Snow Frederick Philip
Form 4
November 05, 2018

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL

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Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Snow Frederick Philip

(Last) (First) (Middle)

C/O FACTSET RESEARCH SYSTEMS INC., 601 MERRITT 7

(Street)

NORWALK, CT 06851

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
FACTSET RESEARCH SYSTEMS INC [FDS]

3. Date of Earliest Transaction (Month/Day/Year)
11/01/2018

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Chief Executive Officer

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	11/01/2018		F		363 (1)	D	$ 221.88	3,688	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Employee Stock Option (right to buy)	$ 221.88	11/01/2018		A		26,422		(2)	11/01/2028	Common Stock	26,422

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Snow Frederick Philip C/O FACTSET RESEARCH SYSTEMS INC. 601 MERRITT 7 NORWALK, CT 06851	X		Chief Executive Officer	

Signatures

/s/ F. Philip Snow	11/05/2018
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Represents the number of shares withheld to cover the cost of taxes upon vesting of restricted stock that was granted on November 1, 2013 and that was previously reported.

(2) Options vest 20% annually on the anniversary date of the grant and are fully vested after five years.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. fiscal years beginning after December 15, 2008. All prior-period earnings per share data presented shall be adjusted retrospectively. Early application is not permitted. IDACORP is currently evaluating the impact of FSP EITF 03-6-1.

FSP FAS 142-3: In April 2008, the FASB issued 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. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008. IDACORP and IPC are currently evaluating the impact of FSP FAS 142-3.

2. INCOME TAXES:

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP's effective rate on continuing operations for the six months ended June 30, 2008, was 24.2 percent, compared to 16.2 percent for the six months ended June 30, 2007. IPC's effective tax rate for the six months ended June 30, 2008, was 33.6 percent, compared to 34.3 percent for the six months ended June 30, 2007. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the six months ended June 30, 2008, IDACORP entered into the following transactions involving its common stock:

85,430 original issue shares were used for awards granted under the 2000 Long-Term Incentive and Compensation Plan.

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

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

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139,372 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, 2008, the maximum number of shares available under the LTICP and RSP were 1,562,142 and 66,887, respectively. The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC's employees (in thousands of dollars):

	IDACORP Six months ended June 30,		**IPC Six months ended June 30,**	
	2008	**2007**	**2008**	**2007**
Compensation cost	$ 2,289	$ 1,556	$ 2,160	$ 996
Income tax benefit	$ 895	$ 608	$ 845	$ 390

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for restricted stock awards granted during the first six months of 2008 was $30.54.

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

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

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

4. FINANCING:

Credit Facilities

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

IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, 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 are due on March 31, 2009. 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. The Loans may be prepaid, but may not be reborrowed. The Term Loan Credit Agreement is a short-term arrangement; however $166.1 million was classified as long-term debt as allowed by SFAS No. 6 Classification of Short-Term Obligations Expected to Be Refinanced. IPC has the ability to refinance the term loan on a long-term basis by utilizing its credit facility which expires April 25, 2012, 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. At June 30, 2008, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings were as follows at June 30, 2008, and December 31, 2007 (in thousands of dollars):

	June 30, 2008			**December 31, 2007**		
	IPC	**IDACORP**	**Total**	**IPC**	**IDACORP**	**Total**
Commercial paper outstanding	$ 210,349	$ 65,172	$ 275,521	$136,585	$ 49,860	$ 186,445
Other short-term borrowings	3,900	-	3,900	-	-	-
Total	$ 214,249	$ 65,172	$ 279,421	$136,585	$ 49,860	$ 186,445
Weighted-avg. interest rate	3.07%	3.07%	3.07%	5.56%	5.45%	5.53%

Long-Term Financing

IDACORP has $629 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to $350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H. On July 10, 2008, IPC issued $120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018. IPC used the net proceeds to pay down short-term debt. As of August 6, 2008, IPC has $230 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds (including medium-term notes) and unsecured debt.

Pollution Control Revenue Refunding Bonds

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

5. REGULATORY MATTERS:

Idaho 2007 General Rate Case

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

Danskin CT1 Power Plant Rate Case

On March 7, 2008, IPC filed an application with the IPUC requesting recovery of the costs associated with the construction of the Danskin CT1 plant, a gas-fired combustion turbine located at the Evander Andrews Power Complex near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. In the filing, IPC requested adding to rate base approximately $65 million attributable to the cost of constructing the generating facility and the necessary transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or $9 million in annual revenues.

On May 30, 2008, the IPUC authorized IPC to add to its rate base $64.2 million for the Danskin CT1 plant and associated transmission and interconnection system upgrades, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or $8.9 million in annual revenues. Costs not approved in this order will be included in future filings.

Deferred Net Power Supply Costs

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

	June 30,	December 31,

	2008	2007

Idaho PCA current year				
Deferral for the 2008-2009 rate year*	$	-	$	85,732
Deferral for the 2009-2010 rate year		10,162		-
Idaho PCA true-up awaiting recovery:				
Authorized in May 2007		-		6,591
Authorized in May 2008		102,437		-
Oregon deferral:				
2001 Costs		2,794		2,993
2006 Costs		1,218		2,107
2008 Power cost adjustment mechanism		1,484		-
Total deferral	$	118,095	$	97,423

*The 2008-2009 PCA deferral balance is reduced by $16.5 million of emission allowance sales in 2007.

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

The annual adjustments are based on two components:

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.

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

<u>2008-2009 PCA:</u> On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing requested an increase to existing revenues of approximately $87.2 million.

Subsequently, the IPUC issued an order directing IPC to apply $16.5 million of gains from the sale of excess SO2 emission allowances, including interest, against the PCA. This order reduced IPC's request to approximately $70.7 million. IPC and the IPUC Staff each proposed deviations from standard IPUC approved PCA methodology. IPC proposed to flow through to customers 100 percent of the deviation in net power supply costs and PURPA project expenses for the 2008-2009 PCA year instead of a 90/10 sharing between customers and shareholders. This was denied by the IPUC. The IPUC Staff proposed using a "normal" forecast for power supply costs and equally dividing the net power supply expenses implemented in the rate change on March 1, 2008 resulting from the 2007 general rate case. The IPUC approved the IPUC Staff's recommendations on May 30, 2008. The adopted distribution methodology results in an equal amount of power supply costs across all months as compared to a more seasonal allocation that would have recognized significantly more power supply costs in the third quarter and less in the first and second quarters. The IPUC decision is not expected to have a material impact on annual financial results.

On May 30, 2008, the IPUC adopted the IPUC Staff's proposal to use a "normal" forecast for power supply costs and approved an increase to existing revenues of $73.3 million, effective June 1, 2008, which results in an average rate increase to IPC's customers of 10.7 percent.

In its order the IPUC also directed IPC to set up workshops to address PCA-related issues such as sharing methodology, forecasting methodology, distribution of power cost deferrals and load growth adjustment rate. An informational workshop was held on July 30, 2008, and a second workshop is scheduled for August 13, 2008.

2007-2008 PCA: On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then-existing level, which was $46.8 million below base rates, to a level that is $30.7 million above those base rates. This $77.5 million increase was net of $69.1 million of proceeds from sales of excess SO2 emission allowances. The new rates became effective June 1, 2007.

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

The IPUC-approved settlement of the 2007 general rate case (discussed above in "Idaho 2007 General Rate Case") reset the LGAR to $62.79 per MWh, but applies that rate to only 50 percent of the load growth beginning in March 2008. In that general rate case, IPC filed normalized firm base load of 15.6 million MWh as compared with 14.8 million MWh in the 2005 general rate case.

Emission Allowances: During 2007, IPC sold 35,000 SO2 emission allowances for a total of $19.6 million. The sales proceeds allocated to the Idaho jurisdiction are approximately $18.5 million. On April 14, 2008, the IPUC ordered that $16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that $0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and is reflected in PCA rates in effect from June 1, 2007, to May 31, 2008.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" (which means above base power supply costs) power supply expenses. IPC requested authorization to defer an estimated $5.7 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is awaiting an order from the OPUC.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. A settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further in Note 6 under "Western Energy Proceedings at the FERC." Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Oregon Power Costs

On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost recovery mechanism similar to the Idaho PCA. A joint stipulation was filed with the OPUC on March 14, 2008, and the OPUC approved the stipulation on April 28, 2008.

The new mechanism will allow IPC to recover excess net power supply costs in a more timely fashion than through the existing deferral process. The mechanism differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case.

The new regulatory mechanism has two parts: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU has two components: the "October Update," where each October IPC will calculate its estimated normalized net power supply expenses for the following April through March test period, and the "March Forecast," where each March IPC will file a forecast of its normalized 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 will be adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up to be filed in February of each year beginning in 2009. The filing will calculate the deviation between actual net power supply expenses incurred for the preceding January through December period 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 by application of an asymmetrical deadband 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, with new combined rates effective each June 1.

On October 29, 2007, IPC filed its first October Update with the OPUC reflecting the estimated net power supply expenses for the April 2008 through March 2009 test period. On March 24, 2008, IPC submitted testimony to the OPUC revising its calculation of the October Update to conform to the methodology agreed to by the parties in the stipulation. IPC also submitted the March Forecast, reflecting expected hydroelectric generating conditions and forward prices for the April 2008 through March 2009 test period. The expected power supply costs of $150 million represented an increase of approximately $23 million over the October Update.

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

Fixed Cost Adjustment Mechanism (FCA)

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

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 year. IPC accrued $0.4 million of FCA net over-recovery of fixed costs in the first half of 2008.

Open Access Transmission Tariff (OATT)

On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of $11 million based upon 2004 test year data. The rates were accepted subject to refund pending the outcome of the hearing and settlement process.

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

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements. If the Initial Decision is implemented, IPC estimates that it would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $4.2 million for the June 1, 2006, through June 30, 2008, period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process. IPC is awaiting a final FERC order.

On June 2, 2008, 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 2007 test year. The draft informational filing includes a proposed rate of $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. A customer meeting to discuss the informational filing was held on June 17, 2008. A final filing will be submitted to the FERC by September 1, 2008 with new rates effective October 1, 2008.

Idaho Pension Expense Order

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the 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. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million was deferred to a regulatory asset beginning in the third quarter. In the first half of 2008, $3.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

6. COMMITMENTS AND CONTINGENCIES:

Guarantees

IPC has agreed to guarantee the performance of one-third of the reclamation activities at Bridger Coal Company, of which IERCO owns a one-third interest. This guarantee, which is renewed each December, was $60 million at June 30, 2008. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying the reclamation costs and expects that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

Legal Proceedings

From time to time IDACORP and IPC are parties to legal claims, actions and complaints in addition to those discussed below. Although they will vigorously defend against them, 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, 2007, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, for a discussion of all material pending legal proceedings to which IDACORP and IPC and their subsidiaries are parties. The following discussion provides a summary of material developments that occurred in those proceedings during the period covered by this report and of any new material proceedings instituted during the period covered by this report.

