be recovered was reduced by $0.9 million of emission allowance sales (including interest) during the same period allocated to Oregon, resulting in an approved deferral balance of $5.5 million. IPC recorded the $6.4 million deferral in the second quarter 2009 as a reduction to power cost adjustment expense. The emission allowances sales were previously deferred. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. On May 28, 2009, the OPUC issued its order adopting the stipulation.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year ($1.9 million for 2009 based on 2008 revenues). On October 6, 2008, the OPUC issued an order clarifying that the PCAM is a deferral under the Oregon statute.

IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC. Full recovery of the 2001 deferral is expected in the third quarter of 2009. The 2006-2007 deferral of $2.4 million, the May 1 - December 31, 2007 deferral of $6.0 million and the $5.6 million 2008 PCAM balance will have to be recovered sequentially following the full recovery of the 2001 deferral.

On June 30, 2009, IPC filed an application with the OPUC to begin amortizing through rates the 2006-2007 deferral of $2.0 million plus $0.4 million of accrued interest, effective September 1, 2009. IPC expects amortization of this deferral to take approximately 16 months.

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

IPC deferred fixed costs of $2.0 million related to the FCA during the first six months of 2009.

On March 13, 2009, IPC filed an application requesting a $5.2 million rate increase under the FCA pilot program for the net under-recovery of fixed costs during 2008, effective June 1, 2009 through May 31,

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2010. On May 29, 2009, the IPUC approved IPC s application to increase rates under the FCA pilot program as filed.

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

Energy Efficiency Matters
Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in conservation, energy efficiency and demand response programs. On March 13, 2009, IPC filed an application with the IPUC requesting an increase in Rider funding to 4.75 percent of base revenues effective June 1, 2009. On May 29, 2009, the IPUC approved IPC s application to increase the Rider as filed. As a result of the IPUC approval, based on

2008 test year revenue, IPC expects Rider revenues of $27.3 million in 2009 and $33.2 million in each of 2010 and 2011. Effective June 1, 2008, IPC began collecting 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

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

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

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

Advanced Metering Infrastructure (AMI)

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

IPC filed AMI evaluation and deployment reports with the IPUC on May 1 and August 31, 2007, in compliance with an IPUC order. Consistent with the implementation plan contained in those reports, IPC entered into a number of contracts for materials and resources that allowed for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of its customers by the end of 2011.

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

On March 13, 2009, IPC filed an application with the IPUC for authority to increase its rates due to the inclusion of AMI investment in rate base. The filing requested inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and those investments that would be made during a June 1, 2009, through May 31, 2010 test year. IPC requested a first year revenue requirement of $11.2 million in the Idaho jurisdiction effective June 1, 2009, for service provided on or after that date. In its calculations, IPC reflected the reduction in investment and the accelerated depreciation costs related to the removal of current metering equipment, as well as changes in operating expenses that accompany the changes in plant investment.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on IPC s actual investment in AMI to date, annualized through December 31, 2009, rather than IPC s proposed test year. The IPUC also allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. The actual depreciation expense for fiscal year 2009 will occur over seven months totaling $5.5 million.

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

Depreciation Filings

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

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million. The OPUC Staff accepted IPC s settlement offer, and a stipulation was filed on June 5, 2009. In the settlement offer, IPC proposed that the OPUC Staff not make adjustments to the depreciation rates adopted by the IPUC and also proposed to commit to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction.

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

Idaho Open Access Transmission Tariff (OATT) Shortfall Filing

On July 20, 2009 IPC filed a request with the IPUC for authorization to defer $8.1 million in costs associated with the difference between the revenue credits and the amount of OATT revenues IPC has received since March 2008 and will receive through May 2010. For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to the IPC s overall revenue requirement. In the last two general rate cases, IPC included an estimate of OATT revenues from third parties based on the forecasted OATT rate less a reserve. However, as discussed below in OATT, the FERC order issued on January 15, 2009 had a significant impact on actual third-party transmission revenues IPC received from June 2006 to date, resulting in the overstating of the revenue credits in the Idaho jurisdictional revenue requirement authorized by the IPUC. Included in the filing are $4.3 million for the period March 1, 2008

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through January 31, 2009, the effective period of the February 28, 2008 general rate case order and $3.8 million estimated for the period February 1, 2009 through May 31, 2010, the expected effective period of the January 30, 2009 general rate case order. IPC has filed a request for rehearing of the FERC order and is taking additional measures to address the revenue shortfall. If the FERC issues are resolved in IPC s favor, IPC will reduce the deferral. IPC requested to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning June 1, 2010 and to receive a carrying charge on the balance until rate recovery begins.

OATT

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

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

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

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

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

Amended Legacy Agreements: Subsequent to the January 15, 2009 FERC Order, IPC has sought to mitigate the resulting revenue shortfall by revising certain of the Legacy Agreements as provided for in the agreements.

On April 3, 2009, IPC notified PacifiCorp that it was terminating its provision of a portion of the services that it provides under the Restated Transmission Service Agreement (RTSA), a Legacy Agreement, effective June 12, 2009. IPC made a filing with the FERC on April 13, 2009 submitting revised rate schedule sheets. The FERC accepted the revised rate schedule sheets by letter order on May 14, 2009. On June 12, 2009 IPC submitted a filing for the purpose of replacing the terminated contract services with OATT service, effective June 13, 2009. An amended RTSA between IPC and PacifiCorp and three long term service agreements were filed to provide for the OATT service. As calculated in the filings, the estimated net transmission revenue increase for the period June 13, 2009 through June 12, 2010 is approximately $3.2 million. The FERC accepted IPC s filing, effective June 13, 2009, by letter order on July 28, 2009.

On June 19, 2009 IPC submitted a filing to increase rates under the Agreement for Interconnection and Transmission Services (ITSA) contract, another Legacy Agreement between IPC and PacifiCorp. The filing requested an increase of rates to the level paid by OATT customers for Point to Point service and an August 19, 2009 effective date. As calculated in the filing, the estimated net transmission revenue increase for the period September 1, 2009 through August 31, 2010 is approximately $3.9 million. PacifiCorp has intervened in the case and on July 10, 2009 filed a motion to suspend the case for five months and pursue settlement or go to hearing.

2009 OATT: On June 1, 2009, IPC posted on its Open Access Same-Time Information System (OASIS) website its draft informational filing which contains the annual update of the formula rate to the 2008 test year. The draft informational filing includes a proposed rate of $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. The impact of this rate increase on IPC s revenues will be dependent on transmission volume sold, which can be highly variable. A customer meeting to discuss the informational filing was held on June 16, 2009. A final filing will be submitted to the FERC by September 1, 2009 with new rates effective October 1, 2009.

2008 OATT: On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The new rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. New rates were effective October 1, 2008. IPC has adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009, order.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations

The following four items are the only material changes to purchase obligations made outside of the ordinary course of business since December 31, 2008:

IPC entered into a contract to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. The contract is expected to total $127 million from 2010 to 2014.

In February 2009, IPC entered into a contract with EnerNOC to implement and operate a demand response program for its commercial and industrial customers. IPC estimates it will spend approximately $12.2 million on the program during the five year term of the contract. On May 15, 2009 the IPUC approved the EnerNOC contract and authorized IPC to recover the costs of the program from Energy Efficiency Rider funds.

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

On May 7, 2009, IPC entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company for design, engineering,

procurement, construction management and construction services for Langley Gulch. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost for Langley Gulch.

Guarantees

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $63 million at June 30, 2009. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At this time Bridger Coal Company is revising their estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, Bridger Coal Company has the ability to add a per ton surcharge if it is determined that future liabilities exceed the trust s assets. Because of the existence of the fund and the ability to apply a per ton surcharge, the estimated fair value of this guarantee is minimal.

Legal Proceedings

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

Reference is made to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, for a discussion of all material pending legal proceedings to which IDACORP and IPC and their subsidiaries are parties. The following discussion provides a summary of material developments that occurred in those proceedings during the period covered by this report and of any new material proceedings instituted during the period covered by this report.

Western Energy Proceedings at the FERC:

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

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

<u>California Refund:</u> This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC s order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20,

2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

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

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

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection, but, consistent with obligations established in a settlement which is described in the following paragraph, IE and IPC withdrew that request for rehearing to the extent it pertained to the disputes about the cost filing between IE and IPC and parties that had joined the settlement. On June 18, 2009 FERC issued an order with respect to the cost filings of other sellers and in that order also stated that it was not ruling on the IE and IPC request for rehearing because it had been withdrawn. On July 8, 2009 IE and IPC sought further rehearing pointing out to the FERC that the withdrawal pertained only to the parties with whom IE and IPC had settled. On June 18, 2009 in a separate order, the FERC also ruled that net refund recipients in the California refund proceeding were responsible for the costs associated with all cost filings. Most of the parties that joined the IE and IPC settlement described below were net refund recipients, but until the Cal ISO completes its refund calculations it is uncertain whether any parties who opted not to join the settlement are net refund recipients. If there are no such parties, then the requests for rehearing will be moot. IE and IPC are unable to predict how or when the FERC might rule on their requests for rehearing, but their effect is confined to obligations of IE and IPC to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and

IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

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

Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

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

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

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict Mobile-Sierra standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources (CDWR) in the proceeding. A number of parties have sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. On June 26, 2009 IE and IPC joined with a number of other parties in a request to extend the time for the filing of a joint petition for a writ of certiorari. On June 29, 2009 Justice Kennedy extended the time for the filing of the petition until September 4, 2009. On May 22, 2009 the California Parties filed a motion with the FERC to sever the CDWR sales from the remainder of the Pacific Northwest proceedings and to consolidate the CDWR sales portion of the Pacific Northwest case with ongoing proceedings in cases that IE or IPC have settled and with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled. (Brown Complaint) On August 4, 2009, IE and IPC, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed positions in response to the motion of the California Parties. Also on August 4, 2009 the City of Tacoma, Washington and the Port of Seattle, Washington filed a motion with the FERC in connection with the California refund proceeding, the Lockyer remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and IPC previously were dismissed), the Brown *Complaint* and the Pacific Northwest refund remand proceeding. This latter motion asks the FERC (1) to

make findings on a summary basis that the entire West-wide wholesale electricity market, including the Pacific Northwest, was affected by market manipulation and that, as a result, jurisdictional sellers' rates exceeded just and reasonable levels throughout the Western energy crisis of 2000 - 2001, to grant market-wide refunds to all purchasers for amounts collected in excess of a just and reasonable price and to establish procedures to determine specific refund obligations applicable to sellers or, in the alternative, (2) to institute an evidentiary hearing and establish related procedures to respond to the remand proceedings ordered by the Ninth Circuit in Port of Seattle, Washington v. FERC that would include supplemental evidence filed with the motion and consideration of claimed violations of Market Based Rate Tariffs from January 1, 2000 through June 20, 2001, thereby expanding the scope of potential refunds to a period beginning prior to December 25, 2000. IE and IPC intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations or cash flows.

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

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

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

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 appealed the District Court s decision to the U.S. Court of Appeals for the Ninth Circuit. On June 4, 2009, the Ninth Circuit issued a Memorandum Opinion affirming the District Court s dismissal of the action. On June 18, 2009, plaintiffs filed with the Ninth Circuit a Petition for Rehearing En Banc, seeking rehearing of the Memorandum Opinion. On July 28, 2009, the Ninth Circuit denied the Petition for Rehearing. If pursued by plaintiffs, IPC intends to vigorously defend its position in this proceeding. IPC believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: IPC continues to monitor the Sierra Club and the Wyoming Outdoor Council suit against PacifiCorp filed in February 2007 in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal fired plant in Sweetwater County, Wyoming. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. IPC is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

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

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs response to the motion was filed February 25, 2009, and PGE s reply was filed April 8, 2009. The State of Oregon filed an amicus brief on April 1, 2009, addressing the substantive positions set forth in PGE s December 5, 2008, motion to dismiss and the plaintiffs February 25, 2009, response to the motion. The amicus brief does not state a position on the merits of the motion to dismiss but corrects what it perceives to be erroneous statements of law made by the plaintiffs and PGE regarding Oregon air quality regulations concerning the Prevention of Significant Deterioration program that were approved by the Environmental Protection Agency and incorporated into Oregon s State Implementation Plan. Plaintiffs filed a sur-response in opposition to the motion to dismiss on May 18, 2009. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

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

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

Fifth Judicial Circuit, which has jurisdiction over SRBA matters including the Swan Falls case.

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

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On April 24, 2009, the Governor of Idaho signed into law legislation approving provisions contained in the settlement agreement. On May 6, 2009, as part of the settlement, IPC, the Governor of Idaho and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. IPC and the State have also filed a joint motion to the SRBA court to dismiss the Swan Falls case and enter the stipulated water right decrees set forth in the settlement agreement. The SRBA court held a status conference on the joint motion on July 21, 2009, and is expected to issue an order setting a briefing and hearing schedule for the joint motion in the near future.

U.S. Bureau of Reclamation: IPC has also filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the U.S. for the lost generation resulting from the reduced flows and a prospective declaration of contractual rights so as to prevent the U.S. from continued failure to fulfill its contractual and fiduciary duties to IPC. On May 22, 2009, the court entered an order extending the discovery schedule until September 2, 2009 and requiring that discovery be completed and pre-trial motions filed by February 3, 2010. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy in Canyon County, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho against IDACORP and IPC. The plaintiffs complaint asserted claims for negligence, negligence per se, gross negligence, nuisance, and fraud. The claims were based on allegations that from 1972 until at least March 2005, IPC discharged stray voltage from its electrical facilities that caused physical harm and injury to the plaintiffs dairy herd. Plaintiffs sought compensatory damages of not less than $1 million. In April 2009, IDACORP and IPC settled the lawsuit with the plaintiffs, and on May 8, 2009 the Idaho Supreme Court dismissed the plaintiffs appeal pursuant to stipulation of the parties. The settlement did not have a material effect on IDACORP or IPC.

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

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

Bureau of Land Management (BLM) Fire Claims: Effective July 1, 2009, IPC reached an agreement with the Idaho District of the BLM to settle for approximately $1 million 15 Idaho District wildland fire related claims, or potential claims, by the BLM. The fires occurred between 2005 and 2008 in the vicinity of electrical facilities operated by IPC. The BLM had not determined the exact cause of any of these fires, and in settling the claims IPC did not admit liability for the BLM s damages. With limited exceptions, this agreement settles all known or unknown claims in the BLM Idaho District, as of the effective date of the settlement. IPC has also agreed to an investigative protocol applicable to future fire claims.

8. BENEFIT PLANS:

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

	Pension Plan		Senior Management Security Plan		Postretirement Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	$ 4,052	$ 3,730	$ 403	$ 319	$ 278	$ 224
Interest cost	6,985	6,600	713	668	900	797
Expected return on plan assets	(5,895)	(8,562)	-	-	(545)	(685)
Amortization of transition obligation	-	-	-	-	510	510
Amortization of prior service cost	163	162	58	48	(133)	(134)
Amortization of net loss	2,308	-	165	122	231	-
Net periodic benefit cost	7,613	1,930	1,339	1,157	1,241	712
Costs not recognized due to the effects of regulation(1)	(7,613)	(1,930)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	$ -	$ -	$ 1,339	$ 1,157	$ 1,241	$ 712

(1)

Under IPUC order, income statement recognition of pension costs has been deferred until cash contributions are made and costs are recovered through rates.

