COMMITMENT

1- 14465

1- 03198

Commitments take many forms.

Our commitments to dams,
power lines and substations
are surpassed only by
our long-term, intangible
commitments. Our values.
Our mission and vision.
People and prosperity.
Sustainability, community
and you.

These are the commitments
that drive us.

Today and every day.

2008 Annual Report

IDACORP®

COMMITMENT

Our Mission

Prosper by providing reliable, responsible, fair-priced energy services, today and tomorrow.

TO OUR FELLOW OWNERS

Trust is one of IDACORP's most valuable renewable resources. The trust of our customers, employees and you, our shareowners, is earned through our commitments and how we fulfill them each day.

Commitments take many forms. At IDACORP, our commitments to dams, power lines and substations are surpassed only by our long-term, intangible commitments. Our values. Our mission and vision. People and prosperity. Sustainability, community and you. These are the commitments that drive us.

Over the last year, we have seen the greatest economic turmoil since the Great Depression. Like others, our company faced numerous challenges. The downturn in the economy and the capital market crisis weakened financial performance across the globe. However, the course of prudence we set in early 2008 enabled IDACORP to successfully manage the business and deliver improved annual results.

Last year at this time, numerous challenges waited on the horizon not only for Idaho Power, IDACORP's core business, but for the utility industry as a whole. Many of those challenges continue today. Our strategy kept our course true then and remains strong today as reflected in the many business successes we achieved in 2008.

We saw a continuation of below-normal hydroelectric conditions in 2008, however our company is experienced in dealing with adversity. Our successful handling of drought conditions in six of the last seven years uniquely positions us to handle adversity's many forms, as evidenced in our annual earnings results. Net income was up in 2008, $98.4 million compared to $82.3 million in 2007. Earnings per diluted share increased to $2.17 from $1.86 in 2007.

This year's annual report will help you understand who our leaders are, our strategy for success, and how commitments to our employees, our customers, and you, our owners, position us favorably as we manage through ongoing uncertainty.

Idaho Power's strategy to ensure adequate energy supplies, enabling a strong going concern, can be broken down to three elements: responsible planning, responsible development and protection of resources and responsible energy use. This three-part strategy ensures we focus on the things that matter, the things that move your company forward.

As we look forward to 2009, we also look back. The commitments we've made throughout our 93-year history shape what we do. Our actions fulfilling those commitments define who we are.

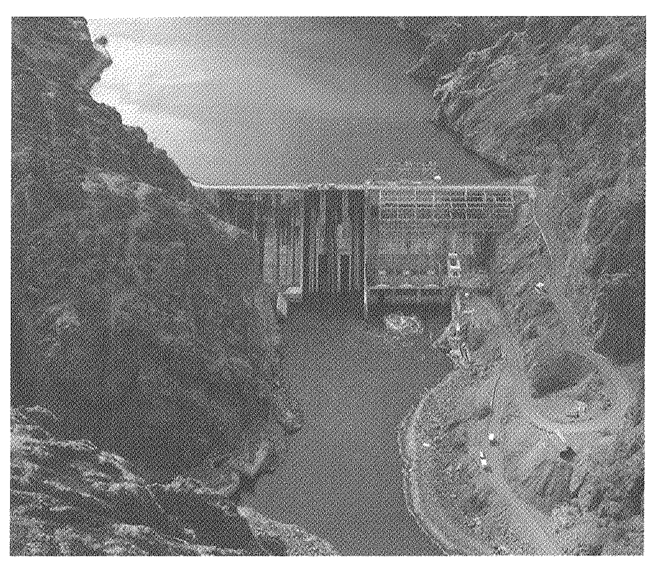
We are 2,000 exceptional men and women proud to work for IDACORP, proud to steward your company and proud of the trust you placed in us to transform today's challenges into tomorrow's successes.

Jon Miller

Jon Miller, Chairman of the Board

J. LaMont Keen

J. LaMont Keen, President & Chief Executive Officer



SUCCEEDING IN UNCERTAIN TIMES

The world is a dramatically different place than it was even a year ago. Last year's economic tsunami ravaged our economy to an extent not seen in generations: capital markets tightened, unemployment escalated, housing starts decreased and consumer confidence collapsed. Those lacking foresight and preparation became victims of market volatility. No one knows when we as a nation will come out of the downslide, however our three-part strategy, especially the focus on responsible planning, gives you confidence your company is on the right course.

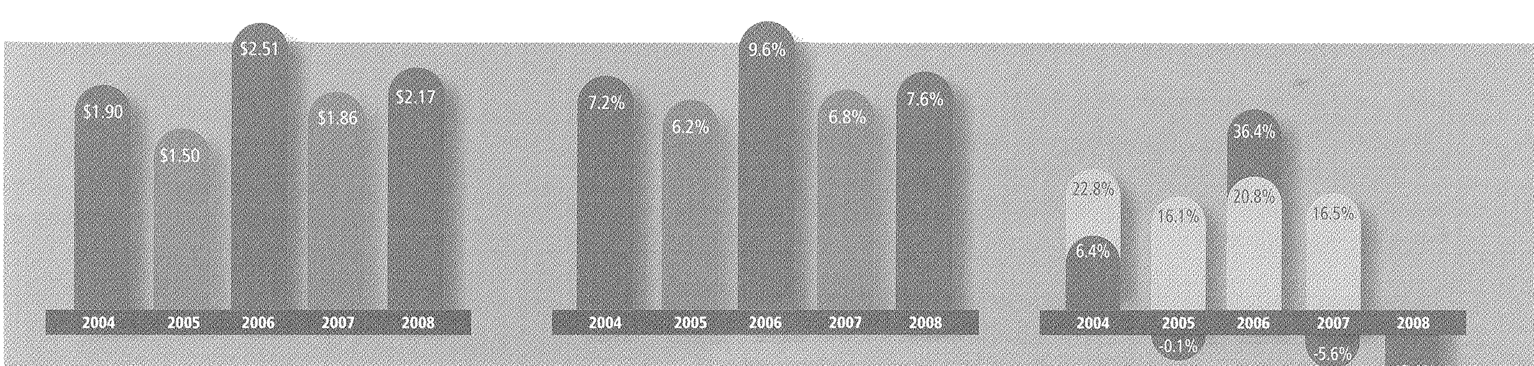
In February 2008, we paused and took a closer look at financial indicators and the national fiscal outlook. Concerns caused leadership to adopt a more austere approach to the company's financial management, resulting in aggressive cost-cutting and new operational efficiency measures. Employees stepped up, doing more with less. Additionally, we reduced our contractor staffing levels dramatically. This comprehensive approach minimized financial obligations and created needed flexibility.

When the capital markets collapsed in September, IDACORP's hard work to realize its mission positioned the company to manage successfully through the uncertainty. We improved our financial performance and experienced one of the strongest third quarters in company history. Additionally, our actions situate the company for continued success in 2009. Although the lingering economic uncertainty poses many challenges, IDACORP demonstrated the ability to succeed in difficult times.

2008 Highlights

Thousands of Dollars, Except Per Share Amounts	2008	2007	% Change
Electric Utility Revenues	$956,076	$875,401	9.2
Other Revenue	$4,338	$3,933	8.6
Total Operating Revenues	$960,414	$879,394	9.2
Net Income	$98,414	$82,339	19.5
Earnings Per Diluted Common Share	$2.17	$1.86	16.7
Dividends Paid Per Common Share	$1.20	$1.20	--
Total Assets	$4,022,845	$3,653,308	10.1
Number of Employees (full time)	2,073	2,044	1.4

The world is a dramatically different place than it was even a year ago. Our three-part strategy gives you confidence that your company is on the right course.

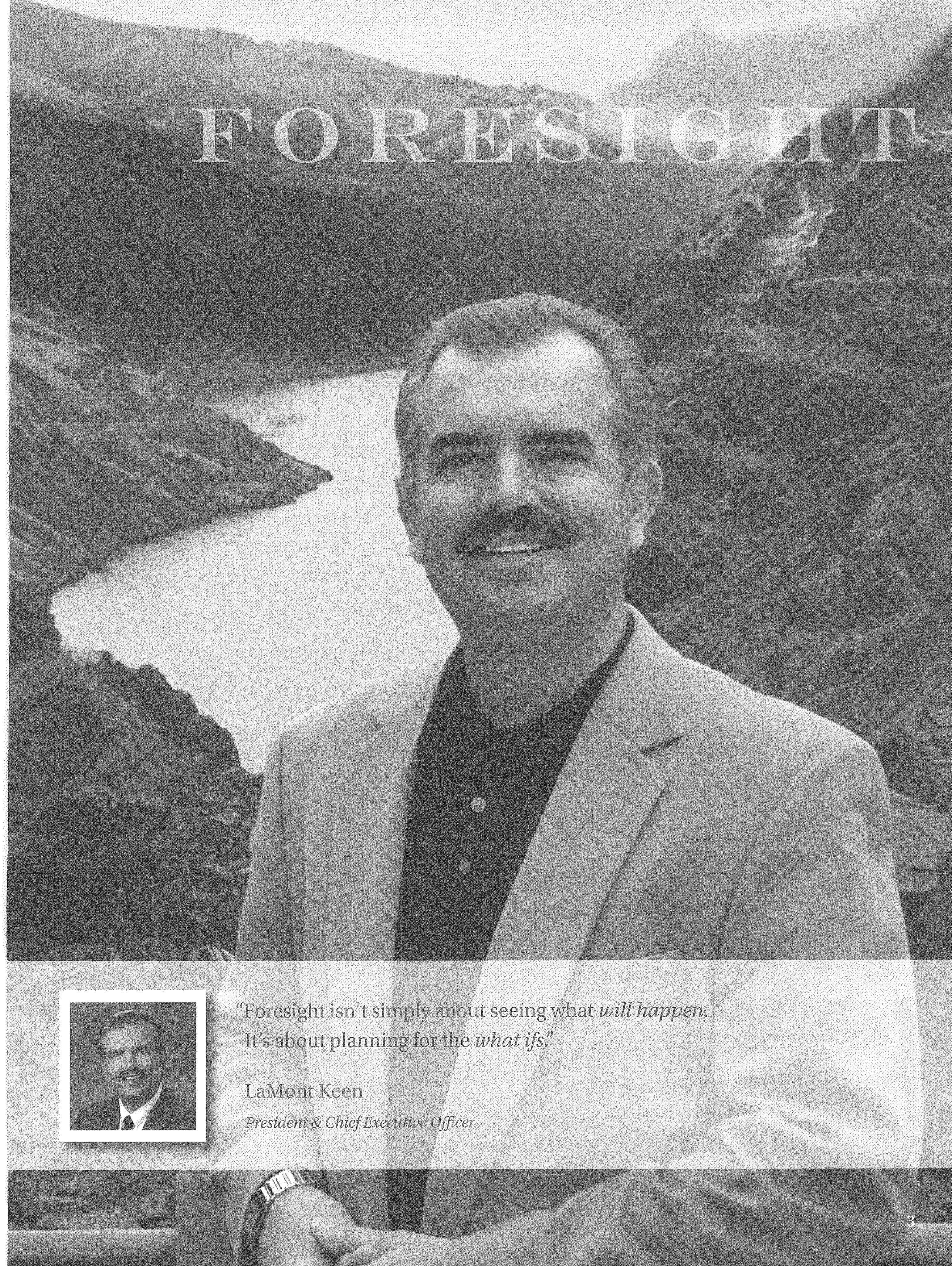


Earnings Per Share
(Diluted)
Current Annual Dividend $1.20

Return on Year-End Equity

Total Return
IDACORP
EEI Electric Utilities Index

FORESIGHT

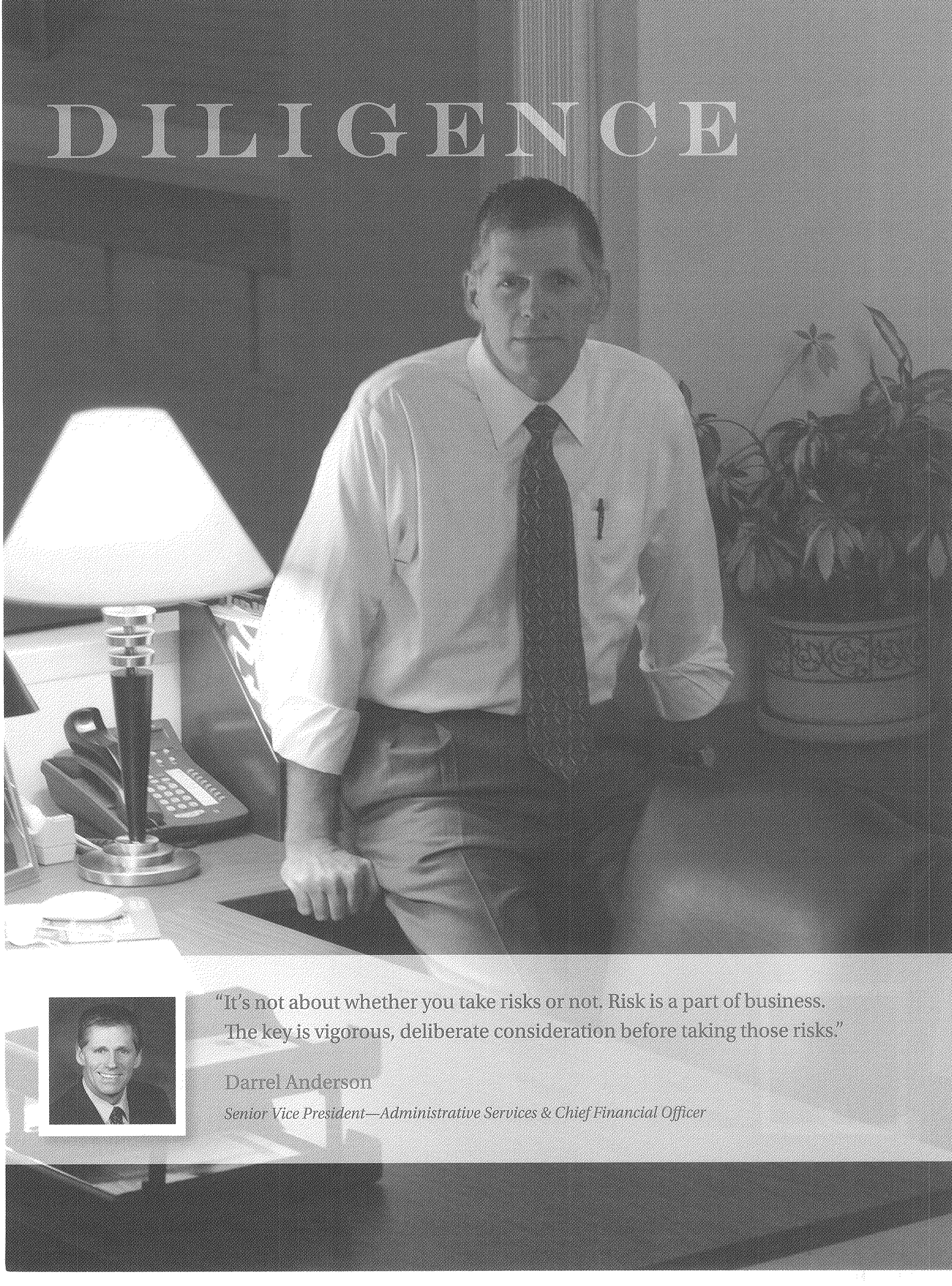


"Foresight isn't simply about seeing what *will happen*.
It's about planning for the *what ifs*."

LaMont Keen

President & Chief Executive Officer

DILIGENCE



"It's not about whether you take risks or not. Risk is a part of business. The key is vigorous, deliberate consideration before taking those risks."

Darrel Anderson

Senior Vice President—Administrative Services & Chief Financial Officer

OUR PLAN TO MEET CUSTOMER DEMAND

In 1901, the first long-distance, high-voltage transmission line was brought on-line in Idaho. The 22,000-volt line brought power from our Swan Falls hydroelectric plant to nearby mines, stimulating growth and prosperity in the region.

Responsible planning, the first part of our strategy, allows each of the IDACORP companies to make forward-looking decisions, prepare for the future and ensure the prosperity of our shareowners, customers and employees. At Idaho Power, responsible planning is driven primarily by customer demand, even in times of slowing customer growth. Last year we finished with 5,514 new customer connections, significantly down from previous years. However, our forecasters predict long-term increases in population expansion and service area electric consumption, offsetting this short-term slow down.

Even with the decline in customer connections, we experienced a new winter peak on January 24, 2008 of 2,464 megawatts (MW) and a new summer peak on June 30 of 3,214 MW. Increasing summer consumption continues to outpace our generation capacity, driving the need to build. IDACORP's management continues to keep a diligent eye on customer growth and electricity consumption and will, if needed, adjust our strategy.

Electricity demand, customer growth, environmental regulations and other resource issues drive our Integrated Resource Plan (IRP)—our roadmap for meeting anticipated customer energy needs for the next 20 years. Previous IRPs identified necessary investments in generation and transmission, improvements ensuring reliable, responsible energy services for generations to come. Our 2009 IRP, detailing how we expect to meet these challenges, will be filed with the Idaho and Oregon utility commissions later this summer.

We first identified the need for a new baseload resource in our 2004 IRP. At that time, an effort to alleviate pressure on future customer rates pointed us toward a coal resource. However in 2007, when regulatory, price and environmental issues related to coal technology intensified, we considered alternative strategies to address the resource deficit.

Today our diligence and foresight is realized in the proposed 300-MW Langley Gulch Power Plant. This natural gas-fired combined-cycle combustion turbine was approved as the selection by your Board of Directors in February after a year-long request for proposal process. We filed for approval of the project with the Idaho Public Utilities Commission (IPUC) in March, and if approved, the plant will come on-line in 2012. This new generation resource is one of the ways we fulfill our commitments to customers and shareowners; it will help Idaho Power ensure reliability, emits less than half the carbon of a traditional coal plant and will reduce the amount of power we purchase during summer peak periods, giving us a cost-savings over the long term.

The story does not end with a new generation resource. Inadequate transmission infrastructure remains a challenge across the nation. Idaho Power's lines and the northwestern regional transmission grid are now at or near maximum capacity. The need to address transmission system constraints is vital to ensuring a responsible, reliable energy future.

Our 1,150-mile Gateway West and 300-mile Boardman to Hemingway transmission projects will provide reliable electricity to customers for years to come. Work on the 500-kilovolt (kV) projects began two years ago and the siting processes are underway. These transmission projects, portions of which are scheduled to be in service beginning in 2013, will facilitate our ability to buy and sell energy to serve our customers and strengthen the regional transmission grid.

Partnerships on these projects mitigate risks and allow for stronger solutions. We are working with Rocky Mountain Power on Gateway West, and partners are being sought for the Boardman to Hemingway project. We continue reaching out to our communities to get input, create understanding and gain support. These transmission resources enable us to meet commitments to our customers and provide a new foundation for bringing much-needed energy to their doors.

OUR COMMITMENT TO FUTURE GENERATIONS

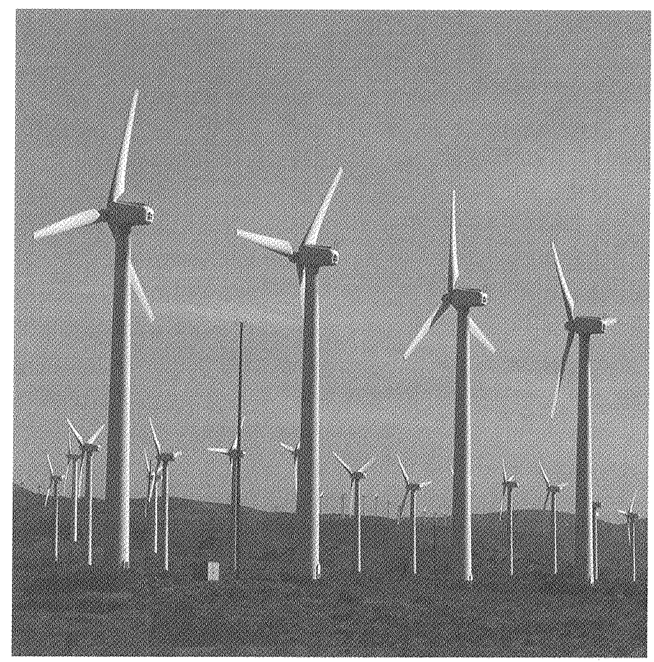
Our commitment to future generations and stewardship of resources is rooted in our history. From Swan Falls in 1901 to the Hells Canyon three-dam complex in 1967, which powered the expansion of the 1970s, 1980s and 1990s, to alternative resources and energy efficiency programs today, we remain committed to providing long-term, financially responsible solutions.

Climate change legislation, expected to be enacted later this year, will help ensure a healthy future. However, it will also impact our utility operations and increase costs to the company and our customers. While there are numerous pieces of legislation under consideration, there is one consistent outcome: the cost to do business will increase.

Nevertheless, IDACORP's core business, Idaho Power, is uniquely positioned to address potential climate change legislation requirements with our low-emission hydroelectric operations providing more than 50 percent of our generation capacity under normal water conditions. Additionally, the IPUC recently approved our request to retire 2007 and 2008 green tags, also called renewable energy credits, generated from the Elkhorn Valley wind project and the Raft River geothermal projects. Retiring these tags allows us to prepare for Renewable Portfolio Standards—mandates requiring a specific amount of generation from renewable resources. Idaho Power's significant hydroelectric base and a balanced resource portfolio position us well to meet future challenges.