Western Energy Proceedings at the FERC:

Throughout this report, the term "western energy situation" is used to refer to the California energy crisis that occurred during 2000 and 2001, which resulted in energy shortages 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).

California Refund: In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. That plan included the potential for orders directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund the portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

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

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

On March 21, 2008, the FERC issued an order responding to the remand by Ninth Circuit. The FERC's order established hearing procedures to permit wholesale purchasers that made short-term market-based rate purchases through the Cal ISO and the California Power Exchange (CalPX), as well as those making spot market purchases of energy through the California Energy Resources Scheduling Division of the California Department of Water Resources from January 1, 2000 to October 1, 2000, to (i) present evidence that any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus caused its market-based rates to be unjust and unreasonable and (ii) permit sellers to present evidence to the contrary. Before formal hearing procedures commenced, the FERC directed that the matter be presented to a settlement judge to attempt to settle individual cases. The FERC's March 21, 2008 order expands the field of those who may present evidence in the case from the original complaint of the California Attorney General and also is more restrictive in terms of what must be proven to establish a case. On April 7, 2008, IE and IPC joined with a number of other parties that already had settled this proceeding with the California Attorney General and the other California Parties requesting that they be dismissed from the case. The California Attorney General and the other California Parties indicated their agreement to the dismissal. On April 15, 2008, the FERC issued an order dismissing parties that already had settled, including IE and IPC, from these remanded proceedings. No party sought rehearing of the FERC's dismissal order within the time allowed by statute and the dismissal is now final.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Port of Seattle withdrew its petition for review in one of the three consolidated cases and filed its initial brief on February 29, 2008. The FERC filed its respondent brief on May 30,

2008. On June 30, 2008, IE and IPC filed a joint brief with other companies supporting the FERC, and the California Parties filed a joint brief supporting the FERC on the same day. Final briefs are due by August 31, 2008. A date for argument has not been set. IE and IPC are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the "gaming" and "partnership" show cause orders. The FERC staff submitted a motion to the FERC to dismiss the "partnership" proceeding, which was approved by the FERC in an order issued on January 23, 2004. The "gaming" settlement was approved by the FERC on March 4, 2004.

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

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001 concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and the refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation submitted by the petitioners for the period January 1, 2000, to June 21, 2001, would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. On June 26, 2008, the U.S. Supreme Court issued a decision in one of these cases, Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), and 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 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.

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

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, the structure and content of the FERC's market-based rate regime, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE are unable to predict the outcome of any of these petitions for review.

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

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

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the U.S. District Court for the District of Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to $32,500 per day per violation and the plaintiff's costs of litigation, including reasonable attorney fees.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity compliance status of the Plant. The court has not yet ruled on these motions. On March 13, 2008, the District Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. On July 7, 2008, the plaintiffs filed a motion requesting the court to schedule a date for oral argument on the pending motions for summary judgment. On July 17, 2008, PacifiCorp filed an opposition to plaintiffs' motion based on the court's order on Initial Pretrial Conference, which stated that "dispositive motions will be decided on the briefs without oral argument." The court has yet to rule on plaintiffs' motion. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on the consolidated financial position, results of operations or cash flows.

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

Snake River Basin Adjudication: IPC is engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

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

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

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

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

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court scheduled a hearing for September 16, 2008, for arguments on summary judgment motions on the recharge issue. The State of Idaho and IPC are now in the process of completing discovery, and briefing and filing summary judgment motions on recharge. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the State of Idaho and other water users through an advisory committee in the development of a Comprehensive Aquifer Management Plan (CAMP) to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan. However, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the U.S. on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the U.S. has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, on October 15, 2007, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. to recover damages from the U.S. for the lost generation resulting from the reduced flows. On October 15, 2007, IPC filed a second action in the United States District Court for the District of Idaho in Boise, Idaho, to compel the U.S. to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. The U.S. Bureau of Reclamation filed answers in each of these cases on February 15, 2008. On March 4, 2008, the U.S. District Court for the District of Idaho entered a preliminary scheduling order, setting that case for trial on December 15, 2009. The action in the U.S. District Court of Federal Claims has not yet been set for trial but the court has set a discovery schedule requiring that discovery be completed and pre-trial motions filed by July 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of these actions.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy near Wilder, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho (Canyon County) against IDACORP and IPC. On March 28, 2008, the plaintiffs filed a First Amended Complaint and Demand for Jury Trial. On July 23, 2008, the plaintiffs were permitted to file a Second Amended Complaint and Demand for Jury Trail. The plaintiffs' assert claims for negligence, negligence per se, nuisance, breach of contract, and fraud. The claims are based on allegations that from 1972 until May 25, 2005, IPC discharged "stray voltage" from its electrical facilities that caused physical harm and injury to the plaintiffs' dairy herd. Plaintiffs seek compensatory damages in excess of $10,000 to be proven at trial.

On June 9, 2008, IDACORP and IPC filed a motion to dismiss the complaint, contending that the court lacks jurisdiction over the matter because plaintiffs have failed to exhaust administrative remedies before the IPUC. The companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

7. BENEFIT PLANS:

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

	Deferred	**Postretirement**

Pension Plan	Compensation Plan	Benefits

2008	2007	2008	2007	2008	2007

Service cost	$	3,730	$	3,803	$	319	$	352	$	224	$	379
Interest cost		6,600		6,115		668		593		797		895
Expected return on plan assets		(8,562)		(8,351)		-		-		(685)		(690)
Amortization of transition obligation		-		-		-		-		510		510
Amortization of prior service cost		162		162		48		44		(134)		(134)
Amortization of net loss		-		-		122		141		-		132
Net periodic benefit cost	$	1,930	$	1,729	$	1,157	$	1,130	$	712	$	1,092

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

	Pension Plan				**Deferred Compensation Plan**				**Postretirement Benefits**			
	2008		**2007**		**2008**		**2007**		**2008**		**2007**	
Service cost	$	7,460	$	7,606	$	639	$	704	$	551	$	758
Interest cost		13,196		12,229		1,335		1,186		1,677		1,790
Expected return on plan assets		(17,056)		(16,693)		-		-		(1,423)		(1,380)
Amortization of transition obligation		-		-		-		-		1,020		1,020
Amortization of prior service cost		325		325		96		87		(267)		(268)
Amortization of net loss		-		-		244		283		-		264
Net periodic benefit cost	$	3,925	$	3,467	$	2,314	$	2,260	$	1,558	$	2,184

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

8. SEGMENT INFORMATION:

IDACORP's only reportable segment at June 30, 2008, is utility operations, for which the primary source of revenue is the regulated operations of IPC. IFS, which had previously been identified as a reportable segment, is now included in the "All Other" column. IDACOMM, which had previously been identified as a reportable segment, is now reported as discontinued operations (See Note 9).

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

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

	Utility	**All**		**Consolidated**

Operations	Other	Eliminations	Total

Three months ended June 30, 2008:								
Revenues	$	228,945	$	1,281	$	-	$	230,226
Income from continuing operations		17,728		(213)		-		17,515
Three months ended June 30, 2007:								
Revenues	$	212,526	$	1,246	$	-	$	213,772
Income from continuing operations		16,164		2,301		-		18,465
Total assets at June 30, 2008	$	3,602,710	$	196,839	$	(50,973)	$	3,748,576
Six months ended June 30, 2008:								
Revenues	$	441,740	$	1,925	$	-	$	443,665
Income from continuing operations		38,999		232		-		39,231
Six months ended June 30, 2007:								
Revenues	$	418,455	$	2,029	$	-	$	420,484
Income from continuing operations		39,495		3,551		-		43,046

9. DISCONTINUED OPERATIONS:

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. The operating results of IDACOMM have been separately classified and reported as discontinued operations on IDACORP's condensed consolidated statements of income. There were no discontinued operations activities in the three months ended June 30, 2008 or 2007.

A summary of discontinued operations is as follows (in thousands of dollars):

	Six months ended June 30,	
	2008	**2007**
Revenues	$ -	$ 1,278
Operating expenses	-	(1,309)
Other expense	-	(25)
Loss on disposal	-	(2,877)
Pre-tax losses	-	(2,933)
Income tax benefit	-	3,000
Income from discontinued operations	$ -	$ 67

10. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

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

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

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

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

The following table presents information about IDACORP's and IPC's assets and liabilities measured at fair value on a recurring basis as of June 30, 2008 (in thousands of dollars). IDACORP's and IPC's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical	**Significant Other Observable**	**Significant Unobservable Inputs**

	Assets (Level 1)	Inputs (Level 2)	(Level 3)	Total
IDACORP				
Assets:				
Derivatives	$ 182	$ 7,940	$ -	$ 8,122
Trading securities	7,464	-	-	7,464
Available-for-sale securities	20,919	-	-	20,919
Liabilities:				
Derivatives	$ 350	$ 24	$ -	$ 374
IPC				
Assets:				
Derivatives	$ 182	$ 7,940	$ -	$ 8,122
Trading securities	5,935	-	-	5,935
Available-for-sale securities	20,919	-	-	20,919
Liabilities:				
Derivatives	$ 350	$ 24	$ -	$ 374

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IDACORP and IPC adopted the provisions of SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115 (SFAS 159) on January 1, 2008. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS 115, Accounting for Certain Investments in Debt and Equity Securities, applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. IDACORP and IPC did not elect the fair value option for any existing eligible items. However, IDACORP and IPC will continue to evaluate new items on a case-by-case basis for consideration of the fair value option.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the "Company") as of June 30, 2008, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2008 and 2007, and of cash flows for the six-month periods ended June 30, 2008 and 2007. These interim financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of IDACORP, Inc. and subsidiaries as of December 31, 2007, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated February 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, and Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R). In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2007 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
August 6, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary (the "Company") as of June 30, 2008, and the related condensed consolidated statements of income and comprehensive income, for the three-month and six-month periods ended June 30, 2008 and 2007, and of cash flows for the six-month periods ended June 30, 2008 and 2007. These interim financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary as of December 31, 2007, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for the year then ended (not presented herein); and in our report dated February 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, and Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R). In our opinion, the information set forth in the accompanying condensed consolidated balance sheet and statement of capitalization as of December 31, 2007 is fairly stated, in all material respects, in relation to the consolidated balance sheet and statement of capitalization from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
August 6, 2008

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

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

INTRODUCTION:

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

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

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

IDACORP's other subsidiaries include:

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

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

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

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

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements of IDACORP and IPC. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2007, and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, and should be read in conjunction with the discussions in those reports.