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

	Pension Plan		Senior Management Security Plan		Postretirement Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	$ 8,257	$ 7,460	$ 805	$ 639	$ 610	$ 551
Interest cost	13,932	13,196	1,427	1,335	1,782	1,677
Expected return on plan assets	(11,983)	(17,056)	-	-	(1,073)	(1,423)
Amortization of transition obligation	-	-	-	-	1,020	1,020
Amortization of prior service cost	326	325	116	96	(267)	(267)
Amortization of net loss	4,428	-	330	244	421	-
Net periodic benefit cost	14,960	3,925	2,678	2,314	2,493	1,558
Costs not recognized due to the effects of regulation(1)	(14,960)	(3,925)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	$ -	$ -	$ 2,678	$ 2,314	$ 2,493	$ 1,558

(1) Under IPUC order, income statement recognition of pension costs have been deferred until cash contributions are made and costs are recovered through rates.

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid required contributions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of the funding requirements. IDACORP and IPC have elected to use asset smoothing.

On March 31, 2009, the U.S. Treasury Department (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from a range of months in selecting a yield curve, rather than requiring the use of prescribed rates. The Treasury s announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. The revisions in the PPA, WRERA, Treasury guidance, and IRS guidance resulted in IDACORP and IPC revising the funded status as of January 1, 2009 to being above the minimum required funding level, effectively reducing or delaying the required contributions from IDACORP and IPC from what would otherwise be required, and what was previously disclosed. Based on the provisions and methodologies allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to their pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in each of 2011 and 2012, and $41 million in 2013. IDACORP and IPC may elect to make contributions earlier than the required dates.

Changes in expected contributions from amounts disclosed in prior filings are due to preliminary actuarial estimates not fully reflecting provisions and methodologies allowed under the PPA, WRERA, Treasury guidance, and IRS guidance. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact funding requirements. IDACORP and IPC continue to monitor the legislative and regulatory environments for additional funding relief proposals, evaluating them for their potential impact on funding requirements and strategies.

9. INVESTMENTS IN DEBT AND EQUITY SECURITIES:

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

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

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

	June 30, 2009			**December 31, 2008**		
	Gross Unrealized Gain	**Gross Unrealized Loss**	**Fair Value**	**Gross Unrealized Gain**	**Gross Unrealized Loss**	**Fair Value**
Available-for-sale - IPC	$ 603	$ 183	$ 15,074	$ -	$ -	$ 14,451
	3	-	495	3	25	9,448

Held-to-maturity - IFS

At the end of each reporting period, IDACORP and IPC analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At June 30, 2009, one available-for-sale security was in an unrealized loss position. The security is an investment in broadly diversified equity index funds used to fund IPC s Senior Management Security Plan (SMSP). Based on the severity and duration of the loss, IDACORP and IPC did not recognize an other-than-temporary impairment for the unrealized loss.

The following table summarizes securities that were in an unrealized loss position at June 30, 2009, and December 31, 2008, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Less than 12 months		**12 months or longer**	
	Aggregate Unrealized Loss	**Aggregate Related Fair Value**	**Aggregate Unrealized Loss**	**Aggregate Related Fair Value**
2009:				
Available-for-sale equity securities (IPC)	$ 183	$ 4,507	$ -	$ -
2008:				
Held-to-maturity debt securities (IFS)	-	-	25	3,975

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

	Three months ended June 30,		**Six months ended June 30,**	
	2009	**2008**	**2009**	**2008**
Proceeds from sales	$ 4,103	$ -	$ 8,965	$ -
Gross realized gains from sales	-	-	11	-
Gross realized losses from sales	35	-	35	-

10. FAIR VALUE MEASUREMENTS:

The following tables present information about IDACORP s and IPC s assets and liabilities measured at fair value on a recurring basis as of June 30, 2009 (in thousands of dollars). IDACORP s and IPC s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
IDACORP				
Assets:				
Derivatives	$ 394	$ 22	$ -	$ 416
Money market funds	8,411	-	-	8,411
Trading securities: Equity securities	5,391	-	-	5,391
Available-for-sale securities:				
Equity securities	15,076	-	-	15,076
Liabilities:				
Derivatives	$ (929)	$ (5,994)	$ -	$ (6,923)
IPC				
Assets:				
Derivatives	$ 394	$ 22	$ -	$ 416
Money market funds	8,059	-	-	8,059
Trading securities: Equity securities	4,499	-	-	4,499
Available-for-sale securities:				
Equity securities	15,076	-	-	15,076
Liabilities:				
Derivatives	$ (929)	$ (5,994)	$ -	$ (6,923)

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

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

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

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

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

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

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

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

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

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

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

	June 30, 2009			
	Carrying Amount		**Estimated Fair Value**	
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable	$	2,238	$	2,238
Debt Securities		492		495
Liabilities:				
Long-term debt	$	1,202,193	$	1,136,459
IPC				
Liabilities:				
Long-term debt	$	1,197,754	$	1,132,021

11. SEGMENT INFORMATION:

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

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

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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 June 30, 2009:				
Revenues	$ 242,518	$ 1,116	$ -	$ 243,634
Income attributable to IDACORP, Inc.	26,326	1,149	-	27,475
Total assets at June 30, 2009	3,914,849	153,128	(25,301)	4,042,676
Three months ended June 30, 2008:				
Revenues	$ 228,945	$ 1,281	$ -	$ 230,226
Income (loss) attributable to IDACORP, Inc.	17,728	(213)	-	17,515
Six months ended June 30, 2009:				
Revenues	$ 470,547	$ 1,661	$ -	$ 472,208
Income attributable to IDACORP, Inc.	45,610	749	-	46,359
Six months ended June 30, 2008:				
Revenues	$ 441,740	$ 1,925	$ -	$ 443,665
Income attributable to IDACORP, Inc.	38,999	232	-	39,231

12. DERIVATIVE INSTRUMENTS

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

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

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

As of June 30, 2009, IPC had the following outstanding derivative commodity forward contracts that were entered into for the purpose of economically hedging forecasted purchases and sales:

Commodity	**Number of Units**	
Electricity purchases	564,800	MWh
Electricity sales	220,000	MWh
Natural gas	2,797,750	MMBtu
Diesel	446,150	gallons

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The following table presents the fair values and locations of derivatives not designated as hedging instruments recorded in the balance sheet at June 30, 2009 (in thousands of dollars):

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

Current:							
	Financial swaps	Other current assets	$	1,002	Other current liabilities	$	2,224
	Financial swaps	Other current liabilities		1,470	Other current assets		613
	Forward contracts			-	Other current liabilities		5,994
Long term:							
	Financial swaps	Other assets		391	Other liabilities		260
	Financial swaps	Other liabilities		41			-
	Forward contracts	Other liabilities		22			-
Total			$	2,926		$	9,091

The following table presents the effect on income of derivatives not designated as hedging instruments under SFAS 133 for the quarter ended June 30, 2009 (in thousands of dollars):

Commodity derivatives	**Location of Gain/(Loss) Recognized in Income on Derivative**	**Amount of Gain/(Loss) Recognized in Income on Derivative** [(1)]	
Financial swaps	Off-system sales	$	2,287
Financial swaps	Purchased power		(1,664)

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

The following table presents the effect on income of derivatives not designated as hedging instruments under SFAS 133 for the six months ended June 30, 2009 (in thousands of dollars):

Commodity derivatives	**Location of Gain/(Loss) Recognized in Income on Derivative**	**Amount of Gain/(Loss) Recognized in Income on Derivative** [(1)]	
Financial swaps	Off-system sales	$	2,287
Financial swaps	Purchased power		(2,421)

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

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

Credit Risk

At June 30, 2009, IPC does not have material credit exposure from financial instruments, including derivatives. IPC monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. IPC manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits or letters of credit from counterparties or their affiliates, as deemed necessary. The majority of IPC s contracts are under the Western Systems Power Pool agreement that provides for adequate assurances if a counterparty has debt that is downgraded to below investment grade by at least one rating agency. IPC also requires North American Energy Standards Board

contracts as necessary for physical gas transactions, and International Swaps and Derivatives Association, Inc. contracts as needed for financial transactions.

Credit-Contingent Features

Certain of IPC s derivative instruments contain provisions that require IPC s unsecured debt to maintain an investment grade credit rating from each of the major credit rating agencies. If IPC s unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on June 30, 2009, is $7.6 million. IPC has posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on June 30, 2009, IPC could have been required to post $6.7 million of cash collateral to its counterparties.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the Company) as of June 30, 2009, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2009 and 2008, and of cash flows for the six-month periods ended June 30, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

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

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

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

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
August 6, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary (the Company) as of June 30, 2009, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2009 and 2008, and of cash flows for the six-month periods ended June 30, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

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

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

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

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
August 6, 2009

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

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

INTRODUCTION:

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

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

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

IDACORP s other subsidiaries include:

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

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

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

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements of IDACORP and IPC. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2008, and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, and should be read in conjunction with the discussions in those reports.

FORWARD-LOOKING INFORMATION:

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

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

Changes in and compliance with state and federal laws, policies and regulations, including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the

North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates;

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

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

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

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

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

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

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

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

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

Population growth rates and other demographic patterns;

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

Increases in uncollectible customer receivables;

Fluctuations in sources and uses of cash;

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

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

Changes in interest rates or rates of inflation;

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

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

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

Homeland security, acts of war or terrorism;

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

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

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

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

EXECUTIVE OVERVIEW:

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

	Three months ended June 30,		**Six months ended June 30,**	
	2009	**2008**	**2009**	**2008**
Net income attributable to IDACORP, Inc.	$ 27,475	$ 17,515	$ 46,359	$ 39,231
Average outstanding shares - diluted (000s)	46,977	45,155	46,927	45,101
Earnings per diluted share	$ 0.58	$ 0.39	$ 0.99	$ 0.87

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for the three and six months ended June 30, 2008 to June 30, 2009 (in millions):

		Three months ended		**Six months ended**	
June 30, 2008			$ 17.5		$ 39.2
Change in IPC net income:					
Improved generating conditions and regulatory changes	$	11.9		$ 17.8	
Reduced sales volumes, net of cost adjustment mechanism		(10.2)		(15.0)	
Change in distribution of base net power supply costs		6.5		-	
Oregon 2007 excess power cost deferral order		6.4		6.4	
Reduced transmission revenues		(1.7)		(2.9)	
Improved results at Bridger Coal Company		0.4		4.5	
Gain on the sale of the Southwest Intertie Project		(3.0)		(2.9)	
Other		(1.7)		(1.3)	
Total increase in IPC net income			8.6		6.6
Other net increases (shown net of tax)			1.4		0.6

June 30, 2009	$ 27.5	$ 46.4

Changes to the Idaho PCA mechanism and base rate increases that both took effect February 1, 2009, positively impacted net income, as did improved hydroelectric generating conditions.

IPC s retail customer sales volumes were down eight percent for the quarter and six percent year-to-date, due primarily to weather conditions. To a lesser extent economic factors contributed to the reduction in sales volume. Precipitation in the second quarter of 2009 was more than double the same period in 2008, contributing to a 19 percent decrease in sales to irrigation customers. Temperatures were more moderate in IPC s service territory, resulting in 22 percent and 9 percent declines in heating degree days in the quarter and year-to-date, respectively.

In May 2008 an Idaho Public Utilities Commission (IPUC) Order changed the allocation of base net power supply costs in IPC s PCA mechanism, retroactive to March 1, 2008. The PCA deferral for the second quarter of 2008 was reduced $6.5 million to reflect the effect of the order on the March 2008 PCA calculation (thereby reducing earnings in the second quarter of 2008). A May 2009 Oregon Public Utility Commission (OPUC) stipulation allowed the deferral for future recovery of $6.4 million of excess power supply costs incurred in 2007 and reduced PCA expense in the second quarter of 2009.

Also contributing to the increase in year-to-date earnings was the return to more normal operations at Bridger Coal Company, which had experienced losses in the first half of 2008, primarily due to difficulties related to its longwall mining operation. These 2008 first half losses were recovered by year end 2008 through increased coal prices.

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Transmission revenues for the quarter and year-to-date periods were lower than 2008 principally due to reductions in prices and volumes sold. In 2008 IPC recorded a $3.0 million gain on the sale of a portion of the Southwest Intertie Project.

Capital Requirements

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

Langley Gulch power plant (2012 baseload resource): On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). Langley Gulch will be a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs and is anticipated to be in operation by December 2012, although IPC is working to advance the in-service date from December 2012 to June 2012. IPC proposes to construct Langley Gulch in Payette County, approximately four miles south of New Plymouth, Idaho, commencing in summer 2010 at an estimated cost of $427 million. On July 14-16, 2009, the IPUC conducted both technical and public hearings on IPC s application. IPC anticipates an order will be issued in the third quarter of 2009.

Gateway West transmission project: IPC and PacifiCorp are jointly exploring the Gateway West Project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. The estimated cost for IPC s share of the project is between $500 million and $600 million. The lines will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third-party transmission service requests. This project is intended to relieve existing congestion by increasing transmission capacity and to improve reliability to comply with reliability regulations. Initial phases of the project could be completed by 2014.

Boardman-Hemingway transmission project: IPC is also exploring alternatives for the construction of a 500-kV line between southwestern Idaho at the Hemingway substation and the Northwest at the Boardman substation. IPC estimates construction costs of $600 million and expects to seek partners for up to 50 percent of the project when construction commences. The Boardman-Hemingway Line will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third-party transmission service requests. This project is intended to relieve existing congestion by increasing transmission capacity and to improve reliability to comply with reliability regulations. Current estimates for the project in-service date have been delayed from 2013 to 2015.

Liquidity

Pension Plan: Provisions of the Pension Protection Act (PPA), relief provisions of the Worker, Retiree, and Employer Recovery Act (WRERA), U.S. Treasury Department (Treasury) guidance, and IRS guidance require that if a company does not meet minimum funding levels, the company must make additional contributions to improve the funded status of the plan. The funded status of IPC s pension plan at January 1, 2009, was above the minimum required funding levels as revised by the PPA, WRERA, Treasury guidance and IRS guidance. Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to the pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in both 2011 and 2012, and $41 million in 2013.

Regulatory Matters

Oregon 2009 General Rate Case: On July 31, 2009, IPC filed an application with the OPUC requesting an average rate increase of approximately 22.6 percent, or $7.3 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.68 percent with equity at 49.8 percent of total capitalization. Oregon jurisdictional rate base included in the application is $110.8 million.

IPC filed its case based upon a 2009 test year. The new rates are filed with a requested effective date of August 31, 2009. Assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs, the new rates would become effective May 31, 2010. IPC is unable to predict what relief the OPUC will grant.

Oregon 2007-2008 Excess Power Costs: On May 28, 2009, the OPUC adopted a stipulation allowing IPC to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for the period May 1 through December 31, 2007. IPC recorded this deferral in the second quarter of 2009. The amount to be recovered was reduced by $0.9 million of emission allowance sales previously deferred, resulting in an approved deferral balance of $5.5 million. This deferral is discussed in more detail in REGULATORY MATTERS - Oregon - 2007-2008 Excess Power Costs.