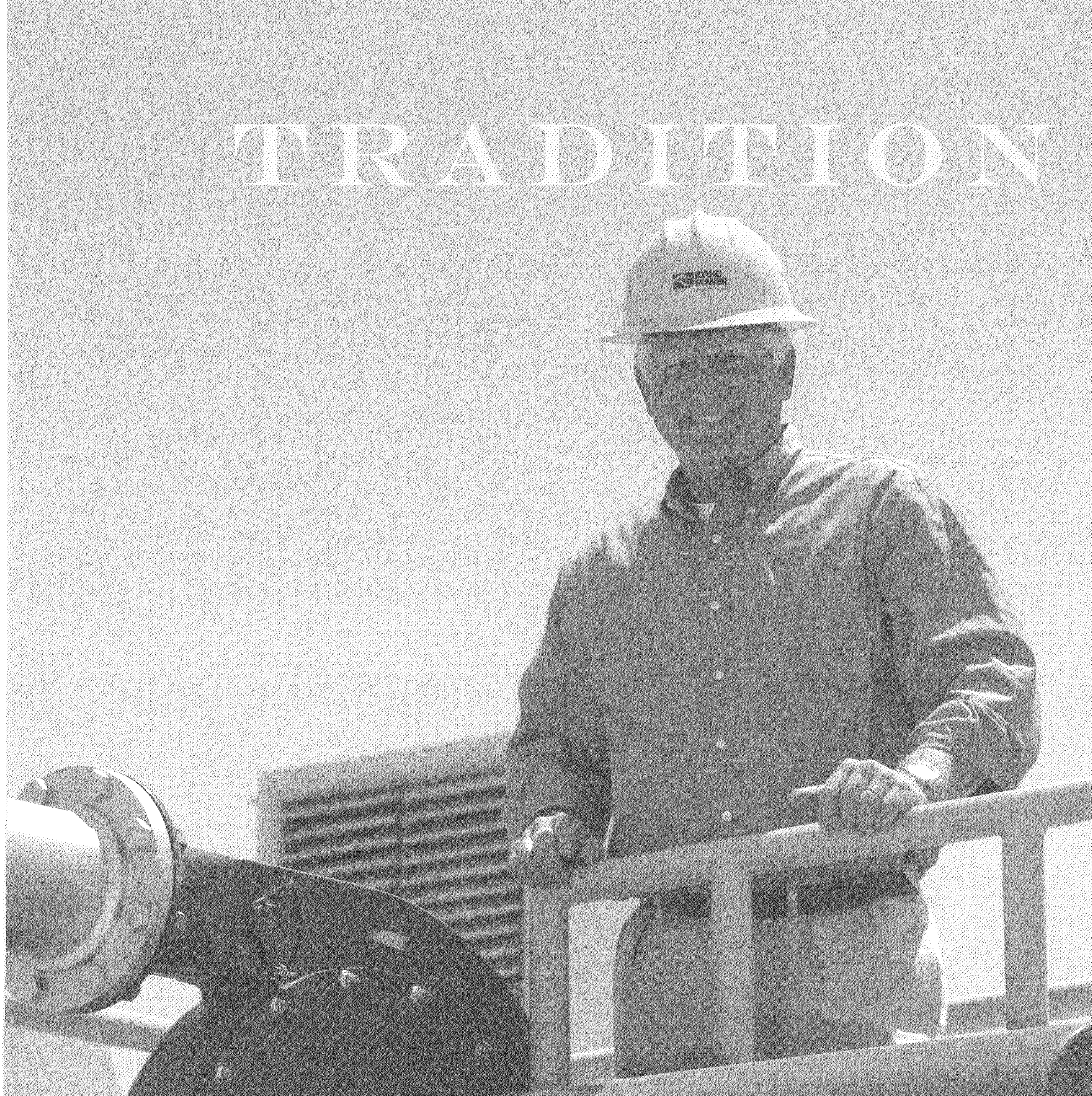
The second part of our strategy, responsible protection of the resources that keep rates low for our customers, helps ensure a strong, viable company. Preservation of our hydroelectric resources remains a top priority and area of intense activity. The heart of Idaho Power since our founding in 1916, hydroelectric generation remains vital to ensuring reliability and maintaining rates among the lowest in the nation for the 487,000 customers we serve. What was once a battle over a precious resource is now a cooperative effort among Idaho's water users. Our participation with impacted parties on the Comprehensive Aquifer Management Plan provided breakthroughs in a number of areas, specifically the critical trust-building process and striking a balance that enables IDACORP to remain strong.

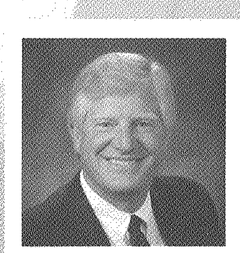
For nearly a century, we've prepared effectively for what may come. In the next 100 years, we'll continue this diligence to fulfill our commitment to maintain a strong and flexible company.



Our commitment to future generations and stewardship of resources is rooted in our history. We remain committed to providing long-term, financially responsible solutions.

TRADITION





"Tradition allows us to learn lessons from our history. We build on that tradition to raise the bar."

Jim Miller

Senior Vice President—Power Supply

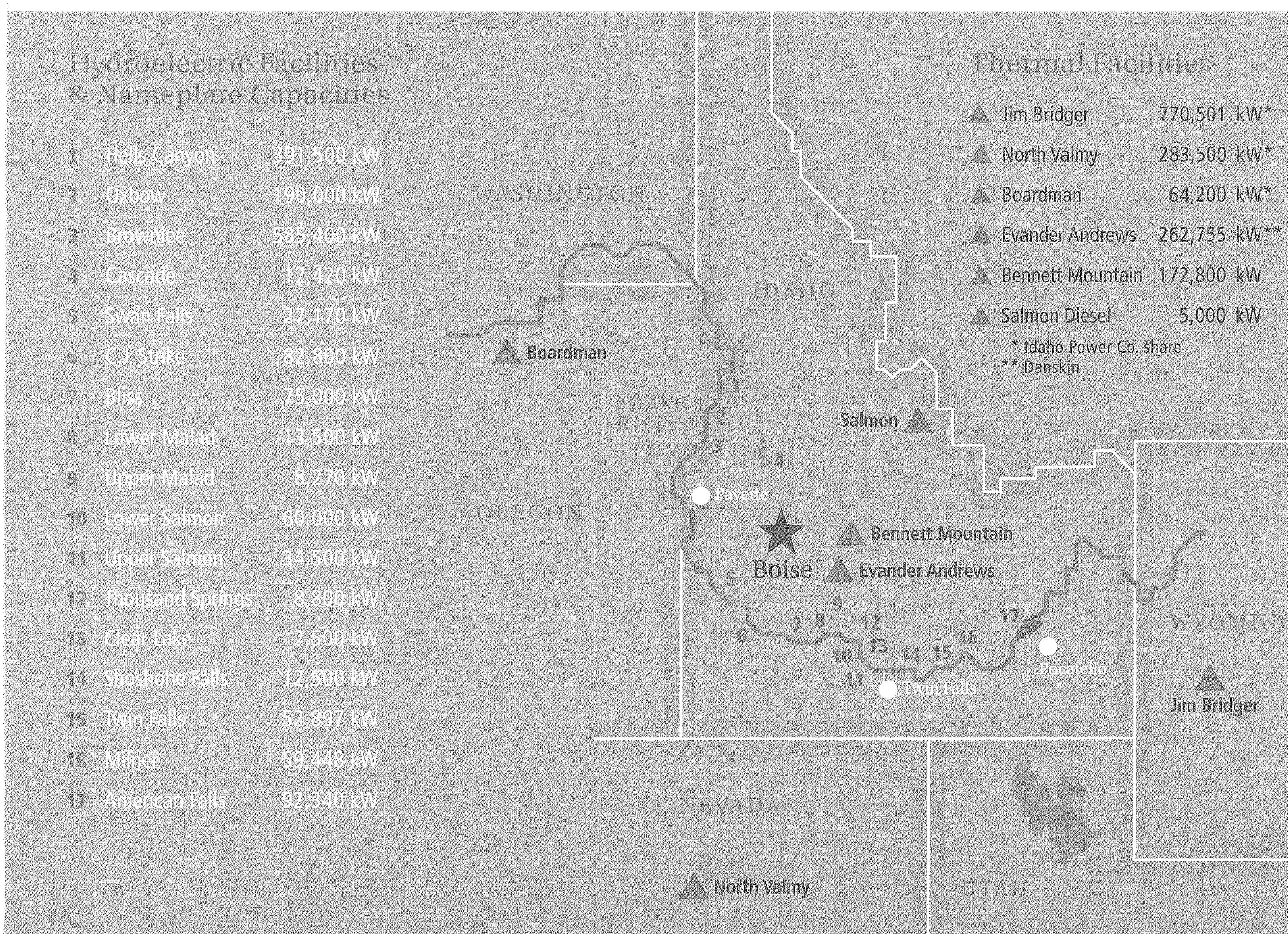
POWERING MORE WITH LESS

In the mid-1930s, Clifford "C.J." Strike, Idaho Power's president, put forth a bold vision to bring energy to the door of every farm in the company's service area. Strike's vision was equaled by his commitment to provide reliable, responsible, home-grown energy to Idaho Power customers.

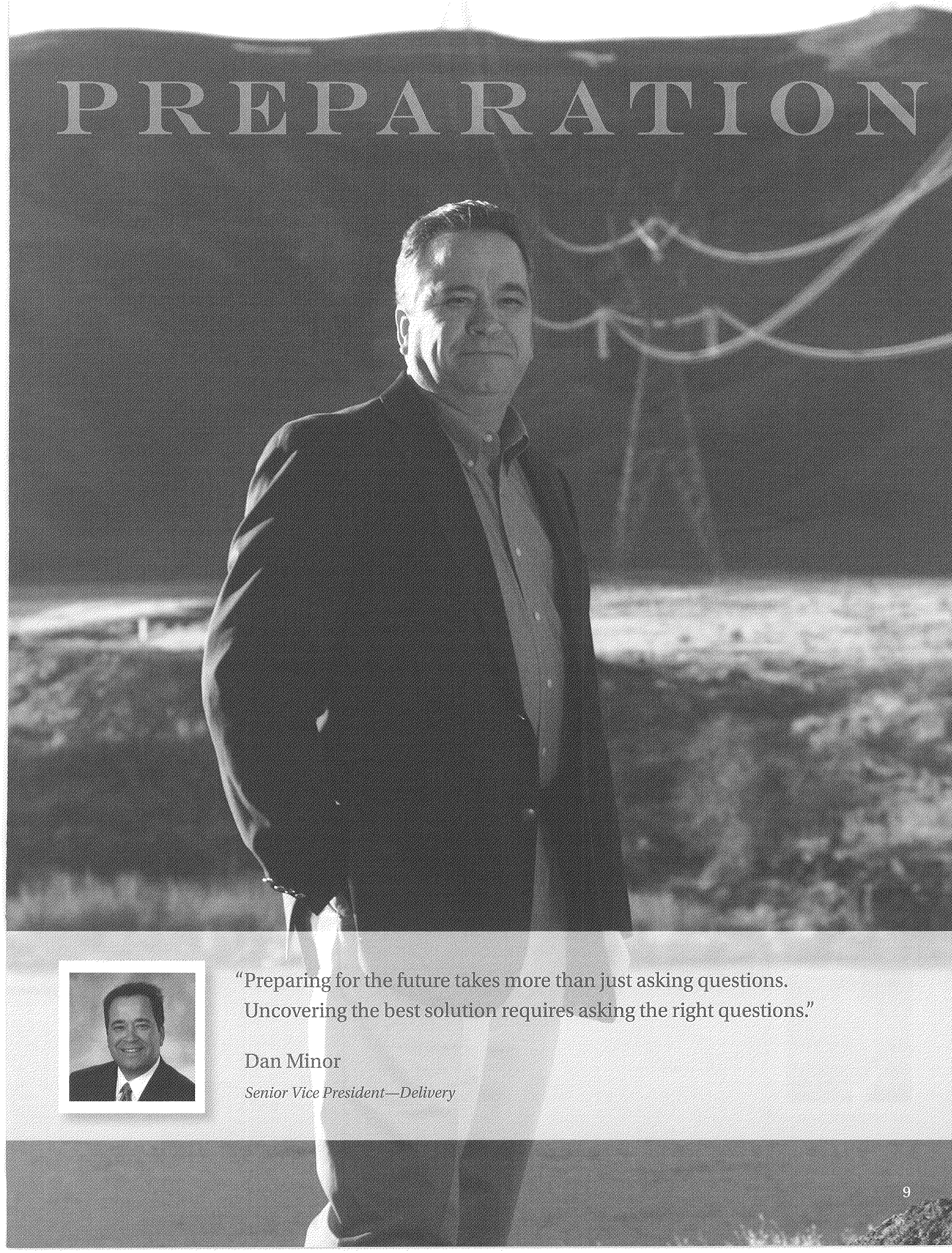
The third part of our strategy, responsible energy use, provides the foundation of a new tradition: we must convince our customers to use less of our product. Every kilowatt we save is one we do not have to generate, reducing the number of additional new resources required and the need to purchase power on the open market. Responsible energy usage and active conservation ensure reliability and enable a financially stronger company.

Idaho Power currently offers 15 energy efficiency and demand management programs, and we are extending our reach by launching six more programs this year. We are proud to be ahead of the curve in our conservation efforts.

Through Idaho Power's energy efficiency efforts in 2008, we reduced energy usage by an estimated 140,000 megawatt hours, enough energy to supply 11,000 homes. Our energy future depends upon the success of many programs and initiatives now underway at the company. We are setting a course establishing mindful, responsible energy use allowing future generations to enjoy the comfort and security each of our customers enjoys today.



PREPARATION

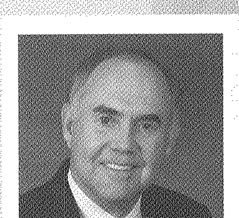


"Preparing for the future takes more than just asking questions. Uncovering the best solution requires asking the right questions."

Dan Minor

Senior Vice President—Delivery

COURAGE



"The strongest test of courage isn't evidenced in fearlessness. It's seen in the willingness to take deliberate and thoughtful action in the face of uncertainty."

Tom Saldin

Senior Vice President & General Counsel

OUR FOUNDATION FOR SUCCESS

The foundation of IDACORP, and the reason for its continued success, is the men and women who are proud to call themselves not only employees, but customers and oftentimes shareowners. Skilled and dedicated, they help us build trust each and every day.

We continue developing our safe, engaged and effective employee workforce. The focus remains on creating a high performance culture, resulting in many opportunities for the company. Increasing operational efficiencies, positioning the company as an employer of choice and cultivating employee ambassadors to share our story are just a few outcomes of this effort.

Challenges remain, however we continue to work together to become an exceptional utility. We are confident the company's actions—a diligent focus on safety, leadership, proactive employee engagement and following through on our commitments to our employees—will keep our workforce strong.

The courage demonstrated by IDACORP's leaders and employees to take positive action in the face of uncertainty is the mark of your company. Our commitments to customers, employees and you, our owners, are realized in the hard work of over 2,000 men and women who steward your company. They are the reason for our improved financial performance, bright future and fulfillment of our mission: prosper by providing reliable, responsible, fair-priced energy services today and tomorrow.

IDACORP and Idaho Power Officers
(shown at left)

FRONT ROW (left to right)

Lisa A. Grow (21)
Vice President, Delivery Engineering and Operations*

Naomi Shankel (8)
Vice President, Audit and Compliance

Ric Gale (25)
Vice President, Regulatory Affairs*

Luci K. McDonald (4)
Vice President, Human Resources

Lori D. Smith (25)
Vice President, Corporate Planning and Chief Risk Officer

MIDDLE ROW (left to right)

Warren Kline (35)
Vice President, Customer Service and Regional Operations*

Dennis C. Gribble (30)
Vice President and Chief Information Officer

Patrick A. Harrington (23)
Corporate Secretary

Steven R. Keen (26)
Vice President and Treasurer

BACK ROW (left to right)

James C. Miller (31)
Senior Vice President, Power Supply*

Daniel B. Minor (23)
Senior Vice President, Delivery*

J. LaMont Keen (34)
President and Chief Executive Officer

Darrel T. Anderson (13)
Senior Vice President, Administrative Services and Chief Financial Officer

NOT SHOWN

Rex Blackburn (1)
Senior Vice President and General Counsel
Appointment effective April 1, 2009

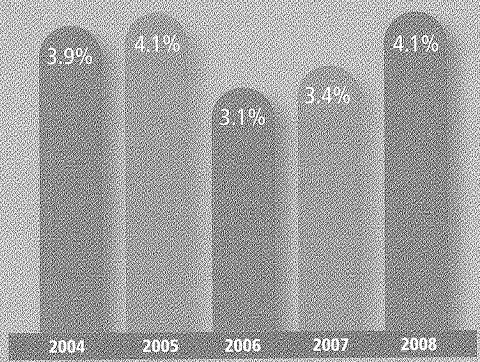
Thomas R. Saldin (4)
Senior Vice President and General Counsel
Retired March 31, 2009

Jeffrey L. Malmen (1)
Vice President, Public Affairs

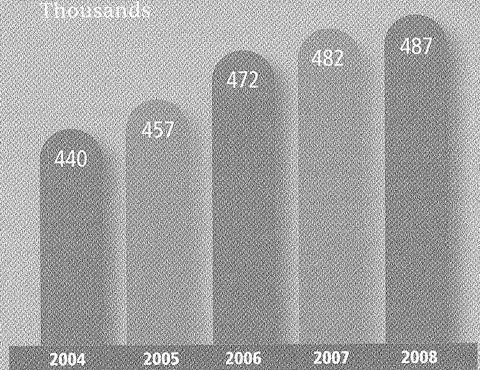
( ) Years of service
* Idaho Power Only

Investors' References

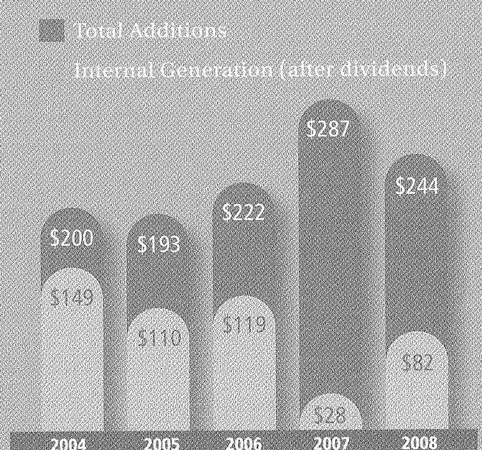
Current Yield
At year end



General Business Customers
Thousands



Additions to Property, Plant And Equipment
Millions of dollars



Dividend Payment Dates
For IDACORP, Inc. Common Stock
Quarterly on or about the 28th of February, and the 30th of May, August and November.

Transfer Agents/Registrar
For IDACORP, Inc. Common Stock
Wells Fargo Shareowner Services,
161 N. Concord Exchange St.,
South St. Paul, Minnesota 55075-1139
1-800-565-7890

Common Stock Information
Ticker symbol: IDA
Listed: New York Stock Exchange, 20 Broad Street
New York, New York 10005

Contact
Broker/Analyst Contact: Lawrence F. Spencer,
Director of Investor Relations
(208) 388-2664 Fax: (208) 388-6916
E-mail: lspencer@idacorpinc.com

Shareowner Contact: 1-800-635-5406 Fax: (208) 388-6955
E-mail: cshepard@idahopower.com
or barbsmith@idahopower.com

Corporate Headquarters
Web site: www.idacorpinc.com
Mailing: P.O. Box 70, Boise, Idaho 83707-0070
Street: 1221 W. Idaho St., Boise, Idaho 83702-5627
Phone: (208) 388-2200

SEC Form 10-K
The IDACORP, Inc. and Idaho Power Company combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders are also available on our Web site at www.idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be transmitted, nor is it to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

2009 Annual Meeting
The 2009 Annual Meeting of Shareholders will be held at Idaho Power's Corporate Headquarters, 1221 W. Idaho St., Boise, Idaho, 10 a.m. local time on Thursday, May 21, 2009. Formal notice of the meeting will be mailed to shareholders on or about Monday, April 6, 2009.

On May 16, 2008, IDACORP's Chief Executive Officer certified, without qualification, to the New York Stock Exchange that he was not aware of any violation by IDACORP of New York Stock Exchange corporate governance listing standards as of the date of that certification.

IDACORP has filed with the Securities and Exchange Commission, as Exhibits 31.1 and 31.2 to its Annual Report on Form 10-K for the year ended December 31, 2008, the Sarbanes-Oxley Act Section 302 certifications by IDACORP's Chief Executive Officer and Chief Financial Officer regarding the quality of its public disclosure.

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

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2008

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street Boise, ID 83702-5627 (208) 388-2200	

State of incorporation: Idaho
Websites: www.idacorpinc.com and www.idahopower.com

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:		Name of exchange on which registered
IDACORP, Inc.:	Common Stock, without par value	New York

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes (X) No ( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.

IDACORP, Inc.:

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

Idaho Power Company:

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

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Aggregate market value of voting and non-voting common stock held by nonaffiliates (June 30, 2008):

IDACORP, Inc.: $1,299,654,720 Idaho Power Company: None

Number of shares of common stock outstanding at January 31, 2009:

IDACORP, Inc.:	46,909,973
Idaho Power Company:	39,150,812 all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14 Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009.

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

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

COMMONLY USED TERMS

AFUDC	-	Allowance for Funds Used During Construction
APCU	-	Annual Power Cost Update
Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
cfs	-	Cubic feet per second
EIS	-	Environmental impact statement
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch, Inc.
FPA	-	Federal Power Act
GAAP	-	Generally Accepted Accounting Principles
HCC	-	Hells Canyon Complex
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCo	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
LGAR	-	Load Growth Adjustment Rate
maf	-	Million acre feet
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
Moody's	-	Moody's Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NOx	-	Nitrogen Oxide
NWRFC	-	National Weather Service Northwest River Forecast Center
O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
RH BART	-	Regional Haze - Best Available Retrofit Technology
RFP	-	Request for Proposal
S&P	-	Standard & Poor's Ratings Services
SFAS	-	Statement of Financial Accounting Standards
SO_2	-	Sulfur Dioxide
SRBA	-	Snake River Basin Adjudication
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

TABLE OF CONTENTS

*Except as indicated in Item 12, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2009 Annual Meeting of Shareholders.

SAFE HARBOR STATEMENT
This Form 10-K contains "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-K at Part II, Item 7- "Management's Discussion and Analysis of Financial Condition and Results of Operations - FORWARD-LOOKING INFORMATION." Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of the words "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue," or similar expressions.

PART I - IDACORP, Inc. and Idaho Power Company

ITEM 1. BUSINESS

OVERVIEW:

IDACORP, Inc. (IDACORP) is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power Company (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 engaged in the generation, transmission, distribution, sale and purchase of electric energy and is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (Bridger Coal), 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.

IDACORP's strategy emphasizes IPC as IDACORP's core business. Although growth in number of customers slowed in 2008, IPC is experiencing customer growth in its service area and must be prepared to meet customers' electricity needs in the future. IPC must make investments in infrastructure to ensure adequate electricity supply and reliable service. IPC's regulatory efforts have resulted in finalizing the 2007 general rate case and receiving an order in the 2008 general rate case. IPC continues to make efforts to speed recovery of the financial and operating costs of new facilities and system improvements. IFS and Ida-West remain components of the corporate strategy.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of IDACORP Technologies, Inc. to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited, and on February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 16 to IDACORP's and IPC's Consolidated Financial Statements.