FORWARD-LOOKING INFORMATION:

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

Changes in and compliance with governmental policies, including new interpretations of existing policies, and regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission, and the Oregon Public Utility Commission with respect to allowed rates of return, industry and rate structure, day-to-day business operations, acquisition and disposal of assets and facilities, operation and construction of plant facilities, provision of transmission services, including critical infrastructure protection and system reliability, relicensing of hydroelectric projects, recovery of power supply costs, recovery of capital investments, present or prospective wholesale and retail competition, including but not limited to retail wheeling and transmission costs, and other refund proceedings;

Changes arising from the Energy Policy Act of 2005;

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

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

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

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

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

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

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

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

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

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

Population growth rates and other demographic patterns;

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

Fluctuations in sources and uses of cash;

Results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by factors such as credit ratings and general economic conditions;

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

Changes in interest rates or rates of inflation;

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

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

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

Homeland security, acts of war or terrorism;

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

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

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

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

EXECUTIVE OVERVIEW:

Second Quarter and Year-to-date 2008 Financial Results

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

	Three months ended June 30,		**Six months ended June 30,**	
	2008	**2007**	**2008**	**2007**
Net income	$ 17,515	$ 18,465	$ 39,231	$ 43,113
Average outstanding shares - diluted (000s)	45,096	43,884	45,050	43,845
Earnings per diluted share	$ 0.39	$ 0.42	$ 0.87	$ 0.98

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

IPC's net income, the primary component of IDACORP's net income, was $17.7 million for the quarter, an increase of $1.6 million. The key factors causing the change in IPC's net income include:

General business revenue increased $16.2 million due to an increase of $19.0 million from higher retail base rates and power cost adjustment (PCA) rates, partially offset by a $2.8 million decrease from reduced sales. Sales were reduced due to weather variations, primarily affecting irrigation customers, partially offset by customer growth.

Improved hydroelectric generating conditions decreased net power supply costs (fuel and purchased power less off-system sales) by $10.7 million.

The PCA deferral decreased $25.2 million primarily due to improved hydroelectric generating conditions, increases in PCA rates, and an increase in the monthly allocation of base net power supply costs, which decreased earnings $5.6 million. It is expected that the third quarter results will reflect a decrease in the monthly allocation of base net power supply costs of approximately $10 million.

Operation and maintenance expenses decreased $2.0 million primarily due to reduced maintenance costs at thermal facilities.

The sale of a portion of the Southwest Intertie Project (SWIP) rights-of-way increased net income $1.8 million.

Bridger Coal Company reduced net income $1.6 million due to increased costs to produce coal.

Higher interest charges, due to increases in long-term debt balances and increased rates on variable rate instruments, reduced earnings $1.4 million.

IFS earnings decreased $1.1 million due to lower tax benefits from aging investments.

Net loss at the holding company decreased earnings $1.5 million. This loss was primarily due to intra-period tax allocations recorded at the holding company.

The key factors affecting the change in IDACORP's net income for the six months ended June 30, 2008 include (amounts shown are net of income taxes):

IPC's net income, the primary component of IDACORP's net income, was $39 million for the six months ended June 30, 2008, a decrease of $0.5 million. The key factors causing the change in IPC's net income include:

General business revenue increased net income $34.5 million, due to an increase of $32.0 million from higher retail base rates and PCA rates and $2.5 million due to an increase in usage (weather-related and customer growth).

Increased fuel expense primarily in the first quarter, due to an increase in contracted coal price and an increase in generation volume at thermal facilities, raised net power supply costs by $4.6 million.

The PCA deferral decreased $27.5 million primarily due to the net effect of increases in PCA rates and an increase to the monthly allocation of base net power supply costs, which decreased earnings $5.6 million, partially offset by increased fuel expenses in the first quarter.

Operation and maintenance expenses decreased $1.3 million primarily due to reduced maintenance costs at thermal facilities.

The sale of a portion of the SWIP rights-of-way increased earnings $1.8 million.

Bridger Coal Company reduced net income $3.9 million due to increased costs to produce coal.

Higher interest charges, due to increases in long-term debt balances and increased rates on variable rate instruments, reduced net income $3.0 million.

IFS earnings decreased $2.1 million due to lower tax benefits from aging investments.

Net loss at the holding company decreased earnings $1.2 million. These losses were primarily due to intra-period tax allocations recorded at the holding company.

2008 Outlook

Actual observed Brownlee Reservoir inflow for the April through July 2008 period is 4.4 million acre-feet (maf). The NWRFC's 30-year average measured inflow into Brownlee is 6.3 maf during the period. In 2007, April-July inflows were 2.8 maf.

The outlook for key operating and financial metrics is:

	2008 Estimates	
Key Operating & Financial Metrics	**Current**	**Previous**
Idaho Power Operation & Maintenance Expense (Millions)	No change	$285-$295
Idaho Power Capital Expenditures (Millions)(1)	$255-$270	$270-$290
Idaho Power Hydroelectric Generation (Million MWh) (2)	6.5-7.5	6.0-8.0
Non-regulated Subsidiary Earnings Per Share (3)	No change	$0.05-$0.10
Effective Tax Rates: (4)		
Idaho Power	No change	32%-36%
Consolidated - IDACORP	22%-26%	20%-24%

(1) The decrease in capital expenditures is due to the estimated decline in new customer connections and the deferral of capital expenditures.

(2) The range of estimated hydroelectric generation has been revised to reflect refinements related to river flows.

(3) Estimates include contributions from Ida-West and IFS netted against holding company expenses.

(4) Increase is a result of greater estimated income before tax at IPC for the year as compared to previous estimates.

General rate cases

2008: On June 27, 2008, IPC filed an application with the IPUC requesting an average rate increase of approximately 9.9 percent. IPC's proposal would increase its revenues $67 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.55 percent. IPC filed its case based upon a 2008 forecast test year and expects that the new rates will go into effect by February 1, 2009. IPC is unable to predict what relief the IPUC will grant.

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

Power Cost Adjustment

On May 30, 2008, the IPUC approved a $73.3 million increase to revenues, effective June 1, 2008, which resulted in an average rate increase to IPC's customers of 10.7 percent. The increase is net of approximately $16.5 million of gains on sales of excess emission allowances, including interest. In its order, the IPUC adopted the IPUC Staff's proposal to distribute base net power supply costs equally across all months rather than in a method that reflects moderate seasonal variation. While the distribution methodology utilized does not affect the total amount of base net power supply costs used to calculate the PCA deferral, it does affect the quarters in which they are allocated. The impacts of this distribution methodology are discussed in more detail in "REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - Distribution of Base Net Power Supply Costs."

In its order, the IPUC also directed IPC to hold workshops to address PCA-related issues, including the load growth adjustment rate (LGAR), 90/10 customer/shareholder sharing, forecast methodology, distribution of power cost deferrals and third party transmission expense. An informational workshop was held on July 30, 2008 and a second workshop is scheduled for August 13, 2008.

Danskin CT1 Power Plant Rate Case

On March 7, 2008, IPC filed an application with the IPUC requesting recovery of the costs associated with the construction of its new natural gas-fired plant as discussed in "Regulatory Matters - Idaho General Rate Cases - Danskin CT1 Power Plant Rate Case." On May 30, 2008, the IPUC authorized IPC to add to its rate base $64.2 million for the Danskin CT1 plant and associated transmission and interconnection system upgrades, effective June 1, 2008, resulting in a base rate increase of 1.37 percent or $8.9 million in annual revenues.

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 of preserving, to the fullest extent possible, the long-term availability of water for use at IPC's hydroelectric projects on the Snake River. IPC's involvement includes active participation in the Snake River Basin Adjudication, a judicial action initiated in 1987 to determine the nature and extent of water use in the Snake River basin, judicial and administrative proceedings relating to the conjunctive management of ground and surface water rights, and management and planning processes intended to reverse declining trends in river, spring, and aquifer levels and address the long-term water resource needs of the state. On occasion, resolution of these water management issues involves litigation. IPC is involved in legal actions regarding not only its water rights but also the water rights of others. One such action, initiated in the Snake River Basin Adjudication, involves IPC's water rights at the Swan Falls project on the Snake River and several other upstream hydroelectric projects that are the subject of a 1984 agreement with the State of Idaho known as the Swan Falls Agreement.

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

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court scheduled a hearing for September 16, 2008, for arguments on summary judgment motions on the recharge issue. The state and IPC are now in the process of completing discovery and briefing and filing summary judgment motions on recharge. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the state and other water users through an advisory committee in the development of a Comprehensive Aquifer Management Plan (CAMP) to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan. However, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards.

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

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

RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and IPC's earnings during the three and six months ended June 30, 2008. In this analysis, the results for 2008 are compared to the same period in 2007.

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

	Three months ended June 30,		**Six months ended June 30,**	
	2008	**2007**	**2008**	**2007**
IPC - Utility operations	$ 17,728	$ 16,164	$ 38,999	$ 39,495
IDACORP Financial Services	701	1,759	1,502	3,621
Ida-West Energy	908	836	963	1,042
IDACORP Energy	(11)	(21)	(23)	(76)
Holding company	(1,811)	(273)	(2,210)	(1,036)
Discontinued operations	-	-	-	67
Total earnings	$ 17,515	$ 18,465	$ 39,231	$ 43,113
Average common shares outstanding (diluted)	45,096	43,884	45,050	43,845
Diluted earnings per share	$ 0.39	$ 0.42	$ 0.87	$ 0.98

Utility Operations

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

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

Hydroelectric generation increased 35 percent for the quarter and 10 percent year-to-date as compared to the same periods in 2007. However, hydroelectric generation is 11 percent and 19 percent below the 30-year average for the quarter and the year-to-date, respectively. Delayed spring runoff and recovery from below normal Snake River system reservoir carryover from last year continued to affect stream flows into the second quarter of 2008.

Actual observed Brownlee Reservoir inflow for the April through July 2008 period is 4.4 million acre-feet (maf), or 70 percent of average, an improvement from the 2007 April through July inflow of 2.8 maf, or 44 percent of average. Storage in selected federal reservoirs upstream of Brownlee, as of July 22, 2008, was 113 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 6.5 and 7.5 million MWh from its hydroelectric facilities in 2008, compared to 6.2 million MWh in 2007.

IPC is actively pursuing opportunities to lease water to enhance river flows to produce additional generation at its hydroelectric plants. Idaho is a semi-arid state and the annual availability of water to lease is highly dependent on climate conditions. Water leases are also subject to approval by the IDWR to ensure that other water rights are not impacted. For 2008, IPC has entered into an agreement with the City of Pocatello, Idaho to lease 20,000 acre-feet of water that is targeted to flow during late summer 2008. The IDWR held a hearing on July 31, 2008, and a decision is pending. IPC has submitted an application and payment for the lease of approximately 49,000 acre-feet of water from the Idaho Water District #1 water rental pool that is also targeted to flow during late summer 2008. Additional leases are in negotiation.