Idaho and Oregon Rate Orders: IPC received five additional rate orders from the IPUC and the OPUC at the end of May 2009. The IPUC rate orders are for the Fixed Cost Adjustment Mechanism, Idaho Energy Efficiency Rider, Advanced Metering Infrastructure, and Power Cost Adjustment, and the additional OPUC rate order is for the Annual Power Cost Update. Each of these orders increases rates, but only the Advanced Metering Infrastructure order involves an increase in IPC s rate base, relating to the installation of new meters. These orders are discussed in additional detail in REGULATORY MATTERS.

Idaho OATT Shortfall Filing: On July 20, 2009, IPC filed a request with the IPUC for authorization to defer $8.1 million associated with shortfalls in the amount of OATT revenues that IPC will receive between March 2008 and May 2010. The filing includes $4.3 million for the period through January 2009, and $3.8 million estimated for the period from February 2009 to May 2010. IPC requested to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning June 1, 2010 and to receive a carrying charge on the balance until rate recovery begins. This filing is discussed in more detail in REGULATORY MATTERS Idaho OATT Shortfall Filing.

OATT Amended Legacy Agreements: In April and June 2009 IPC submitted filings to the FERC to increase rates under agreements IPC has with PacifiCorp. The combined annual transmission revenue impact of the revised agreements is estimated to be a $7.1 million net increase. On July 28, 2009, the FERC accepted one of IPC s filings for a net transmission revenue increase of $3.2 million. PacifiCorp has intervened in the other case and on July 10, 2009 filed a motion to suspend the case for five months and pursue settlement or go to hearing. The filings are discussed in more detail in REGULATORY MATTERS Federal Regulatory Matters OATT Amended Legacy Agreements.

Integrated Resource Plan: IPC is currently preparing the 2009 IRP, which was originally expected to be completed in June 2009. In light of the economic changes since September 2008 and in response to the OPUC s desire for additional analysis regarding the Boardman to Hemingway Transmission Project, IPC filed a request for extension with the IPUC and OPUC to delay the filing of the 2009 IRP until December 2009. The IPUC and OPUC have granted the requested extension and IPC is currently updating the load forecast that will be used for the 2009 IRP.

Environmental Issues

Climate Change: Climate change regulations will have major implications for IPC and the energy industry. IPC has increased disclosure about its CO_2 emissions and will continue to track and analyze pending greenhouse gas legislation. In addition, the American Clean Energy and Security Act of 2009 as passed in the U.S. House of Representatives on June 26, 2009, would require utilities to obtain 15 percent of their electricity from renewable sources by 2020, and reduce demand an additional five percent through conservation and increased energy efficiency. These issues are discussed in more detail in LEGAL AND ENVIRONMENTAL ISSUES Environmental Issues.

Idaho Water Management Issues: Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at IPC s hydroelectric projects on the Snake River. On March 25, 2009, IPC and the State of Idaho (State)

entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters. For a further discussion of water management issues see LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues.

Other Issues

American Recovery and Reinvestment Act of 2009: The American Recovery and Reinvestment Act of 2009 (ARRA), enacted on February 17, 2009, includes tax and appropriation benefits to the utility industry. IPC continues to evaluate opportunities under ARRA as the details are clarified. On July 15, 2009, IPC submitted a Letter of Intent with the Department of Energy (DOE) regarding IPC s nonbinding intention to apply for the DOE s Integrated and/or Crosscutting Systems. The grant application to the DOE is expected to be submitted August 6, 2009, and details the $45 million of currently budgeted project funds IPC would invest towards the Smart Grid as well as incremental projects that would be funded if awarded a DOE matching grant.

2009 Operating and Financial Metrics Outlook

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

	2009 Estimates	
	Current	**Previous**
IPC Operation & Maintenance Expense (Millions)	No change	$280-$290
IPC Capital Expenditures (Millions) (1)	No change	$220-$230
IPC Hydroelectric Generation (Million MWh) (2)	7.5-8.5	6.5-8.5
Non-regulated Subsidiary Earnings and Holding Company Expenses (Millions)	No change	$0.0-$3.0
Effective Tax Rates(3):		
IPC	26%-31%	31%-35%
Consolidated IDACORP	19%-24%	24%-28%

(1) For the three-year period, 2009-2011, IPC expects to spend approximately $730-750 million. This amount includes expenditures for the siting and permitting of major transmission expansions for Boardman to Hemingway, Gateway West, Hemingway Station and the Hemingway Bowmont facilities, but excludes the costs for the Langley Gulch power plant. On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant. A decision from the IPUC is expected in the third quarter of 2009. If the IPUC issues the CPCN in a form that permits IPC to secure financing on acceptable terms, IPC expects to spend between $50 million and $55 million during 2009 on this project. IPC s estimate for construction of Langley Gulch power plant is $427 million, including transmission interconnection costs.

(2) The range of estimated hydroelectric generation has been revised to reflect actual generation through June and estimated ranges of generation for the remainder of the year. Significant drivers include above normal precipitation during June and the impacts of above normal storage levels in reservoirs above Brownlee dam.

(3) The effective tax rate ranges at IPC and IDACORP are lower principally due to the settlement of the 2006 IRS examination and the state of Idaho s adoption of the 2009 federal bonus depreciation provisions.

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RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP s and IPC s earnings during the three and six months ended June 30, 2009. In this analysis, the results for 2009 are compared to the same periods in 2008.

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

	Three months ended June 30,		**Six months ended June 30,**	
	2009	**2008**	**2009**	**2008**
IPC - Utility operations	$ 26,326	$ 17,728	$ 45,610	$ 38,999
IDACORP Financial Services	188	701	329	1,502
Ida-West Energy	1,384	908	1,572	963
IDACORP Energy	(29)	(11)	(48)	(23)
Holding company	(394)	(1,811)	(1,104)	(2,210)
Net income attributable to IDACORP, Inc.	$ 27,475	$ 17,515	$ 46,359	$ 39,231

Average common shares outstanding (diluted)		46,977		45,155		46,927		45,101
Earnings per diluted share	$	0.58	$	0.39	$	0.99	$	0.87

Utility Operations

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

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

Hydroelectric generation in the first six months of 2009 was much improved over 2008, due to a combination of above normal June rainfall and near normal runoff from an improved snowpack. Hydroelectric generation was 124 percent and 99 percent of the 30-year average for the quarter and year-to-date, respectively.

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The following table presents IPC s power supply for the three and six months ended June 30:

MWh

	Hydroelectric Generation	Thermal Generation	Total System Generation	Purchased Power	Total
Three months ended:					
June 30, 2009	2,976	1,121	4,097	539	4,636
June 30, 2008	2,077	1,393	3,470	968	4,438
Six months ended:					
June 30, 2009	4,561	3,087	7,648	1,200	8,848
June 30, 2008	3,740	3,372	7,112	1,655	8,767

As of July 31, 2009, reservoir levels in selected federal reservoirs upstream of Brownlee were at 122 percent of average. The observed April through July Brownlee reservoir inflow was 5.6 million acre-feet (maf), or 89 percent of the NWRFC average, an increase over the 2008 April through July inflow of 4.4 maf, which was 70 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 7.5 and 8.5 million MWh from its hydroelectric facilities in 2009, compared to 6.9 million MWh in 2008.

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

IPC s system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand established on June 30, 2008 is 3,214 MW. During this and other similar heavy load periods IPC s system is fully committed to serve loads and meet required operating reserves. The all-time winter peak demand is 2,464 MW, set on January 24, 2008.

General business revenue: The following table presents IPC s general business revenues, MWh sales, number of customers and Boise, Idaho weather conditions for the three and six months ended June 30:

	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Revenue				
Residential	$ 77,757	$ 74,067	$ 184,204	$ 169,309
Commercial	53,415	47,333	104,957	92,008

Industrial	33,307	29,280	64,352	55,937
Irrigation	36,106	38,068	36,676	38,806
Deferred revenue related to Hells Canyon relicensing AFUDC	(2,370)	-	(4,047)	-
Total	$ 198,215	$ 188,748	$ 386,142	$ 356,060
MWh				
Residential	1,048	1,097	2,582	2,686
Commercial	894	926	1,851	1,924
Industrial	755	827	1,536	1,678
Irrigation	559	686	566	697
Total	3,256	3,536	6,535	6,985
Customers (average)				
Residential	404,590	401,934	404,499	401,545
Commercial	64,113	63,297	64,097	63,124
Industrial	126	122	125	122
Irrigation	18,800	18,388	18,666	18,264
Total	487,629	483,741	487,387	483,055
Customers (period end)				
Residential			404,804	402,320
Commercial			64,115	63,427
Industrial			127	122
Irrigation			18,859	18,485
Total			487,905	484,354
Heating degree-days	641	821	3,173	3,501
Cooling degree-days	208	213	208	213
Precipitation (inches)	3.24	1.44	5.57	4.14

Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average of the daily high and low temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. Normal heating degree-days for the second quarter and year-to-date are 767 and 3,341 degree-days, respectively. Normal cooling degree days for the second quarter and year to date are both 156 degree-days. Normal precipitation for the second quarter and year-to-date is 3.28 and 7.22 inches, respectively.

As part of its February 1, 2009, general rate case order, the IPUC allowed IPC to recover AFUDC for the Hells Canyon Complex relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. IPC expects to collect approximately $10.6 million annually, but must defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service. This deferral offset revenues by approximately $2.4 million for the quarter and $4.0 million year-to-date.

General business revenue increased $9.5 million for the quarter and $30.1 million year-to-date as compared to the same periods in 2008. This increase is primarily attributable to the effects of rate changes and was partially offset by a decrease in customer usage:

Rates: Rate changes positively impacted general business revenue $23.9 million for the quarter and $52.2 million year-to-date due to PCA rate increases of $14.2 million and $31.2 million for the quarter and year-to-date, respectively. Increases in retail base rates, discussed in REGULATORY MATTERS, also increased revenues $9.8 million and $20.9 million for the quarter and year-to-date, respectively.

Also impacting rates is a new tiered rate structure for residential and small commercial customers implemented as part of the February 1, 2009, general rate case. In shoulder months, when customers are using less heating or cooling, revenues should be lower compared to the prior year. However, during peak heating and cooling months, revenues should be higher compared to the prior year. The table below presents the residential rates by tier.

Residential Rate Structure February 1, 2008	**Summer**	**Non-Summer**	**Residential Rate Structure February 1, 2009**	**Summer**	**Non-Summer**
0-300 kWh	5.6973 cent	5.6973 cent	0-800 kWh	5.9750 cent	5.5792 cent
Above 300 kWh	6.4125 cent	5.6973 cent	801-2,000 kWh	7.2798 cent	6.1991cent
			Above 2,000 kWh	8.7358cent	7.1290cent

- **Customers**: Growth in customer count in IPC s service territory increased revenue $2.9 million for the quarter and $5.1 million year-to-date. Average customer count by class increased from the prior period as follows:

Customer Class	**Quarter Change %**	**Year-to-date Change %**
Residential	0.7	0.7
Commercial	1.2	1.4
Industrial	3.2	2.8
Irrigation	2.2	2.2
Overall weighted total	1.5	1.4

Usage: Changes in usage decreased general business revenue $17.4 million for the quarter and $27.1 million year-to-date, due to milder temperatures, increased precipitation and a weaker economy. The impact of this reduction is partially mitigated by the Load Growth Adjustment Rate (LGAR) and Fixed Cost Adjustment (FCA) Mechanisms, both of which were put in place to manage the impact of changes in sales volumes from levels included in base rates.

Off-system sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The following table presents IPC s off-system sales for the three and six months ended June 30:

	Three months ended June 30,		**Six months ended June 30,**	
	2009	**2008**	**2009**	**2008**

Revenue	$	26,667	$	25,641	$	55,198	$	59,004
MWh sold		1,095		504		1,672		1,022
Revenue per MWh	$	24.35	$	50.88	$	33.01	$	57.73

Off-system sales revenue increased $1.0 million, or four percent, for the quarter and decreased $3.8 million, or seven percent year-to-date. Although lower system load and improved hydroelectric generating conditions increased the amount of electricity available for sale, there was a corresponding drop in the price for wholesale power.

Other revenues: The table below presents the components of other revenues for the three and six months ended June 30:

	Three months ended June 30,				**Six months ended June 30,**			
	2009		**2008**		**2009**		**2008**	
Transmission services and property rental	$	8,963	$	10,628	$	16,476	$	19,383
Energy efficiency		8,673		3,928		12,731		7,293
Total	$	17,636	$	14,556	$	29,207	$	26,676

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

An IPUC order allows IPC to record energy efficiency program expenditures as an operating expense with an offsetting amount recorded in other revenues, resulting in no net effect on earnings. Energy efficiency revenues and expenses increased $4.7 million for the quarter and $5.4 million year-to-date, reflecting increased program expenditures.

Purchased power: The following table presents IPC s purchased power expenses and volumes for the three and six months ended June 30:

	Three months ended June 30,				**Six months ended June 30,**			
	2009			**2008**	**2009**		**2008**	
Purchased power expense	$	25,091	$	50,089	$	57,886	$	95,387
MWh purchased		539		968		1,200		1,655
Cost per MWh purchased	$	46.55	$	51.74	$	48.24	$	57.64

Purchased power expense decreased $25.0 million, or 50 percent, for the quarter and $37.5 million, or 40 percent year-to-date. Lower system loads and more favorable hydroelectric generating conditions decreased the amount of purchased power IPC needed to serve loads and the cost per MWh.

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

	Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008	
Fuel expense	$	24,475	$	28,681	$	63,608	$	65,918
Thermal MWh generated		1,121		1,394		3,087		3,372
Cost per MWh	$	21.83	$	20.57	$	20.61	$	19.55

Fuel expense decreased $4.2 million, or 15 percent, for the quarter and $2.3 million, or four percent, year-to-date due to lower system load and increased hydro generation. The nine percent decrease in volume was partially offset by a five percent increase in price due to coal costs at the Jim Bridger plant, which increased due to Bridger Coal Company s continuing transition to underground mining.

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

The following table presents the components of the PCA for the three and six months ended June 30:

		Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008
Idaho power supply cost accrual (deferral)	$	8,402	$	(4,969)	$	(2,005)	$	(25,169)
Oregon 2007-2008 excess power cost order		(6,358)		-		(6,358)		-
Amortization of prior year authorized balances		24,718		4,140		50,984		6,596
Total power cost adjustment	$	26,762	$	(829)	$	42,621	$	(18,573)

The PCA and PCAM increased expenses $27.6 million for the quarter and $61.2 million year-to-date, primarily due to an increase in the amortization of prior year authorized balances and changes in actual and forecasted net power supply costs. In addition, an order from OPUC that allows IPC to defer for future recovery $6.4 million of costs incurred in 2007 and 2008 was recorded in the second quarter of 2009. Also, due to the IPUC s approval of the even monthly distribution of base net power supply costs on May 30, 2008 retroactive to March 1, 2008, IPC recognized

$6.5 million of PCA expense related to the March 2008 time period in the second quarter 2008.

Effect of the Distribution of Base Net Power Supply Costs on Quarterly Results:
On May 30, 2008, the IPUC approved changes from a seasonal distribution to an even monthly distribution of the base net power supply costs included in the 2007 general rate case for use in the calculation of the Idaho PCA deferral. The adopted allocation was effective retroactive to March 1, 2008. Effective February 1, 2009, the monthly allocation method was changed again, to a method based on monthly general business sales volumes.

While the distribution methodology used does not affect the total amount of base net power supply costs used to calculate the PCA deferral for a full year, it does affect the quarters in which they are allocated and thus impacts quarterly results.