At December 31, 2008, IDACORP had 2,073 full-time employees, 2,057 of which were employed by IPC.

IDACORP's only reportable business segment is IPC, which contributed $94 million to income from continuing operations in 2008.

IDACORP and IPC make available free of charge their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to these reports filed or furnished pursuant to

Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the Securities and Exchange Commission, through IDACORP's website at www.idacorpinc.com and through a link to the IDACORP website from the IPC website at www.idahopower.com.

UTILITY OPERATIONS:

IPC was incorporated under the laws of the state of Idaho in 1989 as successor to a Maine corporation organized in 1915. IPC's service territory covers approximately 24,000 square miles in southern Idaho and eastern Oregon, with an estimated population of approximately one million. IPC holds franchises in 71 cities in Idaho and nine cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 25 counties in Idaho and three counties in Oregon. As of December 31, 2008, IPC supplied electric energy to approximately 487,000 general business customers.

IPC is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. IPC owns and operates 17 hydroelectric generation developments, two natural gas-fired plants and one diesel-powered generator and shares ownership in three coal-fired generating plants. These generating plants and their capacities are listed in Item 2 - "Properties." IPC's coal-fired plants are in Wyoming, Oregon and Nevada, and use low-sulfur coal from Wyoming and Utah.

The primary influences on electricity sales are weather, customer growth and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps.

Variations in weather, customer growth and economic conditions also impact power supply costs. Drought conditions and customer growth cause a greater reliance on more expensive thermal generation and purchased power to meet load requirements. Favorable hydroelectric generation conditions increase production at IPC's hydroelectric generating facilities, and reduce the need for more expensive thermal generation and purchased power. Changes in economic conditions can also affect the price of commodities, including fuel costs, which may impact power supply costs.

IPC's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, forest products, beet sugar refining and winter recreation. On January 26, 2009, the Idaho Public Utilities Commission (IPUC) granted authority to temporarily amend IPC's electric service agreement with one of its largest customers for the period January 1, 2009, through June 30, 2009, to provide the customer flexibility in restructuring its operations. This amendment is not expected to have a significant impact on IPC's earnings.

On September 17, 2008, IPC entered into an electric service agreement with a new customer, Hoku Materials, Inc. (Hoku), to provide electric service to Hoku's polysilicon production facility under construction in Pocatello, Idaho. The initial term of the agreement is four years beginning June 1, 2009, with automatic annual renewal after June 1, 2013 unless either party gives 12 months prior written notice of termination. The agreement provides for a maximum demand obligation during the initial term of 82 megawatts (MW). After June 1, 2013, Hoku may increase or decrease its total demand to between 25 MW and 175 MW. The agreement was submitted to the IPUC for approval in October 2008.

Regulation

IPC is under the regulatory jurisdiction (as to rates, service, accounting and other general matters of utility operation) of the FERC, the IPUC and the Oregon Public Utility Commission (OPUC). IPC is also under the regulatory jurisdiction of the IPUC, the OPUC and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. IPC's retail rates are established under the jurisdiction of the state regulatory commissions (see "Rates" below). Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions have each issued orders and rules regulating IPC's purchase of power from cogeneration and small power production (CSPP) facilities.

IPC is subject to the provisions of the Federal Power Act as a "public utility" and as a "licensee" as therein defined and is subject to regulation by the FERC. The Energy Policy Act of 2005 (Energy Act) granted the

FERC increased statutory authority to implement mandatory transmission and reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. As a licensee under Part I of the FPA, IPC and its licensed hydroelectric projects are subject to conditions set forth in the FPA and related FERC regulations. These conditions and regulations include provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment, severance damages and other matters.

As a public utility under Part II of the FPA, IPC has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its Open Access Transmission Tariff (OATT).

The state of Oregon has a Hydroelectric Act providing for licensing of hydroelectric projects in that state. IPC's Brownlee, Oxbow and Hells Canyon facilities are on the Snake River where it forms the boundary between Idaho and Oregon and occupy lands in both states. With respect to project property located in Oregon, these facilities are subject to the Oregon Hydroelectric Act. IPC has obtained Oregon licenses for these facilities and these licenses are not in conflict with the FPA or IPC's FERC licenses (see Part II, Item 7 - "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects").

Rates

The rates IPC charges to its general business customers are determined by the IPUC and the OPUC. Approximately 95 percent of IPC's general business revenue comes from customers in Idaho. IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC's actual net power supply costs (fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates. Prior to February 1, 2009, approximately 90 percent of the difference between the actual and forecasted costs was deferred with interest. Beginning on February 1, 2009, this percentage was increased to 95 percent.

IPC also has a power cost recovery mechanism in Oregon with two components that became effective June 1, 2008. The annual power cost update (APCU) allows IPC to recover excess net power supply costs in a more timely fashion than through the previous deferral process because it reestablishes base net power supply costs annually. The power cost adjustment mechanism (PCAM) provides for 90 percent customer sharing of deviations in actual net power supply costs from those included in the APCU if the deviations are outside of prescribed ranges and IPC meets a return-on-equity test.

The rates IPC charges to its transmission customers are determined by the FERC. IPC's OATT is a formula rate, which allows for transmission rates to be revised each year based on financial and operational data IPC is required to file annually with the FERC in its Form 1.

Significant rate cases and proceedings are discussed in more detail in Part II, Item 7 - "MD&A - REGULATORY MATTERS."

Power Supply

IPC meets its system load requirements using a combination of its own generation, mandated purchases from private developers (see "CSPP Purchases" below) and purchases from other utilities and power wholesalers. IPC's generating plants and capacities are listed in Item 2 - "Properties."

IPC's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,214 MW, set on June 30, 2008. The previous hourly system peak of 3,193 MW was set July 13, 2007. The all-time winter peak demand is 2,464 MW set on January 24, 2008. The previous hourly system winter peak of 2,459 MW was set in 1998. Including the expected impact of the Hoku electric service agreement, IPC expects total system average load to grow 2.6 percent annually over the next three years.

Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC's hydroelectric projects are reduced, IPC's hydroelectric generation is reduced.

This results in less generation from IPC's resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased power supply costs.

The following table presents IPC's system generation for the last three years:

	MWh			Percent of total generation		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
	(thousands of MWhs)					
Hydroelectric	6,908	6,181	9,207	48%	46%	57%
Thermal	7,496	7,367	7,021	52%	54%	43%
Total system generation	14,404	13,548	16,228	100%	100%	100%

Under normal stream flow conditions, IPC's system generation mix is approximately 55 percent hydroelectric and 45 percent thermal.

Stream flow conditions improved slightly in 2008 resulting in an increase of 0.7 million MWh generated from IPC's hydroelectric facilities as compared to 2007. The observed stream flow data released in August 2008 by the U.S. Army Corps of Engineers, Northwest Division indicated that Brownlee reservoir inflow for April through July 2008 was 4.4 million acre-feet (maf), or 70 percent of the National Weather Service Northwest River Forecast Center (NWRFC) average, compared to 2.8 maf, or 44 percent of the NWRFC average, in 2007.

Storage in selected federal reservoirs upstream of Brownlee as of February 11, 2009, was 110 percent of average. The stream flow forecast released on February 20, 2009, by the NWRFC predicts that Brownlee reservoir inflow for April through July 2009 will be 3.3 maf, or 53 percent of the NWRFC average.

IPC's generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum load-carrying capability and reliability. IPC's transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration (BPA), Avista Corporation, PacifiCorp, NorthWestern Energy and NV Energy (formerly Sierra Pacific Power Company). Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase and sale of power among all major electric systems in the west. IPC is a member of the Western Electricity Coordinating Council, the Western Systems Power Pool, the Northwest Power Pool, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the western grid. See "Competition - Wholesale" below.

Fuel: IPC, through its subsidiary IERCo, owns a one-third interest in Bridger Coal, which owns the Jim Bridger mine that supplies coal to the Jim Bridger generating plant (one-third owned by IPC) in Wyoming. The mine, located near the Jim Bridger plant, operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface, high-wall, and underground sources. The Jim Bridger mine has sufficient reserves to provide coal deliveries for the term of the sales agreement. IPC also has a coal supply contract providing for annual deliveries of coal through 2014 from the Black Butte Coal Company's Black Butte and Leucite Hills mines located near the Jim Bridger plant. This contract supplements the Bridger Coal deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant's rail load-in facility and unit coal train allow the plant to take advantage of potentially lower-cost coal from other mines for tonnage requirements above established contract minimums.

The Bridger Coal mine experienced difficulties in meeting its production volume and operating cost goals during early 2008. The problems stemmed from soft floor and roof stability issues that began in late December 2007 in the underground longwall mining operation (longwall). The impact on December 2007 production was relatively minor; however the problems persisted and January 2008 production volume was approximately 20 percent of forecast. Bridger Coal's overall 2008 production and cost objectives were achieved by modifying the surface mine operation plan to offset the underground mining difficulties and by purchasing additional Black Butte coal. As of year-end 2008, the longwall was operating at normal production levels. IPC anticipates that budgeted production from both the underground and surface operations will be achieved in 2009.

NV Energy, as operator of the North Valmy generating plant, has an agreement with Arch Coal Sales Company, Inc. to supply coal to the plant through 2011. As a 50 percent owner of the plant, IPC is obligated to purchase one-half of the coal, ranging from 515,000 tons to 762,500 tons annually. NV Energy also has a coal supply contract with Black Butte Coal Company's Black Butte Mine for deliveries through 2009. IPC is obligated to purchase one-half of the coal purchased under this agreement, ranging from 450,000 to 600,000 tons annually.

The Boardman generating plant receives coal from the Powder River Basin through annual contracts. Portland General Electric, as operator of the Boardman plant, had an agreement with Buckskin Mining Company to supply all of Boardman's coal requirements through 2008 and has entered into a contract with Foundation Energy Sales, Inc. to supply coal from 2009 through 2011. As a ten percent owner of the plant, IPC is obligated to purchase ten percent of the coal purchased under these agreements, which ranged from 230,000 to 270,000 tons annually under the Buckskin agreement and ranges from 87,500 to 211,000 tons annually under the Foundation Energy Sales contract. The Boardman partners are in the process of securing contracts for additional coal tonnage that will be needed in 2010 and 2011.

IPC owns and operates the Danskin and Bennett Mountain combustion turbines, which are supplied gas through Northwest Pipeline GP's pipeline. Gas is purchased as needs are identified for summer peaks or to meet system requirements. The gas is transported under a long-term agreement with Northwest Pipeline GP for 24,523 million British thermal units (MMBtu) per day. This agreement runs through February 28, 2022, with annual extensions at IPC's sole discretion. IPC also has the ability to flow a total of 73,569 MMBtu on an alternate firm basis without incurring a reservation charge on the additional amount. IPC also has entered into an agreement with Northwest Pipeline GP for 22,000 MMBtu per day of gas transport. Gas transmission will begin November 1, 2012 and run through November 30, 2027. In addition to this agreement, IPC has entered into a long-term agreement with Northwest Pipeline GP for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project located in Lewis County, Washington. As the project is developed, storage capacity will be phased into service and allocated to IPC on a monthly basis. IPC's current storage allotment is approximately 33 percent of its total, and its full allotment is expected to be reached by January 2011. The firm storage contract extends through November 1, 2043, with bilateral termination rights at the end of the contract. Storage gas will be purchased and stored with the intent of fulfilling needs as identified for summer peaks or to meet system requirements.

Water Rights: Except as discussed below, IPC has acquired water rights under applicable state law for all waters used in its hydroelectric generating facilities. In addition, IPC holds water rights for domestic, irrigation, commercial and other necessary purposes related to other land and facility holdings within the state. The exercise and use of all of these water rights are subject to prior rights, and with respect to certain hydroelectric generating facilities, IPC's water rights for power generation are subordinated to certain future upstream diversions of water for irrigation and other recognized consumptive uses.

Over time, increased irrigation development and other consumptive diversions have resulted in a reduction in the stream flows available to fulfill IPC's water rights at certain hydroelectric generating facilities. In reaction to these reductions, IPC initiated and continues to pursue a course of action to determine and protect its water rights. As part of this process, IPC and the state of Idaho signed the Swan Falls agreement on October 25, 1984, which provided a level of protection for IPC's hydropower water rights at specified plants by setting minimum stream flows and establishing an administrative process governing the future development of water rights that may affect IPC's hydroelectric generation. In 1987, Congress passed, and the President signed into law, House Bill 519. This legislation permitted implementation of the Swan Falls agreement and further provided that during the remaining term of certain of IPC's project licenses the relationship established by the agreement would not be considered by the FERC as being inconsistent with the terms of IPC's project licenses or imprudent for the purposes of determining rates under Section 205 of the FPA. The FERC entered an order implementing the legislation on March 25, 1988.

In addition to providing for the protection of IPC's hydroelectric water rights, the Swan Falls agreement contemplated the initiation of a general adjudication of all water uses within the Snake River basin. In 1987, the director of the Idaho Department of Water Resources filed a petition in state district court asking that the court adjudicate all claims to water rights, whether based on state or federal law, within the Snake River basin. The court signed a commencement order initiating the Snake River Basin Adjudication (SRBA) on November 19, 1987. This legal proceeding was authorized by state statute based upon a determination by the Idaho Legislature that the effective management of the waters of the Snake River basin required a comprehensive determination of the nature, extent and priority of all water uses within the basin. The adjudication is proceeding and is expected to continue for at least the next several years. IPC has filed claims to its water rights within the basin and is actively participating in the adjudication in an effort to ensure that its water rights and the operation of its hydroelectric facilities are not adversely impacted. In certain instances, the adjudication of water rights in the SRBA results in the initiation of litigation, called subcases, to determine the scope and nature of a particular water right. IPC is involved in subcases involving not only its water rights but also the water rights of other claimants. One such subcase 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 the Swan Falls Agreement. 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.

Please see further discussion in Part II, Item 7 - "MD&A - LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues" and "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

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

The two primary goals of the 2006 IRP were to (1) identify sufficient resources to reliably serve the growing demand for electric service within IPC's service area throughout the 20-year planning period and (2) ensure that the portfolio of resources selected balances cost, risk and environmental concerns.

The IPUC accepted the 2006 IRP in March 2007 and the OPUC acknowledged the 2006 IRP in September 2007. With its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other Idaho utilities. To comply with this request, IPC provided an update on the status of the 2006 IRP to both the IPUC and OPUC in June 2008. An IRP Addendum was also filed with the OPUC in February 2009 to address the need for the Boardman to Hemingway Transmission Project. IPC is currently preparing the 2009 IRP, which is scheduled to be completed in June 2009. Please see further discussion in Part II - Item 7 - "MD&A - REGULATORY MATTERS - Integrated Resource Plan."

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

During 2008, at the IPUC's direction, IPC conducted workshops to review the Published Avoided Cost model input components. A settlement stipulation was filed with the IPUC for its consideration that, if accepted, will result in an increase in the non-fuel component of the Published Avoided Costs.

As of December 31, 2008, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Seventy-nine of these facilities, with a combined nameplate capacity of 267 MW, were on-line at the end of 2008; the other 13 facilities under contract, with a combined nameplate capacity of 190 MW, are projected to come on-line during 2009 and 2010. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2008, IPC purchased 756,014 megawatt-hours (MWh) from these projects at a cost of $45.9 million, resulting in a blended price of 6.1 cents per kilowatt hour.

Wholesale Energy Market Activities: Guided by a risk management policy and frequently updated operating plans, IPC participates in the wholesale energy market by buying power to help meet load demands and selling power that is in excess of load demands. IPC's market activities are influenced by its customer loads, market prices, and cost and availability of generating resources. Some of IPC's hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run generation units and when to store water in reservoirs. These decisions affect the timing and volumes of market purchases and market sales. Even in below normal water years, there are opportunities to vary water usage to maximize generation unit efficiency, capture marketplace economic benefits and meet load demand. Compliance factors, such as allowable river stage elevation changes and flood control requirements, and wholesale energy market prices influence these dispatch decisions.

IPC has one firm wholesale power sales contract. The sales contract is with the Raft River Electric Cooperative for up to 15 MW. This contract expires in September 2009; however, Raft River Electric Cooperative has provided notice that it intends to renew the contract, as allowed in the original agreement, through September 2011.

IPC has one wholesale reserve sales contract, with United Materials of Great Falls, Inc. (United Materials). This agreement requires IPC to carry up to 0.45 MW of reserves associated with an energy sales agreement dated January 2004 between IPC and United Materials from the Horseshoe Bend Wind Farm. The term of this agreement began in January 2008, and runs seasonally through May 2013.

IPC has four firm wholesale purchased power contracts. One contract is with PPL Montana, LLC, now known as PPL EnergyPlus, LLC, for 83 MW per hour during heavy load hours, to address increased demand during June, July and August. The term of this contract began in June 2004 and runs through August 2009. IPC entered into a second seasonal contract for 83 MW with PPL EnergyPlus, LLC that runs from June 2010 through August 2011. In January 2008, the IPUC approved a power purchase agreement for 13 MW (nameplate generation) from the Raft River Geothermal Power Plant Unit #1 located in southern Idaho that converted a CSPP contract to a purchased power contract. The contract term is through April 2033. The fourth contract is with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through December 2027.

Transmission Services

IPC provides wholesale transmission service and provides firm and non-firm wheeling services for eligible transmission customers. IPC's system lies between and is interconnected with the winter-peaking northern and summer-peaking southern regions of the western power system. This geographic position allows IPC to provide transmission services and to reach a broad power market.

IPC and PacifiCorp are jointly exploring the Gateway West project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. Initial phases of the project could be completed by 2014. Remaining phases of the project could be constructed as demand requires.

Construction of a new 500-kV station named Hemingway is expected to address growth, capacity and operating constraints. The station was originally part of the Gateway West Project but the timing of this addition was accelerated to 2010 to help meet forecast deficits and improve reliability. As part of the Hemingway Station Project, the Hemingway-Hubbard transmission line is expected to provide power to the Treasure Valley area of southwest Idaho by 2010. The Hemingway-Hubbard line will consist of a new 230-kV double circuit transmission line and convert an existing 138-kV transmission line to 230-kV.

The Boardman-Hemingway transmission line is expected to relieve existing congestion by increasing transmission capacity and improving reliability. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. IPC expects to seek partners for up to 50 percent of the project when construction commences. The line has a target in-service date of June 2013.

These projects are discussed in more detail in Part II - Item 7 - "MD&A – LIQUIDITY AND CAPITAL RESOURCES – Capital Requirements" and "MD&A - REGULATORY MATTERS - Transmission Projects."

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

Environmental Regulation

IPC's activities are subject to a broad range of federal, state, regional and local laws and regulations designed to protect, restore and enhance the quality of the environment. Environmental regulation continues to impact IPC's operations due to the cost of installation and operation of equipment and facilities required for compliance with such regulations, and the modification of system operations to accommodate such regulations. IPC's environmental compliance costs will continue to be significant for the foreseeable future.

Based upon present environmental laws and regulations, IPC estimates its 2009 capital expenditures for environmental matters, excluding Allowance for Funds Used During Construction (AFUDC), will total $17 million. Studies and measures related to environmental concerns at IPC's hydroelectric facilities account for $6 million and investments in environmental equipment and facilities at the thermal plants account for $11 million. For 2010 and 2011, environmental-related capital expenditures, excluding AFUDC, are estimated to be $74 million. Anticipated expenses related to IPC's hydroelectric facilities account for $44 million, and thermal plant expenses are expected to total $30 million.

IPC anticipates approximately $20 million in annual operating costs for environmental facilities during 2009. Hydroelectric facility expenses and thermal plant expenses account for the majority of the costs at approximately $14 million and $6 million, respectively. For 2010 and 2011, total environmental related operating costs are estimated to be approximately $57 million. Expenses related to the hydroelectric facilities are expected to be $43 million, and thermal plant expenses are expected to be $14 million during this period.

Water: As required under the Federal Water Pollution Control Act Amendments of 1972, IPC has received necessary environmental permits and authorizations and has prepared necessary plans relating to operations and water quality, such as effluent discharge, spill prevention and countermeasures, and storm water pollution prevention.

The FERC licenses issued for IPC's American Falls and Cascade hydroelectric generating plants require aeration of turbine water to meet dissolved oxygen standards in the tail waters downstream from the plants. In order to comply with the licenses, IPC installed and operates aeration equipment at both plants and submits compliance reports to the appropriate regulatory agencies.

The FERC licenses issued for IPC's Milner, Shoshone Falls, Twin Falls, Upper Salmon, Lower Salmon, Bliss and CJ Strike hydroelectric projects require dissolved oxygen and temperature monitoring and reporting. IPC submits compliance reports to the appropriate regulatory agencies.

The FERC license for the CJ Strike project also requires monitoring of total dissolved gas during spill periods. IPC installs monitors during periods of spill that record gas levels in spilled water and reports the results to the appropriate regulatory agencies.

Hazardous/Toxic Wastes and Substances: Under the Toxic Substances Control Act, the EPA has adopted regulations governing the use, storage, inspection and disposal of electrical equipment that contains polychlorinated biphenyls (PCBs). The regulations permit the continued use and servicing of certain equipment (including transformers and capacitors) that contain PCBs. IPC continues to meet federal requirements of the Toxic Substances Control Act for the continued use of equipment containing PCBs. IPC continues to eliminate PCBs as part of its long-term strategy. This program will reduce costs associated with the long-term monitoring of PCB-containing equipment, responding to spills and reporting to the EPA. In 2008, IPC spent approximately $0.6 million identifying and eliminating PCBs.

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 located in Wyoming; Boardman located in Oregon; and Valmy located in Nevada.

For a more detailed discussion of these and other environmental issues, including greenhouse gases, climate change and endangered species please see Part II, Item 7 – "MD&A – Legal and Environmental Issues – Environmental Issues."

Energy Efficiency Programs

In 2008, IPC spent approximately $21.2 million to promote energy efficiency and summer peak reduction through its energy efficiency programs, which have previously been referred to as Demand Side Management programs. Approximately $18.9 million of funding for program development, implementation and administration comes from the Idaho and Oregon tariff riders for energy efficiency. The balance of the funding comes from IPC base rates and a small amount was previously obtained from residual funds from the BPA's Conservation and Renewables Discount which was discontinued in 2007.