IPC's system load is dual peaking, with the larger peak demand occurring in the summer. IPC set a new record system peak demand of 3,214 MW on June 30, 2008. The previous system peak of 3,193 MW occurred on July 13, 2007. The all-time winter peak demand is 2,464 MW set on January 24, 2008.

The 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, 2008	2,077	1,393	3,470	968	4,438
June 30, 2007	1,539	1,461	3,000	1,527	4,527
Six months ended:					
June 30, 2008	3,740	3,372	7,112	1,655	8,767
June 30, 2007	3,385	3,208	6,593	2,502	9,095

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

Non-GAAP Financial Measures

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

The presentation of electric utility margin is intended to supplement the information available to investors for evaluating IPC's operating performance. When viewed in conjunction with IPC's operating income, electric utility margin provides a more complete understanding of the factors and trends affecting IPC's business, and users can assess which information best suits their needs. However, this measure is not intended to replace operating income, or any other measure calculated in accordance with GAAP, as an indicator of operating performance.

IPC's management uses electric utility margin, in addition to GAAP measures, to determine whether IPC is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. Electric utility margin also provides both management and investors with a better understanding of the effects of regulatory mechanisms on IPC's operating income. The primary limitation associated with this measure is that IPC's electric utility margin may not be comparable to other companies' electric utility margins. However, management uses electric utility margin as an internal tool for evaluating and conducting the business, and is therefore unburdened by this limitation.

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

	Three months ended June 30,		Six months ended June 30,	
	2008	**2007**	**2008**	**2007**
General business revenue	$ 188,748	$ 162,212	$ 356,060	$ 299,463
PCA water deferral *	(3,662)	2,615	(9,627)	10,389
PCA amortization	(4,140)	2,539	(6,596)	5,742
Total	180,946	167,366	339,837	315,594
Power supply costs:				
Off-system sales	(25,641)	(37,177)	(59,004)	(95,016)
Purchased power	50,089	80,467	95,387	131,285
Fuel	28,681	27,520	65,918	58,432
PCA deferral excluding PCA water deferral	(8,631)	(37,018)	(34,796)	(47,577)
Total	44,498	33,792	67,505	47,124
Third party transmission expense	1,903	3,733	2,399	4,532
Other revenues (excluding Demand Side Management (DSM))	10,628	10,589	19,383	19,313
Electric utility margin	$ 145,173	$ 140,430	$ 289,316	$ 283,251
Electric utility margin as a percentage of total general business revenue, PCA water deferral, and PCA amortization	80%	84%	85%	90%

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

The decline in electric utility margin as a percentage of total general business revenue, PCA water deferral, and PCA amortization is the result of the change in the PCA methodology (discussed below in "REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - Distribution of Base Net Power Supply Costs"), and net power supply costs, including the PCA deferral, increasing at a greater rate than general business revenue, primarily due to changes in PCA rates.

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

	Three months ended June 30,	Six months ended June 30,

	2008	2007	2008	2007
Electric utility margin	$ 145,173	$ 140,430	$ 289,316	$ 283,251
Other operations and maintenance (excluding third party transmission expense)	(73,714)	(75,155)	(142,144)	(142,183)
Gain on sale of emission allowances	346	882	346	882
Depreciation	(26,617)	(25,613)	(52,367)	(50,903)
Taxes other than income taxes	(4,800)	(4,636)	(9,603)	(9,554)
Operating income - electric utility (GAAP)	$ 40,388	$ 35,908	$ 85,548	$ 81,493

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

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Revenue				
Residential	$ 74,067	$ 62,886	$ 169,309	$ 141,468
Commercial	47,333	39,983	92,008	76,191
Industrial	29,280	23,294	55,937	45,393
Irrigation	38,068	36,049	38,806	36,411
Total	$ 188,748	$ 162,212	$ 356,060	$ 299,463
MWh				
Residential	1,097	1,067	2,686	2,531
Commercial	926	939	1,924	1,882
Industrial	827	835	1,678	1,707
Irrigation	686	815	697	820
Total	3,536	3,656	6,985	6,940
Customers (average)				
Residential	401,934	396,282	401,545	395,373
Commercial	63,297	61,279	63,124	61,014
Industrial	122	127	122	126
Irrigation	18,388	18,050	18,264	17,957
Total	483,741	475,738	483,055	474,470
Heating degree-days	821	573	3,501	2,909
Cooling degree-days	213	288	213	288
Precipitation (inches)	1.44	2.24	4.14	4.02

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

General business revenue increased $26.5 million and $56.6 million for the quarter and year-to-date, respectively, as compared to the same period in 2007. This increase is primarily attributable to three factors: 1) the effects of rate changes for the current year, 2) increased customer usage, and 3) continued customer growth.

Rates: Rate changes had a positive impact on general business revenue of $31.2 million for the quarter and $52.5 million year-to-date due primarily to a general rate increase of 5.2 percent effective March 1, 2008 and PCA rate increases of 14.5 percent on June 1, 2007, and 10.7 percent on June 1, 2008.

Usage: General business revenue from usage decreased $6.9 million for the quarter and was unchanged for the year-to-date. In the second quarter, a decrease in irrigation usage decreased revenues by $6.4 million. For the year-to-date, the decline in irrigation usage decreased revenue $6.1 million; however, this decrease was offset by increases in usage by other customer classes.

Customers: Moderate growth in customer count in IPC's service territory increased revenue $2.2 million for the quarter and $4.2 million year-to-date as compared to the same periods in 2007.

Off-system sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy.

The following table presents IPC's off-system sales for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Revenue	$ 25,641	$ 37,177	$ 59,004	$ 95,016
MWh sold	504	526	1,022	1,490
Revenue per MWh	$ 50.88	$ 70.70	$ 57.73	$ 63.77

Off-system sales revenue in 2007 was impacted by revenues associated with financial hedge activity, which made up all of the variance for the quarter and 34 percent of the variance year-to-date. The remaining variance is primarily due to a decrease in sales volumes.

Other revenues: The following table 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,	
	2008	2007	2008	2007
Transmission services and property rental	$ 11,549	$ 11,016	$ 21,060	$ 20,284
DSM	3,928	2,548	7,293	4,663
Provision for rate refund	(921)	(427)	(1,677)	(971)
Total	$ 14,556	$ 13,137	$ 26,676	$ 23,976

An IPUC order allows IPC to record DSM program expenditures as an operating expense with an offsetting amount recorded in other revenues, resulting in no net effect on earnings. IPC recorded $3.9 million for the quarter and $7.3 million for the year-to-date related to DSM activities in other revenues, an increase of $1.4 million and $2.6 million for the quarter and year-to-date, respectively, which reflects increased program expenditures.

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

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

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Purchased power expense	$ 50,089	$ 80,467	$ 95,387	$ 131,285
MWh purchased	968	1,527	1,655	2,502
Cost per MWh purchased	$ 51.74	$ 52.70	$ 57.64	$ 52.47

Purchased power expense in 2007 was impacted by costs associated with financial hedge activity, which made up 33 percent of the variance for the quarter and 28 percent of the variance year-to-date. The remaining variance is due to an increase in available water which allowed IPC to better utilize its own generation resources and make fewer market purchases to serve load.

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,		Six months ended June 30,	
	2008	2007	2008	2007
Fuel expense	$ 28,681	$ 27,520	$ 65,918	$ 58,432
Thermal MWh generated	1,394	1,462	3,372	3,208
Cost per MWh	$ 20.57	$ 18.83	$ 19.55	$ 18.21

For the quarter, the increase in fuel expense was due to an increase in contracted coal prices, which was partially offset by a decrease in volume generated. For the year-to-date, both the contracted coal prices and the volume generated increased.

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

The change in PCA expenses is due to a combination of an increase in the base cost deferral, an increase in the levels forecasted above the base costs and the intra-period allocation of base costs discussed in "REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - Distribution of Base Net Power Supply Costs." The quarter was also impacted by increased net power supply costs, while the net power supply costs for the year-to-date decreased. The following table presents the components of PCA expense for the three and six months ended June 30:

	Three months ended June 30,		**Six months ended June 30,**	
	2008	**2007**	**2008**	**2007**
Current year power supply cost deferral	$ (4,969)	$ (39,633)	$ (25,169)	$ (57,966)
Amortization of prior year authorized balances	4,140	(2,539)	6,596	(5,742)
Total power cost adjustment	$ (829)	$ (42,172)	$ (18,573)	$ (63,708)

Other operations and maintenance expenses: Other operations and maintenance expenses decreased four percent for the quarter and one percent for the year-to-date. The decreases were primarily attributable to lower thermal O&M due to lower outage costs.

Non-utility operations

IFS: IFS earnings decreased $1.1 million for the quarter and $2.1 million year-to-date as compared to the same periods of 2007. The reduction is primarily due to lower tax benefits and higher investment amortization expense caused by a reduction in the amount of new investments combined with the continued aging of existing investments. IFS' income is derived principally from the generation of federal income tax credits and accelerated tax depreciation benefits related to its investments in affordable housing and historic rehabilitation developments. IFS made $8.5 million in new investments and generated tax credits of $5.5 million for the six months ended June 30, 2008.

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

Interest Expense

Interest charges increased $1.6 million for the quarter and $3.9 million for the year-to-date. The increases were primarily due to increases in long-term debt balances and increases in variable interest rates.

Income Taxes

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP's effective rate on continuing operations for the six months ended June 30, 2008, was 24.2 percent, compared to 16.2 percent for the six months ended June 30, 2007. IPC's effective tax rate for the six months ended June 30, 2008, was 33.6 percent, compared to 34.3 percent for the six months ended June 30, 2007. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

LIQUIDITY AND CAPITAL RESOURCES:

Operating cash flows

IDACORP's and IPC's operating cash inflows for the six months ended June 30, 2008 were $53 million and $61 million, respectively. Compared to 2007, IDACORP's operating cash inflows increased $12 million and IPC's operating cash inflows increased $21 million.

The increases in IDACORP's and IPC's operating cash inflows is primarily the result of a $40 million decrease in the amount of net power supply costs deferred in 2008 as compared to 2007. This decrease was partially offset by $26 million and $21 million in changes to working capital items and other liabilities for IDACORP and IPC, respectively.

Investing cash flows

IDACORP's and IPC's investing cash outflows for the six months ended June 30, 2008 were $116 million and $109 million, respectively, compared to $113 million and $120 million, respectively, for the six months ended June 30, 2007. Investing cash outflows are primarily the result of IPC's utility construction, partially offset by IDACORP's withdrawal of $20 million from its $45 million refundable income tax deposit made in 2006. Additionally, IPC had a cash inflow of $5.7 million from the sale of SWIP rights-of-way and made an $8.7 million contribution to its joint venture, Bridger Coal Company. IDACORP made an $8.5 million investment in affordable housing through its subsidiary, IFS.