The following table reconciles base net power supply costs used in the PCA mechanism in 2008 and 2009 and shows the estimated after-tax earnings impact of the change in allocation method. The third and fourth quarter 2009 amounts are projections based on the mechanism currently in effect (in millions of dollars):

	June 30 year-to-date	**Third Quarter**	**Fourth Quarter**	**Total**
Base net power supply costs 2008	$ 51.2	$ 31.2	$ 31.2	$ 113.7
Change in monthly allocation method	(4.7)	7.6	(2.9)	-
Increase due to base changes from rate cases	22.5	8.7	6.3	37.4
Base net power supply costs 2009	$ 69.0	$ 47.5	$ 34.6	$ 151.1
Estimated impact on net income of the changes in allocation methods (2009 vs. 2008), after jurisdictionalization	$ 2.6	(4.2)	$ 1.6	$ -

Due to the IPUC s approval of the even monthly distribution of base net power supply costs on May 30, 2008, retroactive to March 1, 2008, IPC recognized $6.5 million of PCA expense related to the March 2008 time period in the second quarter 2008.

Other operations and maintenance expenses: Other operations and maintenance expense increased $0.9 million for the quarter and $1.3 million year-to-date. The quarter increase was primarily attributable to a $3.4 million increase in payroll-related expense and a $0.8 million increase in charges for uncollectible accounts, partially offset by a $3.2 million decrease in outside services due to budget reductions.

The year-to-date increase was primarily attributable to a $5.5 million increase in payroll-related expenses, a $1.7 million increase for a FERC fees refund to ratepayers, a $1.0 million increase in charges to uncollectible accounts, and a $1.2 million increase in thermal O&M due to higher maintenance costs at the Bridger plant. Partially offsetting these increases are a decrease of $4.3 million in outside services due to budget reductions, and a $3.1 million decrease from the fixed cost adjustment mechanism.

The increases in charges for uncollectible accounts are due to the deterioration of the economy across IPC s service area and are driven primarily by write-offs for residential and commercial customers. Although receivables for these customer classes decreased nine percent from December 31, 2008, to June 30, 2009, the related allowance for uncollectible accounts increased seven percent, corresponding with the increase in write-offs for these customer classes. Irrigation allowance reserves are seasonal, and decreased 61 percent from December 31, 2008, to June 30, 2009, primarily due to irrigation reserves at December 31, 2008, being written off or reversed due to collection by June 30, 2009. There were no significant fluctuations in industrial customer class write-offs or reserves.

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Non-utility Operations

IFS: IFS s net income decreased $0.5 million for the quarter and $1.2 million year-to-date compared to the same periods of 2008. The reductions are principally due to lower tax benefits caused by the continued aging of existing investments. IFS s 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 $12.1 million in new investments and generated tax credits of $4.1 million through June 30, 2009.

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 for the six months ended June 30, 2009, was 20.5 percent, compared to 24.2 percent for the six months ended June 30, 2008. IPC s effective tax rate for the six months ended June 30, 2009, was 27.7 percent, compared to 33.6 percent for the six months ended June 30, 2008. The decrease in the 2009 estimated annual effective tax rates from 2008 is primarily due to an examination settlement, state bonus depreciation, and timing and amount of other regulatory flow-through tax adjustments at IPC. The decreases were partially offset by additional income tax expense from greater pre-tax earnings at IDACORP and IPC, and lower tax credits from IFS.

In April 2009, the state of Idaho adopted the federal bonus depreciation provisions enacted as part of the American Recovery and Reinvestment Act of 2009. IPC s regulatory tax accounting method allows for the flow-through of certain state tax adjustments, including accelerated depreciation. Due to the application of the bonus depreciation provision, IPC was able to reduce its income tax expense by $1.5 million as of June 30, 2009.

The Internal Revenue Service (IRS) completed its examination of IDACORP s 2006 tax year in May 2009. The 2006 examination report was submitted for U.S. Congress Joint Committee on Taxation (JCT) review in June. In July, the JCT completed its review and accepted the report without change. As of June 30, 2009, IDACORP considered all uncertain tax positions related to its 2006 tax year effectively settled and decreased IPC s liability for unrecognized tax benefits by $1.3 million.

In March 2009, the JCT completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 IRS examination report. The JCT accepted both items without change. IDACORP considered these matters effectively settled in 2008 and recorded the related financial effects in its December 31, 2008 financial statements.

The IRS began its examination of IDACORP s 2007-2008 tax years in July 2009. In May 2009, IDACORP formally entered the IRS Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. The 2007-2009 examinations are expected to be completed in 2010. IDACORP and IPC are unable to predict the outcome of these examinations.

LIQUIDITY AND CAPITAL RESOURCES:

Operating Cash Flows

IDACORP s and IPC s operating cash inflows for the six months ended June 30, 2009, were $111 million and $114 million, respectively. These amounts were an increase of $57 million and $53 million, respectively, compared to the six months ended June 30, 2008.

The following are significant items that affected operating cash flows in 2009:

Collection of previously deferred net power supply costs increased $44 million compared to 2008.

Income tax refunds of $13 million and $23 million for IDACORP and IPC, respectively for the settlement of the 2005 IRS examination were received in the first quarter.

A refund of $13 million was made to IPC s transmission customers upon a final order from the FERC on IPC s OATT. The OATT is discussed further in REGULATORY MATTERS - Federal Regulatory Matters - OATT.

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

Investing Cash Flows

IDACORP s and IPC s investing cash outflows were $96 million and $99 million, respectively for the six months ended June 30, 2009. Investing cash outflows are primarily for IPC s utility construction and a $6 million investment in affordable housing at IFS. The outflows were partially offset by $9 million received from the sale of investments held by IFS, $2 million proceeds from the sale of the SWIP by IPC and $2 million proceeds from the sale of emission allowances by IPC.

Financing Cash Flows
IDACORP s and IPC s financing cash outflows for the six months ended June 30, 2009 were each $7 million compared to inflows of $63 million and $49 million, respectively, for the six months ended June 30, 2008.

The following are significant items that affected financing cash flows in 2009:

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

Under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan, IDACORP issued 204,340 common shares for proceeds of $4.9 million.

IDACORP and IPC reduced short-term debt by $72 million and $76 million, respectively.

IDACORP and IPC paid dividends of $28 million.

On February 27, 2009, IFS repaid $7 million of its outstanding debt.

Economic Environment
IDACORP and IPC continue to assess the impact on their financial position, if any, of financial market developments, such as the bankruptcy and restructuring or merging of certain financial institutions. IDACORP and IPC continue to have access to the capital markets and have been able to generate funds internally and acquire funds externally to meet their capital requirements. IDACORP s and IPC s ability to attract the necessary financial capital at reasonable terms is critical to their overall strategic plan because IDACORP and IPC rely on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of funding for capital requirements not satisfied by internally generated funds. IDACORP and IPC expect that operating cash flows, together with the revolving credit facilities and other external financing, will be adequate to meet their operating and capital needs, although it is possible that changes in the global capital and credit markets will restrict or deny access to these markets on commercially acceptable terms.

Financing Programs

Shelf Registrations: IDACORP has approximately $588 million remaining on a shelf registration statement that can be used for the issuance of debt securities and common stock. On March 30, 2009, IPC issued $100 million of its 6.15% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt in anticipation of utilizing short-term debt to repay its $80 million 7.20% First Mortgage Bonds that mature on December 1, 2009. IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

Credit Facilities: The following table outlines available liquidity.

	June 30, 2009				December 31, 2008			
	IDACORP		IPC		IDACORP		IPC	
Revolving credit facility	$	100,000	$	300,000	$	100,000	$	300,000
Commercial paper outstanding		(42,369)		(32,830)		(13,400)		(108,950)
Floating rate draw		-		-		(25,000)		-
Identified for other use [1]		-		(24,245)		-		(24,245)
Net balance available	$	57,631	$	242,925	$	61,600	$	166,805

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

IDACORP s credit facility is a $100 million five-year credit agreement that terminates on April 25, 2012. IDACORP s credit facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million. IDACORP has the right to request an increase in the aggregate principal amount of the IDACORP Facility to $150 million and to request one-year extensions of the then existing termination date. At June 30, 2009, no loans were outstanding on IDACORP s credit facility and $42 million of commercial paper was outstanding. At August 3, 2009, no loans and $42 million of commercial paper was outstanding.

IPC s credit facility is a $300 million five-year credit agreement that terminates on April 25, 2012. IPC s credit facility, which will be used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IPC has the right to request an increase in the aggregate principal amount of the IPC Facility to $450 million and to request one-year extensions of the then existing termination date. At June 30, 2009, no loans were outstanding on IPC s credit facility and $33 million of commercial paper was outstanding. At August 3, 2009, no loans and $22 million of commercial paper was outstanding.

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

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

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

Debt Covenants: The IDACORP credit facility, the IPC credit facility and the Term Loan Credit Agreement each contain covenants requiring the company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At June 30, 2009, the leverage ratios for IDACORP and IPC were 52 percent and 54 percent, respectively. At June 30, 2009, IDACORP and IPC were each in compliance with all other covenants in

their respective credit facilities and the Term Loan Credit Agreement. Please refer to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008, for a discussion of additional debt covenants.

Pollution Control Revenue Refunding Bonds: On April 3, 2008, IPC made a mandatory purchase of two series of Pollution Control Revenue Refunding Bonds issued for the benefit of IPC, the $116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of the financial guarantor s credit ratings deterioration. The Pollution Control Bonds remain outstanding and have not been retired or cancelled. IPC is the current holder of the bonds.

IPC has given notice, subject to rescission, to adjust the interest rate period of the Pollution Control Bonds from a weekly interest rate period to a term interest rate period effective August 20, 2009 in connection with the remarketing of the bonds to investors without the financial guaranty insurance policy.

Credit Ratings

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

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

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

Capital Requirements

IPC is experiencing a cycle of heavy infrastructure investment needed to address expected customer growth, peak demand growth, reliability, and aging plant and equipment. IPC must also add capacity to its baseload generation, transmission system and distribution facilities to ensure adequate supply of electricity, to provide new service to customers and to maintain system reliability. IPC s aging hydroelectric and thermal facilities require continuing upgrades and component replacement, and the costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Due to the heavy infrastructure requirements from 2009-2011, IPC has focused only on critical infrastructure needs that relate to system reliability and resource adequacy, which has reduced its estimated ongoing capital expenditures in the table below. IPC expects to spend between $730 and $750 million on construction related activities from 2009 to 2011, excluding the Langley Gulch power plant. While internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2009 through 2011, IDACORP and IPC expect minimal, if any, need for external financing in 2009 and 2010, except for issuances under dividend reinvestment and employee-related plans. IDACORP and IPC expect to continue financing capital requirements with a combination of internally generated funds and externally financed capital.

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

	2009		2010-2011	
Ongoing capital expenditures	$	150-155	$	360-375
Advanced Metering Infrastructure (AMI)		20-22		40-50
Major projects excluding Langley Gulch (detailed below)		50-53		85-95
Minimum transmission for Baseload Resource		-		15-20
Total	$	220-230	$	500-540

Major Projects:

Langley Gulch Power Plant (2012 Baseload Resource): On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant. IPC requested that the IPUC issue its order in the Langley Gulch CPCN case by September 1, 2009. Langley Gulch will be a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs. The plant is anticipated to be in operation by December 2012, although IPC is working to advance the in-service date from December 2012 to June 2012. IPC proposes to construct Langley Gulch near New Plymouth, Idaho, commencing in summer 2010. The plant would connect to existing transmission lines.

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

IPC s estimate for construction of Langley Gulch is $427 million, including transmission interconnection costs. IPC s application requests that amounts incurred in excess of the estimate would be included in rates only if the IPUC agreed the additional amounts were prudent and should be included in rates. Should the CPCN be granted by the IPUC, IPC would spend between $50 and $55 million during 2009 on the project.

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

On May 29, 2009 a joint motion was filed in the Langley Gulch case by the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the Snake River Alliance, the Idaho Conservation League and the Northwest &

Intermountain Power Producers Coalition, requesting that the IPUC stay the Langley Gulch case for at least ten months (Request for Stay). The Request for Stay asserted that the stay should be granted by the IPUC because (1) IPC should first respond to the advisory shareholder proposal adopted by IDACORP s shareholders in May 2009, relating to reductions in IPC greenhouse gas emissions, (2) IPC s 2009 Integrated Resource Plan is not scheduled to be filed until December 2009, (3) IPC s request for IPUC ratemaking preapproval for Langley Gulch, based on Idaho s newly adopted rate commitment statute, increases the importance of the IPUC s decision on Langley Gulch, (4) IPC should be able to negotiate an extension, perhaps at additional cost, of the September 1, 2009, payment dates for the purchase of the Siemens turbines for Langley Gulch, (5) IPC has already delayed the on-line date for Langley Gulch from

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the summer of 2012 to December 2012, and IPC s next peak load following the summer of 2012 will not occur until the summer of 2013, (6) the continuing recession has reduced the demand for new IPC generation facilities, and the need for Langley Gulch should be reassessed when a general economic recovery has begun, (7) PacifiCorp is mothballing planned generation expansions, and (8) the impacts of IPC s demand response programs have not been ascertained.

On June 12, 2009, IPC filed its response opposing the Request for Stay. IPC asserted the stay should not be granted because delaying the IPUC decision until after September 1, 2009, would delay the 2012 in-service date for the project and jeopardize IPC s ability to meet customer loads in 2012 and beyond. Langley Gulch is scheduled to fill the key 2012 baseload resource requirement identified in IPC s current IRP and customer load projections continue to show the need for Langley Gulch generation capacity by a 2012 in-service date. Based on the current load projections, IPC is working to advance the Langley Gulch in-service date from December 2012 to June 2012 by providing incentives to the construction contractors.

Delaying the IPUC CPCN decision beyond September 1, 2009, would increase IPC s exposure to cancellation fees and non-refundable contract payments under IPC s gas turbine and steam turbine purchase agreements for Langley Gulch. The gas turbine and steam turbine are the largest equipment items for Langley Gulch, with a total price of approximately $90 million.

On June 19, 2009, the IPUC issued a finding which concluded that there are very real consequences to the requested stay and the case should continue on its originally established schedule. On July 14-16, 2009, the IPUC conducted both technical and public hearings on IPC s application.

On July 31, 2009, a joint renewed motion for a Request for Stay for at least 10 months was filed by the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the Snake River Alliance, the Idaho Conservation League, the Northwest & Intermountain Power Producers Coalition, and the Community Action Partnership Alliance. The Request for Stay asserted that the stay should be granted by the IPUC because (1) IPC did not fully comply with IPUC Order No. 30201, which directed IPC to pursue energy efficiency and demand response to potentially displace or defer the need for additional future peaking generation, (2) IPC s pre-purchase of equipment for the project should not justify denial of the Request for Stay, (3) the RFP process was flawed and a failure to delay the proceedings will send the wrong signal to the development community, (4) the forecast demand for electricity in

IPC s service territory versus the actual trends for such demand support a stay of the proceeding, and (5) regulatory pre-approval for Langley Gulch expenditures is unnecessary and would be imprudent in light of serious concerns surrounding the Langley Gulch project. IPC has not responded to this motion.