Approximately $2.4 million was spent on research, analysis and development, education, technology evaluation, and market transformation. A portion of this activity was accomplished in conjunction with the Northwest Energy Efficiency Alliance (NEEA). IPC contributed $0.9 million to the NEEA.

The following energy efficiency programs target savings across the entire year for a wide range of customer segments with an emphasis on reducing energy during the summer peak:

- Approximately $4.4 million was devoted to achieving summer peak reduction through focusing on irrigation pumping and residential air conditioning equipment control measures.
- The residential energy efficiency programs targeted new and existing homes, focusing on customer education and the application of energy efficiency remediation, including energy efficient building techniques, insulation augmentation, air duct sealing, and the use of efficient lighting. This program's 2008 spending was approximately $4.2 million.
- Programs for new or existing industrial and commercial facilities focus on application of energy efficient techniques and technologies as well as operational and management processes to reduce energy consumption. Approximately $8.1 million was spent on these programs.
- Approximately $2.1 million was devoted to irrigation efficiency programs. Irrigation customers can receive financial incentives for either improving the energy efficiency of an irrigation system or installing a new energy efficiency system.

In 2008, IPC's energy efficiency programs reduced energy usage by approximately 134,000 MWh and the targeted demand reduction programs resulted in a summer peak reduction of about 54 MW.

Competition

Retail: Electric utilities have historically been recognized as natural monopolies and have operated in a highly regulated environment in which they have an obligation to provide electric service to their customers in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return. In the past, some state regulatory authorities explored changing utility regulations in response to federal and state statutory changes, with the intent of increasing retail competition. However, restructuring of the electric industry has stalled at both the national level and in the Pacific Northwest.

Wholesale: The 1992 National Energy Policy Act and the FERC's rulemaking activities have established the regulatory framework to open the wholesale energy market to competition. This act permits entities to develop independent electric generating plants for sales to wholesale customers, and authorizes the FERC to order transmission access for third parties to transmission facilities owned by another entity. This act does not, however, permit the FERC to require transmission access to retail customers. Open-access transmission for wholesale customers provides energy suppliers with opportunities to sell and deliver electricity at market-based prices. IPC actively monitors and participates, as appropriate, in energy industry developments, to maintain and enhance its ability to effectively participate in wholesale energy markets in a manner consistent with its business goals. For more information, see Part II, Item 7 - "MD&A - REGULATORY MATTERS – Federal Regulatory Matters."

Utility Operating Statistics
The following table presents IPC's revenues and energy use by customer type for the last three years. IPC's operations are discussed further in Part II, Item 7 - "MD&A - RESULTS OF OPERATIONS - Utility Operations:"

	Years Ended December 31,		
	2008	**2007**	**2006**
Revenues (thousands of dollars)			
Residential	$ 353,262	$ 308,208	$ 299,594
Commercial	203,035	170,001	162,391
Industrial	122,302	101,409	102,958
Irrigation	105,712	88,685	71,432
Total general business	784,311	668,303	636,375
Off-system sales	121,429	154,948	260,717
Other	50,336	52,150	23,381
Total	$ 956,076	$ 875,401	$ 920,473
Energy use (thousands of MWh)			
Residential	5,297	5,227	5,068
Commercial	3,970	3,937	3,761
Industrial	3,355	3,454	3,475
Irrigation	1,922	1,924	1,635
Total general business	14,544	14,542	13,939
Off-system sales	2,047	2,744	5,821
Total	16,591	17,286	19,760

IFS:

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS generated tax credits of $11 million, $15 million and $19 million in 2008, 2007 and 2006, respectively. IFS's portfolio also includes historic rehabilitation projects such as, the Empire Building in Boise, Idaho. IFS made $8 million of new investments during 2008 and will continue to review future legislation for new opportunities for investment that will be commensurate with the ongoing needs of IDACORP.

IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk. Over 90 percent of IFS's investments have been made through syndicated funds. At December 31, 2008, the gross amount of IFS's portfolio equaled $183 million in tax credit investments. These investments cover 49 states, Puerto Rico and the U.S. Virgin Islands. The underlying investments include over 700 individual properties, of which all but three are administered through syndicated funds.

IDA-WEST:

Ida-West operates and has a 50 percent interest in nine hydroelectric plants with a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. IPC purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $8 million each year in 2008, 2007 and 2006.

ITEM 1A. RISK FACTORS

The following are factors that could have a significant impact on the operations and financial results of IDACORP, Inc. and Idaho Power Company and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements:

- **Reduced hydroelectric generation can reduce revenues and increase costs.** Idaho Power Company has a predominately hydroelectric generating base. Because of Idaho Power Company's heavy reliance on hydroelectric generation, water can significantly affect its operations. When hydroelectric generation is reduced, Idaho Power Company must increase its use of generally more expensive thermal generating resources and purchased power and opportunities for off-system sales are reduced, which reduces revenues. In addition, while Idaho Power Company can expect to recover a portion of the increase in its net power supply costs above the level included in its base rates, recovery of the amounts does not occur until the subsequent power cost adjustment year.

- **Continuing declines in stream flows and over-appropriation of water in Idaho may reduce hydroelectric generation and revenues and increase costs.** The combination of declining Snake River base flows, over-appropriation of water and drought conditions have led to disputes among surface water and ground water irrigators, and the state of Idaho. Recharging the Eastern Snake Plain Aquifer, which contributes to Snake River flows, by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the dispute. Diversions from the Snake River for aquifer recharge may further reduce Snake River flows available for hydroelectric generation and reduce Idaho Power Company's revenues and increase costs. Idaho Power Company is also involved in legal actions involving the water rights it holds for hydroelectric purposes. One such action, initiated in the Snake River Basin Adjudication, involves Idaho Power Company'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. Idaho Power Company also has initiated legal action against the U.S. Bureau of Reclamation over the interpretation and effect of a 1923 contract with the U.S. Bureau of Reclamation on the operation of the American Falls Reservoir and the release of water from that reservoir to be used at Idaho Power Company's downstream hydroelectric projects. The resolution of these matters may affect Snake River flows available for hydroelectric generation and thereby reduce Idaho Power Company revenues and increase costs.
- **Load growth in Idaho Power Company's service territory exposes it to greater market and operational risk and could increase costs and reduce earnings and cash flows.**
  - Increases in both the number of customers and the demand for energy have resulted and may continue to result in increased reliance on purchased power to meet customer load requirements. Since the Federal Energy Regulatory Commission implemented market-based wholesale power rates in 1997, the price volatility of electricity has substantially increased from what it was at the inception of the power cost adjustment. While Idaho Power Company can expect to recover a portion of the increase in its net power supply costs above the level included in its base rates, the remaining amount is absorbed by Idaho Power Company. As Idaho Power Company's reliance on purchased power continues to increase, the risks associated with the remaining amount not recovered through the power cost adjustment could increase costs and reduce earnings and cash flows.
  - Idaho Power Company's load growth adjustment rate adjusts the net power supply costs Idaho Power Company includes in its annual power cost adjustment for differences between actual load and the load used in calculating base rates. If the Idaho Public Utilities Commission increases the rate or modifies the method used to calculate the load growth adjustment rate Idaho Power Company's earnings and cash flows could be reduced.
  - Increased load growth can result in the need for additional investments in Idaho Power Company's infrastructure to serve the new load. If Idaho Power Company were unable to secure timely rate relief from the Idaho Public Utilities Commission, the Oregon Public Utility Commission or the Federal Energy Regulatory Commission to recover the costs of these additional investments, the resulting regulatory lag would have a negative effect on earnings and cash flow.
  - Increased and unexpected load growth can create planning and operating difficulties for Idaho Power Company that can impact its ability to reliably serve customers.
- **Idaho Power Company's reliance on coal and natural gas to fuel its power generation facilities exposes it to risk of increased costs and reduced earnings.** In addition to hydroelectric generation, Idaho Power Company relies on coal and natural gas to fuel its generation facilities. Market price increases in coal and natural gas can result in reduced earnings. Increases in demand for natural gas, including increases in demand due to greater industry reliance on natural gas for power generation, may result in market price increases and/or supply availability issues. In addition, delivery of coal and natural gas depends upon gas pipelines, rail lines, rail cars and roadways. Any disruption in Idaho Power Company's fuel supply may require the company to find alternative fuel sources at higher costs, to produce power from higher cost generation facilities or to purchase power from other sources at higher costs.
- **Changes in temperature and precipitation can reduce power sales and revenues.** Warmer than normal winters, cooler than normal summers and increased rainfall during the irrigation seasons will reduce retail revenues from power sales.

- **Climate change could affect customer demand and hydroelectric generation and disrupt transmission and distribution systems, reducing earnings and cash flows.** Changes in temperature, precipitation and snow pack conditions will affect customer demand and the amount and timing of hydroelectric generation. Extreme weather events can disrupt transmission and distribution systems, and cause service interruptions and extended outages. Decreased customer demand and hydroelectric generation and increased operations and maintenance costs from disrupted transmission and distribution systems will reduce earnings and cash flows.
- **The cost of complying with environmental laws and regulations will increase capital expenditures and operating costs and may reduce Idaho Power Company's earnings and cash flows and ability to meet the electricity needs of its customers.** IDACORP, Inc. and Idaho Power Company are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, natural resources and health and safety. Compliance with these environmental statutes, rules and regulations involves significant capital and operating expenditures. These expenditures could become even more significant in the future if legislation, regulations and enforcement policies change. For instance, considerable attention has been focused on emissions from coal-fired generating plants, including carbon dioxide, and their potential role in contributing to global warming. Proposals by Congress and the Environmental Protection Agency could lead to the adoption of a mandatory federal program to reduce carbon dioxide emissions. Such a program would raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because technologies for reducing carbon dioxide emissions from coal, including carbon capture and storage, are not yet proven. The effects of mercury and other pollutant emissions from coal-fired plants are also subject to extensive regulation. The adoption of new statutes, rules and regulations to implement carbon dioxide, mercury or other emission controls will result in increased capital expenditures and could increase the cost of operating coal-fired generating plants or make them uneconomical to operate and result in reduced earnings and cash flows
- **The costs of complying with state or federal renewable energy portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.** Idaho Power Company's operations in Oregon will be required to comply with a ten percent renewable energy portfolio standard beginning in 2025. The new federal administration has called on Congress to adopt a federal renewable energy portfolio standard and it is possible that Idaho and other states in which Idaho Power Company operates or sells power could adopt renewable energy portfolio standards in the future. New state or federal renewable energy portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.
- **If the Idaho Public Utilities Commission, the Oregon Public Utility Commission or the Federal Energy Regulatory Commission grant less rate recovery in rate case filings than Idaho Power Company needs to cover increased costs of providing services, earnings and cash flows may be reduced and economic expansion may be limited.** If the Idaho Public Utilities Commission, the Oregon Public Utility Commission or the Federal Energy Regulatory Commission grant less rate recovery in rate case filings than Idaho Power Company needs to cover increased costs of providing services, it may have a negative effect on earnings and cash flows and could result in downgrades of IDACORP, Inc.'s and Idaho Power Company's credit ratings. Failure to obtain regular and timely rate relief may limit Idaho Power Company's ability to serve additional customers.
- **Conditions that may be imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric production and reduce earnings and cash flows.** Idaho Power Company is currently involved in renewing federal licenses for several of its hydroelectric projects. The Federal Energy Regulatory Commission may impose conditions with respect to environmental, operating and other matters in connection with the renewal of Idaho Power Company's licenses. These conditions could have a negative effect on Idaho Power Company's operations, require large capital expenditures and increase operating costs, reduce hydroelectric production and reduce earnings and cash flows.
- **IDACORP, Inc., IDACORP Energy and Idaho Power Company are subject to costs and other effects of legal and regulatory proceedings, settlements, investigations and claims.** IDACORP, Inc., IDACORP Energy and Idaho Power Company are involved in a number of proceedings, including the California refund proceeding, a portion of which remains pending before the Federal Energy Regulatory Commission and the United States Court of Appeals for the Ninth Circuit; a refund proceeding affecting sellers of wholesale power in the spot market in the Pacific Northwest; and show cause proceedings originating at the Federal Energy Regulatory Commission, a portion of which remains pending in the United States Court of Appeals for the Ninth Circuit. It is possible that additional proceedings related to

the western energy situation may be filed in the future against IDACORP, Inc., IDACORP Energy or Idaho Power Company. IDACORP, Inc. and Idaho Power Company are or may also be subject to costs and other effects of additional legal claims, actions and complaints, including those related to the Jim Bridger and Boardman coal-fired plants, in which Idaho Power Company holds an ownership interest. To the extent the companies are required to make payments in connection with any legal or regulatory proceeding, settlement, investigation or claim, earnings and cash flows will be negatively affected.

- **Idaho Power Company's business is subject to substantial governmental regulation and may be adversely affected by increased costs resulting from, or liability under, existing or future regulations or requirements.** Idaho Power Company is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the Environmental Protection Agency, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council and the public utility commissions in Idaho, Oregon and Wyoming. Some of these regulations are changing or subject to interpretation, and failure to comply may result in penalties or other adverse consequences. Compliance with these requirements directly influences Idaho Power Company's operating environment and may significantly increase Idaho Power Company's operating costs.
- **Increased capital expenditures can significantly affect liquidity.** Increases in both the number of customers and the demand for energy require expansion and reinforcement of transmission and distribution systems and generating facilities. If Idaho Power Company does not receive timely regulatory recovery, Idaho Power Company will have to rely more on external financing for its future utility construction expenditures. These large planned expenditures may weaken the consolidated financial profile of IDACORP, Inc. and Idaho Power Company. Additionally, a significant portion of Idaho Power Company's facilities were constructed many years ago. Aging equipment, even if maintained in accordance with industry practices, may require significant capital expenditures. Failure of equipment or facilities used in Idaho Power Company's system could potentially increase repair and maintenance expenses, purchased power expenses and capital expenditures.
- **As a holding company, IDACORP, Inc. does not have its own operating income and must rely on the upstream cash flows from its subsidiaries to pay dividends and make debt payments.** IDACORP, Inc. is a holding company and thus its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power Company. Consequently, IDACORP, Inc.'s ability to pay dividends and to service its debt is dependent upon dividends and other payments received from its subsidiaries. IDACORP, Inc.'s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, Inc., whether through dividends, loans or other payments. The ability of IDACORP, Inc.'s subsidiaries to pay dividends or make distributions to IDACORP, Inc. depends on several factors, including their actual and projected earnings and cash flow, capital requirements and general financial condition, and the prior rights of holders of their existing and future first mortgage bonds and other debt securities.
- **A downgrade in IDACORP, Inc.'s and Idaho Power Company's credit ratings could negatively affect the companies' ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties.** Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP, Inc. and Idaho Power Company. IDACORP, Inc. and Idaho Power Company also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper. Downgrades of IDACORP, Inc.'s or Idaho Power Company's credit ratings, or those affecting bond insurers or relationship banks, could limit the companies' ability to access capital, including the commercial paper markets, require IDACORP, Inc. and Idaho Power Company to pay a higher interest rate on their debt and require the companies to post collateral with transaction counterparties.
- **Volatility and decreased lending capacity in the financial markets may negatively affect IDACORP, Inc.'s and Idaho Power Company's ability to access capital and/or increase their cost of borrowing.** IDACORP, Inc. and Idaho Power Company require liquidity to pay operating expenses and principal of and interest on debt and to finance capital expenditures. Financial markets have recently experienced extreme volatility and disruption, causing the cost of borrowing to rise and the availability of liquidity and credit for borrowers to decrease; actions taken by the United States Government, the Federal Reserve and other governmental and regulatory bodies may not be sufficient to stabilize these markets. As a result, IDACORP, Inc. and Idaho Power Company may experience higher interest costs and/or be unable to access capital, including the commercial paper markets. These conditions may adversely affect IDACORP, Inc.'s and Idaho Power Company's results of operations, financial condition and cash flows.
- **IDACORP and Idaho Power Company may incur losses on their investments or be unable to sell**

their investments when they desire to do so, which could adversely affect their liquidity and financial condition. IDACORP and Idaho Power Company invest cash in short-term interest bearing accounts, including money market funds. Volatility in the financial markets has resulted in a lack of liquidity and declines in value of some money market funds. The companies may realize additional losses on some or all of their invested funds or be unable to sell their investments when they desire to do so. This could adversely affect IDACORP's and Idaho Power Company's liquidity and financial condition.

- **National and regional economic conditions may cause increased late payments and uncollectible accounts, which would reduce earnings and cash flows.** Recent concerns over inflation, energy costs, the availability and cost of credit, declining business and increased unemployment have contributed to a recession. These factors have resulted, and may continue to result, in an increase in late payments and uncollectible accounts and reduce IDACORP Inc.'s and Idaho Power Company's earnings and cash flows.
- **Terrorist threats and activities could result in reduced revenues and increased costs.** IDACORP, Inc. and Idaho Power Company are subject to direct and indirect effects of terrorist threats and activities. Potential targets include generation and transmission facilities. The effects of terrorist threats and activities could prevent Idaho Power Company from purchasing, generating or transmitting power and result in reduced revenues and increased costs.
- **Adverse results of income tax audits could reduce earnings and cash flows.** The outcome of ongoing and future income tax audits could differ materially from the amounts currently recorded, and the difference could reduce IDACORP's and Idaho Power Company's earnings and cash flows.
- **Employee workforce factors could increase costs and reduce earnings.** Idaho Power Company is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, and an aging workforce. The costs of attracting and retaining appropriately qualified employees to replace an aging workforce could reduce earnings and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

IPC's system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, two natural gas-fired plants located in southern Idaho and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada and Oregon. The system also includes approximately 4,752 miles of high-voltage transmission lines, 23 step-up transmission substations located at power plants, 22 transmission substations, eight switching stations, 223 energized distribution substations (excluding mobile substations and dispatch centers) and approximately 65,045 miles of distribution lines.

IPC holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. These projects and the other generating stations and their nameplate capacities are listed below:

Project	Nameplate Capacity (kW)	License Expiration
Hydroelectric Developments:		
Properties subject to federal licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	12,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee-Oxbow-Hells Canyon	1,166,900	2005 (1)
Swan Falls	27,170	2010
American Falls	92,340	2025
Cascade	12,420	2031
Milner	59,448	2038
Twin Falls	52,897	2040
Other Hydroelectric:		
Clear Lakes - Thousand Springs	11,300	
Total Hydroelectric	1,709,045	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired) (2)	770,501	
Valmy (coal-fired) (2)	283,500	
Boardman (coal-fired) (2)	64,200	
Danskin (gas-fired)	262,755	
Salmon (diesel-internal combustion)	5,000	
Bennett Mountain (gas-fired)	172,800	
Total Steam and Other	1,558,756	
Total Generation	3,267,801	

(1) Licensed on an annual basis while application for new multi-year license is pending.
(2) IPC's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy and 10 percent for Boardman. Amounts shown represent IPC's share.

Relicensing of IPC's hydroelectric projects is discussed in Part II, Item 7 - "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

At December 31, 2008, the composite average ages of the principal parts of IPC's system, based on dollar investment, were: production plant, 25 years; transmission lines and substations, 25 years; and distribution lines and substations, 21 years. IPC considers its properties to be well-maintained and in good operating condition.

IPC owns in fee all of its principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. IPC's property is also subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. In addition, IPC's property is subject to minor defects common to properties of such size and character that do not materially impair the value to, or the use by, IPC of such properties.
IERCo owns a one-third interest in Bridger Coal Company and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant.

Ida-West holds 50 percent interests in nine operating hydroelectric plants with a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Please see Note 7 to IDACORP's and IPC's Consolidated Financial Statements.

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

None

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of all of the executive officers of IDACORP, Inc. and Idaho Power Company are listed below along with their business experience during the past five years. Mr. J. LaMont Keen and Mr. Steven R. Keen are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was elected.

J. LAMONT KEEN President and Chief Executive Officer, appointed July 1, 2006. Mr. Keen also serves as President and Chief Executive Officer of Idaho Power Company, appointed November 17, 2005. Mr. Keen was Executive Vice President of IDACORP, Inc., from March 1, 2002, to July 1, 2006, and President and Chief Operating Officer of Idaho Power Company from March 1, 2002, to November 17, 2005. Mr. Keen was Senior Vice President – Administration and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company from May 5, 1999, to March 1, 2002. Mr. Keen also serves on the Board of Directors of both IDACORP, Inc. and Idaho Power Company. Age 56.

DARREL T. ANDERSON Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, appointed July 1, 2004. Mr. Anderson was Vice President, Chief Financial Officer and Treasurer of IDACORP, Inc. and Idaho Power Company from March 1, 2002, to July 1, 2004 and Vice President – Finance and Treasurer of IDACORP Inc. and Idaho Power Company from May 5, 1999, to March 1, 2002. Age 50.

THOMAS R. SALDIN Senior Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company, appointed October 1, 2004. Mr. Saldin was Executive Vice President and General Counsel of Albertson's Inc., a supermarket chain, from January 29, 1999, to his retirement on August 31, 2001. Age 62.

JAMES C. MILLER Senior Vice President – Power Supply of Idaho Power Company, appointed July 1, 2004. Mr. Miller was Senior Vice President – Delivery of Idaho Power Company from October 1, 1999, to July 1, 2004. Age 54.

DANIEL B. MINOR Senior Vice President – Delivery of Idaho Power Company, appointed July 1, 2004. Mr. Minor was Vice President - Administrative Services & Human Resources of IDACORP, Inc. and Idaho Power Company from November 20, 2003, to July 1, 2004, Vice President – Corporate Services of Idaho Power Company from May 15, 2003, to November 20, 2003 and Director of Audit Services of Idaho Power Company from July 2001 to May 15, 2003. Age 51.

STEVEN R. KEEN Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, appointed June 1, 2006. Mr. Keen was President of IDACORP Financial Services from September 8, 1998 to May 31, 2007. Age 48.

PATRICK A. HARRINGTON Corporate Secretary of IDACORP, Inc. and Idaho Power Company, appointed March 15, 2007. Mr. Harrington was Senior Attorney from June 7, 2003, to March 15, 2007. Age 48.

DENNIS C. GRIBBLE Vice President and Chief Information Officer of IDACORP, Inc. and Idaho Power Company, appointed June 1, 2006. Mr. Gribble was Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, from July 15, 2004, to June 1, 2006 and Finance Controller of Idaho Power Company from January 1, 1997, to July 15, 2004. Age 56.