Financing cash flows

IDACORP's and IPC's financing cash inflows for the six months ended June 30, 2008 were $63 million and $49 million, respectively. These inflows result primarily from increases in short-term borrowing of $89 million and $74 million at IDACORP and IPC, respectively, partially offset by dividends paid of $27 million. Additionally, IPC had a cash inflow of $170 million from its Term Loan Credit Agreement, of which $166.1 million was used to purchase pollution control revenue refunding bonds.

Discontinued operations

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

Financing Programs

Consolidated capitalization ratios were as follows:

	IPC	IDACORP

	June 30,	December 31,	June 30,	December 31,

2008	2007	2008	2007

Common shareholders' equity	45.4%	46.5%	45.9%	47.1%
Long-term debt*	46.0%	47.8%	43.6%	45.6%
Short-term debt	8.6%	5.7%	10.5%	7.3%

*Includes the current portion of long-term debt

Shelf Registrations: IDACORP currently has $629 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. As of August 6, 2008, IDACORP has 1,082,145 shares of common stock available to be issued pursuant to its Sales Agency Agreement with BNY capital markets, Inc., dated December 15, 2005, as amended.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to $350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H. On July 10, 2008, IPC issued $120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018. IPC used the net proceeds to pay down short-term debt. As of August 6, 2008, IPC has $230 million remaining on the shelf registration statement.

Credit facilities: IDACORP's credit facility is a $100 million five-year credit agreement that terminates on April 25, 2012. IDACORP's credit facility, which is used for general corporate purposes and commercial paper backup, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million. IDACORP has the right to request an increase in the aggregate principal amount of the credit facility to $150 million and to request one-year extensions of the then existing termination date. At June 30, 2008, no loans were outstanding on IDACORP's facility and $65 million of commercial paper was outstanding. At August 6, 2008, $65 million of commercial paper was outstanding.

IPC's credit facility is a $300 million five-year credit agreement that terminates on April 25, 2012. IPC's credit facility, which is used for general corporate purposes and commercial paper backup, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IPC has the right to request an increase in the aggregate principal amount of the credit facility to $450 million and to request one-year extensions of the then existing termination date. At June 30, 2008, no loans were outstanding on IPC's facility and $210 million of commercial paper was outstanding. At August 6, 2008, $87 million of commercial paper was outstanding.

IDACORP's and IPC's credit facilities both contain covenants requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At June 30, 2008, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively. At June 30, 2008, IDACORP and IPC were each in compliance with all other covenants in their respective credit facilities.

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, National Association and Wachovia Bank, N.A., as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans are due on March 31, 2009. The loans may be prepaid but may not be reborrowed. IPC used the proceeds to effect a mandatory purchase on April 3, 2008, of the pollution control bonds (as discussed below in "Pollution Control Revenue Refunding Bonds"), and to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement.

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

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

Contractual obligations

There have been no material changes in contractual obligations outside of the ordinary course of business since December 31, 2007 with the exception of the following: On April 1, 2008, IPC entered into a Term Loan Credit Agreement in the amount of $170 million. The Term Loan is due March 31, 2009. Additional details relating to the Term Loan are discussed above under "Financing Programs - Term Loan Credit Agreement." On June 2, 2008, IPC entered into a purchased power contract with PPL EnergyPlus, LLC that is expected to total $19.1 million during 2010-2011. IPC has also entered into contracts with four companies in connection with the deployment of Advanced Metering Infrastructure (AMI). IPC estimates it will spend up to $71 million from 2009 through 2011 for AMI. The AMI contracts are further discussed in "REGULATORY MATTERS - Advanced Metering Infrastructure."

Credit ratings

Moody's: On June 3, 2008, Moody's Investors Service (Moody's) announced that it had revised its rating outlook to negative from stable for IDACORP and IPC, while affirming the existing ratings for both companies. Moody's affirmed its Baa2 Issuer Rating on IDACORP and Baa1 senior unsecured rating on IPC, and its P-2 commercial paper rating on both companies.

Moody's stated that the outlook revision primarily reflects its concern about weakness in IPC's credit metrics in recent periods, reflecting the effects of poor hydro conditions and the adverse impact of the load growth adjustment rate on IPC's earnings and cash flow. Moody's also stated that IPC faces a higher than historical average capital program over the next several years, which will require significant external financing to fund the expected negative free cash flow.

Fitch: On March 24, 2008, Fitch Ratings, Inc. (Fitch) announced that it revised its rating outlook to negative from stable for IDACORP and IPC, while affirming the existing ratings for both companies. Fitch affirmed its BBB Issuer Default Rating (IDR) on IDACORP and IPC, its F2 short-term IDR rating on IDACORP and IPC, its A- rating on IPC's senior secured debt, its BBB+ rating on IPC's senior unsecured debt and its F2 ratings on IDACORP's and IPC's commercial paper.

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

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

	S&P		**Moody's**		**Fitch**	
	IPC	**IDACORP**	**IPC**	**IDACORP**	**IPC**	**IDACORP**
Corporate Credit Rating	BBB	BBB	Baa 1	Baa 2	None	None
Senior Secured Debt	A-	None	A3	None	A-	None
Senior Unsecured Debt	BBB- (prelim)	BBB- (prelim)	Baa 1	Baa 2	BBB+	BBB
Short-Term Tax-Exempt Debt	BBB-/A-2	None	Baa 1/ VMIG-2	None	None	None
Commercial Paper	A-2	A-2	P-2	P-2	F2	F2
Credit Facility	None	None	Baa 1	Baa 2	None	None
Rating Outlook	Stable	Stable	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

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

REGULATORY MATTERS:

Idaho General Rate Cases

2008 General Rate Case: On June 27, 2008, IPC filed an application with the IPUC requesting an average rate increase of approximately 9.9 percent. IPC's proposal would increase its revenues $67 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.55 percent. IPC filed its case based upon a 2008 forecast test year and expects that the new rates will go into effect by February 1, 2009. IPC is unable to predict what relief the IPUC will grant.

2007 General Rate Case: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of 10.35 percent ($63.9 million annually). On February 28, 2008, the IPUC approved a settlement stipulation that included an average increase of 5.2 percent (approximately $32.1 million annually). New rates were effective March 1, 2008. Neither an overall rate of return nor a return on equity was specified in the settlement. The currently authorized rate of return remains at 8.1 percent.

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

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

On March 12, 2008, IPC, the IPUC Staff, and other parties to this general rate case conducted a workshop to discuss the appropriate approach to the development of a forecast test year. IPC described a method that would start with historical, regulatory-adjusted financial information that could be audited by the IPUC Staff and others. That information would be escalated under prescribed methods into the forecast test year for revenues, expenses and rate base. IPC would support the historical information, the adjustments, and the escalation methods as part of its general rate case filing. The parties to the workshop expressed general agreement to this approach and also agreed that no further workshops would be necessary. IPC developed the 2008 test year using this method in its 2008 general rate case filing made on June 27, 2008.

Danskin CT1 Power Plant Rate Case: On March 7, 2008, IPC filed an application with the IPUC requesting recovery of the costs associated with the construction of the Danskin CT1 plant, a gas-fired combustion turbine located at the Evander Andrews Power Complex near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. In the filing, IPC requested adding to rate base approximately $65 million attributable to the cost of constructing the generating facility and the necessary transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or $9 million in annual revenues.

On May 30, 2008, the IPUC authorized IPC to add to its rate base $64.2 million for the Danskin CT1 plant and associated transmission and interconnection system upgrades, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or $8.9 million in annual revenues. Costs not approved in this order will be included in future filings.

Deferred Net Power Supply Costs

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

	June 30, 2008	**December 31, 2007**
Idaho PCA current year:		
Deferral for the 2008-2009 rate year *	$ -	$ 85,732
Deferral for the 2009-2010 rate year	10,162	-
Idaho PCA true-up awaiting recovery:		
Authorized in May 2007	-	6,591
Authorized in May 2008	102,437	-
Oregon deferral:		
2001 costs	2,794	2,993
2006 costs	1,218	2,107

2008 Power cost adjustment mechanism	1,484	-
Total deferral	$ 118,095	$ 97,423

*The 2008-2009 PCA deferral balance is reduced by $16.5 million of emission allowance sales in 2007.

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

The annual adjustments are based on two components:

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.

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

2008-2009 PCA: On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing requested an increase to existing revenues of approximately $87.2 million.

Subsequently, the IPUC issued an order directing IPC to apply $16.5 million of gains from the sale of excess SO2 emission allowances, including interest, against the PCA. This order reduced IPC's request to approximately $70.7 million. IPC and the IPUC Staff each proposed deviations from standard IPUC approved PCA methodology. IPC proposed to flow through to customers 100 percent of the deviation in net power supply costs and PURPA project expenses for the 2008-2009 PCA year instead of a 90/10 sharing between customers and shareholders. This was denied by the IPUC. The IPUC Staff proposed using a "normal" forecast for power supply costs and equally dividing the net power supply expenses implemented in the rate change on March 1, 2008 resulting from the 2007 general rate case. The IPUC approved the IPUC Staff's recommendations on May 30, 2008. As discussed below in "Distribution of Base Net Power Supply Costs," the adopted distribution methodology results in an equal amount of power supply costs across all months as compared to a more seasonal allocation that would have recognized significantly more power supply costs in the third quarter and less in the first and second quarters. The IPUC decision is not expected to have a material impact on annual financial results.

On May 30, 2008, the IPUC adopted the IPUC Staff's proposal to use a "normal" forecast for power supply costs and approved an increase to existing revenues of $73.3 million, effective June 1, 2008, which results in an average rate increase to IPC's customers of 10.7 percent.

In its order the IPUC also directed IPC to set up workshops to address PCA-related issues such as sharing methodology, forecasting methodology, distribution of power cost deferrals and load growth adjustment rate. An informational workshop was held on July 30, 2008 and a second workshop is scheduled for August 13, 2008.

Distribution of Base Net Power Supply Costs: On May 30, 2008, the IPUC approved the IPUC Staff's recommendation for monthly allocation of the base net power supply costs included in the 2007 general rate case. The adopted allocation was effective March 1, 2008, and results in an equal monthly distribution of base net power supply costs used in the calculation of the Idaho PCA deferral. IPC had requested a moderate seasonal distribution for base net power supply costs.

While the distribution methodology utilized does not affect the total amount of base net power supply costs used to calculate the PCA deferral, it does affect the quarters in which they are allocated.

As a result of the 2007 general rate case, $127.5 million of net power supply costs have been included in base rates beginning March 1, 2008. After adjusting for the Idaho jurisdictional split and recognizing the 90/10 sharing between customers and shareholders, base net power supply costs used in the PCA deferral calculation are approximately $117.5 million.