For the project, IPC entered into two equipment supply contracts with Siemens Energy, Inc. (Siemens) a gas turbine purchase agreement dated December 19, 2008, and a steam turbine purchase agreement dated February 11, 2009. IPC has paid approximately $9 million to Siemens to reserve the turbine equipment purchases under the contracts, with no further payment required before September 2009. Each contract requires: IPC pay a fixed price for the equipment; Siemens to guarantee delivery of the equipment to the site by specific dates that will accommodate the project schedule, or incur liquidated damages; Siemens to guarantee that the equipment will meet specified performance and emission standards, or incur liquidated damages; Siemens to warrant for a period of time that the equipment is free from defects; and Siemens to provide certain technical field assistance and consultation services under the contracts. The contracts are assignable by IPC with the consent of Siemens (which consent may not be unreasonably withheld). IPC also has the right to cancel the contracts at any time by paying specified cancellation charges detailed below.

Under the gas turbine purchase agreement with Siemens (Gas Turbine Agreement), IPC s purchase of the gas turbine is subject to IPUC issuance of the CPCN by September 1, 2009, among other conditions. In the event IPC does not receive the CPCN by September 1, 2009, the Gas Turbine Agreement would automatically terminate, unless IPC and Siemens reach an agreement within 30 days after that date to modify the contract price, equipment delivery schedule and other affected terms and conditions of the Gas Turbine Agreement. Upon such termination, IPC would be required to pay a cancellation fee of 35 percent of the total purchase price of the gas turbine, less any payments already made by IPC under the Gas Turbine Agreement. The Gas Turbine Agreement also contains a schedule of cancellation fees IPC must pay if it

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terminates the Gas Turbine Agreement at any time during the contract term, absent assignment of the Gas Turbine Agreement by IPC with the written consent of Siemens. The cancellation fees are based on a percentage of the total gas turbine purchase price and increase monthly from 20 percent on July 1, 2009 to 100 percent on or after September 1, 2010.

The steam turbine purchase agreement with Siemens (Steam Turbine Agreement) also contains a cancellation fee schedule. IPC has the right to terminate the Steam Turbine Agreement at any time upon paying a cancellation fee to Siemens based on a percentage of the total purchase price of the steam turbine, absent assignment of the Steam Turbine Agreement by IPC with the written consent of Siemens. The Steam Turbine Agreement cancellation fee percentage increases monthly from 10 percent on February 1, 2009 to 100 percent on or after May 1, 2011. The cancellation fee is 15 percent on September 1, 2009.

IPC must make non-refundable contract payments to Siemens under the Gas Turbine Agreement beginning on September 1, 2009, in addition to its previous non-refundable reservation fee payment of $2.75 million. IPC s September 1, 2009 contract payment is approximately 20 percent of the total gas turbine purchase price, with additional monthly payments thereafter, concluding with the final contract payment on January 1, 2011. The cumulative amount of IPC s contract payments under the Gas Turbine Agreement would be offset against any cancellation fees owed by IPC under the Gas Turbine Agreement.

IPC must make non-refundable contract payments to Siemens under the Steam Turbine Agreement beginning on September 11, 2009, in addition to its previous non-refundable payments for the steam turbine - the reservation fee payment of approximately $2.9 million and the initial contract payment of approximately $3.1 million. IPC s September 11, 2009 contract payment is 14 percent of the total steam turbine purchase price, with additional contract payments due in March 2010, September 2010 and April 2011, and a smaller final contract payment due at final acceptance of the steam turbine. The cumulative amount of IPC s contract payments under the Steam Turbine Agreement would be offset against any cancellation fees owed by IPC under the Steam Turbine Agreement.

On May 7, 2009, IPC entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company (collectively, the Contractor), for design, engineering, procurement, construction management and construction services for Langley Gulch.

The EPC Agreement is the primary agreement governing the proposed development of Langley Gulch, providing for the specific design, engineering and construction work to be performed, as well as the equipment procurement. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost.

The EPC Agreement provides that IPC is to issue a Full Notice to Proceed (FNTP) to the Contractor no later than September 1, 2009 to authorize the Contractor to commence and complete all work under the EPC Agreement. IPC plans to issue the FNTP by September 1, 2009 if it has (1) received an acceptable CPCN from the IPUC, (2) received board approval and (3) identified satisfactory financing options for the project at that time. The EPC Agreement provides that if IPC does not issue the FNTP by November 1, 2009, the Contractor may terminate the EPC Agreement, which termination will be without liability to either party other than for the Contractor s costs properly incurred pursuant to any work performed under the Master Services Agreement between IPC and the Contractor dated October 3, 2008. The amounts payable under the Master Services Agreement are not expected to be material to IPC.

IPC is required to make monthly progress payments to the Contractor under the EPC Agreement beginning in October 2009. The first twelve monthly progress payments between October 2009 and September 2010 will represent approximately one-fourth of the total payments scheduled to be made by IPC under the EPC Agreement. IPC may terminate the EPC Agreement at any time if it abandons the Langley Gulch project. Upon such termination, the Contractor is entitled to keep the progress payments previously paid by IPC, and IPC would be required to pay the value of the work completed to the date of termination not previously covered by IPC progress payments, plus a 15 percent markup on such costs.

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

Hemingway-Bowmont Transmission Line: As part of the Hemingway Station Project, the Hemingway-Bowmont transmission line is expected to provide power to the Treasure Valley in southwest Idaho by 2010. The Hemingway-Bowmont line will consist of 12 miles of new 230-kV double circuit transmission line. Originally, this transmission line was planned to pass near Bowmont and terminate at Hubbard. The original plan called for 12 miles of new line and reconstruction of 17 miles of existing 138-kV transmission line to 230-kV. The change of termination points from Hubbard to Bowmont allows the Hemingway Station to be energized and provide improved reliability at a reduced cost. The 230-kV connection between Bowmont and Hubbard will be built in the future as system needs dictate. The new estimate for this project is approximately $15 million.

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

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. This project will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. It is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC s share of the initial phase of engineering, environmental review, permitting and rights-of-way is approximately $40 million and cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table. Construction costs are currently not included in our 2009 to 2011 forecast. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires. On July 16, 2009, the BLM, IPC and PacifiCorp announced an agreement to extend the time period for the public to submit reasonable alternatives into the draft environmental impact statement (DEIS) for the project. The DEIS was originally scheduled to be issued in August or September 2009. The new schedule will allow for input until September 4, 2009, which will delay the issuance of the DEIS for six or seven months. It is not known how this will ultimately affect the construction schedule at this time.

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

As a result of continued uncertainty in credit and financial markets, IDACORP and IPC continue to assess their capital expenditure plans.

Contractual Obligations

The following items are the only material changes to contractual obligations made outside of the ordinary course of business since December 31, 2008:

IPC entered into a contract to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. IPC s coal purchases under the contract are expected to total $127 million from 2010 to 2014.

On February 4, 2009, IPC entered into a $170 million Term Loan Credit Agreement. The loans are due February 3, 2010 and are discussed above under Financing Programs Term Loan Credit Agreement.

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

On May 13, 2009, IFS issued a $6 million equity funding obligation to finance its investment in affordable housing. The obligation is scheduled to mature in 2010.

In February, 2009, IPC entered into a contract with EnerNOC to implement and operate a demand response program for its commercial and industrial customers. IPC estimates it will spend approximately $12.2 million on the program during the five year term of the contract.

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

As discussed above in Capital Requirements Major Projects Langley Gulch Power Plant (2012 Baseload Resource), IPC entered into a contract with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company for design, engineering, procurement, construction management and construction services for Langley Gulch. If the IPUC approves the project, the total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost for Langley Gulch.

Pension funding has been revised downward, as discussed below.

Pension Plan

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid required contributions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. IPC has elected to use asset smoothing. On March 31, 2009, the U.S. Treasury Department (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from the range of months in selecting a rate, rather than requiring the use of the rate in the month of measurement (December for calendar year-end companies). The Treasury s announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years.

The revisions in the PPA, WRERA, Treasury guidance and IRS guidance resulted in IDACORP and IPC revising the funded status of their pension plan at January 1, 2009, to above the minimum required funding levels and reducing or delaying future required contributions from what was previously disclosed. Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to their pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in each of 2011 and 2012, and $41 million in 2013. IDACORP and IPC may elect to make contributions earlier than the required dates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

REGULATORY MATTERS:

Idaho Rate Cases

2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased IPC s Idaho revenue requirement by an additional $6.1 million, to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

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

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Langley Gulch (2012 Baseload Resource)

On March 6, 2009, IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). Six parties have filed to intervene in the proceeding. Hearings were held July 14-16, 2009. IPC is awaiting a final order. Please see further discussion in LIQUIDITY AND CAPITAL RESOURCES - Major Projects - Langley Gulch Power Plant (2012 Baseload Resource).

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

Special Customer Electric Service Agreements

Micron: On January 26, 2009, the IPUC granted authority to temporarily amend IPC s electric service agreement with one of its largest customers, Micron Technology, Inc. (Micron) for the period January 1, 2009, through June 30, 2009 to provide Micron flexibility in restructuring its operations. This amendment was revenue neutral for IPC and did not have a significant impact on IPC s earnings. On June 17, 2009 IPC filed a subsequent application requesting an order approving an extension of the temporary amendment to the electric service agreement through December 31, 2009. The extension is not expected to have a significant impact on IPC s 2009 earnings. The IPUC approved IPC s application on July 31, 2009.

Hoku: On September 17, 2008, IPC entered into an electric service agreement with a new customer, Hoku Materials, Inc. (Hoku), to provide electric service to Hoku s polysilicon production facility under construction in Pocatello, Idaho. The IPUC approved the electric service agreement on March 16, 2009. The initial term of the agreement was four years beginning June 1, 2009, with a maximum demand obligation during the initial term of 82 MW.

On May 27 and June 19, 2009, IPC and Hoku amended certain provisions of the electric service agreement (Amended ESA). The Amended ESA was filed with the IPUC for approval on June 22, 2009, and approved by the IPUC on July 24, 2009. Under the Amended ESA, the starting date for Hoku s required purchases of power under the ESA will be delayed from June 1, 2009 to December 1, 2009. Under the Amended ESA (i) IPC will provide electricity to Hoku at the current Schedule 19 Large Industrial tariff rate through November 30, 2009; (ii) Hoku will take no more than 5 MW of electric power through July 2009, 10 MW during August 2009 and 25 MW for each month from September through November 2009; (iii) Hoku will take reduced levels of electric power of no more than 43 MW during the period June 16, 2012 through August 15, 2012 and 67 MW during the period August 16, 2012 through September 15, 2012; and (iv) Energy Efficiency Rider charges will be added to a portion of the electricity demand charges, beginning on December 1, 2011.

The ESA Amendment is not expected to have a material impact on IPC s 2009 earnings. While the six-month delay in the starting date for Hoku s required energy purchases will reduce IPC s 2009 revenues, this revenue reduction is expected to be largely offset by corresponding reductions in IPC s costs of providing service to Hoku. Any revenue reductions that are not offset by corresponding cost reductions would flow through IPC s power cost adjustment mechanism in Idaho, further reducing the impact on IPC s earnings.

Oregon Rate Cases

2009 General Rate Case: On July 31, 2009, IPC filed an application with the OPUC requesting an average rate increase of approximately 22.6 percent, or $7.3 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.68 percent with equity at 49.8 percent of total capitalization. Oregon-jurisdictional rate base included in the application is $110.8 million. IPC filed its case based upon a 2009 test year. The new rates are filed with a requested effective date of August 31, 2009. Assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs, the new rates would become effective May 31, 2010. IPC is unable to predict what relief the OPUC will grant.

Deferred (Accrued) Net Power Supply Costs

The following table presents the balances of deferred (accrued) net power supply costs, including applicable carrying charges:

	June 30, 2009	December 31, 2008
Idaho PCA current year:		
Deferral for the 2009-2010 rate year	$ -	$ 93,657
Accrual for the 2010-2011 rate year	(8,418)	-
Idaho PCA true-up awaiting recovery:		
Authorized in May 2008	-	47,164
Authorized in May 2009	101,719	-
Oregon deferral:		

2001 Costs		536		1,663
2006 Costs		2,369		1,215
2007 Costs		5,985		-
2008 Power cost adjustment mechanism		5,615		5,400
Total deferral	$	107,806	$	149,099

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

The annual adjustments are based on two components:

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

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

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

<u>2009-2010 PCA:</u> On April 15, 2009, IPC filed its 2009-2010 PCA with the IPUC with a requested effective date of June 1, 2009. The filing requested an increase to existing revenues of approximately $93.8 million or 11.4 percent. IPC subsequently provided its updated April operating plan, which reflected the need for increased revenues of $84.3 million or 10.2 percent.

The 2009-2010 PCA reflects a new methodology, approved by the IPUC on January 9, 2009, and discussed in PCA Workshops below that utilizes IPC s most recent operating plan to forecast power supply expenses rather than the previous method based on a forecast of Brownlee Reservoir inflow and a regression formula.

On May 29, 2009, the IPUC approved the 2009-2010 PCA of $84.3 million or 10.2 percent, effective June 1, 2009.

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

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

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

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

LGAR - the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on the formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.

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

Inclusion of third-party transmission expense - transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of

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net power supply costs. Deviation in these types of costs from levels included in base rates is now reflected in PCA computations.

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

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

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

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

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

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast resulted in a requested increase to Oregon revenues of 11.46 percent, or $3.9 million annually. A joint stipulation relating to the October Update and the March Forecast by IPC, the OPUC Staff and the Citizens Utility Board in support of IPC s requested increase was filed with the OPUC on May 4, 2009. On May 26, 2009, the OPUC issued its order adopting the stipulation and approving the rate increases set forth in the stipulation effective on June 1, 2009.

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

2008 PCAM: On February 27, 2009, IPC filed the true-up of its net power supply costs for the period January 1 through December 31, 2008, with the OPUC. The 2008 PCAM filing reflects a deviation of actual net power supply costs above the forecast for that period of $7.4 million. After the application of the deadband, the filing requests that $5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed below under 2007-2008 Excess Power Costs. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference was held July 7, 2009. As a result of the conference, IPC will file updated testimony that reflects agreed upon changes to the calculation of the deferral.

2007-2008 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the 8-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was determined that IPC should be allowed to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for that period. The amount to be recovered was reduced by $0.9 million of emission allowance sales (including interest) during the same period allocated to Oregon, resulting in an approved deferral balance of $5.5 million. IPC recorded the $6.4 million deferral in the second quarter 2009 as a reduction to power cost adjustment expense. The emission allowances sales were previously deferred. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. On May 28, 2009, the OPUC issued its order adopting the stipulation.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year ($1.9 million for 2009 based on 2008 revenues). On October 6, 2008, the OPUC issued an order clarifying that the PCAM is a deferral under the Oregon statute.

IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC. Full recovery of the 2001 deferral is expected in the third quarter of 2009. The 2006-2007 deferral of $2.4 million, the May 1-December 31, 2007 deferral of $6.0 million and the $5.6 million 2008 PCAM balance will have to be recovered sequentially following the full recovery of the 2001 deferral.

On June 30, 2009, IPC filed an application with the OPUC to begin amortizing through rates the 2006-2007 deferral of $2.0 million plus $0.4 million of accrued interest, effective September 1, 2009. IPC expects amortization of this deferral to take approximately 16 months.

Fixed Cost Adjustment Mechanism (FCA)

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

IPC deferred fixed costs of $2.0 million related to the FCA during the first six months of 2009.