LORI D. SMITH Vice President – Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, appointed January 1, 2008. Ms. Smith was Vice President - Finance and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company from July 15, 2004, to January 1, 2008, and Director of Strategic Analysis of Idaho Power Company from January 1, 2000 to July 15, 2004. Age 48.

LUCI K. MCDONALD Vice President - Human Resources of IDACORP, Inc. and Idaho Power Company, appointed December 6, 2004. Ms. McDonald was Corporate Staff Director of Human Resources of Boise Cascade Corporation, a forest products company, from September 16, 1999, to November 19, 2004. Age 51.

NAOMI SHANKEL Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, appointed September 21, 2006. Ms. Shankel was Director, Audit Services of IDACORP, Inc. and Idaho Power Company from July 2003, to September 21, 2006. Age 37.

JOHN R. GALE Vice President - Regulatory Affairs of Idaho Power Company, appointed March 15, 2001. Age 58.

LISA A. GROW Vice President – Delivery Engineering and Operations of Idaho Power Company, appointed July 20, 2005. Ms. Grow was General Manager of Grid Operations and Planning of Idaho Power Company from October 23, 2004, to July 20, 2005, Operations Manager (Grid Ops) of Idaho Power Company from March 2, 2002, to October 23, 2004. Age 43.

WARREN KLINE Vice President – Customer Service and Regional Operations of Idaho Power Company, appointed July 20, 2005. Mr. Kline was General Manager of Regional Operations of Idaho Power Company from March 2, 2002, to July 20, 2005. Age 53.

JEFFREY MALMEN Vice President – Public Affairs of IDACORP, Inc. and Idaho Power Company, appointed October 1, 2008. Mr. Malmen was Senior Manager – Governmental Affairs of IDACORP, Inc. and Idaho Power Company from December 2007 to October 1, 2008, Chief of Staff of the Office of Idaho Governor C.L. "Butch" Otter from January 2007 to November 2007, and Chief of Staff of the Office of Idaho Congressman C.L. "Butch" Otter from January 2001 through December 2006. Age 41.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP's common stock, without par value, is traded on the New York Stock Exchange. On February 23, 2009, there were 14,266 holders of record and the stock price was $25.08 per share.

The outstanding shares of IPC's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of IPC on October 1, 1998.

The amount and timing of dividends payable on IDACORP's common stock are within the sole discretion of IDACORP's Board of Directors. The Board of Directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, legislative and regulatory developments affecting the electric utility industry in general and IPC in particular, competitive conditions and any other factors the Board of Directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily IPC.

A covenant under IDACORP's credit facility, IPC's credit facility and IPC's term loan credit agreement described in "MD&A - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs – Debt Covenants" requires IDACORP and IPC to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined, of no more than 65 percent at the end of each fiscal quarter.

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

IPC's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or IPC's Code of Conduct. At December 31, 2008, the leverage ratios for IDACORP and IPC were 52 percent and 54 percent, respectively. Based on these restrictions, IDACORP's and IPC's dividends were limited to $536 million and $447 million, respectively, at December 31, 2008.

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. IPC paid dividends to IDACORP of $54 million, $53 million and $51 million in 2008, 2007 and 2006, respectively.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2008 and 2007 as reported in the consolidated transaction reporting system.

	2008 Quarters			
Common Stock, without par value:	1st	2nd	3rd	4th
High	$35.11	$33.36	$33.89	$30.66
Low	28.74	28.55	27.96	21.88
Dividends paid per share	0.30	0.30	0.30	0.30

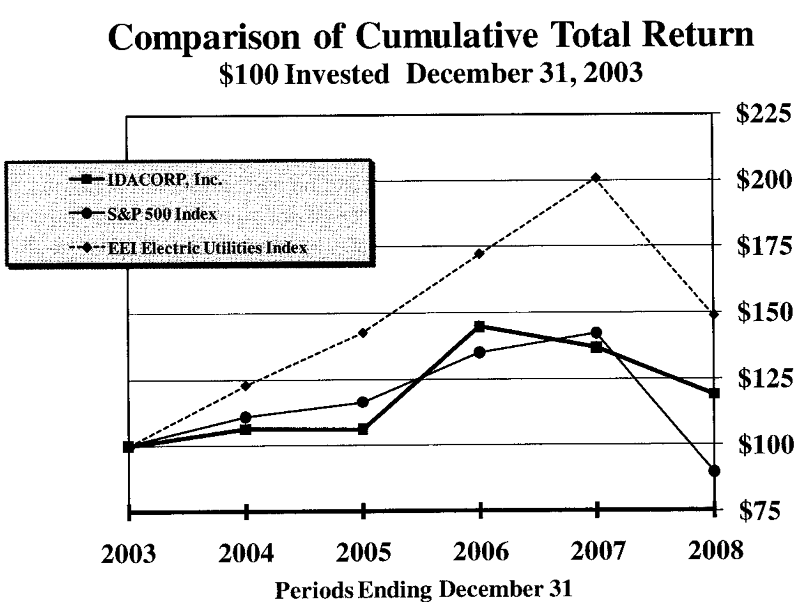
	2007 Quarters			
Common Stock, without par value:	1st	2nd	3rd	4th
High	$39.19	$35.18	$36.57	$36.72
Low	32.00	31.22	30.07	32.36
Dividends paid per share	0.30	0.30	0.30	0.30

Issuer Purchases of Equity Securities:

None

Performance Graph

The following performance graph shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on December 31, 2003, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.



Source: Bloomberg and Edison Electric Institute

	IDACORP	S & P 500	EEI Electric Utilities Index
2003	$ 100.00	$ 100.00	$ 100.00
2004	106.40	110.87	122.84
2005	106.25	116.31	142.56
2006	144.89	134.67	172.18
2007	136.78	142.06	200.66
2008	118.99	89.51	148.68

The foregoing performance graph and data shall not be deemed "filed" as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and should not be deemed incorporated by reference into any other filing of IDACORP or IPC under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or IPC specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars except per share amounts)

	2008	2007	2006	2005	2004
Operating revenues	$ 960,414	$ 879,394	$ 926,291	$ 842,864	$ 827,856
Operating income	190,667	152,078	169,704	154,653	106,233
Income from continuing operations	98,414	82,272	100,075	85,716	80,781
Diluted earnings per share from continuing operations	2.17	1.86	2.34	2.02	2.10
Dividends declared per share	1.20	1.20	1.20	1.20	1.20
Financial Condition:					
Total assets	$ 4,022,845	$ 3,653,308	$ 3,445,130	$ 3,364,126	$ 3,234,172
Long-term debt	1,269,979	1,168,336	1,023,773	1,039,852	1,058,152
Financial Statistics:					
Times interest charges earned:					
Before tax (1)	2.47	2.35	2.78	2.65	1.99
After tax (2)	2.23	2.16	2.54	2.37	2.32
Market-to-book ratio (3)	106%	131%	151%	121%	128%
Payout ratio (4)	55%	65%	48%	79%	63%
Return on year-end common equity(5)	7.6%	6.8%	9.6%	6.2%	7.2%
Book value per share (6)	$ 27.76	$ 26.79	$ 25.65	$ 24.05	$ 23.88

The financial statistics listed above are calculated in the following manner:
(1) The sum of interest on long-term debt, other interest expense excluding the allowance for funds used during construction credits (AFUDC), and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
(2) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
(3) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in (6) below
(4) Dividends paid per common share for the year divided by earnings per diluted share.
(5) Net income divided by total shareholders' equity at the end of the year.
(6) Total shareholders' equity at the end of the year divided by shares outstanding at the end of the year.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. and IDACOMM as assets held for sale. IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 16 to IDACORP's and IPC's Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

INTRODUCTION:

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

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

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

IDACORP's other subsidiaries include:

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

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

While reading the MD&A, please refer to the accompanying Consolidated Financial Statements of IDACORP and IPC, which present the financial position at December 31, 2008 and 2007, and the results of operations and cash flows for each company for the years ended December 31, 2008, 2007 and 2006.

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 Annual Report on Form 10-K, 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:
The effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission and the Federal Energy Regulatory Commission affecting our ability to recover costs and/or earn a reasonable rate of return including, but not limited to, the disallowance of costs that have been deferred;

- Changes in and compliance with state and federal laws, policies and regulations, including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public

Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates;

- Changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or other taxing jurisdiction;
- Litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability;
- Changes in and compliance with laws, regulations and policies including changes in law and compliance with environmental, natural resources, endangered species and safety laws, regulations and policies and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies;
- Global climate change and regional weather variations affecting customer demand and hydroelectric generation;
- Over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities;
- Construction of power generation, transmission and distribution facilities, including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up;
- Operation of power generating facilities including performance below expected levels, breakdown or failure of equipment, availability of transmission and fuel supply;
- Changes in operating expenses and capital expenditures, including costs and availability of materials, fuel and commodities;
- Blackouts or other disruptions of Idaho Power Company's transmission system or the western interconnected transmission system;
- Population growth rates and other demographic patterns;
- Market prices and demand for energy, including structural market changes;
- Increases in uncollectible customer receivables;
- Fluctuations in sources and uses of cash;
- Results of financing efforts, including the ability to obtain financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets and other economic conditions;
- Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;
- Changes in interest rates or rates of inflation;
- Performance of the stock market, interest rates, credit spreads and other financial market conditions, as well as changes in government regulations, which affect the amount and timing of required contributions to pension plans and the reported costs of providing pension and other postretirement benefits;
- Increases in health care costs and the resulting effect on medical benefits paid for employees;
- Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;
- Homeland security, acts of war or terrorism;
- Natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire;
- Adoption of or changes in critical accounting policies or estimates; and
- New accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements.

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

EXECUTIVE OVERVIEW:

2008 Financial Results
IDACORP's net income and earnings per diluted share for the last three years were as follows:

	2008	2007	2006
Net income	$ 98,414	$ 82,339	$ 107,403
Average outstanding shares - diluted (000s)	45,332	44,291	42,874
Earnings per diluted share	$ 2.17	$ 1.86	$ 2.51

The key factor affecting the change in IDACORP's net income was IPC's operating income, which increased $34.6 million over 2007 levels. Rate increases during 2007 and 2008 increased general business revenues in 2008 as compared to 2007. These increases combined with more favorable hydroelectric generating conditions resulted in improved operating income. However, increases in operating and maintenance expenses and interest expense due to higher long-term debt balances reduced the earnings contribution at IPC. IPC earnings in the fourth quarter were also negatively impacted by a FERC decision that resulted in an increase to IPC's Open Access Transmission Tariff (OATT) refund to its transmission service customers and an impairment charge for a decline in the market value of equity securities.

The following table presents a reconciliation of IDACORP net income for 2007 to 2008 (shown net of tax):

IDACORP 2007 Net Income	$82,339	
Increased electric utility operating income	21,070	(1)
Gain on sale of Southwest Intertie Project (SWIP)	1,849	
Decreased net income at IFS	(3,686)	
Decreased loss at holding company	1,585	
Increased IPC interest expense	(6,518)	
Impairment of equity securities	(4,159)	
Settlement of prior years' tax returns	2,753	
Other net increases	3,181	
IDACORP 2008 Net Income	$98,414	

(1) Increased electric utility operating income includes increased general business revenue of $70.6 million, decreased other revenue of $4.8 million due to the OATT refund, decreased net power supply costs (fuel and purchased power less off-system sales) of $5.9 million, a PCA expense decrease of $44.9 million, and increased O&M expense of $4.6 million.

Business Strategy
IDACORP is focusing on a strategy that emphasizes IPC as IDACORP's core business. Although growth in number of customers slowed in 2008, IPC is experiencing customer growth in its service area and must be prepared to meet customers' electricity needs in the future. This corporate strategy recognizes that IPC must make investments in infrastructure to ensure adequate supply and reliable service. IPC's regulatory efforts have resulted in finalizing the 2007 general rate case and receiving an order in the 2008 general rate case. IPC continues to make efforts to speed recovery of the financial and operating costs of new facilities and system improvements. IFS and Ida-West remain components of the corporate strategy.

Regulatory Matters
Idaho 2008 General Rate Case: On January 30, 2009, the IPUC issued its final order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four principal areas of the order having a combined Idaho jurisdictional revenue requirement impact of approximately $8 million annually. The request for reconsideration is discussed in more detail in "REGULATORY MATTERS - Idaho Rate Cases - 2008 General Rate Case."

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

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 related facilities, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or $8.9 million in annual revenues.

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 also directed IPC to hold workshops to address PCA-related issues not resolved in the PCA filing. As a result of the workshops, a settlement stipulation was filed and was approved by the IPUC on January 9, 2009. The approved stipulation changes the sharing ratio between customers and shareholders to 95/5, adjusts the Load Growth Adjustment Rate (LGAR) to $26.52 per MWh based on the 2008 general rate case order, changes the source of the power supply cost forecast and authorizes inclusion of third party transmission expense in the PCA formula. The changes were effective February 1, 2009. The stipulation is discussed in more detail in "REGULATORY MATTERS - Deferred Net Power Supply Costs – Idaho – PCA Workshops."

Oregon Power Cost Recovery Mechanism: On April 28, 2008, the OPUC approved a power cost recovery mechanism with two components, the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process. The APCU allows IPC to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up that provides for 90 percent customer sharing of deviations in actual net power supply costs from those included in the APCU if the deviations are outside of prescribed ranges and IPC meets a return-on-equity test. These mechanisms are discussed in more detail in "REGULATORY MATTERS - Deferred Net Power Supply Costs – Oregon – Oregon Power Cost Recovery Mechanism."

OATT: Effective June 1, 2006, IPC's OATT was made a formula rate based on financial and operational data IPC is required to file annually with the FERC in its Form 1. On January 15, 2009, the FERC issued an unfavorable order affecting the way IPC calculates its OATT. The order requires IPC to reduce its transmission service rates to FERC jurisdictional customers and make refunds in the total amount of $13.3 million (including $1.1 million in interest) for the period since June 2006. IPC had previously reserved a portion of this amount, but reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008 to bring the total reserve amount to $13.3 million. IPC has filed a request for rehearing with the FERC. The OATT is discussed in more detail in "REGULATORY MATTERS - Federal Regulatory Matters - OATT."

Record system peaks

IPC's system is dual peaking, with the larger peak demand occurring in the summer. IPC set a new system peak of 3,214 MW on June 30, 2008. The previous hourly system peak of 3,193 MW was set on July 13, 2007. Although IPC was able to meet all of its load requirements during this period of increased demand, all available resources of IPC's system were fully committed.

Integrated Resource Plan

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

Prior to filing, the IRP requires extensive involvement by IPC, the IPUC Staff, the OPUC Staff, and customer and environmental representatives, as well as input on the cost of various generation technologies. The IRP is the starting point for demonstrating prudence in IPC's resource decisions. The two primary goals of the 2006 IRP were to (1) identify sufficient resources to reliably serve the growing demand for electric service within IPC's service area throughout the 20-year planning period and (2) ensure that the portfolio of resources selected balances cost, risk and environmental concerns.

The IPUC accepted the 2006 IRP in March 2007 and the OPUC acknowledged the 2006 IRP in September 2007. With its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other Idaho utilities. To comply with this request, IPC provided updates on the status of the 2006 IRP to both the IPUC and OPUC in June 2008 and to the OPUC in February 2009 and is currently preparing the 2009 IRP which is scheduled to be completed in June 2009. See further discussion in "REGULATORY MATTERS - Integrated Resource Plan."

Transmission Projects

IPC and PacifiCorp are jointly exploring the Gateway West Project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. The 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. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC's share of the initial phase of engineering, environmental review, permitting and rights-of-way is approximately $40 million. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way, acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of the project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires.

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. The Boardman-Hemingway Line is expected to relieve existing congestion by increasing transmission capacity and improving reliability. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. The initial project phase estimate of $50 million will be funded by IPC and includes the engineering, environmental review, permitting and rights-of-way. Cost estimates for the project (including initial phase project estimate and construction costs of the line) are approximately $600 million. IPC expects to seek partners for up to 50 percent of the project when construction commences. The line has a target in-service date of June 2013. Please see further discussion in "REGULATORY MATTERS – Transmission Projects - Boardman-Hemingway Line."

In order to connect the Gateway West Project and the Boardman-Hemingway Line to IPC's primary load center and also to help meet forecast deficits and improve reliability, IPC is constructing a new 500-kV station named Hemingway. As part of the Hemingway Station Project, the new Hemingway-Hubbard Transmission Line will provide power to the Treasure Valley in southwest Idaho. The project is expected to be completed by 2010. The project will include adding a 230-kV double circuit transmission line and converting an existing 138-kV to 230-kV. Cost estimates for the Hemingway Station Project include $52 million for the station and $25 million for the Hemingway-Hubbard Transmission Line.

Liquidity

In the fourth quarter of 2008, the global credit markets suffered a significant contraction, including the failure of some large financial institutions. As a result, the U.S. government took control of certain financial institutions, and some institutions were bought out or declared bankruptcy. Despite the recent turmoil in the global credit markets, IDACORP and IPC had access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan because IDACORP and IPC rely on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by internally generated funds. IDACORP and IPC have continued to issue commercial paper at times, but have also made draws under their respective credit facilities when commercial paper at desired maturities was not available. IDACORP and IPC expect that operating cash flow, together with the revolving credit facilities and other external financing, will be adequate to meet their operating and capital needs, although there can be no assurance that continued or increased volatility and disruption in the global capital and credit markets will not restrict either company's ability to access these markets on commercially acceptable terms or at all.

Pension Plan

Financial market volatility and disruption caused a significant decline in the value of qualified pension assets. Current provisions of the Pension Protection Act require that if a company does not maintain a 94 percent funding status for 2009, then the company will need to make additional contributions to become fully funded over a period of seven years. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated minimum required contributions would be approximately $45 million in 2010 and $33 million for each of 2011, 2012, and 2013. These estimates reflect the initial relief measures as passed by Congress; however, additional measures are being proposed, which may impact immediate funding requirements.

Capital Requirements and Cash Flows
IDACORP estimates that it will spend between $780 and $800 million for construction related activities from 2009 to 2011, excluding any amounts from our 2012 Baseload Resource RFP process.

Forecasts indicate that internal cash generation after dividends will provide less than the full amount of total capital requirements for 2009 through 2011. IDACORP and IPC expect to continue financing the utility construction program and other capital requirements with internally generated funds and continued reliance on externally financed capital. Excluding the baseload resource decision, IPC expects financing needs in 2009 to be less than 2008 levels.

The amount of internal cash generation is dependent primarily upon IPC's cash flows from operations, which are subject to risks and uncertainties relating to weather and water conditions and IPC's ability to obtain rate relief to cover its operating costs and provide a return on investment.

Equity Issuances
During 2008, IDACORP issued approximately 1.9 million shares of common stock through its continuous equity program (CEP), dividend reinvestment and stock purchase plan, employee savings plan, restricted stock plan, and long-term incentive and compensation plan. Approximately 1.5 million of these shares were issued under the CEP. In 2008, 2007 and 2006, IDACORP contributed $37 million, $51 million and $47 million, respectively, of additional equity to IPC. No additional shares of IPC common stock were issued.

Idaho Water Management Issues
Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at IPC's hydroelectric projects on the Snake River. 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. For a further discussion of water management issues see "LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues."

2009 Operating and Financial Metrics Outlook
The outlook for key operating and financial metrics for 2009 as compared to actual results for 2008 is:

Key Operating & Financial Metrics	2009 Estimate	2008 Actual
IPC Operation & Maintenance Expense (Millions)	$280-$290	$294
IPC Capital Expenditures (Millions)	$220-$230	$244
IPC Hydroelectric Generation (Million MWh)	6.5-8.5	6.9
Non-regulated subsidiary earnings and holding company expenses (Millions)	$0.0-$3.0	$4.3
Effective Tax Rates:		
IPC	31%-35%	29%
Consolidated – IDACORP	24%-28%	16%

IPC capital expenditures exclude costs for a baseload energy resource. IPC will seek approval from the IPUC relating to the baseload resource during the first quarter of 2009 with a decision from the IPUC expected later in 2009. For the three-year period 2009-2011, IPC expects to spend between $780 million and $800 million for construction-related activities. This amount includes expenditures for the siting and permitting of major transmission expansions for Boardman to Hemingway, Gateway West, and for the Hemingway station and Hemingway to Hubbard line.

As discussed above, the credit and financial markets have recently experienced volatility and disruption. IPC has experienced a slowdown in new customer connections and one of IPC's largest industrial customers has announced workforce reductions. As a result, IPC and IDACORP have reduced or delayed many capital expenditures relating to customer growth and other non-critical projects. Additionally, hiring restrictions have been implemented and are expected to slow the growth of operation and maintenance spending in 2009.

The projected range for annual hydroelectric generation is based on 2008-2009 Snake River Basin snowpack at 77 percent of average on February 17, 2009, with reservoir storage levels in selected federal reservoirs upstream of Brownlee at approximately 110 percent of average as of February 11, 2009. The stream flow forecast released on February 20, 2009, by the NWRFC predicts that Brownlee reservoir inflow for April through July 2009 will be 3.3 maf, or 53 percent of the NWRFC average.

The decrease in estimated non-regulated subsidiary earnings from prior years is a result of expected declines in contributions from IFS because of lower tax benefits from aging investments and no significant new contributions expected in 2009.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES:

When preparing financial statements in accordance with GAAP, IDACORP's and IPC's management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management's control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates.

Management believes the following accounting policies and estimates are the most critical to the portrayal of their financial condition and results of operations and require management's most difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Accounting for Rate Regulation

In order to apply the accounting policies and practices of Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation,* a regulated company must satisfy the following conditions: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator. SFAS 71 requires companies that meet the above conditions to reflect the impact of regulatory decisions in their consolidated financial statements and requires that certain costs be deferred as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced.

IPC follows SFAS 71, and its financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating IPC. The primary effect of this policy is that IPC has recorded $699 million of regulatory assets and $279 million of regulatory liabilities at December 31, 2008. While IPC expects to fully recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, such recovery or refund is subject to final review by the regulatory entities. If future recovery or refund of these amounts ceases to be probable, or if IPC determines that it no longer meets the criteria for applying SFAS 71, IPC would be required to eliminate those regulatory assets or liabilities, unless regulators specify some other means of recovery or refund. Either circumstance could have a material effect on IPC's results of operations and financial position.