The following table compares the quarterly estimated pre-tax impact of the two methodologies:

	Base Net Power Supply Costs March 1, 2008 through February 28, 2009 ($ amounts in millions)					
	2008 First Quarter	**2008 Second Quarter**	**2008 Third Quarter**	**2008 Fourth Quarter**	**2009 First Quarter**	**Total**
PCA Base (seasonal distribution)	$ 3.3	$ 26.6	$ 46.4	$ 29.6	$ 11.6	$ 117.5
PCA Base (even distribution)	9.7	29.4	29.4	29.4	19.6	117.5
PCA Expense increase/(decrease)	$ 6.4(1)	$ 2.8	$ (17.0)	$ (0.2)	$ 8.0	$ 0.0

(1) Due to the IPUC's approval of the even monthly distribution of base net power supply costs on May 30, 2008 with an effective date of March 1, 2008, IPC recognized an additional $6.4 million of PCA expense related to the March 2008 time period in the second quarter 2008.

On July 30 and August 13, 2008, IPC is participating in PCA workshops that will address the future distribution of base net power supply costs along with other PCA matters. IPC expects the distribution issue to be resolved as a result of the workshop proceedings. Until such time as a final PCA base distribution methodology is implemented, the quarterly results will be subject to variability and may experience significant shifts from one quarter to another as compared to historical results; however, the total impact from any distribution methodology should be zero within a twelve month period that base net power supply expenses are collected.

2007-2008 PCA: On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then-existing level, which was $46.8 million below base rates, to a level that is $30.7 million above those base rates. This $77.5 million increase was net of $69.1 million of proceeds from sales of excess SO2 emission allowances. The new rates became effective June 1, 2007.

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

The IPUC-approved settlement of the 2007 general rate case reset the LGAR to $62.79 per MWh, but applies that rate to only 50 percent of the load growth beginning in March 2008. In that general rate case, IPC filed normalized firm base load of 15.6 million MWh as compared with 14.8 million MWh in the 2005 general rate case. IPC's 2008 general rate case filing includes normalized firm base load of 15.9 million MWh. IPC expects to update the LGAR in its 2008 general rate case pending the results of the PCA workshops.

Emission Allowances: During 2007, IPC sold 35,000 SO2 emission allowances for a total of $19.6 million. The sales proceeds allocated to the Idaho jurisdiction are approximately $18.5 million. On April 14, 2008, the IPUC ordered that $16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that $0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and is reflected in PCA rates in effect from June 1, 2007, to May 31, 2008.

The bulk of IPC's accumulated excess emission allowances were sold during the 2005-2007 period. IPC has approximately 22,000 excess SO2 emission allowances currently and anticipates realizing approximately 14,500 excess SO2 emission allowances annually into the near future. Tighter emission restrictions are expected in the long term which may cause IPC to use more emission allowances for its own requirements and reduce the annual amount of excess emission allowances.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" (which means above base power supply costs) power supply expenses. IPC requested authorization to defer an estimated $5.7 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is awaiting an order from the OPUC.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. A settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 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 not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Oregon Power Costs

On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost recovery mechanism similar to the Idaho PCA. A joint stipulation was filed with the OPUC on March 14, 2008, and the OPUC approved the stipulation on April 28, 2008.

The new mechanism will allow IPC to recover excess net power supply costs in a more timely fashion than through the existing deferral process. The mechanism differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case.

The new regulatory mechanism has two parts: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU has two components: the "October Update," where each October IPC will calculate its estimated normalized net power supply expenses for the following April through March test period, and the "March Forecast," where each March IPC will file a forecast of its normalized 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 will be adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up to be filed each February beginning in February 2009. The filing will calculate the deviation between actual net power supply expenses incurred for the preceding January through December period 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 by application of an asymmetrical deadband 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, with new combined rates effective each June 1.

On October 29, 2007, IPC filed its first October Update with the OPUC reflecting the estimated net power supply expenses for the April 2008 through March 2009 test period. On March 24, 2008, IPC submitted testimony to the OPUC revising its calculation of the October Update to conform to the methodology agreed to by the parties in the stipulation. IPC also submitted the March Forecast, reflecting expected hydroelectric generating conditions and forward prices for the April 2008 through March 2009 test period. The expected power supply costs of $150 million represented an increase of approximately $23 million over the October Update.

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

Fixed Cost Adjustment Mechanism (FCA)

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

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 year. IPC accrued $0.4 million of FCA net over-recovery of fixed costs in the first half of 2008.

Idaho Energy Efficiency Rider

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

On May 30, 2008, the IPUC approved IPC's application to increase the Rider from 1.5 percent to 2.5 percent of base revenues, effective June 1, 2008, and approved IPC's request to eliminate the caps on the Rider for residential and irrigation customers. The IPUC denied IPC's request to utilize Rider funding to support customer programs aimed at the installation of small-scale renewable energy projects, but directed IPC to work with the IPUC Staff and other interested parties to develop a renewable energy program and submit it to the IPUC for approval.

Idaho Depreciation Filing

On April 1, 2008, IPC filed an application with the IPUC for revised depreciation rates to be applied prospectively to depreciable plant in service. IPC requested an effective date of August 1, 2008. If approved, the requested rates would result in an annual reduction of depreciation expense of $6.7 million ($6.2 million allocated to Idaho) based upon December 31, 2006, depreciable plant in service. A workshop on the matter was held on June 24, 2008 and another is expected in August 2008.

Idaho Pension Expense Order

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the 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. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million was deferred to a regulatory asset beginning in the third quarter. In the first half of 2008, $3.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

Revised Statement of Policy and Code of Conduct

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

Advance Metering Infrastructure (AMI)

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 has entered into a number of contracts for materials and resources to allow for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of all customers in its service territory by the end of 2011. The executed contracts do not obligate IPC for any level of purchases and specifically allow IPC to cancel the contracts in the event that appropriate regulatory treatment regarding cost recovery is not granted.

On August 4, 2008, IPC filed an application with the IPUC requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. In its application, IPC estimated the three year investment in AMI to be $71 million. The 2009 revenue requirement impact of the AMI deployment is estimated to be $12.2 million. The effect on rates will be addressed in subsequent proceedings after a deployment plan is approved by the IPUC.

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

Open Access Transmission Tariff (OATT)

On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of $11 million based upon 2004 test year data. The rates were accepted subject to refund pending the outcome of the hearing and settlement process.

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

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements. If the Initial Decision is implemented, IPC estimates that it would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $4.2 million for the June 1, 2006, through June 30, 2008, period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process. IPC is awaiting a final FERC order.

On June 2, 2008, 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 2007 test year. The draft informational filing includes a proposed rate of $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. The impact of this rate decrease on IPC's revenues will be dependent on transmission volume sold, which can be highly variable. In 2007, IPC had revenues from sales of transmission to others of $16 million. A customer meeting to discuss the informational filing was held on June 17, 2008. A final filing will be submitted to the FERC by September 1, 2008 with new rates effective October 1, 2008.

Regional Transmission Organization (RTO) costs: On April 30, 2008, the FERC issued an order amending the OATT formula rate to allow IPC to include RTO formation costs previously deferred. The new rates were effective May 1, 2008. The FERC-jurisdictional amount deferred was $0.4 million and will be added to rate base and amortized over five years. The impact on the OATT rate was an increase from $19.31 per kW-year to $19.73 per kW-year, or 2.2 percent.

Northern Tier Transmission Group

On July 17, 2008, the FERC issued an order accepting IPC's compliance filing, subject to modifications and directing further compliance filings within 90 days, regarding the Attachment K transmission planning requirements of Order No. 890. The Attachment K planning processes incorporate local, subregional, and regional transmission planning into IPC's OATT, under which IPC has been operating since the December 7, 2007 initial filing date. The order and pending compliance filings do not constitute a material change in planning obligations and are not expected to have a significant impact on IPC's financial results.

Transmission Projects

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

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

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

Integrated Resource Plan

IPC' s 2006 IRP previewed IPC's load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions. In June 2008, IPC provided an update on the status of the IRP to both the IPUC and OPUC. IPC has also begun preparing the 2009 IRP, which is expected to be filed with the IPUC and OPUC in June 2009. IPC continually evaluates the resource plan and adjusts it to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. Several items from the 2006 IRP have been updated, including:

Geothermal Agreement: The Raft River Geothermal Power Plant Unit #1, which is owned and operated by U.S. Geothermal and located in southern Idaho, began delivering energy to IPC in October 2007 under a PURPA contract which was limited to 10 MW on a monthly basis. On January 9, 2008, the IPUC approved a power purchase agreement for 13 MW from the project which was bid into IPC's 2006 Geothermal RFP. Concurrent with the approval of the new contract, the existing PURPA contract was terminated.

In response to IPC's 2006 RFP, U.S. Geothermal also proposed an additional 6.5 MW at the Raft River site and 26 MW from two units at the Neal Hot Springs site located in eastern Oregon. U.S. Geothermal is continuing exploration and development work on these additional sites; however, there have been delays in the development process and those resources are not expected to meet the 2009 on-line date identified in the 2006 IRP. Contract discussions between IPC and U.S. Geothermal are on-going but IPC is not able to predict the outcome.

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

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

2012 Baseload RFP: In light of the decision to no longer pursue a conventional coal resource in 2013 as identified in the 2006 IRP, on April 1, 2008, IPC issued an RFP for between approximately 250 and 600 MW of dispatchable, physically delivered firm or unit contingent energy to be acquired under power purchase or tolling agreements. A tolling agreement is an arrangement where one party owns, operates and maintains the generating facility and the other party provides fuel, pays capacity charges and receives the contracted output from the project including energy, capacity and ancillary services. The timing of this addition was also accelerated to 2012 to meet forecast deficits resulting from changes in the resource portfolio not anticipated in the 2006 IRP. In June 2008, IPC notified bidders that the RFP quantity had been revised to approximately 300 MW. IPC intends to submit a self-build proposal for a combined-cycle combustion turbine which will serve as a benchmark in the evaluation process. Proposals are due by October 17, 2008.

Relicensing of Hydroelectric Projects

This section summarizes and updates the discussion of relicensing projects in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

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

The relicensing costs are recorded and held in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $100 million and $4 million for HCC and Swan Falls, respectively, were included in construction work in progress at June 30, 2008.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately two-thirds of IPC's hydroelectric generating capacity and 40 percent of its total generating capacity. In July 2003, IPC filed an application for a new license in anticipation of the July 2005 expiration of the then existing license. IPC is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the new license is issued.
Consistent with the requirements of the National Environmental Policy Act of 1969, as amended (NEPA), the FERC Staff prepared and issued on August 31, 2007, a final environmental impact statement (EIS) for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, the federal and state agencies, Native American tribes and the public about the environmental effects of IPC's proposed operation of the HCC. IPC is continuing to review the final EIS and expects to file comments with the FERC in 2008.