On March 13, 2009, IPC filed an application requesting a $5.2 million rate increase under the FCA pilot program for the net under-recovery of fixed costs during 2008, effective June 1, 2009 through May 31, 2010. On May 29, 2009, the IPUC approved IPC s application to increase rates under the FCA pilot program as filed.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of $2.4 million to be distributed to residential and small general service customer classes

equally on an energy used basis during the June 1, 2008, through May 31, 2009, FCA revenue collection period.

Energy Efficiency Matters

Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in conservation, energy efficiency and demand response programs. On March 13, 2009, IPC filed an application with the IPUC requesting an increase in Rider funding to 4.75 percent of base revenues effective June 1, 2009. On May 29, 2009, the IPUC approved IPC s application to increase the Rider as filed. As a result of the IPUC approval, based on 2008 test year revenue, IPC expects Rider revenues of $27.3 million in 2009 and $33.2 million in each of 2010 and 2011.

Effective June 1, 2008, IPC began collecting 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

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

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

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

Commercial Demand Response: On March 2, 2009, IPC filed for approval of a voluntary Commercial Demand Response program for commercial and industrial customers larger than 200 kilowatts. IPC signed a five-year contract with a third-party aggregator, EnerNOC, to operate the program and make arrangements with IPC s customers to achieve peak reductions. This program is dispatchable (meaning IPC will have flexibility to schedule peak reduction benefits during times of greatest need) and, in the next four years, is expected to increase to 50 MW of summer peak demand reduction availability by 2012. The anticipated cost of the program, which will be funded through the Rider, is approximately $12.2 million over its first five years. The IPUC approved the program on May 15, 2009.

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

Renewable Energy Certificates

On November 14, 2008 IPC filed an application requesting authority from the IPUC to retire renewable energy certificates (RECs), sometimes referred to as green tags, associated with the Elkhorn Valley Wind Project and the Raft River Geothermal Project. IPUC Staff and the Industrial Customers of Idaho Power (ICIP) filed comments opposing the retirement of IPC s RECs, while various environmental groups expressed support. On January 26, 2009, the IPUC approved IPC s application requesting authority to retire the RECs. Thereafter ICIP filed a Petition for Reconsideration which was granted. On May 20, 2009 the IPUC reversed its decision and ordered IPC to sell its eligible RECs generated in 2007 and 2008. It is expected that the proceeds from the sale of the RECs will be included in IPC s 2010 PCA filing.

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

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million. The OPUC Staff accepted IPC s settlement offer, and a stipulation was filed on June 5, 2009. In the settlement offer, IPC proposed that the OPUC Staff not make adjustments to the depreciation rates adopted by the IPUC and also proposed to commit to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction. IPC s request was filed in conjunction with the October 3, 2008, application discussed below in Advanced Metering Infrastructure (AMI).

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

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

IPC filed AMI evaluation and deployment reports with the IPUC on May 1 and August 31, 2007, in compliance with an IPUC order. Consistent with the implementation plan contained in those reports, IPC entered into a number of contracts for materials and resources that allowed for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of its customers by the end of 2011.

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

On March 13, 2009, IPC filed an application with the IPUC for authority to increase its rates due to the inclusion of AMI investment in rate base. The filing requested inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and those investments that would be made during a June 1, 2009, through May 31, 2010 test year. IPC requested a first year revenue requirement of $11.2 million in the Idaho jurisdiction effective June 1, 2009, for service provided on or after that date. In its calculations, IPC reflected the reduction in investment and the accelerated depreciation costs related to the removal of current metering equipment, as well as changes in operating expenses that accompany the changes in plant investment.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on IPC s actual investment in AMI to date, annualized through December 31, 2009, rather than IPC s proposed test year. The IPUC also allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. The actual depreciation expense for fiscal year 2009 will occur over seven months totaling $5.5 million.

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

Deferred Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the pension plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, Employers' Accounting for Pensions, as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. IPC deferred $14.9 million of pension expense in the first six months of 2009 and has deferred $25.5 million since the order became effective in 2007. IPC does not receive a carrying charge on the deferral balance.

Idaho OATT Shortfall Filing

On July 20, 2009 IPC filed a request with the IPUC for authorization to defer $8.1 million in costs associated with the difference between the revenue credits and the amount of OATT revenues IPC has received since March 2008 and will receive through May 2010. For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to the IPC s overall revenue requirement. In the last two general rate cases, IPC included an estimate of OATT revenues from third parties based on the forecasted OATT rate less a reserve. However, as discussed below in Federal Regulatory Matters OATT, the FERC order issued on January 15, 2009 had a significant impact on actual third-party transmission revenues IPC received from June 2006 to date, resulting in the overstating of the revenue credits in the Idaho jurisdictional revenue requirement authorized by the IPUC. Included in the filing are $4.3 million for the period March 1, 2008 through January 31, 2009, the effective period of the February 28, 2008 general rate case order, and $3.8 million estimated for the period February 1, 2009 through May 31, 2010, the expected effective period of the January 30, 2009 general rate case order. IPC has filed a request for rehearing of the FERC order and is taking additional measures to address the revenue shortfall. If the FERC issues are resolved in IPC s favor, IPC will reduce the deferral. IPC requested to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning June 1, 2010 and to receive a carrying charge on the balance until rate recovery begins.

Rule H Modifications

On October 30, 2008, IPC filed an application seeking authority to modify its Rule H tariff, which governs the allocation between real-estate developers and IPC of the costs of installing or altering distribution equipment to serve new customers. The application requested an increase to the charges for new service attachments, distribution line installations and alterations in order to shift more of the cost burden to new customers requesting construction for these services. On July 1, 2009 the IPUC approved the application with minor modifications. The IPUC also clarified that IPC should not bear the costs incurred to relocate distribution facilities located in public rights-of-way when the relocation is ordered for the benefit of a private development. These changes to Rule H are effective on November 1, 2009. The IPUC has received requests for reconsideration from four parties.

Federal Regulatory Matters

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

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

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

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

A mediation process within the Ninth Circuit Court was initiated in an attempt to settle issues raised in the appeals. Three meetings were held in February and March 2009 between the BPA, IOUs, other regional customers of the BPA and state utility commissions to determine if there is common ground for an overall settlement of the Residential Exchange Program issues. The mediation effort was unsuccessful, and the court established briefing schedules with initial briefs to be filed on August 19, 2009 and briefing to conclude on February 26, 2010. Oral argument has not yet been scheduled.

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

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

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

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

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

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

<u>Amended Legacy Agreements:</u> Subsequent to the January 15, 2009 FERC Order, IPC has sought to mitigate the resulting revenue shortfall by revising certain of the Legacy Agreements as provided for in the agreements.

On April 3, 2009, IPC notified PacifiCorp that it was terminating its provision of a portion of the services that it provides under the Restated Transmission Service Agreement (RTSA), a Legacy Agreement, effective June 12, 2009. IPC made a filing with the FERC on April 13, 2009 submitting revised rate schedule sheets. The FERC accepted the revised rate schedule sheets by letter order on May 14, 2009. On June 12, 2009 IPC submitted a filing for the purpose of replacing the terminated contract services with OATT service, effective June 13, 2009. An amended RTSA between IPC and PacifiCorp and three long term service agreements were filed to provide for the OATT service. As calculated in the filings, the estimated net transmission revenue increase for the period June 13, 2009 through June 12, 2010 is approximately $3.2 million. The FERC accepted IPC s filing, effective June 13, 2009, by letter order on July 28, 2009.

On June 19, 2009 IPC submitted a filing to increase rates under the Agreement for Interconnection and Transmission Services (ITSA) contract, another Legacy Agreement between IPC and PacifiCorp. The filing requested an increase of rates to the level paid by OATT customers for Point to Point service and an August 19, 2009 effective date. As calculated in the filing, the estimated net transmission revenue increase

for the period September 1, 2009 through August 31, 2010 is approximately $3.9 million. PacifiCorp has intervened in the case and on July 10, 2009 filed a motion to suspend the case for five months and pursue settlement or go to hearing.

2009 OATT: On June 1, 2009, IPC posted on its Open Access Same-Time Information System (OASIS) website its draft informational filing which contains the annual update of the formula rate to the 2008 test year. The draft informational filing includes a proposed rate of $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. The impact of this rate increase on IPC s revenues will be dependent on transmission volume sold, which can be highly variable. A customer meeting to discuss the informational filing was held on June 16, 2009. A final filing will be submitted to the FERC by September 1, 2009 with new rates effective October 1, 2009.

2008 OATT: On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The new rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. New rates were effective October 1, 2008. IPC has adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009, order.

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

Public Utility Regulatory Policies Act of 1978

As mandated by the enactment of PURPA and the adoption of avoided cost rates by the IPUC and the OPUC, IPC has entered into contracts for the purchase of energy from a number of private developers. Under these contracts, IPC is required to purchase all of the output from the facilities located inside the IPC service territory. For projects located outside the IPC service territory, IPC is required to purchase the output that IPC has the ability to receive at the facility s requested point of delivery on the IPC system. The IPUC jurisdictional portion of the costs associated with CSPP contracts are fully recovered through base rates and the PCA. For IPUC jurisdictional contracts, projects that generate up to ten average MW of energy on a monthly basis are eligible for IPUC Published Avoided Costs for up to a 20-year contract term. The OPUC jurisdictional portion of the costs associated with CSPP contracts is recovered through general rate case filings. For OPUC jurisdictional contracts, projects with a nameplate rating of up to ten MW of capacity are eligible for OPUC Published Avoided Costs for up to a 20-year contract term. The Published Avoided Cost is a price established by the IPUC and the OPUC to estimate IPC s cost of developing additional generation resources. If a PURPA project does not qualify for Published Avoided Costs, then IPC is required to negotiate the terms, prices and conditions with the developer of that project. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location and size) and the benefits to the IPC system and must be consistent with other similar energy alternatives.

On March 12, 2009, the IPUC increased the Published Avoided Cost rates. For example, the rate for a 20 year levelized 2009 contract increased from $69.54/MWh to $88.92/MWh. This increase will result in the

continuation of a favorable climate for PURPA project development, and may require IPC to enter into additional PURPA agreements. The requirement to enter into additional PURPA agreements may result in IPC acquiring energy at above wholesale market prices and at times when a surplus already exists as well as requiring additional operational integration costs, thus increasing costs to its customers.

Integrated Resource Plan

IPC s integrated resource planning process forecasts IPC s load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. IPC s most recent IRP was completed in 2006 and the IRP is typically updated every two years.

At the request of the IPUC, the submittal of IPC s next IRP was delayed until June 2009 in order for IPC to align the submittal of its next IRP with the IRP s of other Idaho utilities. In June 2008, IPC filed the 2008 IRP Update as an informational filing with the IPUC and OPUC. IPC also prepared and filed the IRP Addendum with the OPUC in February 2009. The IRP Addendum specifically addressed the need for the Boardman to Hemingway Transmission Project and was later withdrawn due to public opposition to proposed routes and also to allow IPC to analyze the project in the 2009 IRP process.

IPC began preparing the 2009 IRP in August 2008. However, in light of the economic recession that developed since September 2008 when IPC prepared the load forecast being used for the 2009 IRP, and in response to the OPUC s desire for additional analysis regarding the Boardman to Hemingway Transmission Project, in April 2009 IPC filed a request for an extension with the IPUC and OPUC to delay the filing of the 2009 IRP until December 2009. The IPUC and OPUC have granted the requested extension and IPC is currently updating the load forecast that will be used for the 2009 IRP.

During the time between resource plan filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. IPC continues to analyze and evaluate the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. In addition, load and resource forecasts are routinely updated as described earlier in RESULTS OF OPERATIONS Utility Operations. Each of the sections below provides an update of items identified in the resource planning process.

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

Geothermal RFPs:
Although the 2008 Geothermal RFP for 50-100 MW did not result in IPC acquiring additional geothermal energy, IPC continues to work with project developers capable of delivering energy to its service area. IPC also continues to monitor developments in geothermal technology and is hopeful geothermal energy will become an economic and readily available resource for its customers.

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

Wind RFP: The 2006 IRP included 150 MW of wind generation coming on-line in 2012. In May 2009, IPC issued an RFP for up to 150 MW of wind generation to come on-line no later than the end of 2012. IPC accelerated the release of this RFP to take advantage of the benefits offered in the ARRA (the economic stimulus package). Proposals were received and are currently being evaluated.

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

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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 $110 million and $4 million for HCC and Swan Falls, respectively, were included in construction work in progress at June 30, 2009.

The IPUC authorized IPC to include in rates approximately $6.8 million ($10.6 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. This became effective February 1, 2009, and IPC collected approximately $2.2 million in the second quarter and $3.9 million year-to-date. Collecting these amounts in current rates will reduce future rates related to obtaining the new license once the accumulated relicensing costs are placed in service. Further discussion is provided above in Idaho Rate Cases 2008 General Rate Case.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately 68 percent of IPC s hydroelectric generating nameplate capacity and 36 percent of its total generating nameplate capacity. In July 2003, IPC filed an application for a new license in anticipation of the July 2005 expiration of the then-existing license. IPC is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the new license is issued.

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

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

Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, IPC has filed Water Quality Certification Applications, required under section 401 of the Clean Water Act, with the States of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Temperature and other water quality issues are of interest to various federal and state agencies, Native American tribes, and other parties who may provide input to the states certification process. IPC continues to work with Idaho and Oregon to ensure that any discharges from the HCC will comply with the necessary state water quality standards so that appropriate water quality certifications can be issued for the project.

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

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. In June 2008, IPC filed a license application with the FERC. On January 9, 2009, the FERC issued a scoping document giving notice of scheduled scoping meetings, soliciting scoping comments and of its intent to prepare an EIS pursuant to the NEPA. FERC held scoping meetings on February 10 and 11, 2009. On May 5, 2009, FERC issued Scoping Document 2 for the project, advising that based on the scoping meetings and comments received that staff will prepare an EIS, which the FERC will use to determine whether, and under what conditions, to issue a new hydropower license for the project. On June 16, 2009, FERC issued its Notice of Application Ready for Environmental Analysis and Soliciting Comments, Recommendations, Terms and Conditions, and Prescriptions. The deadline for filing comments, recommendations, terms and conditions, and prescriptions is August 15, 2009. The FERC expects to complete the EIS in 2010.

Section 401 of the Clean Water Act requires that an applicant for a federal license to conduct an activity that results in any discharge to navigable waters must provide the licensing agency with a certification from the state in which the discharge occurs that the discharge will comply with applicable water quality standards. In conformance with that section, on June 6, 2008, IPC filed an application with the Idaho Department of Environmental Quality (IDEQ) for section 401 water quality certification. On April 1, 2009, the IDEQ issued public notice, seeking public comment on a draft section 401 certification for the project. No public comments were submitted and the IDEQ issued the section 401 certification on May 4, 2009.