Asset Impairment

Available-for-sale securities: IPC has investments in four mutual funds that experienced a significant decline in fair value in 2008. SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities,* requires that these and other securities be evaluated periodically to determine whether a decline in fair value is other than temporary. If the decline in fair value is other than temporary, the cost of the investment is written down to fair value and the loss is recorded as a realized loss. Two significant factors that are considered when evaluating investments for impairment are the length of time and the extent to which the market value has been less than cost. IPC's investments had lost between 32 percent and 43 percent of their value, primarily during the stock market downturn in September and October 2008 and had been in loss positions from six to 12 months at December 31, 2008. Because of the severity of the declines in value, IPC determined that the loss in value was other-than-temporary and recorded a pre-tax loss of $6.8 million in the fourth quarter of 2008.

Equity-Method Investments: IFS has affordable housing investments with a net book value of $75 million at December 31, 2008, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for one investment now consolidated in accordance with GAAP, these investments are accounted for under the equity method of accounting as described in Accounting Principles Board Opinion No. (APB) 18, *The Equity Method of Accounting for Investments in Common Stock.* The standard for determining whether impairment must be recorded under APB 18 is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses on these investments were performed in 2008 and no impairment was noted. These estimates required IDACORP to make assumptions about future stream flows, revenues, cash flows and other items that are inherently uncertain. Actual results could vary significantly from the assumptions used, and the impact of such variations could be material.

Pension and Other Postretirement Benefits

IPC maintains a qualified defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP), and a postretirement medical benefit plan.

The costs IDACORP and IPC record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends and future expectations. Estimates of future stock market performance, changes in interest rates and other factors used to develop the actuarial assumptions are uncertain. Actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and IPC utilize data published in the Citigroup Pension Liability Index and apply the rates therein against the projected cash outflows of the plans. The discount rate used to calculate the 2009 pension expense will be decreased to 6.1 percent from the 6.4 percent used in 2008.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

Gross pension and other postretirement benefit expense for these plans totaled $16 million, $15 million, and $16 million for the three years ended December 31, 2008, 2007 and 2006, respectively, including amounts allocated to capitalized labor and amounts deferred as regulatory assets. For 2009, gross pension and other postretirement benefit costs are expected to total approximately $40 million, which takes into account the change in the discount rate noted above, as well as a decrease in expected return on plan assets and a new amortization of net loss both caused by a decrease in plan assets due to poor market conditions during 2008. No changes were made to the other key assumptions used in the actuarial calculation.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in the discount rate and rate of return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2009	2008	2009	2008
	(millions of dollars)			
Effect of 0.5% increase	$ (3.8)	$ (1.4)	$ (1.5)	$ (2.2)
Effect of 0.5% decrease	4.1	1.7	1.5	2.2

No cash contributions were required or made to the qualified plan from 2006 through 2008, and a $24 million contribution is calculated for 2009 (though payment is not expected until 2010). Under the SMSP, IPC makes payments directly to participants in the plan. Benefit payments are expected to be $3.0 million in 2009 and averaged $2.6 million per year from 2006 to 2008. Gross postretirement plan contributions are expected to be $4.1 million in 2009, and averaged $4.3 million from 2006 to 2008.

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 accrued pension expense under SFAS 87, *Employers' Accounting for Pensions,* as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. IPC began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. The deferral of pension expense began in 2007 with $2.8 million being deferred to a regulatory asset beginning in the third quarter. At December 31, 2008, $10.6 million of expense was deferred as a regulatory asset. Approximately $30 million is expected to be deferred in 2009.

Please refer to Note 8 of IDACORP's and IPC's Consolidated Financial Statements, which contains additional information about the pension and postretirement plans.

Contingent Liabilities

Contingent liabilities are accounted for in accordance with SFAS 5, *Accounting for Contingencies.* According to SFAS 5, an estimated loss from a loss contingency is charged to income if (a) it is probable that an asset had been impaired or a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated no accrual is recorded but disclosure of the contingency in the notes to the financial statements is required. Gain contingencies are not recorded until realized.

IDACORP and IPC have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria of SFAS 5 have been met, liabilities have been recorded. Estimates of this nature are highly subjective and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

Income Taxes

IDACORP and IPC account for income taxes in accordance with SFAS 109, *Accounting for Income Taxes* and FIN 48, *Accounting for Uncertainty in Income Taxes.* Judgment and estimation are used in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

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 over the last three years. In this analysis, the results of 2008 are compared to 2007 and the results of 2007 are compared to 2006.

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

		2008		2007		2006
IPC - Utility operations	$	94,115	$	76,579	$	93,929
IDACORP Financial Services		3,426		7,112		9,509
IDACORP Energy		406		(171)		5
Ida-West Energy		2,353		2,223		2,564
Holding company expenses		(1,886)		(3,471)		(5,932)
Discontinued operations		-		67		7,328
Total earnings	$	98,414	$	82,339	$	107,403
Average outstanding shares - diluted (000s)		45,332		44,291		42,874
Earnings per diluted share	$	2.17	$	1.86	$	2.51

Utility Operations

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

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

Stream flow conditions improved slightly in 2008 resulting in 6.9 million MWh generated from IPC's hydroelectric facilities, compared to 6.2 million MWh in 2007. The observed stream flow data released in August 2008, by the U.S. Army Corps of Engineers, Northwest Division indicated that Brownlee reservoir inflow for April through July 2008 was 4.4 million acre-feet (maf), or 70 percent of the National Weather Service Northwest River Forecast Center (NWRFC) average. Brownlee reservoir inflow for 2008 totaled 10.1 maf, or 66 percent of the NWRFC average compared to 8.5 maf in 2007. Storage in selected federal reservoirs upstream of Brownlee as of February 11, 2009, was 110 percent of average. The stream flow forecast released on February 20, 2009, by the NWRFC predicts that Brownlee reservoir inflow for April through July 2009 will be 3.3 maf, or 53 percent of the NWRFC average.

In 2008, IPC leased approximately 0.1 maf of storage water from four sources in an effort to enhance hydroelectric generation. This water was released during the higher demand summer and winter periods.

On December 30, 2008, IPC issued a request for proposals (RFP) seeking to acquire additional water through leases. Proposals were received in February 2009 and are currently being evaluated. This action is in part to offset the impact of drought and changing water use patterns in southern Idaho — challenges diminishing the company's ability to meet mid-summer electrical demands. Acquiring water through lease also helps IPC improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex. IPC plans to include these costs in its annual PCA filing.

IPC's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,214 MW, set on June 30, 2008. The previous hourly system peak of 3,193 MW was set on July 13, 2007. Although IPC was able to meet all of its load requirements during these periods of increased demand, all available resources of IPC's system were fully committed during several heavy load periods. The all-time winter peak demand is 2,464 MW set on January 24, 2008. The previous hourly system winter peak of 2,459 MW was set in 1998. The following table presents IPC's power supply for the last three years:

	MWh				
	Hydroelectric Generation	**Thermal Generation**	**Total System Generation**	**Purchased Power**	**Total**
2008	6,908	7,496	14,404	3,716	18,120
2007	6,181	7,367	13,548	5,196	18,744
2006	9,207	7,021	16,228	4,964	21,192

IPC's modeled median annual hydroelectric generation is 8.5 million MWh, based on hydrologic conditions for the period 1928 through 2007 and adjusted to reflect the current level of water resource development.

General Business Revenue: The primary influences on electricity sales are weather, customer growth and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Precipitation levels during the agricultural growing season affect sales to customers who use electricity to operate irrigation pumps. Increased precipitation reduces electricity usage by these customers.

The following table presents IPC's general business revenues, MWh sales, average number of customers and Boise, Idaho weather conditions for the last three years:

	2008	**2007**	**2006**
Revenue			
Residential	$ 353,262	$ 308,208	$ 299,594
Commercial	203,035	170,001	162,391
Industrial	122,302	101,409	102,958
Irrigation	105,712	88,685	71,432
Total	$ 784,311	$ 668,303	$ 636,375
MWh			
Residential	5,297	5,227	5,068
Commercial	3,970	3,937	3,761
Industrial	3,355	3,454	3,475
Irrigation	1,922	1,924	1,635
Total	14,544	14,542	13,939
Customers (average)			
Residential	402,520	397,285	387,707
Commercial	63,492	61,640	59,050
Industrial	122	126	130
Irrigation	18,401	18,043	18,081
Total	484,535	477,094	464,968
Heating degree-days	5,586	5,128	5,195
Cooling degree-days	1,068	1,290	1,209
Precipitation (inches)	9.3	8.1	12.1

Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. Normal heating degree-days and cooling degree-days are 5,727 and 807, respectively. Normal precipitation is 12.2 inches.

2008 vs. 2007:

- **Rates:** Rate changes positively impacted general business revenue by $113.5 million in 2008 as compared to 2007. PCA rate increases accounted for $82.3 million of the increases and base rate changes contributed $31.2 million of the increase. The base rate changes included a general rate increase of 5.2 percent effective March 1, 2008, and a 1.37 percent increase for the Danskin plant effective June 1, 2008;
- **Customers:** General business customer growth of 1.6 percent increased revenue $7.8 million; and
- **Usage:** Changes in usage, primarily resulting from cooler summer temperatures, decreased general business revenue $5.3 million.

2007 vs. 2006:

- **Rates:** Rate increases improved general business revenue by $3.0 million in 2007 as compared to 2006. A PCA increase on June 1, 2007, increased rates by an average of 14.5 percent, but was moderated by the prior year net effect of the 19.3 percent PCA reduction, which was partially offset by a one percent net base rate increase;
- **Customers:** Customer growth improved general business revenue $11.7 million for the year, as IPC experienced moderate customer growth in its service territory. The general business customer base (12-month average) increased 2.6 percent over prior year; and
- **Usage:** Weather variations positively impacted general business revenue by $17.2 million. Irrigation usage was higher due to drier than normal conditions in the summer of 2007 as compared to 2006. Residential, industrial and commercial usage was positively impacted by warmer weather conditions during the summer months.

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 last three years:

	2008	2007	2006
Revenue	$ 121,429	$ 154,948	$ 260,717
MWh sold	2,048	2,744	5,821
Revenue per MWh	$ 59.29	$ 56.47	$ 44.79

2008 vs. 2007: Off-system sales revenue declined 22 percent in 2008. Sales volumes decreased due to changes to IPC's risk management policy guidelines implemented in 2008 that have resulted in less forward sales activity overall. Revenue per MWH increased due to the impact of higher energy commodity prices through much of 2008.

2007 vs. 2006: In 2007, the MWh volume sold decreased 53 percent and revenues decreased 41 percent. Deteriorated stream flow conditions throughout Southern Idaho decreased total system generation and electricity available for surplus sales. Revenue decreases from lower volumes were moderated by higher prices. Prior year prices were lower due to the abundance of energy in the region.

Other revenues: The following table presents the components of other revenues:

	2008	2007	2006
Transmission services and property rental	$ 41,436	$ 39,739	$ 34,737
Provision for rate refund	(9,980)	(1,076)	(1,211)
Energy efficiency	18,880	13,487	-
Rate case tax settlement	-	-	(4,745)
Irrigation lost revenues	-	-	(5,400)
Total	$ 50,336	$ 52,150	$ 23,381

2008 vs. 2007: Other revenues decreased $1.8 million due mainly to the following:

- Provision for rate refund reduced revenues $8.9 million compared to 2007. In January 2009, the FERC issued an order finalizing an OATT rate increase that had been implemented in June 2006. IPC accrued an estimated refund pending the final rate order, but the final order requires a significantly higher refund. Of the total provision recorded in 2008, $6.0 million relates to 2008 transmission services, $2.3 million relates to 2007 and $1.7 million relates to 2006. The OATT is discussed in more detail in "REGULATORY MATTERS – Federal Regulatory Matters – Open Access Transmission Tariff (OATT);"

- Wheeling revenues increased $1.7 million; and
- Energy efficiency revenues increased $5.4 million. These revenues mirror program expenditures and result in a zero net impact on net income. Energy efficiency revenues and expenses have steadily increased as program activity has increased.

2007 vs. 2006: Other revenues increased $28.8 million due mainly to the following:

- Beginning in January 2007, a new IPUC accounting order became effective for the treatment of IPC's energy efficiency expenses. The $13.5 million of energy efficiency costs are recorded in Energy efficiency programs and are offset by the same amount recorded in Other revenues resulting in no net effect on earnings. See "Energy efficiency;"
- Other revenues increased $10.1 million from the completed amortization of tax settlement and irrigation lost revenue accruals. From June 2005 to May 2006 IPC was collecting and recording in general business revenues, with a corresponding reduction to Other revenues, amounts related to a 2003 Idaho general rate case tax settlement and amounts related to an irrigation load reduction program. Revenues for the rate case tax settlement were accrued from September 2004 to May 2005; and
- Transmission revenues increased $4.1 million primarily due to the OATT rate increase that began in June 2006.

Purchased power: The following table presents IPC's purchased power expenses and volumes:

	2008	2007	2006
Expense	$ 231,137	$ 289,484	$ 283,440
MWh purchased	3,716	5,196	4,964
Cost per MWh purchased	$ 62.20	$ 55.71	$ 57.10

2008 vs. 2007: Purchased power expense decreased $58.3 million due to improved hydroelectric generation conditions and more normal weather, which allowed IPC to better utilize its own generation resources. Despite improved water conditions in the region, overall market prices remained higher early in the year due to a gradual spring runoff and a need to re-fill reservoirs. In addition, increases in energy commodity prices impacted the electricity market.

2007 vs. 2006: Purchased power expense increased $6.0 million in 2007. Deteriorated system generation, due to poor hydroelectric generation conditions, combined with the second year in a row of record high temperatures and demand during July and August, led to increased purchases. This increase in purchases was partially offset by a lower overall cost per MWh in 2007. During 2006, IPC made forward purchases in conformance with its risk management policy in response to early water year indications that suggested continued drought conditions. Hydroelectric generation conditions for 2006 turned out to be more favorable than forecasted and actual market prices ended up being lower than the prices of the forward purchases. These higher priced forward purchases inflated the cost per MWh that IPC realized for 2006. IPC began utilizing financial hedge instruments in 2007 in addition to physical forward power transactions for the purpose of mitigating price risk related to conforming to IPC's energy risk management policy, managing IPC's energy portfolio to meet customer load, and reacting to changes in market conditions to minimize net power supply costs.

Fuel expense: The following table presents IPC's fuel expenses and generation at its thermal generating plants:

	2008	2007	2006
Fuel expense	$ 149,403	$ 134,322	$ 115,018
Thermal MWh generated	7,496	7,367	7,021
Cost per MWh	$ 19.93	$ 18.23	$ 16.38

2008 vs. 2007: Fuel expense increased $15.1 million due to higher coal prices at the Valmy and Jim Bridger plants. Coal prices at Valmy increased 13 percent due to higher transportation costs. Production costs at Bridger Coal Company were 13 percent higher due to difficulties with its underground longwall mining operation in January and February, the continued transition to underground mining operations, and rising prices for fuel and other commodities. The increases were partially offset by a nine percent reduction in fuel expense at IPC's natural gas fired plants, which had favorable market conditions in the fourth quarter due to pipeline transportation constraints in the region.

2007 vs. 2006: Fuel expense increased $19.3 million in 2007. The increase is largely due to an 11 percent rise in average prices accompanied by a five percent increase in MWh volume. Coal costs increased $7.3 million due to higher market demand and higher rail transportation costs. Generation from the coal fired power plants was up three percent in 2007, attributable to fewer planned and unplanned outages at Valmy and Boardman than the previous year. Additional generation from natural gas-fired plants contributed $12 million to the increase in fuel expense in 2007. These plants were readily available for dispatch in 2007 to meet peak loads and as market conditions warranted. The Bennett Mountain plant was not available during the summer of 2006 due to a turbine failure.

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

The following table presents the components of the PCA:

		2008		**2007**		**2006**
Current year net power supply cost deferral	$	(113,884)	$	(120,844)	$	(27,094)
Amortization of prior year authorized balances		66,471		(287)		(2,432)
Total power cost adjustment	$	(47,413)	$	(121,131)	$	(29,526)

2008 vs. 2007: The $73.7 million decrease in 2008 PCA expense is due primarily to higher amortization from prior year excess net power supply costs to match increased revenues. In each year presented, net power supply costs were higher than the amounts estimated in the annual PCA forecast, resulting in the deferral of costs for recovery in subsequent rate years. As the deferred costs are being recovered in rates, the deferred balances are amortized.

2007 vs. 2006: In 2007, net power supply costs were significantly higher than the amounts reflected in the annual PCA forecast, while in 2006 the deferred costs were much lower due to good hydroelectric generation.

Other operations and maintenance (O&M) expenses:
2008 vs. 2007: Other O&M expenses increased $7.5 million due mainly to the following:

- An increase in labor-related expenses of $10.6 million due to higher incentive-based compensation, salaries and employee count;
- New water leases of $2.2 million to optimize our hydroelectric generation;
- Uncollectible accounts increased $1.8 million, primarily due to deteriorating economic conditions in IPC's service area;
- An increase of $2.4 million in outside services;
- An increase of $2.1 million for reserves for workers' compensation and legal matters;
- Transmission costs decreased $3.1 million due to lower purchased power volumes;
- Thermal O&M expenses decreased $3.6 million due to lower annual outages; and
- FCA charges decreased $5.9 million due to a $4.6 million change in the amount deferred and a $1.3 million increase in amortization of the prior year amounts.

2007 vs. 2006: Other O&M expenses increased $22 million due mainly to the following:

- Regulatory commission expenses increased $5.1 million primarily due to the September 2006 reversal of FERC fee accruals of $3.3 million and an increase in legal fees of $1.6 million related to the OATT filing and the FERC investigation;
- Transmission O&M expenses increased $3.1 million due to higher third-party transmission costs;
- Outside services increased $3.1 million primarily due to an increase in intercompany allocations as well as legal fees;
- Distribution O&M expense increased $2.6 million due to an increase in overhead line maintenance;
- Thermal O&M expenses increased $2.5 million. While much of this increase was due to a planned increase in maintenance activity, the increase also occurred due to unanticipated overhaul costs during

the annual outages in the first half of the year;

- Hydroelectric O&M expenses increased $1.7 million due to the resumption of American Falls bond principal amortization, additional FERC hydroelectric license compliance costs, FERC required inspection costs, and general labor cost increases; and
- Expense for the fixed cost adjustment mechanism, which began in 2007, was $2.6 million.

Energy efficiency: Beginning in January 2007, a new IPUC accounting order became effective for the treatment of IPC's energy efficiency expenses under the energy efficiency rider. Energy efficiency costs were recorded in Other operations and maintenance expenses and were offset by the same amount recorded in Other revenues, resulting in no effect on earnings. Energy efficiency expenses were $18.9 million and $13.5 million in 2008 and 2007, respectively.

Gain on the sale of emission allowances: Gain on sale of emission allowances was $0.5 million, $2.8 million and $8.3 million in 2008, 2007 and 2006, respectively. The bulk of IPC's accumulated excess emission allowances was sold from 2005 to 2007.

Non-utility Operations

IFS: IFS contributed $3 million, $7 million and $10 million to net income in 2008, 2007 and 2006, respectively, principally from the generation of federal income tax credits and accelerated tax depreciation benefits related to its investments in affordable housing and historic rehabilitation developments.

During 2008, IFS recorded $8.3 million in new investments. IFS generated tax credits of $11 million, $15 million and $19 million during 2008, 2007 and 2006, respectively. IFS will continue to review new legislation for opportunities for investment that will be commensurate with the ongoing needs of IDACORP.

Ida-West: Ida-West recorded net income of $2 million, $2 million and $3 million in 2008, 2007 and 2006, respectively. Ida-West continues to hold joint venture investments in independent power projects.

Energy Marketing: In 2003, IE wound down its power marketing operations, closed its business locations and sold its forward book of electricity trading contracts to Sempra Energy Trading. In 2007, all trading contracts expired. IE has not recorded any material net income for the years presented. Currently, IE has no operations but has been working to settle outstanding legal matters surrounding transactions in the California energy markets in 2000 and 2001. These matters are discussed in "LEGAL AND ENVIRONMENTAL ISSUES – Legal and Other Proceedings."

Discontinued Operations: In 2006 and 2007 IDACORP sold its investment in two subsidiaries, IDACORP Technologies, Inc. and IDACOMM, Inc. The operations of these entities are presented as discontinued operations in IDACORP's financial statements. Discontinued operations had no impact on earnings in 2008.

Income Taxes

Status of audit proceedings: Since 2006, IPC has been disputing the Internal Revenue Service's (IRS) disallowance of IPC's use of the simplified service cost method (SSCM) of uniform capitalization for tax years 2001-2004. The dispute has been under review with the IRS Appeals Office. In December 2008, the Appeals Office informed IDACORP that the SSCM settlement computations were complete. IDACORP reviewed the final computations and agreed to the result. In January 2009 the settlement was submitted to the U.S. Congress Joint Committee on Taxation (JCT) for review.

In November 2006, IDACORP made a $44.9 million refundable tax deposit with the IRS related to the disputed income tax assessment for SSCM. In May 2008, IDACORP withdrew $20 million from the deposit. Approximately $21 million from the deposit was applied to the settled income tax deficiency and interest charges with the remaining balance refunded to IDACORP.

The IRS completed its examination of IDACORP's 2004 tax year in August 2008 and its 2005 tax year in October 2008. The 2004 examination report was submitted for JCT review as part of the SSCM settlement and the 2005 report was submitted in November 2008. IDACORP expects the JCT review process for 2001-2005 to be completed in 2009. The settlement of these years resulted in a net income tax benefit of $2.8 million for 2008 at both IDACORP and IPC.

In December 2008 the IRS began its examination of IDACORP's and IPC's 2006 tax year. IDACORP and IPC are unable to predict the outcome of this examination.

LIQUIDITY AND CAPITAL RESOURCES:

Operating Cash Flows

IDACORP's and IPC's operating cash flows for the year ended December 31, 2008 were $137 million and $120 million, respectively. These amounts were an increase of $56 million and $38 million, respectively, compared to the year ended December 31, 2007. The following are significant items that affected operating cash flows in 2008:

- The increases in IDACORP's and IPC's operating cash inflows were primarily the result of a $66 million increase in the collection of previously deferred net power supply costs as compared to 2007.
- Income tax payments increased $17 million and $33 million for IDACORP and IPC, respectively, due to the timing of and increases in taxable income.