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

On January 31, 2007, IPC filed Water Quality Certification Applications, under section 401 of the Clean Water Act (CWA), with the States of Oregon and Idaho. Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, section 401 of the CWA requires that each state certify that any discharge from the project complies with applicable state water quality standards. IPC filed supplemental information to the applications on February 1 and June 30, 2008. IPC continues to work with the ODEQ and the IDEQ to ensure that state water quality standards will be met at the HCC so that the project can be appropriately certified.

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

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contains project-specific information and the results of environmental studies designed to determine project effects. Comments were received from the agencies and one Native American tribe and on February 19, 2008, a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. On June 26, 2008, IPC filed a final license application with the FERC. On July 9, 2008, in conformance with applicable regulations, the FERC issued a Notice of Application Tendered for Filing with the Commission, Soliciting Additional Study Requests, and Establishing Procedural Schedule for Relicensing and a Deadline for Submission of Final Amendments. Pursuant to that notice, state and federal resource agencies, Native American tribes or other interested parties are to file additional study requests with the FERC by August 26, 2008.

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

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

LEGAL AND ENVIRONMENTAL ISSUES:

Legal and Other Proceedings

From time to time IDACORP and IPC are parties to legal claims, actions and complaints in addition to those discussed below. Although they will vigorously defend against them, 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, 2007 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, for a discussion of all material pending legal proceedings to which IDACORP and IPC and their subsidiaries are parties. The following discussion provides a summary of material developments that occurred in those proceedings during the period covered by this report and of any new material proceedings instituted during the period covered by this report.

Western Energy Proceedings at the FERC:

Throughout this report, the term "western energy situation" is used to refer to the California energy crisis that occurred during 2000 and 2001, which resulted in energy shortages 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).

California Refund: In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. That plan included the potential for orders directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund the portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

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

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

On March 21, 2008, the FERC issued an order responding to the remand by Ninth Circuit. The FERC's order established hearing procedures to permit wholesale purchasers that made short-term market-based rate purchases through the Cal ISO and the California Power Exchange (CalPX), as well as those making spot market purchases of energy through the California Energy Resources Scheduling Division of the California Department of Water Resources from January 1, 2000 to October 1, 2000, to (i) present evidence that any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus caused its market-based rates to be unjust and unreasonable and (ii) permit sellers to present evidence to the contrary. Before formal hearing procedures commenced, the FERC directed that the matter be presented to a settlement judge to attempt to settle individual cases. The FERC's March 21, 2008 order expands the field of those who may present evidence in the case from the original complaint of the California Attorney General and also is more restrictive in terms of what must be proven to establish a case. On April 7, 2008, IE and IPC joined with a number of other parties that already had settled this proceeding with the California Attorney General and the other California Parties requesting that they be dismissed from the case. The California Attorney General and the other California Parties indicated their agreement to the dismissal. On April 15, 2008, the FERC issued an order dismissing parties that already had settled, including IE and IPC, from these remanded proceedings. No party sought rehearing of the FERC's dismissal order within the time allowed by statute and the dismissal is now final.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Port of Seattle withdrew its petition for review in one of the three consolidated cases and filed its initial brief on February 29, 2008. The FERC filed its respondent brief on May 30, 2008. On June 30, 2008, IE and IPC filed a joint brief with other companies supporting the FERC, and the California Parties filed a joint brief supporting the FERC on the same day. Final briefs are due at the end of August 2008. A date for argument has not been set. IE and IPC are unable to predict when or how the Ninth Circuit might rule on these consolidated petitions for review.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the "gaming" and "partnership" show cause orders. The FERC staff submitted a motion to the FERC to dismiss the "partnership" proceeding, which was approved by the FERC in an order issued on January 23, 2004. The "gaming" settlement was approved by the FERC on March 4, 2004.

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

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001, concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and the refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. On June 26, 2008, the U.S. Supreme Court issued a decision in one of these cases, Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), and 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 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.

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

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, the structure and content of the FERC's market-based rate regime, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE are unable to predict the outcome of any of these petitions for review.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in U.S. District Court for the District of Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to $32,500 per day per violation and the plaintiff's costs of litigation, including reasonable attorney fees.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity compliance status of the Plant. The court has still not yet ruled on these motions. On March 13, 2008, the Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. On July 7, 2008, the plaintiffs filed a motion requesting the court to schedule a date for oral argument on the pending motions for summary judgment. On July 17, 2008, PacifiCorp filed an opposition to plaintiffs' motion based on the court's order on Initial Pretrial Conference, which stated that "dispositive motions will be decided on the briefs without oral argument." The court has yet to rule on plaintiffs' motion. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on the consolidated financial position, results of operations or cash flows.

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

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

Environmental Issues

The section below summarizes and provides an update of environmental issues as discussed in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

Idaho Water Management Issues: From 2000 through 2005, and throughout 2007 and the first half of 2008, below normal precipitation and stream flows have exacerbated a developing water shortage in Idaho, manifested by a number of water issues including declining Snake River base flows and declining levels in the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer that has been estimated to hold between 200 - 300 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 Idaho Department of Water Resources (IDWR), demanding that it manage ground water withdrawals pursuant to the prior appropriation doctrine of "first in time is first in right" and curtail junior ground water rights that are depleting the aquifer and affecting flows to senior surface water rights. These delivery calls have resulted in several administrative actions before the IDWR to enforce senior water rights as well as judicial actions before the state court challenging the constitutionality of state regulations used by the IDWR to conjunctively administer ground and surface water rights. Because IPC holds water rights that are dependent on the Snake River, spring flows and the overall condition of the ESPA, IPC continues to monitor and participate in these actions, as necessary, to protect its water rights.

IPC, together with other interested water users and state interests, also continues to explore and encourage the development of a long-term management plan that will protect the ESPA and the Snake River from further depletion. On February 14, 2007, the Idaho Water Resource Board (IWRB) presented the framework for an ESPA management plan to the Idaho Legislature recommending the development of a Comprehensive Aquifer Management Plan (CAMP). The proposed goal of the CAMP is to sustain the economic viability and social and environmental health of the ESPA by adaptively managing a balance between water use and supplies. Through House Concurrent Resolution 28 and House Bill 320, the 2007 Idaho Legislature appropriated funds and directed the IWRB to proceed with the development of the CAMP. Pursuant to the IWRB recommendation in the CAMP Framework, an advisory committee has been established to make recommendations to the IWRB on the development of the CAMP. IPC sits on the CAMP advisory committee and will be working with the IWRB on the development of the CAMP. The advisory committee expects to submit recommendations on the CAMP to the IWRB in the fourth quarter of 2008.

IPC is also engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

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

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

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

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

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The court scheduled a hearing for September 16, 2008, for arguments on summary judgment motions on the recharge issue. The State and IPC are now in the process of completing discovery, and briefing and filing summary judgment motions on recharge. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the State and other water users through an advisory committee in the development of a CAMP to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan. However, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the U.S. on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the U.S. has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, on October 15, 2007, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. to recover damages from the U.S. for the lost generation resulting from the reduced flows. On October 15, 2007, IPC filed a second action in the United States District Court for the District of Idaho in Boise, Idaho, to compel the U.S. to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. The U.S. Bureau of Reclamation filed answers in each of these cases on February 15, 2008. On March 4, 2008, the U.S. District Court for the District of Idaho entered a preliminary scheduling order, setting that case for trial on December 15, 2009. The action in the U.S. District Court of Federal Claims has not yet been set for trial but the court has set a discovery schedule requiring that discovery be completed and pre-trial motions filed by July 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of these actions.

Air Quality Issues

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

National Ambient Air Quality Standards: In March 2008, the EPA promulgated a final regulation which revised the 8-hour ozone NAAQS. For the primary (health-based) standard, the EPA lowered the standard from 0.08 parts per million (ppm) to 0.075 ppm. Under the EPA's final rule, states must make recommendations to the EPA by March 2009 for areas to be designated attainment, nonattainment and unclassifiable. Several states, environmental organizations and private parties have challenged the EPA's regulations. The impact of the new standard will not be known until data is collected, analyzed, and released to the public, the judicial appeals are completed and the associated regulatory programs are promulgated and implemented. On May 8, 2008, the EPA issued a final rule implementing the NSR program for emissions of particulate matter of less than 2.5 micrometers in diameter (PM2.5). This rule establishes the framework for requiring preconstruction permit review of PM2.5 emissions from new or modified major stationary sources such as the power plants owned by IPC. The impacts of the PM2.5 NSR standards on IPC will not be known until individual states adopt revised plans and regulations to implement these federal requirements and they become applicable to IPC due to activities at its power plants.

Clean Air Interstate Rule (CAIR): The CAIR, issued by the EPA on March 10, 2005, establishes a permanent cap on emissions of NOx and SO2 primarily from power plants in 28 eastern states and the District of Columbia. While the CAIR does not apply to any of the power plants owned by IPC, it is an important rule for the electric utility industry because of its broad applicability and its close relation to the CAMR. The CAIR was subjected to legal challenges by a number of states, industry, and environmental groups. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAIR. The potential impacts of this court ruling will not be fully understood until any future appeals are resolved or until such time as the EPA and/or individual states respond to the court's ruling.

Clean Air Mercury Rule: The CAMR, issued by the EPA on March 15, 2005, limits mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will permanently cap utility mercury emissions. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR and remanded it back to the EPA for reconsideration consistent with the court's interpretation of the Clean Air Act. On March 24, 2008, the EPA petitioned the U.S. Court of Appeals for the D.C. Circuit to reconsider its decision to overturn the CAMR, which was rejected by the court on May 20, 2008. The impact of the court's decision will not be known until the judicial appeals process has been completed or until such time as the EPA develops a new regulation in response. It is possible that the D.C. Circuit's decision to remand the CAMR back to the EPA for reconsideration could result in changes to mercury rules or regulations adopted by the states in which IPC has partial ownership interests in coal-fired power plants. At this time, however, it is uncertain how state mercury rules or requirements might be affected and if there will be any resulting impacts to IPC.

Regional Haze - Best Available Retrofit Technology: In accordance with federal regional haze rules, the Wyoming Department of Environmental Quality and the Oregon Department of Environmental Quality are conducting an assessment of emission sources pursuant to a RH BART process. Coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. IPC continues to monitor RH BART processes at the Jim Bridger and Boardman plants.

Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) regulations and judicial decisions that would affect electric utilities. Such regulations could increase IPC's capital expenditures and operating costs and reduce earnings and cash flows. At the national level, numerous GHG bills were introduced in the U.S. Senate and House of Representatives during 2007 and 2008, including the Climate Security Act of 2008 (S. 3036), which was debated on the Senate floor but not voted on in June 2008.