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

LEGAL AND ENVIRONMENTAL ISSUES:

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

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

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

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

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were

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proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds. A number of public entities filed petitions for panel rehearing in June 2007 and certain marketers filed petitions for rehearing and rehearing en banc in November 2007. Those requests were denied by the Ninth Circuit on April 6, 2009. The Ninth Circuit issued a mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court s decision.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection, but, consistent with obligations established in a settlement which is described in the following paragraph, IE and IPC withdrew that request for rehearing to the extent it pertained to the disputes about the cost filing between IE and IPC and parties that had joined the settlement. On June 18, 2009 FERC issued an order with respect to the cost filings of other sellers and in that order also stated that it was not ruling on the IE and IPC request for rehearing because it had been withdrawn. On July 8, 2009 IE and IPC sought further rehearing pointing out to the FERC that the withdrawal pertained only to the parties with whom IE and IPC had settled. On June 18, 2009 in a separate order, the FERC also ruled that net refund recipients in the California refund proceeding were responsible for the costs associated with all cost filings. Most of the parties that joined the IE and IPC settlement described below were net refund recipients, but until the Cal ISO completes its refund calculations it is uncertain whether any parties who opted not to join the settlement are net refund recipients. If there are no such parties, then the requests for rehearing will be moot. IE and IPC are unable to predict how or when the FERC might rule on their requests for rehearing, but their effect is confined to obligations of IE and IPC to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

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

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming (gaming) or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs.

In 2004, the FERC dismissed the partnership show cause proceeding against IPC. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by IPC.

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

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict Mobile-Sierra standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources (CDWR) in the proceeding. A number of parties have sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. On June 26, 2009 IE and IPC joined with a number of other parties in a request to extend the time for the filing of a joint petition for a writ of certiorari. On June 29, 2009 Justice Kennedy extended the time for the filing of the petition until September 4, 2009. On May 22, 2009 the California Parties filed a motion with the FERC to sever the CDWR sales from the remainder of the Pacific Northwest proceedings and to consolidate the CDWR sales portion of the Pacific Northwest case with ongoing proceedings in cases that IE or IPC have settled and with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled (Brown Complaint). On August 4, 2009, IE and IPC, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed positions in response to the motion of the California Parties. Also on August 4, 2009 the City of Tacoma, Washington and the Port of Seattle, Washington filed a motion with the FERC in connection with the California refund proceeding, the Lockyer remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and IPC previously were dismissed), the Brown *Complaint* and the Pacific Northwest refund remand proceeding. This latter motion asks the FERC (1) to make findings on a summary basis that the entire West-wide wholesale electricity market, including the

Pacific Northwest, was affected by market manipulation and that, as a result, jurisdictional sellers' rates exceeded just and reasonable levels throughout the Western energy crisis of 2000 - 2001, to grant market-wide refunds to all purchasers for amounts collected in excess of a just and reasonable price and to establish procedures to determine specific refund obligations applicable to sellers or, in the alternative, (2) to institute an evidentiary hearing and establish related procedures to respond to the remand proceedings ordered by the Ninth Circuit in Port of Seattle, Washington v. FERC that would include supplemental evidence filed with the motion and consideration of claimed violations of Market Based Rate Tariffs from January 1, 2000 through June 20, 2001, thereby expanding the scope of potential refunds to a period beginning prior to December 25, 2000. IE and IPC intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations or cash flows.

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

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

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

Sierra Club Lawsuit Bridger: IPC continues to monitor the Sierra Club and the Wyoming Outdoor Council suit against PacifiCorp filed in February 2007 in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant in Sweetwater County, Wyoming. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. IPC is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

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

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs response to the motion was filed February 25, 2009, and PGE s reply was filed April 8, 2009. The State of Oregon filed an amicus brief on April 1, 2009, addressing the substantive positions set forth in PGE s December 5, 2008, motion to dismiss and the plaintiffs February 25, 2009 response to the motion. The amicus brief does not state a position on the merits of the motion to dismiss but corrects what it perceives to be erroneous statements of law made by the plaintiffs and PGE regarding Oregon air quality regulations concerning the Prevention of Significant Deterioration program that were approved by the Environmental Protection Agency (EPA) and incorporated into Oregon s State Implementation Plan. Plaintiff s filed a sur-response in opposition to the motion to dismiss on May 18, 2009. IPC continues to monitor the status of this matter but is unable to predict its

outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

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

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

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

Environmental Issues

The section below summarizes and provides an update of environmental issues as discussed in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

Global Climate Change: Climate change regulations will have major implications for IPC and the energy industry. IPC has increased disclosure about its CO_2 emissions by posting additional information at the environmental section of its website and by submitting detailed information in May 2009 to the Carbon Disclosure Project (CDP), an independent not-for-profit organization that claims the largest database of corporate climate change information in the world. The website disclosure details:

Information about IPC s generation resources;

IPC s (and its unregulated energy affiliate, Ida-West Energy Company) emissions ranking as one of the 30 lowest carbon dioxide emitters per megawatt hour produced among the nation s 100 largest electricity producers according to a collaborative report from Ceres, the Natural Resources Defense Council, Public Service Enterprise Group, and PG&E Corporation using publicly reported 2006 generation and emissions data.

The CDP will post responding companies information at their website in the fall including IPC s estimated CO_2 Emission Rate (Lbs/MWh) from IPC generation facilities was 1,150 and 1,097 for 2007 and 2008, respectively.

IPC continues to closely track and analyze pending greenhouse gas (GHG) legislation. The analysis will continue in the ongoing 2009 IRP process, which includes involvement by and input from government, public and environmental organizations. The IRP process forecasts IPC s load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. The IRP process will review modeling options to address GHG and renewable portfolio standard issues.

On April 10, 2009, the EPA published the proposed mandatory GHG emissions reporting rule in the Federal Register that would require reporting from large sources of GHG emissions. The EPA plans to use the emission information collected to assist it in making future climate policy decisions, including the potential future regulation of GHG emissions. The comment period on the proposed rule closed on June 9, 2009. The reporting rule is scheduled to be finalized later this year.

On April 24, 2009, the EPA published a proposed endangerment finding in the Federal Register for GHG emissions from mobile sources that was the first step leading to the regulation of GHG emissions from mobile sources under the existing Clean Air Act. On May 19, 2009, the EPA and the U.S. Department of Transportation announced their intention to jointly develop national GHG emission standards for motor vehicles, applicable to model year 2012. On June 30, 2009, the EPA granted a request from the State of California to enable California to enforce its GHG emission standards for new motor vehicles. Based on these developments, it is possible that the EPA could subsequently make similar findings and proposals with respect to GHG emissions from stationary sources.

A modified version of the American Clean Energy and Security Act of 2009 bill from sponsors Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) passed the U.S. House of Representatives on June 26, 2009. Senate Environment & Public Works Chairman Barbara Boxer (D-CA) announced her intent to introduce a climate change bill on the Senate floor in early September. In addition, states and regional initiatives (including the Western Climate Initiative) are considering regional market-based mechanisms to reduce GHG emissions.

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

Renewable Electricity/Portfolio Standards: The American Clean Energy and Security Act of 2009 as passed in the U.S. House of Representatives on June 26, 2009, requires utilities to obtain 15 percent of their electricity from renewable sources by 2020, and reduce demand an additional five percent through conservation and increased energy efficiency. The Senate version, contained in the American Clean Energy Leadership Act of 2009, as reported favorably out of the Senate Committee on Energy and Natural Resources on June 17, 2009, requires electric utilities to meet 15 percent of their electricity sales through renewable sources of energy or energy efficiency by 2021. Resources eligible to meet these standards include wind, solar, geothermal, biomass, landfill gas, ocean, and incremental hydropower (efficiency improvements or new capacity). Both proposals recognize the benefits of existing hydroelectric generation by allowing utilities to subtract generation from existing hydroelectric projects from their total sales base prior to calculating the percentage requirement.

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

IPC is currently purchasing energy from seven wind projects with a combined nameplate rating of 193.7 MW. IPC also has an additional 163.5 MW of wind generation with signed, and IPUC approved, contracts that have not yet been constructed. In addition, IPC has 64.5 MW of wind generation with signed contracts that are awaiting IPUC approval. These projects have not yet been constructed. In addition to the above wind projects, IPC also is evaluating proposals received in response to an RFP issued in May 2009 to purchase up to approximately 150 MW of wind-powered generation by the end of 2012. IPC anticipates acquiring this generation through a power purchase agreement (PPA); however, IPC may consider other ownership arrangements. IPC continues to pursue additional geothermal and combined heat and power (CHP) generation resources with individual developers. Other renewable generation resources anticipated from future CSPP contracts include solar, biomass, CHP and additional wind projects. IPC does not have rights to the RECs from the PURPA projects. IPC does have rights to the RECs associated with the 101 MW Elkhorn wind project and a portion of the RECs associated with the Raft River geothermal project. However, currently the IPUC has ordered IPC to sell the eligible 2007 and 2008 RECs from the Elkhorn and Raft River projects and it is unclear whether IPC will be allowed to retire RECs in the future.

Air Quality: IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. IPC continues to actively monitor, evaluate and work on air quality issues pertaining to federal and state mercury emission rules, possible legislative amendment of the Clean Air Act, New Source Review (NSR) permitting, National Ambient Air Quality Standards (NAAQS), and Regional Haze Best Available Retrofit Technology (RH BART). The sulfur dioxide (SO_2) scrubber upgrade project has been completed on Units 2 and 4 at the Jim Bridger plant and scrubber upgrade projects on the other two units at the plant will be completed by the end of 2011.

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

PacifiCorp submitted a RH BART application for the Jim Bridger plant in January 2007. On June 3, 2009, WDEQ issued a public notice requesting comment from the public on the draft RH BART State Implementation Plan (SIP) arising out of the application. WDEQ has proposed to issue a RH BART air quality permit for modification of Bridger requiring installation of low-NOx burners with separated over-fire air for NOx reduction, and flue gas conditioning to enhance performance of the electrostatic precipitator particulate controls. According to WDEQ, these controls will allow Bridger to meet the EPA s presumptive RH BART emission limits. The plant is already in the process of installing low NOx burners and SO_2 scrubber upgrades that are proposed in the application. IPC expects to spend approximately $22 million between 2009 and 2012 to complete these projects. WDEQ is further proposing to require Bridger Units 3 and 4 to be equipped with selective catalytic reduction (SCR) NOx controls before December 31, 2015 and December 31, 2016, respectively. WDEQ is requiring installation of the two SCR units as part of its long-term strategy in the regional haze SIP. IPC s estimated share of the cost to install the two SCRs is $100 million.

Installation of this SCR pollution control equipment could require extended maintenance outages. In addition, WDEQ has proposed to require PacifiCorp to submit an application by January 15, 2015, to install add-on NOx controls at Bridger Units 1 and 2 by December 31, 2023. Design and cost estimates for meeting this proposed requirement are not yet available. Following public comment, the WDEQ will prepare and submit the SIP to the EPA for approval. Legal challenges or appeals of the final SIP are possible. IPC is reviewing and evaluating WDEQ s proposal.

On August 20, 2008, the ODEQ issued a draft RH BART proposal for the Boardman plant. The RH BART proposal was approved by the Oregon Environmental Quality Commission (EQC) on June, 19, 2009. The pollution control requirements for RH BART and the long term strategy are estimated to cost approximately $59 million (IPC share). IPC s share of the cost to comply with the proposal would be approximately $38 million by 2014 with an additional $21 million by 2017. Installation of this pollution control equipment could require extended maintenance outages.

New Source Review: Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the New Source Review (NSR) permitting requirements and New Source Performance Standards (NSPS) of the federal Clean Air Act (CAA). This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. The Obama administration has indicated an intention to continue this NSR enforcement initiative. In 2003, the EPA sent an information request to PacifiCorp, under section 114 of the CAA, requesting information relevant to NSR and NSPS compliance at its power plant operations, including the Jim Bridger plant (of which IPC is a one-third owner). PacifiCorp responded to this and another information request from the EPA for Bridger. Similarly, in June 2009, the EPA sent an information request to NV Energy, Inc., under section 114 of the CAA, requesting historical operating and capital project information for the Valmy power plant (of which IPC is a one-half owner). A formal response to the information request for Valmy is being prepared by NV Energy (in consultation with IPC). In addition, in June 2008, the EPA sent an information request to Portland General Electric Company (PGE), under section 114 of the CAA,

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requesting information regarding the Boardman coal plant (of which IPC is a one-tenth owner) to determine whether the plant is in compliance with the Oregon State Implementation Plan, federal New Source Performance Standards and other CAA requirements. On March 20, 2009, PGE received from the EPA a follow up request for information relating to the generation, heat input, and emissions of the Boardman plant. PGE has responded to both requests. A number of utilities that have received section 114 information requests have engaged in negotiations with the EPA to address any allegations of non-compliance with NSR and NSPS requirements. In some cases, such negotiations have resulted in settlements requiring the payment of civil penalties, installation of additional pollution controls, the surrender of emission allowances, and the completion of supplemental environmental projects. IPC cannot predict the outcome of these investigatory matters at this time.

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

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

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

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

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

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

On April 24, 2009, the Governor of Idaho signed into law legislation approving provisions contained in the settlement agreement. On May 6, 2009, as part of the settlement, IPC, the Governor of Idaho and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. IPC and the State have also filed a joint motion to the SRBA court to dismiss the Swan Falls case and enter the stipulated water right decrees set forth in the settlement agreement. The SRBA court held a status conference on the joint motion on July 21, 2009, and is expected to issue an order setting a briefing and hearing schedule for the joint motion in the near future.

U.S. Bureau of Reclamation: IPC has also filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the U.S. for the lost generation resulting from the reduced flows and a prospective declaration of contractual rights so as to prevent the U.S. from continued failure to fulfill its contractual and fiduciary duties to IPC. On May 22, 2009, the court entered an order extending the discovery schedule until September 2, 2009 requiring that discovery be completed and pre-trial motions filed by February 3, 2010. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

OTHER MATTERS:

Southwest Intertie Project

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

Critical Accounting Policies and Estimates

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

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

Adopted Accounting Pronouncements

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

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

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

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

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

SFAS 165: In May 2009, the FASB issued SFAS 165, *Subsequent Events* to provide guidance on accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Entities are required to disclose the date through which subsequent events have been evaluated and the basis for that date. SFAS 165 was adopted on June 30, 2009, and did not have a material impact on IDACORP's or IPC's consolidated financial statements.

Fair Value Measurements: In April 2009, the FASB issued three FSPs intended to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP FAS 157-4,

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, provides

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guidelines for making fair value measurements more consistent with the principles presented in FASB Statement No. 157, Fair Value Measurements. FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities.

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

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

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

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

IDACORP s consolidated financial statements.

New Accounting Pronouncements

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments and derivative commodity instruments sensitive to changes in interest rates, commodity prices and equity prices that were held at June 30, 2009.

Interest Rate Risk

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

Variable Rate Debt: As of June 30, 2009, IDACORP and IPC had $261 million and $219 million, respectively, in net floating rate debt. Assuming no change in financial structure for either company, if variable interest rates were one percentage point higher than the rates in effect on June 30, 2009, interest rate expense would increase and pre-tax earnings would decrease by approximately $2.6 million for IDACORP and $2.2 million for IPC.

Fixed Rate Debt: As of June 30, 2009, IDACORP and IPC each had outstanding fixed rate debt of $1.18 billion. The fair market value of this debt was $1.11 billion. These instruments are fixed rate and,

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therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $93 million for IDACORP and IPC if interest rates were to decline by one percentage point from their June 30, 2009 levels.