IDACORP's and IPC's operating cash flows for 2007 were both $81 million. These amounts were a decrease of $89 million and $50 million, respectively, compared to 2006. The following are significant items that affected operating cash flows in 2007:

- The decreases in IDACORP's and IPC's operating cash inflows were primarily the result of a $111 million increase in the amount of net power supply costs deferred in 2007 as compared to 2006.
- Income tax payments decreased $52 million and $83 million for IDACORP and IPC, respectively, due to the timing of and decreases in taxable income.

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

Investing Cash Flows

IPC's construction expenditures were $244 million, $287 million and $222 million in 2008, 2007 and 2006, respectively. IPC is experiencing a cycle of heavy infrastructure investment needed to address customer growth, peak demand growth, and aging plant and equipment.

Net proceeds from the sales of emission allowances provided investing cash of approximately $3 million, $20 million and $11 million in 2008, 2007 and 2006, respectively. The changes were primarily caused by changes in the number of allowances sold each year as well as changes in market prices. Sales of emission allowances are discussed further in "REGULATORY MATTERS – Emission Allowances."

In November 2006, IDACORP made a refundable deposit of $45 million with the IRS related to a disputed income tax assessment. In August 2007, IPC reimbursed IDACORP for the refundable tax deposit IDACORP made on IPC's behalf. In May 2008, IPC withdrew $20 million from the deposit and in December 2008 the remainder of the deposit was applied to accrued taxes and interest. Income tax matters are discussed further in Note 2 to IDACORP's and IPC's Consolidated Financial Statements.

Additionally in 2008, IPC had a cash inflow of $5.7 million from the sale of SWIP rights-of-way and IDACORP made an $8.3 million investment in affordable housing through its subsidiary, IFS.

Financing Cash Flows

Debt issuances: On April 1, 2008, IPC entered into a $170 million Term Loan Credit Agreement, of which $166.1 million was used to purchase pollution control revenue refunding bonds. On February 4, 2009, IPC entered into a new $170 million Term Loan Credit Agreement to replace this term loan credit agreement. See "Term Loan Credit Agreement" below for further discussion of these agreements.

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. On October 18, 2007, IPC issued $100 million of 6.25% First Mortgage Bonds, Secured Medium-Term Notes, Series G, due October 15, 2037. On June 22, 2007, IPC issued $140 million of 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15, 2037. These issuances were used to retire short-term debt and long-term debt and finance capital expenditures:

Equity issuances: On December 15, 2005, IDACORP entered into a Sales Agency Agreement (2005 Agency Agreement) with BNY Capital Markets, Inc. (BNYCM), as IDACORP's agent, for the offer and sale by IDACORP of up to 2,500,000 shares of its common stock from time to time in at-the-market offerings. IDACORP issued 881,337 shares under the 2005 Agency Agreement in 2007 at an average price of $28.72. In 2008, IDACORP sold the remaining 1,082,145 shares of common stock under the 2005 Agency Agreement at an average price of $28.56, including 879,145 shares in the fourth quarter 2008 at an average price of $28.11 per share.

On December 5, 2008, IDACORP entered into a new Sales Agency Agreement (2008 Agency Agreement) with BNY Mellon Capital Markets, LLC (BNYMCM), as IDACORP's agent, for the offer and sale of up to 3,000,000 shares of its common stock from time to time in at-the-market offerings. In December 2008, IDACORP sold 371,822 shares under the 2008 Agency Agreement at an average price of $29.18 per share.

Under these programs IDACORP received $41.7 million from the issuance of 1,453,967 shares in 2008 and $28.5 million from the issuance of 881,337 shares in 2007. As of December 31, 2008, 2,628,178 shares were available to be issued under the 2008 Agency Agreement.

IDACORP uses original issue common stock for its Dividend Reinvestment and Stock Purchase Plan and 401(k) plan for the purpose of adding additional common equity to its capital structure. Under these plans, IDACORP issued 280,250 shares in 2008 and 250,020 shares in 2007, for proceeds of $8.4 million in both years.

IDACORP issued 30,700 shares in 2008 and 10,070 shares in 2007 in connection with the exercise of stock options, for proceeds of $0.9 million and $0.3 million, respectively.

IDACORP made capital contributions of $37 million and $51 million to IPC in 2008 and 2007, respectively.

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

Financing Programs
IDACORP's consolidated capital structure consisted of common equity of 48 percent and debt of 52 percent at December 31, 2008. IPC's consolidated capital structure consisted of common equity of 46 percent and debt of 54 percent at December 31, 2008.

Shelf Registrations: IDACORP currently has approximately $588 million remaining on its shelf registration statement that can be used for the issuance of debt securities and common stock. IPC currently has $230 million remaining on its shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt. Please see Note 4 to IDACORP's and IPC's Consolidated Financial Statements for more information regarding long-term financing arrangements.

Credit Facilities: The following table outlines available liquidity as of December 31, 2008 and 2007.

	IDACORP		IPC	
	2008	**2007**	**2008**	**2007**
Revolving credit facility	$ 100,000	$ 100,000	$ 300,000	$ 300,000
Commercial paper outstanding	(13,400)	(49,860)	(108,950)	(136,585)
Floating rate draw	(25,000)	-	-	-
Identified for other use (1)	-	-	(24,245)	(24,245)
Net balance available	$ 61,600	$ 50,140	$ 166,805	$ 139,170

(1) Port of Morrow and American Falls bonds that holders may put to IPC.

On April 25, 2007, IDACORP entered into an Amended and Restated Credit Agreement (IDACORP Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P. Morgan Securities Inc., as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders.

The Amended and Restated IDACORP Facility is a $100 million five-year credit agreement that terminates on April 25, 2012. The IDACORP Facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million. IDACORP has the right to request an increase in the aggregate principal amount of the IDACORP Facility to $150 million and to request one-year extensions of the then existing termination date. At December 31, 2008, $25 million in loans were outstanding on IDACORP's Facility and $13 million of commercial paper was outstanding. At February 23, 2009, no loans and $35 million of commercial paper was outstanding.

On April 25, 2007, IPC entered into an Amended and Restated Credit Agreement (IPC Facility) with Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, Keybank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, Wachovia Capital Markets, LLC and J.P. Morgan Securities Inc. as joint lead arrangers and joint book runners, and the other financial institutions party thereto, as lenders.

The Amended and Restated IPC Facility is a $300 million five-year credit agreement that terminates on April 25, 2012. The IPC Facility, which will be used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IPC has the right to request an increase in the aggregate principal amount of the IPC Facility to $450 million and to request one-year extensions of the then existing termination date. At December 31, 2008, no loans were outstanding on IPC's Facility and $109 million of commercial paper was outstanding. At February 23, 2009, no loans and $119 million of commercial paper was outstanding.

Both the IDACORP Facility and the IPC Facility have similar terms and conditions. Under the terms of the facilities IDACORP and IPC may borrow floating rate advances and Eurodollar rate advances. The floating rate is equal to the higher of (i) the prime rate announced by Wachovia Bank or its parent and (ii) the sum of the federal funds effective rate for such day plus 0.50 percent per annum, plus, in each case, an applicable margin. The Eurodollar rate is based upon the British Bankers' Association interest settlement rate for deposits in U.S. dollars published on the REUTERS 01 (Telerate Page 3750 successor) as adjusted by the applicable reserve requirement for Eurocurrency liabilities imposed under Regulation D of the Board of Governors of the Federal Reserve System, for periods of one, two, three or six months plus the applicable margin. The margin is based on the applicable company's rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (S&P), based on the higher of the two ratings. If the ratings are split between Moody's and S&P and the differential is two levels or more, the intermediate rating at the midpoint will apply. If there is no midpoint, the higher of the two intermediate ratings will apply. The margin for the floating rate advances is zero percent unless the applicable company's rating falls below Baa3 from Moody's or BBB- from S&P, at which time it would equal 0.50 percent. The margin for Eurodollar rate advances ranges from 0.15 percent to 0.575 percent depending upon the credit rating. In addition to the margin, if the outstanding aggregate credit exposure exceeds 50 percent of the facility amount, IDACORP or IPC, as applicable, would pay a utilization fee ranging from 0.05 percent to 0.10 percent on outstanding loans depending on the credit rating. At December 31, 2008, the applicable margin under the IDACORP Facility and the IPC Facility was zero percent for floating rate advances and 0.28 percent for IPC and 0.36 percent for IDACORP for Eurodollar rate advances. The utilization fee was 0.05 percent for both companies. A facility fee, payable quarterly, is calculated on the average daily aggregate commitment of the lenders under the relevant credit facility and is also based on the applicable company's rating from Moody's or S&P as indicated above. At December 31, 2008, the facility fee under the IDACORP and IPC Facilities was 0.09 percent and 0.07 percent, respectively.

In connection with the issuance of letters of credit, IDACORP and IPC, as applicable, must pay (i) a fee equal to the applicable margin for Eurodollar rate advances on the average daily undrawn stated amount under such letters of credit, payable quarterly in arrears, (ii) a fronting fee at a per annum rate of 0.125 percent on the average daily undrawn stated amount under each letter of credit, payable quarterly in arrears and (iii) documentary and processing charges in accordance with the letter of credit issuer's standard schedule for such charges.

A ratings downgrade would result in an increase in the cost of borrowing and of maintaining letters of credit, but would not result in any default or acceleration of the debt under either the IDACORP Facility or the IPC Facility.

The events of default under both the IDACORP Facility and the IPC Facility include:

(i) nonpayment of principal when due and nonpayment of reimbursement obligations under letters of credit within one business day after becoming due and nonpayment of interest or other fees within five days after becoming due;
(ii) materially false representations or warranties made on behalf of the applicable company or any of its subsidiaries on the date as of which made;
(iii) breach of covenants, subject in some instances to grace periods;
(iv) voluntary and involuntary bankruptcy of the applicable company or any material subsidiary;
(v) the non-consensual appointment of a receiver or similar official for the applicable company or any of its material subsidiaries or any substantial portion (as defined in the applicable facility) of its property;
(vi) condemnation of all or any substantial portion of the property of the applicable company and its subsidiaries;
(vii) default in the payment of indebtedness in excess of $25 million or a default by the applicable company or any of its subsidiaries under any agreement under which such debt was created or governed which will cause or permit the acceleration of such debt or if any of such debt is declared to be due and payable prior to its stated maturity;
(viii) the applicable company or any of its subsidiaries not paying, or admitting in writing its inability to pay, its debts as they become due;
(ix) the applicable company or any of its subsidiaries failing to pay certain judgments;
(x) the acquisition by any person or two or more persons acting in concert of beneficial ownership (within the meaning of Rule 13d-3 of the Securities Exchange Act of 1934) of 20 percent or more of the outstanding shares of voting stock of the applicable company;
(xi) the failure of IDACORP to own free and clear of all liens, all of the outstanding shares of voting stock of IPC;
(xii) unfunded liabilities of all single employer plans under the Employee Retirement Income Security Act of 1974 exceeding $75 million; and
(xiii) the applicable company or any subsidiary being subject to any proceeding or investigation pertaining to the release of any toxic or hazardous waste or substance into the environment or any violation of any environmental law (as defined in the applicable facility) which could reasonably be expected to have a material adverse effect (as defined in the applicable facility).

A default or an acceleration of indebtedness of IDACORP or IPC in excess of $25 million, including indebtedness under the applicable facility, will result in a cross default under the other Facility.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or IPC or the appointment of a receiver, the obligations of the lenders to make loans under the facility and of the letter of credit issuer to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding 51 percent of the outstanding loans or 51 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and of the letter of credit issuer to issue letters of credit under the facility or declare the obligations to be due and payable. IDACORP and IPC will also be required to deposit into a collateral account an amount equal to the aggregate undrawn stated amount under all outstanding letters of credit and the aggregate unpaid reimbursement obligations thereunder.

If there is a ratings downgrade below investment grade (BBB- or higher by S&P and Baa3 or higher by Moody's), then IPC's authority for continuing borrowings under its regulatory approvals issued by the IPUC and the OPUC must be extended or renewed during the occurrence of the ratings downgrade. The Oregon statutes, however, permit the issuance or renewal of indebtedness maturing not more than one year after the date of such issue or renewal without approval of the OPUC. The IPUC order provides that IPC's authority will not terminate but will continue for a period of 364 days from any downgrade below investment grade provided that IPC notifies the IPUC promptly and files a supplemental application with the IPUC within 7 days requesting a supplemental order to continue its original authority to borrow under the order.

During 2008, bankruptcies and other significant financial difficulties impacted the ability of some banks to continue fulfilling their commitments under established credit facilities. These issues did not impact either the IDACORP or IPC credit facilities. While some consolidation occurred within the credit facility bank group, no banks limited or reduced their commitments under our 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, N.A., and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans were due on March 31, 2009 and could be prepaid but not reborrowed. IPC used 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.

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

The loans bear interest at either a floating rate or a Eurodollar rate. The floating rate is equal to (i) the highest of (a) the prime rate announced by JPMorgan Chase Bank on such day, (b) the sum of (1) the federal funds effective rate in effect on such day plus (2) 0.5 percent per annum and (c) an amount equal to (1) the LIBO Reference Rate on such day plus (2) 1 percent plus (ii) the applicable margin. The Eurodollar rate is (i) the rate published on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) for dollar deposits with a comparable maturity plus (ii) the applicable margin. The LIBO Reference Rate is the rate appearing on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) as the rate for United States dollar deposits for a one month interest period. The applicable margin is currently 2 percent for Eurodollar advances and 1 percent for floating rate advances, but may be increased or decreased based upon the ratings assigned to IPC's senior unsecured debt by Moody's and S&P.

The events of default under the Term Loan Credit Agreement are the same as those under the IPC Facility discussed above.

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

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

On April 3, 2008, IPC made a mandatory purchase of the pollution control bonds. IPC initiated this transaction in order to adjust the interest rate period of the pollution control bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of Ambac's credit ratings deterioration. IPC is the current holder of the bonds, but ultimately expects to remarket the bonds to investors.

Debt Covenants: The IDACORP Facility, the IPC Facility and the Term Loan Credit Agreement each contain a covenant requiring the company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At December 31, 2008, the leverage ratio for IDACORP and IPC was 52 and 54 percent, respectively. At December 31, 2008, IDACORP was in compliance with all other covenants of the IDACORP Facility and IPC was in compliance with all other covenants of the IPC Facility and the Term Loan Credit Agreement. The IDACORP Facility, the IPC Facility and the Term Loan Credit Agreement each contain additional covenants including:

(i) prohibitions against: investments and acquisitions by the applicable company or any subsidiary without the consent of the required lenders subject to exclusions for investments in cash equivalents or securities of the applicable company; investments by the applicable company and its subsidiaries in any business trust controlled, directly or indirectly, by the applicable company to the extent such business trust purchases securities of the applicable company; investments and acquisitions related to the energy business or other business of the applicable company and its subsidiaries not exceeding $750 million in the aggregate at any one time outstanding (provided that investments in non-energy related businesses do not exceed $150 million); and investments by the applicable company or a subsidiary in connection with a permitted receivables securitization (as defined in the facility);

(ii) prohibitions against the applicable company or any material subsidiary merging or consolidating with any other person or selling or disposing of all or substantially all of its property to another person without the consent of the required lenders, subject to exclusions for mergers into or dispositions to the applicable company or a wholly owned subsidiary and dispositions in connection with a permitted receivables securitization;

(iii) restrictions on the creation of certain liens by the applicable company or any material subsidiary subject to exceptions, including the lien of IPC's first mortgage indebtedness; and

(iv) prohibitions on any material subsidiary of the applicable company entering into any agreement restricting its ability to declare or pay dividends to the applicable company except pursuant to a permitted receivables securitization.

Credit Ratings

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

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

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

Capital Requirements

IPC is experiencing a cycle of heavy infrastructure investment needed to address continued customer growth, peak demand growth, and aging plant and equipment. IPC's aging hydroelectric and thermal facilities require continuing upgrades and component replacement. In addition, costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. IPC must also add to its transmission system and distribution facilities to provide new service and to maintain reliability. As a result, IPC expects to spend between $780 and $800 million for construction related activities from 2009 to 2011, excluding any amounts from our 2012 Baseload Resource RFP process.

The following table presents IPC's estimated cash requirements for construction, excluding AFUDC, for 2009 through 2011:

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

Major Projects:

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

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

Boardman-Hemingway Line: The Boardman-Hemingway Line is expected to relieve existing congestion by increasing transmission capacity and improving reliability. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. The initial project phase estimate of $50 million will be funded by IPC and includes the engineering, environmental review, permitting and rights of way. Cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table. Cost estimates for the project (including initial phase project estimate and construction costs of the line) are approximately $600 million. IPC expects to seek partners for up to 50 percent of the project when construction commences. The line has a target in-service date of June 2013. Construction costs are currently not included in IPC's 2009 to 2011 forecast. Please see further discussion in "REGULATORY MATTERS – Boardman-Hemingway Line."

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC's share of the initial phase of engineering, environmental review, permitting and rights of way is approximately $40 million and cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table.. Construction costs are currently not included in our 2009 to 2011 forecast. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires.

2012 Baseload Resource: IPC issued an RFP in 2008 for a resource to meet energy needs identified during its IRP process. IPC prepared a self-build proposal for a combined-cycle combustion turbine, which serves as a benchmark resource and is competing in the RFP evaluation process. Proposals were received in October 2008 and are currently being evaluated. This addition is expected to come online in 2012 to meet forecast deficits as described in the 2006 IRP and the 2008 IRP update. Transmission interconnection and network upgrade costs of approximately $22 million will be incurred by IPC under any scenario. IPC expects to request approval from the IPUC relating to the base load resource during the first quarter of 2009, with an IPUC decision expected later this year.

Other capital requirements: IDACORP's non-regulated capital expenditures are expected to be $15 million in 2009 and $5 million for 2010. These expenditures primarily relate to IFS's tax advantaged investments. Internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2009 through 2010. IDACORP and IPC expect to continue financing capital requirements with internally generated funds and externally financed capital.

Contractual Obligations

The following table presents IDACORP's and IPC's contractual cash obligations for the respective periods in which they are due:

		Payment Due by Period			
	Total	**2009**	**2010-2011**	**2012-2013**	**Thereafter**
		(millions of dollars)			
IPC:					
Long-term debt (a)	$ 1,261	$ 81	$ 122	$ 172	$ 886
Future interest payments (b)	1,137	70	121	105	841
Operating leases (c)	35	3	5	4	23
Uncertain tax positions	4	4	-	-	-
Purchase obligations:					
Cogeneration and small power production	1,772	74	172	192	1,334
Fuel supply agreements	227	66	54	17	90
Purchased power & transmission (d)	133	84	34	5	10
Other (e)	173	83	53	11	26
Total purchase obligations	4,742	465	561	506	3,210
Pension and postretirement plans (g)	220	7	92	80	41
Other long-term liabilities - IPC	3	3	-	-	-
Total IPC	4,965	475	653	586	3,251
Other:					
Long-term debt (a)(f)	33	30	3	-	-
Operating leases (f)	1	-	-	-	1
Total IDACORP	$ 4,999	$ 505	$ 656	$ 586	$ 3,252

(a) For additional information, see Note 4 to IDACORP's and IPC's Consolidated Financial Statements.

(b) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2008.

(c) Approximately $23 million of the obligations included in operating leases have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes.

(d) Approximately $11 million of the obligations included in purchased power and transmission have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes.

(e) Approximately $48 million of the amounts in other purchase obligations are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes.

(f) Amounts include the obligations of IDACORP's subsidiaries other than IPC, which is shown separately.

(g) IPC estimates pension contributions based on actuarial data. IPC cannot estimate contributions beyond 2013 at this time.

In accordance with the Pension Protection Act of 2006 (PPA), companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009, in order to avoid a scheduled series of required annual contributions. As of December 31, 2007, qualified pension liabilities were nearly fully funded; however, recent stock market performance has reduced the value of pension assets during 2008. IPC will need to make additional contributions to become fully funded over a period of seven years. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated minimum required contributions would be approximately $45 million in 2010 and $33 million in each of 2011, 2012, and 2013. These estimates reflect the initial PPA relief measures as passed by Congress, however, additional measures are being proposed that may impact immediate funding requirements.

Environmental Regulation Costs: IPC anticipates approximately $20 million in annual operating costs for environmental facilities during 2009. Hydroelectric facility expenses and thermal plant expenses account for the majority of the costs at approximately $14 million and $6 million, respectively. From 2010 through 2011, total environmental related operating costs are estimated to be approximately $57 million. Expenses related to the hydroelectric facilities are expected to be $43 million and thermal plant expenses are expected to total $14 million during this period. These amounts do not include costs related to possible changes in the environmental legislation and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions from coal-fired generation plants.

Off-Balance Sheet Arrangements
The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. The mining operations at the Bridger Coal Company are subject to these reclamation and closure requirements. IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2008. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying the reclamation costs and expects that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

REGULATORY MATTERS:

Idaho 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 have increased 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.

On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. The order authorized IPC to include in rates approximately $6.8 million of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest.

On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four principal areas of the order. Together, the four areas have a combined Idaho jurisdictional revenue requirement impact of approximately $8 million annually.

Two of the four areas involve reconciling the calculation of IPC's revenue requirement with the order. These items (approximately $7.2 million in annual revenues) relate to the annual amount of labor expense to be included in rates. IPC believes that some aspects of calculation of the revenue requirement with respect to these items were inconsistent with the language of the order.

The third area relates to a $3.3 million expense credit received in 2006 as a result of successful litigation with the FERC and other federal agencies (FERC Credit). In the order, the IPUC directed IPC to refund the FERC Credit to customers over a five year period, thereby reducing IPC's annual revenue requirement by approximately $0.7 million during such period. IPC believes that this was contrary to Idaho law. If IPC is unsuccessful in its challenge of the IPUC's ruling on the FERC Credit, it will recognize a loss for some or all of this amount.

The fourth area involves the use of purchasing cards (P-Cards), which IPC issues to a number of its employees to efficiently process high volume, low value purchases. In its order, the IPUC accepted the IPUC Staff's recommendation to remove approximately $0.9 million of P-Card expenses from IPC's revenue requirement because the IPUC Staff believed this amount was excessive. IPC believes that the IPUC's decision to deny recovery of $0.9 million of P-Card purchases was not supported by evidence in the record.

The IPUC has 28 days in which to decide whether to grant IPC's petition. If the petition is granted, then the matter must be reheard, or written briefs filed, within 13 weeks after the petition filing date, and the IPUC will then have 28 days to issue its order. Other parties may also file petitions or cross-petitions for reconsideration.