The states of Arizona, California, New Mexico, Oregon, Utah and Washington, along with the provinces of British Columbia and Manitoba, Canada, have formed the Western Regional Climate Action Initiative (WCI). On August 22, 2007, the WCI partners released their regional goal to collectively reduce GHGs 15 percent below 2005 levels by 2020. Montana joined the WCI in 2008. The WCI partners have agreed to design a regional market-based multi-sector mechanism, such as a load-based or deliverer-based cap and trade program applicable to the electricity generation industry, to help achieve the goal. The type of regulatory program that the WCI plans to use to achieve reductions from the electricity generation industry is expected to be released in August 2008. The states of Idaho, Nevada and Wyoming have not joined the WCI. It is possible that these and other states in which IPC owns fossil fuel-fired electricity generation facilities or sells electricity into could join the WCI in the future.

In April 2007, the U.S. Supreme Court issued its decision in Massachusetts v. Environmental Protection Agency, a case involving the EPA's authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. The decision, combined with stimulus from state, regional and federal legislative and regulatory initiatives, judicial decisions and other factors may lead to a determination by the EPA to regulate carbon dioxide emissions from stationary sources, including electricity generators. On March 27, 2008, the EPA announced that it would issue an advanced notice of proposed rulemaking (ANPR) to solicit public input on whether GHG emissions should be regulated from stationary sources. On April 2, 2008, Attorneys General from 17 states filed suit in the U.S. Court of Appeals for the D.C. Circuit requesting the court to require the EPA to rule within 60 days on whether carbon dioxide is a danger to public health or welfare and, therefore, subject to regulation under the Clean Air Act. On June 26, 2008, the court denied the request. On July 11, 2008, the EPA released its ANPR inviting public comment on the benefits and ramifications of regulating GHGs under the Clean Air Act. While the majority of current national, regional and state initiatives regarding GHG emissions contemplate market-based compliance programs, a determination by the EPA to regulate GHG emissions under the Clean Air Act could result in GHG emission limits on stationary sources that do not provide market-based compliance options such as cap-and-trade programs or emission offsets. IPC will continue to monitor developments with respect to the possible regulation of GHG emissions from stationary sources under the Clean Air Act.

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

Climate Change: IPC intends to continue to add non-carbon-producing resources to its resource portfolio and will continue to monitor the climate change debate, current climate change research, and recently enacted as well as proposed legislation to identify the potential impacts of global climate change on all aspects of its business. Long-term climate change could significantly affect IPC's business in a variety of ways, including but not limited to the following: (a) extreme weather events and changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation and increase service interruptions, outages and operations and maintenance costs; and (b) legislative and/or regulatory developments related to climate change could affect plans and operations in various ways including placing restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general. IPC cannot, however, quantify the potential impact of global climate change on its business at this time.

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

OTHER MATTERS:

Southwest Intertie Project

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

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

Critical Accounting Policies and Estimates

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

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

Adopted Accounting Pronouncements

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

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

FSP FIN 39-1: IDACORP and IPC adopted FASB Staff Position FIN 39-1 (FSP FIN 39-1), Amendment of FASB Interpretation No. 39 (FIN 39) on January 1, 2008. FSP FIN 39-1 modifies FIN 39, Offsetting of Amounts Related to Certain Contracts, and permits reporting entities to offset receivables or payables recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. IDACORP and IPC have elected to offset these positions, which resulted in an immaterial net decrease to total assets and liabilities at June 30, 2008.

EITF Issue No. 06-11: IDACORP and IPC adopted Emerging Issues Task Force Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF 06-11) on January 1, 2008. EITF 06-11 requires income tax benefits from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified awards and outstanding equity share options to be recognized as an increase in additional paid-in capital and to be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. The adoption of EITF 06-11 did not have a material impact on IDACORP's or IPC's financial statements.

New Accounting Pronouncements

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments and derivative commodity instruments sensitive to changes in interest rates, commodity prices and equity prices that were held at June 30, 2008.

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

Variable Rate Debt: As of June 30, 2008, IDACORP and IPC had $466 million and $401 million, respectively, in floating rate debt, net of temporary investments. Assuming no change in either company's financial structure, if variable interest rates were to average one percentage point higher than the average rate on June 30, 2008, interest expense for the year ending December 31, 2008, would increase and pre-tax earnings would decrease by approximately $4.7 million for IDACORP and $4.0 million for IPC.

IDACORP's and IPC's floating rate debt includes a $170 million term loan credit agreement used to effect a mandatory purchase of $166.1 million of IPC's pollution control bonds. Additional information concerning both the term loan credit agreement and the pollution control bonds can be found in "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs."

Fixed Rate Debt: As of June 30, 2008, IDACORP and IPC had outstanding fixed rate debt of $975 million and $955 million, respectively. The fair market value of this debt was $915 million and $894 million, respectively. These instruments are fixed rate, and therefore do not expose IDACORP or IPC to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $84 million for IDACORP and $83 million for IPC if interest rates were to decline by one percentage point from their June 30, 2008 levels.

Commodity Price Risk
Utility: IPC's commodity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2007. In a limited manner, IPC also utilizes financial energy instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to securing adequate energy to meet utility load requirements in accordance with IPC's Risk Management Policy. This practice falls within the parameters of IPC's Risk Management Policy and these instruments are not used for trading purposes. These financial instruments are used in essentially the same manner as forward transactions to mitigate price risk but are considered derivative instruments under SFAS 133 and are therefore reported at fair value in IDACORP's and IPC's financial statements. Because of the PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Credit Risk
Utility: IPC's credit risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2007.

Equity Price Risk
IDACORP's and IPC's equity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2007.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:
The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of June 30, 2008, have concluded that IDACORP's disclosure controls and procedures are effective.

IPC:
The Chief Executive Officer and the Chief Financial Officer of IPC, based on their evaluation of IPC's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of June 30, 2008, have concluded that IPC's disclosure controls and procedures are effective.

Changes in internal control over financial reporting:

There have been no changes in IDACORP's or IPC's internal control over financial reporting during the quarter ended June 30, 2008, that have materially affected, or are reasonably likely to materially affect, IDACORP's or IPC's internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Reference is made to Note 6 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

ITEM 1A. RISK FACTORS

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

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

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

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

IPC's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would cause their leverage ratios to exceed 65 percent or violate IPC's Code of Conduct. At June 30, 2008, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively and IPC's common equity capital was 45 percent of its total adjusted capital.

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

Issuer Purchases of Equity Securities:

IDACORP, Inc. Common Stock

Period	**(a) Total Number of Shares Purchased** 1	**(b) Average Price Paid per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs**
April 1 - April 30, 2008	-$	-	-	-
May 1 - May 31, 2008	214	31.40	-	-
June 1 - June 30, 2008	-	-	-	-
Total	214	$ 31.40	-	-

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

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

IDACORP, Inc.:

(a) Regular annual meeting of IDACORP, Inc.'s shareholders, held May 15, 2008, in Boise, Idaho.

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

Richard G. Reiten
Thomas J. Wilford
Joan H. Smith

Continuing Directors:

Judith A. Johansen
Gary G. Michael
J. LaMont Keen
Peter S. O'Neill
Christine King
Jan B. Packwood
Jon H. Miller
Robert A. Tinstman

(c) 1) To elect three Director Nominees:

Name	For	Withheld	Total Voted
Richard G. Reiten	38,305,205	1,289,864	39,595,069
Joan H. Smith	38,623,249	971,819	39,595,068
Thomas J. Wilford	38,626,647	968,422	39,595,069

2) To ratify the appointment of Deloitte & Touche LLP as the independent registered public accounting firm for the fiscal year ending December 31, 2008:

Class of Stock	For	Against	Abstain	Total Voted
Common	38,925,041	398,224	271,797	39,595,062

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ITEM 6. EXHIBITS

*Previously Filed and Incorporated Herein by Reference

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

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

	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iii), Thirty-ninth, October 1, 2003
	File number 1-3198, Form 8-K filed 5/10/05, as Exhibit 4, Fortieth, May 1, 2005.
	File number 1-3198, Form 8-K filed 10/10/06, as Exhibit 4, Forty-first, October 1, 2006.
	File number 1-3198, Form 8-K filed 6/4/07, as Exhibit 4, Forty-second, May 1, 2007.
	File number 1-3198, Form 8-K filed 9/26/07, as Exhibit 4, Forty-third, September 1, 2007.
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008.
*4.3	Instruments relating to IPC American Falls bond guarantee (see Exhibit 10.4). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).
*4.4	Agreement of IPC to furnish certain debt instruments. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(f).
*4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments. File number 1-14465, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(c)(ii).
*4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 2(a)(iii).
*4.7	Rights Agreement, dated as of September 10, 1998, between IDACORP, Inc. and Wells Fargo Bank, N.A., as successor to The Bank of New York, as Rights Agent. File number 1-14465, Form 8-K, filed on 9/15/98, as Exhibit 4.
*4.8	First Amendment to Rights Agreement, dated as of May 14, 2007, between IDACORP, Inc. and Wells Fargo Bank, N.A., as successor to The Bank of New York, as Rights Agent. File number 333-143404, Form S-8, filed on 5/31/07, as Exhibit 4(g).
*4.9	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.1.

*4.10	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.2.
*4.11	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.
*10.1	Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).
*10.6	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10.13	

	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).
*10.151	Idaho Power Company Security Plan for Senior Management Employees I - a non-qualified, deferred compensation plan, amended and restated effective December 31, 2004, and as further amended March 14, 2007. File number 1-14465, 1-3198, Form 10-K for the year-ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.15.
*10.161	Idaho Power Company Security Plan for Senior Management Employees II, a non-qualified, deferred compensation plan, effective January 1, 2005, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xxxv).
*10.171	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).
*10.181	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).
*10.191	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on November 2, 2006, as Exhibit 10(h)(vii).
*10.201	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).
*10.211	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended and restated on November 15, 2007. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.21.
*10.221	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and IPC, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).
*10.231	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).
*10.241	Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q

	for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(x).
*10.251	Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xi).
*10.261	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(xii).
*10.271	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).
*10.281	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).
*10.291	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).
*10.301	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (March 20, 2008). File number 1-14465, 1-3198, Form 8-K, filed on 3/26/08, as Exhibit 10.1.
*10.311	IDACORP, Inc. Executive Incentive Plan. File Number 1-14465, 1-3198, Form 8-K/A, filed on 2/27/08, as Exhibit 10.1.
*10.321	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xxxvi).
*10.331	IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.33.
*10.34	Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC's Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.35	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.36	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.37	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal

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

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

1 Management contract or compensatory plan or arrangement

SIGNATURES

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

IDACORP, Inc.
(Registrant)

Date	August 7, 2008	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	August 7, 2008	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date	August 7, 2008	By:	/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer
Date	August 7, 2008	By:	/s/ Darrel T. Anderson Darrel T. Anderson Senior Vice President - Administrative Services and Chief Financial Officer

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EXHIBIT INDEX

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