Commodity Price Risk

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

Credit Risk

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. IPC maintains margin agreements that allow performance assurance collateral to be requested and/or posted with certain counterparties. As of June 30, 2009, IPC had posted approximately $2.1 million of assurance collateral. Should IPC experience a reduction in its credit rating on IPC s unsecured debt to below investment grade, IPC could be subject to additional requests by its wholesale counterparties to post additional performance assurance collateral. Based upon IPC s current energy and fuel portfolio and current market conditions as of June 30, 2009, the approximate amount of additional collateral that could be requested upon a downgrade is approximately $35 million. IPC actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements. Additional information regarding credit risk relating to derivative instruments can be found in Note 12 to IDACORP s and IPC s financial statements.

Equity Price Risk

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

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:

The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of June 30, 2009, have concluded that IDACORP s disclosure controls and procedures are effective.

IPC:

The Chief Executive Officer and the Chief Financial Officer of IPC, based on their evaluation of IPC s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of June 30, 2009, have concluded that IPC s disclosure controls and procedures are effective.

Changes in internal control over financial reporting:

There have been no changes in IDACORP s or IPC s internal control over financial reporting during the quarter ended June 30, 2009, that have materially affected, or are reasonably likely to materially affect, IDACORP s or IPC s internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

These Risk Factors expand or modify and should be read in conjunction with the Risk Factors included in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

Continuing declines in stream flows and over-appropriation of water in Idaho may reduce hydroelectric generation and revenues and increase costs. The combination of declining Snake River base flows, over-appropriation of water and drought conditions have led to disputes among surface water and ground water irrigators, and the state of Idaho. Recharging the Eastern Snake Plain Aquifer, which contributes to Snake River flows, by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the dispute. Diversions from the Snake River for aquifer recharge may further reduce Snake River flows available for hydroelectric generation and reduce Idaho Power Company s revenues and increase costs. Idaho Power Company s recent settlement agreement with the state of Idaho resolves litigation regarding certain Idaho Power Company water rights on the Snake River and provides for ongoing Snake River water issues to be addressed in the comprehensive aquifer management plan process. However, there is no assurance that this process will lead to increased Snake River stream flows for Idaho Power Company s hydroelectric projects. Idaho Power Company also has initiated legal action against the U.S. Bureau of Reclamation over the interpretation and effect of a 1923 contract with the U.S. Bureau of Reclamation on the operation of the American Falls Reservoir and the release of water from that reservoir to be used at Idaho Power Company s downstream hydroelectric projects. The comprehensive aquifer management plan process and the resolution of the litigation may affect Snake River flows available for hydroelectric generation and thereby reduce Idaho Power Company revenues and increase costs.

Climate change could affect customer demand and hydroelectric generation and disrupt transmission and distribution systems, reducing earnings and cash flows. Changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation. Extreme weather events can disrupt transmission and distribution systems, and cause service interruptions and extended outages. Decreased customer demand and hydroelectric generation and increased operations and maintenance costs from disrupted transmission and distribution systems could reduce earnings and cash flows.

Complying with environmental laws and regulations will increase capital expenditures and operating costs and may reduce Idaho Power Company s earnings and cash flows and ability to meet the electricity needs of its customers. Idaho Power Company is subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, natural resources and health and safety. Compliance with these environmental statutes, rules and regulations involves significant capital and operating expenditures. Proposals by Congress and the Environmental Protection Agency could lead to the adoption of a mandatory federal program to reduce carbon dioxide and other greenhouse gas emissions. Such a program would raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because technologies for reducing carbon dioxide emissions from coal, including carbon capture and storage, are not yet proven. On June 26, 2009, the U.S. House of Representatives passed a bill (H.R. #2454) that, if enacted by Congress, would impose stringent new requirements on coal-fired power plants for the control of carbon dioxide and greenhouse gas emissions. Action on the bill in the U.S. Senate is pending. Similarly, on April 24, 2009, the Environmental Protection Agency proposed to make an official finding that carbon dioxide and greenhouse gases endanger the public health and welfare. If made, this endangerment finding will lead to regulation by the Environmental Protection Agency of carbon dioxide and greenhouse emissions from automobiles and may lead to regulation of such emissions from coal-fired power plants under

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the Clean Air Act. The effects of mercury and other pollutant emissions from coal-fired plants are also subject to extensive regulation. The adoption of new statutes, rules and regulations to implement carbon dioxide, greenhouse gas, mercury or other emission controls will result in increased capital expenditures and could increase the cost of operating coal-fired generating plants or make them uneconomical to operate and result in reduced earnings and cash flows.

Complying with state or federal renewable energy portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows. Idaho Power Company s operations in Oregon will be required to comply with a ten percent renewable energy portfolio standard beginning in 2025. The new federal administration has called on Congress to adopt a federal renewable energy portfolio standard and it is possible that Idaho and other states in which Idaho Power Company operates or sells power could adopt renewable energy portfolio standards in the future. A bill passed by the U.S. House of Representatives on June 26, 2009 (H.R. #2454) would, if enacted, require utilities to obtain 15 percent of their electricity from renewable sources by 2020 and reduce demand by an additional 5 percent through conservation and increased energy efficiency. Action on the bill in the U.S. Senate is pending. New state or federal renewable energy portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.

IDACORP, Inc., its affiliate IDACORP Energy and Idaho Power Company are subject to costs and other effects of legal and regulatory proceedings, settlements, investigations and claims. IDACORP, Inc., IDACORP Energy and Idaho Power Company are involved in a number of proceedings, including the California refund proceeding, a portion of which remains pending before the Federal Energy Regulatory Commission and the United States Court of Appeals for the Ninth Circuit; a refund proceeding affecting sellers of wholesale power in the spot market in the Pacific Northwest; and show cause proceedings originating at the Federal Energy Regulatory Commission, a portion of which remains pending in the United States Court of Appeals for the Ninth Circuit. It is possible that additional proceedings related to the western energy situation may be filed in the future against IDACORP, Inc., IDACORP Energy or Idaho Power Company. IDACORP, Inc. and Idaho Power Company are or may also be subject to costs and other effects of additional legal claims, actions and complaints, including those related to the Jim Bridger, Valmy and Boardman coal-fired plants, in which Idaho Power Company holds an ownership interest. If the companies are required to make payments in connection with any legal or regulatory proceeding, settlement, investigation or claim, earnings and cash flows could be negatively affected.

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

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

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

IPC s ability to pay dividends on its common stock held by IDACORP and IDACORP s ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or IPC s Code of Conduct. At June 30, 2009, the leverage ratios for IDACORP and IPC were 52 percent and 54 percent, respectively and IPC s common equity capital was 46 percent of its total adjusted capital. Based on these restrictions, IDACORP s and IPC s dividends were limited to $891 million and $944 million, respectively, at June 30, 2009.

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

Issuer Purchases of Equity Securities:
None

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

IDACORP, Inc.:

(a) Regular annual meeting of IDACORP, Inc. s shareholders, held May 21, 2009, in Boise, Idaho.

(b) Directors elected at the meeting for a three-year term:

C. Stephen Allred	Gary G. Michael
Christine King	Jan B. Packwood

Director elected at the meeting for a two-year term:

Richard J. Dahl

Continuing Directors:

Judith A. Johansen	Richard G. Reiten	Robert A. Tinstman
J. LaMont Keen	Joan H. Smith	Thomas J. Wilford
Jon H. Miller		

(c) 1) To elect five Director Nominees:

Name	For	Withheld	Total Voted
C. Stephen Allred	39,279,018	1,023,500	40,302,518
Richard J. Dahl	39,308,001	994,517	40,302,518
Christine King	27,692,032	12,610,486	40,302,518
Gary G. Michael	38,176,200	2,126,318	40,302,518
Jan B. Packwood	39,164,164	1,138,354	40,302,518

2) To ratify the appointment of Deloitte & Touche LLP as the independent registered public accounting firm for the fiscal year ending December 31, 2009:

Class of Stock	For	Against	Abstain	Total Voted
Common	37,747,794	2,347,981	206,743	40,302,518

3) To act upon a shareholder proposal requesting that the board of directors adopt quantitative goals for reducing greenhouse gas emissions from its products and operations and that IDACORP report to shareholders by September 30, 2009, on its plans to achieve these goals.

Class of Stock	For	Against	Abstain	Broker Non-Votes	Total Voted
Common	14,568,648	13,875,126	4,079,948	7,778,796	32,523,722

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).

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*3.2

Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of IPC, as filed with the Secretary of State of Idaho on November 5, 1991. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(ii).

*3.3

Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of IPC, as filed with the Secretary of State of Idaho on June 30, 1993. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(iii).

*3.4

Articles of Amendment to Restated Articles of Incorporation of IPC, as filed with the Secretary of State of Idaho on June 15, 2000. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 3(a)(iii).

*3.5

Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on January 21, 2005. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 4.5.

*3.6

Articles of Amendment to Restated Articles of Incorporation of IPC, as amended, as filed with the Secretary of State of Idaho on November 19, 2007. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.3.

*3.7

Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998. File number 33-56071-99, Post-Effective Amendment No. 1 to Form S-8, filed on 10/1/98, as Exhibit 3(d).

*3.8

Amended Bylaws of IPC, amended on November 15, 2007, and presently in effect. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.2.

*3.9

Articles of Incorporation of IDACORP, Inc. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.1.

*3.10

Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.2.

*3.11

Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998. File number 333-00139-99, Post-Effective Amendment No. 1 to Form S-3, filed on 9/22/98, as Exhibit 3(b).

*3.12

Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect. File number 1-14456, Form 8-K, filed on 11/19/07, as Exhibit 3.1.

*4.1

Mortgage and Deed of Trust, dated as of October 1, 1937, between IPC and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees. File number 2-3413, as Exhibit B-2.

*4.2

IPC Supplemental Indentures to Mortgage and Deed of Trust:

File number 1-MD, as Exhibit B-2-a, First, July 1, 1939

File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943

File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947

File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948

File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949

File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951

File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957

File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957

File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957

File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958

File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958

File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959

File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960

File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961

File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964

File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966

File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966

File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972

File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974

File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974

File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974

File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976

File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978

File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979

File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981

File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982

File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986

File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989

File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990

File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991

File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991

File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992

File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993

File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993

File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000

File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001

File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003

File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003

File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iii), Thirty-ninth, October 1, 2003

File number 1-3198, Form 8-K filed 5/10/05, as Exhibit 4, Fortieth, May 1, 2005.

File number 1-3198, Form 8-K filed 10/10/06, as Exhibit 4, Forty-first, October 1, 2006.

File number 1-3198, Form 8-K filed 6/4/07, as Exhibit 4, Forty-second, May 1, 2007.

File number 1-3198, Form 8-K filed 9/26/07, as Exhibit 4, Forty-third, September 1, 2007.

File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008.

*4.3

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

*4.4

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

*4.5

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

*4.6

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

*4.7

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

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*4.8

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

*4.9

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

*10.1

Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).

*10.2

Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).

*10.3

Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).

*10.4

Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).

*10.5

Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).

*10.6

Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).

*10.7

Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).

*10.8

Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).

*10.9

Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).

*10.10

Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).

*10.11

Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).

*10.12

Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).

*10.13

Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).

*10.14

Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).

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*10.151

Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.15.

*10.161

Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.16.

*10.17 1

IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).

*10.18 1

IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).

*10.19 1

IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vii).

*10.20 1

Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).

*10.21 1

IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.21.

*10.221

Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and IPC, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).

*10.231

Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).

*10.241

Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.24.

*10.25 1

Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.25.

*10.261

IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.26.

*10.271

IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).

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*10.281

IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).

*10.291

IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).

*10.301

IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.30.

*10.311

IDACORP, Inc. Executive Incentive Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.31.

*10.321

Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.32.

*10.331

IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.33.

*10.34

Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC s Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).

*10.35

Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).

*10.36

Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).

*10.37

Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).

*10.38

Guaranty Agreement, dated February 10, 1992, between IPC and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).

*10.39

Power Purchase Agreement between IPC and PPL Montana, LLC, dated March 1, 2003 and Revised Confirmation Agreement dated May 9, 2003. File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 10(k).

*10.40

$100 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among IDACORP, Inc., various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-14465, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(l).

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*10.41

$300 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among Idaho Power Company, various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(m).

*10.42

$170 Million Term Loan Credit Agreement, dated as of February 4, 2009, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.42.

*10.43

Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.

*10.44

Power Purchase Agreement between IPC and PPL EnergyPlus, LLC, dated June 2, 2008. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2008, filed on 8/7/08, as Exhibit 10.46.

10.45

Amended and Restated Electric Service Agreement between IPC and Hoku Materials, Inc., dated June 19, 2009.

*10.46[1]

Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.46.

*10.471

Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.47.

*10.481

Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.48.

*10.491

Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.49.

*10.501

Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.50.

*10.511

Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.51.

*10.521

Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.52.

*10.531

Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.53.

*10.541

Form of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.54.

*10.551

Form of Letter Agreement to Amend Outstanding IDACORP Financial Services, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.55.

*10.561

Form of Amendment to IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.56.

*10.571

Form of Termination of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.57.

*10.58

Settlement Agreement, dated March 25, 2009, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2009, filed on 5/7/09 as Exhibit 10.58

*10.59[1]

Exhibit A to the IDACORP, Inc. Executive Incentive Plan, as amended February 24, 2009. File number 1-14465, 1-3198, Form 8-K, filed on 3/2/09, as Exhibit 10.1.

*10.60[1]

Consulting Agreement, dated as of April 1, 2009, by and between Thomas R. Saldin and Idaho Power Company, including its parent IDACORP, Inc. and all subsidiaries and affiliates. File number 1-14465, 1-3198, Form 8-K, filed on 4/3/09, as Exhibit 10.1.

*10.61[1]

Idaho Power Company Employee Savings Plan, as amended and restated as of October 1, 2000 (revised). File number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.6.

*10.62[1]

First Amendment to Idaho Power Company Employee Savings Plan, dated May 8, 2002. File number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.7.

*10.63[1]

Second Amendment to Idaho Power Company Employee Savings Plan, dated March 31, 2006. Filed number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.8.

10.64

Contract for Engineering, Procurement and Construction Services, dated May 7, 2009, between IPC and Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for Langley Gulch Power Plant (portions of this exhibit have been redacted and filed separately with the Securities and Exchange Commission in connection with a request for confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended).

12.1

Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)

12.2

Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)

12.3

Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)

12.4

Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)

15

Letter Re: Unaudited Interim Financial Information

*21

Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on 2/28/08, as Exhibit 21.

31.1

IDACORP, Inc. Rule 13a-14(a) CEO certification.

31.2

IDACORP, Inc. Rule 13a-14(a) CFO certification.

31.3

IPC Rule 13a-14(a) CEO certification.

31.4

IPC Rule 13a-14(a) CFO certification.

32.1

IDACORP, Inc. Section 1350 CEO certification.

32.2

IDACORP, Inc. Section 1350 CFO certification.

32.3

IPC Section 1350 CEO certification.

32.4

IPC Section 1350 CFO certification.

99

Earnings press release for the second quarter 2009.

1 Management contract or compensatory plan or arrangement

98

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	August 6, 2009	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	August 6, 2009	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date	August 6, 2009	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	August 6, 2009	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number

10.45	Amended and Restated Electric Service Agreement, between IPC and Hoku Materials, Inc., dated June 19, 2009.
10.64	Contract for Engineering, Procurement and Construction Services, dated May 7, 2009, between IPC and Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for Langley Gulch Power Plant (Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the SEC pursuant to Rule 24b-2. The redacted material is being filed separately with the SEC).
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.3	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
15	Letter Re: Unaudited Interim Financial Information.
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 second quarter 2009