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 in base rates of 5.2 percent (approximately $32.1 million annually), effective March 1, 2008. The settlement did not specify an overall rate of return or a return on equity.

Forecast Test-Year Workshop: On March 12, 2008, IPC, the IPUC Staff, and other parties to the 2007 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 commonly accepted 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 and approved on January 30, 2009, as discussed above.

Danskin CT1 Power Plant Rate Case: On March 7, 2008, IPC filed an application with the IPUC requesting recovery of construction costs associated with the gas-fired Danskin CT1 plant located near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. IPC requested adding to rate base approximately $65 million attributable to the cost of constructing the generating facility and the related transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or approximately $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 related facilities, 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 at December 31 (in thousands of dollars):

	2008	2007
Idaho PCA current year:		
Deferral for the 2008-2009 rate year (1)	$ -	$ 85,732
Deferral for the 2009-2010 rate year	93,657	-
Idaho PCA true-up awaiting recovery:		
Authorized May 2007	-	6,591
Authorized May 2008	47,164	-
Oregon deferral:		
2001 costs	1,663	2,993
2006 costs	1,215	2,107
2008 PCAM	5,400	-
Total deferral	$ 149,099	$ 97,423

(1) 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.

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

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

PCA Workshops: In its May 30, 2008 order approving IPC's 2008-2009 PCA, the IPUC also directed IPC to set up workshops with the IPUC Staff and several of IPC's largest customers (together, the Parties) to address PCA-related issues not resolved in the PCA filing. Consensus was reached on all items except allocation of the PCA among customer classes, which will be re-examined following the conclusion of the 2008 general rate case. A settlement stipulation was filed with the IPUC and approved on January 9, 2009.

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

- PCA Sharing Methodology of 95/5 - the PCA sharing methodology allocates the costs and benefits of net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.
- Load Growth Adjustment Rate (LGAR) of $26.52 per MWh - the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on a formula that, based on filed data from the 2008 general rate case, would have produced an LGAR of $28.14 per MWh. While not quantified in the 2008 general rate case order, IPC believes that the LGAR methodology approved in the stipulation results in a LGAR of $26.52 per MWh. In its request for reconsideration of the IPUC's general rate case order, IPC also requested that the IPUC confirm this amount is correct.
- Use of IPC's Operation Plan Power Supply Cost Forecast - the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year's "true-up" rate. This new methodology will be used to prepare IPC's next PCA filing in April 2009.
- Inclusion of Third-Party Transmission Expense - transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these types of costs from levels included in base rates is now reflected in PCA computations.
- Adjusted Distribution of Base Net Power Supply Costs - base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

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 was $30.7 million above those base rates. This $77.5 million increase was net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates became effective June 1, 2007.

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

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

anticipates realizing approximately 14,500 excess SO_2 emission allowances annually for 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" (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon's jurisdictional share of excess power supply costs of $5.7 million. A hearing is set for April 16, 2009.

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. A settlement agreement was reached with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million, which 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 of gross Oregon revenue 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 Cost Recovery Mechanism: 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 stipulation and OPUC order established a power cost recovery mechanism with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

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

On October 29, 2007, IPC filed the October Update portion of its 2008 APCU 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 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.69 percent, increase in Oregon revenues.

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

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

On October 6, 2008, the OPUC provided an order clarifying that the PCAM is a deferral under the Oregon statute. IPC expects that deferrals under the PCAM component will be subject to the six percent limitation on annual amortization discussed above. IPC had $5.4 million deferred under the PCAM as of December 31, 2008.

IPC expects to make its first PCAM filing on February 27, 2009.

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 deferred $2.5 million of FCA net under-recovery of fixed costs during 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.

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

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. IPC and the IPUC Staff agreed to continue to exchange information and discuss settlement with regard to the remaining $14.7 million, and IPC will file a pleading with the IPUC by April 1, 2009 seeking a prudency determination on the remainder. If resolution with respect to the remaining $14.7 million cannot be reached in the proceedings stemming from the April 1, filing, IPC and the IPUC Staff will recommend a procedure to allow the IPUC to make such a determination.

Depreciation Filings

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

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC's Idaho jurisdiction be authorized for IPC's Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million. This matter is pending and no order has been issued. This request was filed in conjunction with the October 3, 2008, application discussed below in "Advanced Metering Infrastructure (AMI)."

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

Advanced Metering Infrastructure (AMI)

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

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

Idaho: On August 5, 2008, IPC filed an application with the IPUC requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC approved IPC's application on February 12, 2009. In its application, IPC estimated the three year investment in AMI to be $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.

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

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 2008, $7.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

Federal Regulatory Matters

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

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

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

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

A mediation process within the Ninth Circuit Court has been initiated in an attempt to settle Residential Exchange Program issues. The appeals proceedings are being held in abeyance during the mediation process. A meeting was held on February 12, 2009 between the BPA, IOUs and consumer-owned utilities to determine if there is common ground for an overall settlement of the Residential Exchange Program. Two additional meetings are scheduled for March 2009. If mediation is unsuccessful, briefing schedules will be set.

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

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

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

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

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

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

On August 28, 2008, IPC filed its informational filing with the FERC that contains the annual update of the formula rate based on the 2007 test year. The new rate included in the filing is $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 depend on transmission volume sold, which can be highly variable. New rates were effective October 1, 2008. IPC has adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009 order.

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 transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. The 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. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC's share of the initial phase of engineering, environmental review, permitting and rights-of-way is approximately $40 million. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way, acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of the project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires.

Boardman-Hemingway 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. The Boardman-Hemingway Line is expected to relieve existing congestion by increasing transmission capacity and improving reliability. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. The initial project phase estimate of $50 million will be funded by IPC and includes the engineering, environmental review, permitting and rights-of-way. Cost estimates for the project (including initial phase project estimate and construction costs of the line) are approximately $600 million. IPC expects to seek partners for up to 50 percent of the project when construction commences. The line has a target in-service date of June 2013. The existing transmission station at the Boardman power plant in Oregon will serve as the northwest terminal of the project. The Idaho terminal is the Hemingway substation. 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 Comprehensive Progress Report has been submitted to the WECC for review as part of the ratings process. On August 28, 2008, IPC filed a notice of intent (NOI) with the Oregon Department of Energy to apply for a site certificate for the proposed line. On October 3, 2008, IPC filed a project proposal with the Northern Tier Transmission Group Cost Allocation Committee requesting approval of the allocation of costs and benefits for the project. IPC does not expect any recommendation or approval by the NTTG until the second half of 2009. Other planning and project management activities are underway.

On October 22, 2008, IPC and Portland General Electric (PGE) signed a memorandum of understanding (MOU) as the basis for cooperation on the Boardman-Hemingway Line and PGE's proposed Southern Crossing 500kV project. The MOU provides the two utilities an opportunity to integrate a portion of the proposed transmission lines if both projects move forward.

Hemingway Station: Construction of a new 500-kV station named Hemingway is expected to address growth, capacity and operating constraints. The station was originally part of the Gateway West Project but the timing of this addition was accelerated to 2010 to help meet forecast deficits and improve reliability. Cost estimates for the project, including rights-of-way, permitting and substation interconnections, are approximately $52 million.

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

Public Utility Regulatory Policies Act of 1978

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

Ongoing social and political pressure to increase the use of renewable energy is continuing to fuel expansion of renewable energy incentive programs at both the state and federal level. In addition, it is expected that in early

2009, the Published Avoided Costs will be increased by both the IPUC and the OPUC, which will result in the continuation of a favorable climate for PURPA project development and may require IPC to enter into additional PURPA agreements. The requirement to enter into additional PURPA agreements may result in IPC acquiring energy at above wholesale market prices, thus increasing costs to its customers. It is highly likely that the requirement to enter into additional PURPA agreements will add to IPC's surplus during certain times of the year, which could also increase costs to IPC's customers.

As of December 31, 2008, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Seventy-nine of these facilities, with a combined nameplate capacity of 267 MW, were on-line at the end of 2008; the other 13 facilities, with a combined nameplate capacity of 190 MW, are projected to come on-line in 2009 and 2010. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2008, IPC purchased 756,014 MWh from these projects at a cost of $45.9 million, resulting in a blended price of 6.1 cents per kilowatt hour.

Integrated Resource Plan
IPC's integrated resource planning process forecasts IPC's load and resource situation for the next twenty years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. The IRP is typically updated every two years, however with its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other Idaho utilities. To comply with this request IPC provided an update on the status of the IRP to both the IPUC and OPUC in June 2008. An IRP Addendum was also filed with the OPUC in February 2009, which specifically addressed the need for the Boardman to Hemingway Transmission Project. IPC is currently preparing the 2009 IRP, which is expected to be completed in June 2009.

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

Peaking Resource: The construction of a new simple cycle combustion turbine resource at the Danskin plant near Mountain Home, Idaho was completed in the first quarter of 2008 and the new generating unit was available during IPC's 2008 summer peak load period. The combustion turbine provides approximately 166 MW of capacity during the summer and up to 200 MW in the winter.

Geothermal RFPs: An RFP for geothermal-powered generation was released in June 2006. IPC identified U.S. Geothermal, Inc. as the successful bidder in March 2007 based on a proposal to supply 45.5 MW of geothermal energy. In January 2008, the IPUC approved a power purchase agreement for 13 MW (nameplate generation) from the Raft River Geothermal Power Plant Unit #1 located in southern Idaho. This project began operating in October 2007. Contract negotiations for the remaining 32.5 MW continued throughout 2008, however uncertainty in the development schedule and final cost made it impossible for the parties to agree on contract terms and conditions and the negotiation process came to a close in late 2008.

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

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

2012 Baseload Resource RFP: In light of a decision to no longer pursue a conventional coal resource in 2013 as identified in the 2006 IRP, IPC issued an RFP in 2008 for 300 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. IPC prepared a self-build proposal for a combined-cycle combustion turbine, which serves as a benchmark resource and is competing in the RFP evaluation process. Proposals were received in October 2008 and are currently being evaluated. This addition is expected to come online in 2012 to meet forecast deficits as described in the 2006 IRP and the 2008 IRP update. IPC expects to request approval from the IPUC relating to the base load resource during the first quarter of 2009, with an IPUC decision expected later this year.

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

Relicensing of Hydroelectric Projects

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

The relicensing costs are recorded and held in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $105 million and $4 million for HCC and Swan Falls, respectively, were included in construction work in progress at December 31, 2008.

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

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

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

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

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

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contained project-specific information and the results of environmental studies designed to determine project effects. Comments were received from the agencies and one Native American tribe and on February 19, 2008, a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. On June 26, 2008, IPC filed a final license application with the FERC. On July 9, 2008, in conformance with applicable regulations, the FERC issued a Notice of Application Tendered for Filing with the Commission, Soliciting Additional Study Requests, and Establishing Procedural Schedule for Relicensing and a Deadline for Submission of Final Amendments. Pursuant to that notice, state and federal resource agencies, Native American tribes or other interested parties were to file additional study requests with the FERC by August 26, 2008. Additional study requests were filed by the Shoshone-Bannock Tribes and the USFWS. IPC filed responses to these requests on September 26 and 29, 2008, respectively. The FERC is still considering the requests from the Shoshone-Bannock Tribes and the USFWS. On October 7, 2008, IPC received a request from the FERC to provide clarification and additional information on the Swan Falls license application. IPC will submit responses to this request by April 7, 2009. The FERC notified IPC on December 4, 2008, that the final license application had been officially accepted for filing.

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

FERC Market-Based Rate Authority

IPC has FERC-approved market-based rate authority, which permits IPC to sell electric energy at market-based rates rather than being limited to cost-based rates. Every three years, the FERC requires IPC to submit a "triennial filing" providing for a review of the conditions under which this market-based rate authority was granted to ensure that the rates charged thereunder are just and reasonable. On March 21, 2008, IPC submitted a filing to FERC showing that IPC continued to meet FERC's market-based rate tests. On June 24, 2008, FERC accepted IPC's filing, which allowed IPC to continue to maintain market-based rate authority. IPC's next market-based rates triennial filing is due on June 30, 2010.

LEGAL AND ENVIRONMENTAL ISSUES:

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

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

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

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

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, and required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds.

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

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

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 and severed the three cases from the remainder of the consolidated cases. On December 2, 2008, the Ninth Circuit filed an order dismissing the Port of Seattle petitions for review. That dismissal order is now final.

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming ("gaming") or other forms of proscribed market behavior in concert with another party ("partnership") in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the "partnership" show cause proceeding against IPC. The order dismissing IPC from the "partnership" proceedings was not the subject of rehearing requests and is now final. Later in 2004, the FERC approved a settlement of the "gaming" proceeding without finding of wrongdoing by IPC. The Port of Seattle was the only party to appeal the FERC orders approving the "gaming" settlement. On December 8, 2008, the Ninth Circuit issued an order dismissing that appeal. The dismissal order is now final.

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

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

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 that 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. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court's decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court.

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

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

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

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 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." On November 19, 2008, the plaintiffs filed a motion to refer the pending motions for summary judgment to magistrate judge for recommendation decision. On December 2, 2008, PacifiCorp filed an opposition to plaintiff's motion. The court has yet to rule on either motion filed by the plaintiffs. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit – Boardman: On September 30, 2008, Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired power plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE's construction and operation of the plant. The complaint seeks a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, injunctive relief requiring PGE to remediate alleged environmental damage and ongoing impacts, civil penalties of up to $32,500 per day per violation and the plaintiffs' cost of litigation, including reasonable attorney fees. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent and is the operator of the plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs' response to the motion is due March 6, 2009, and PGE's reply is due April 3, 2009. IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

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

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

Other Legal Proceedings: From time to time IDACORP and IPC are parties to legal claims, actions and complaints in addition to those discussed above and in Note 7 to IDACORP's and IPC's Consolidated Financial Statements. Although they will vigorously defend against them, they are unable to predict with certainty whether or not they will ultimately be successful. However, based on the companies' evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IDACORP's or IPC's consolidated financial positions, results of operations or cash flows.

Environmental Issues

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

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

One such action relates to the Milner hydroelectric project which is owned by the North Side Canal Company (NSCC) and the Twin Falls Canal Company (TFCC). In 1990, IPC entered into a contract with the owners relating to the construction and operation of a power plant at Milner Dam. To facilitate the rehabilitation of the Milner dam, IPC and NSCC/TFCC jointly filed for, and were issued, a FERC license for a hydroelectric project at the dam. IPC constructed and operates the project, and participated in the financing of the dam rehabilitation. NSCC and TFCC filed an application for a water right for the project and were issued an approved water right permit by the IDWR in 1993. The permit contained a condition subordinating the water right to all "consumptive beneficial uses of water, other than hydropower and groundwater recharge." Since the issuance of the permit, the NSCC and TFCC have delivered water to and IPC has operated the Milner project under the FERC license. On October 20, 2008, the IDWR issued a water right license for the project that changed the subordination condition in the permit by deleting the reference to groundwater recharge, thereby subordinating the water right to groundwater recharge. On November 4, 2008, NSCC and TFCC filed a petition for hearing with IDWR contesting the change in the subordination condition. The IDWR has appointed a hearing officer and several parties have petitioned to intervene in the case. A hearing date has not been set on the petition. IPC is monitoring but is unable to predict the outcome of the administrative action.

IPC, 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. In December 2008, the CAMP Advisory Committee submitted a draft CAMP to the IWRB for consideration. The IWRB took public comments on the draft CAMP and by resolution dated January 29, 2009 adopted the CAMP and submitted it to the Idaho Legislature for approval. IPC submitted comments to the IWRB supporting the CAMP. If the Legislature approves and funds implementation of the CAMP, IPC will serve on the CAMP Implementation Committee and assist with the development and implementation of CAMP projects that provide benefits to Snake River water quality and flows through the maintenance and enhancement of aquifer and spring levels.

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 State of Idaho and IPC filed summary judgment motions on the recharge issue and completed briefing on the issue. The court held a hearing on December 4, 2008 on the summary judgment motions. After argument, the court took the matter under advisement. 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 the CAMP to protect and enhance water levels in the ESPA and the connected Snake River. While many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan and believe that groundwater recharge is a very high-priority issue, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrogeology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards. IPC is currently engaged in a three to five year pilot study, in cooperation with IDWR and various water users, to determine the temporal and spatial impacts and/or benefits of recharging a maximum of 30,000 acre-feet of water downstream of American Falls Reservoir on the ESPA and the Snake River.

IPC has also filed an action 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 United States 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 United States has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. on October 15, 2007 to recover damages from the United States for the lost generation resulting from the reduced flows. On September 30, 2008, IPC filed an amended complaint in which IPC seeks, in addition to damages for breach of the 1923 contract, a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On October 2, 2008, the court set a discovery schedule requiring that discovery be completed and pre-trial motions filed by October 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

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 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 and climate change 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). Installation of low nitrogen oxide (NOx) burner technology and over-fired upgrades has been completed at the Valmy plant. Installation of low NOx burners on all four coal-fired units at the Jim Bridger plant is in progress. Sulfur dioxide (SO_2) scrubber upgrade projects also have started on unit four at the Jim Bridger plant and scrubber upgrade projects on the other three units at the plant will occur over the next three years. Mercury continuous emission monitoring systems (mercury CEMS) have been installed on all of the coal-fired units at the Jim Bridger, Boardman and Valmy plants and tests to confirm the accuracy of the data being collected are currently underway.

National Ambient Air Quality Standards: In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). Regulations promulgated by the EPA to implement these NAAQS have been challenged and portions have been remanded back to the EPA for reconsideration. The EPA and state efforts to implement the NAAQS adopted in 1997 are ongoing. For example, on May 8, 2008, the EPA issued a final rule implementing the NSR program for emissions of 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. All of the counties in Idaho, Oregon, Nevada and Wyoming where IPC's power plants operate currently are designated as meeting attainment with 8-hour ozone and PM2.5 standards adopted by the EPA in 1997.

In December 2006, the EPA revised the NAAQS for PM2.5. This new standard has been challenged by a number of groups in the U.S. Court of Appeals for the D.C. Circuit. On December 22, 2008, the EPA designated areas as attainment, nonattainment and unclassifiable for the revised PM2.5 NAAQS. All of the counties in Idaho, Nevada, Oregon and Wyoming where IPC's power plants operate were designated as meeting attainment with the revised PM2.5 NAAQS. The impact of the new standard will not be known until the judicial appeals are completed and the associated regulatory programs are promulgated and implemented.

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 regulation. The impact of the revised 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. The EPA is expected to make final air quality designations by March 2010.

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. The EPA and an industry trade association subsequently filed requests with the U.S. Supreme Court to review the D.C. Circuit's decision. On February 6, 2009, the EPA filed a motion with the Court to withdraw its request and on February 23, 2009, the Court denied the industry trade association's request. It is possible that the decision to remand the CAMR back to the EPA for reconsideration could result in the EPA developing maximum achievable control technology standards for mercury emissions from coal-fired power plants. It also is possible that the court's decision could result in changes to the mercury reductions required by the states in which IPC has partial ownership interests in coal-fired power plants. In 2008, the State of Oregon adopted a mercury rule requiring Boardman to reduce mercury emissions by 90 percent or meet an emission rate of 0.6 lbs/trillion BTU by July 2012. The state is now considering allowing up to a two year extension. IPC continues to monitor Wyoming and Nevada actions on mercury emissions. IPC is unable to predict at this time what actions the EPA or the other states may take in response to the court's decision or any resulting impacts to IPC.

Clean Air Interstate Rule (CAIR): The CAIR, issued by the EPA on March 10, 2005, establishes a permanent cap on emissions of NOx and SO_2 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. On December 23, 2008, the U.S. Court of Appeals for the D.C. Circuit issued an order reinstating the CAIR for a temporary period of time until the EPA can address the legal defects identified in the court's July 11, 2008 decision. While reinstating the CAIR will temporarily allow the CAIR to remain in effect, the full 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.

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

PacifiCorp submitted the RH BART application for the Jim Bridger plant in January 2007. The WDEQ is still evaluating the application and will request public comment. If there are no appeals to the application, the WDEQ will prepare a State Implementation Plan (SIP) to present to the Wyoming Environmental Quality Council for approval and submittal to the EPA. The plant is already in the process of installing low NOx burners and scrubber upgrades that are proposed in the application. Over the next four years, IPC's share of these upgrade expenditures are currently estimated at $23.9 million, with a total upgrade expenditures estimated at $34.3 million. IPC and Pacificorp have been meeting with the WDEQ to discuss the potential for additional RH BART and reasonable progress requirements for the Jim Bridger plant. It is possible that additional capital expenditures would be required to satisfy these additional requirements, however, IPC is not able to quantify these expenditures at this time.

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

Greenhouse Gases: IPC continues to monitor and evaluate national, regional, or state greenhouse gas (GHG) proposals and programs as well as judicial decisions that would affect electric utilities. At the federal level, numerous GHG bills were introduced in the U.S. Senate and House of Representatives during 2008, including the Climate Security Act of 2008 (S. 3036), which was debated on the Senate floor in June 2008 but not voted on. The new administration has requested the development of new federal proposals by Congress and the EPA that could lead to the adoption of a mandatory program to reduce GHG emissions through, for example, an economy-wide cap-and-trade program, a carbon tax or a combination of both. Debate continues on the direction, scope and timing of U.S. policy on the regulation of GHG emissions.

The states of Arizona, California, Montana, New Mexico, Oregon, Utah and Washington, along with the provinces of British Columbia, Manitoba, Ontario and Quebec, Canada, have formed the Western Regional Climate Action Initiative (WCI). On August 22, 2007, the WCI partners released their regional goal to collectively reduce GHGs 15 percent below 2005 levels by 2020. The WCI partners have agreed to design a regional market-based multi-sector mechanism to help achieve the goal. On September 23, 2008, the WCI issued its design recommendations to reduce GHG emissions from the electricity generating industry. The recommendations by the WCI include a cap-and-trade program for the electricity generating industry which would apply to in-state electricity generators and the first jurisdictional deliverer of electricity into a WCI partner state. The states of Idaho, Nevada and Wyoming have not joined the WCI. It is possible that these states in which IPC owns fossil fuel-fired electricity generation facilities or sells electricity could join the WCI in the future.

Oregon passed the Global Warming Integration Act in June 2007, which among other things, established the Oregon Global Warming Commission and state-wide GHG emission reduction goals. On May 3, 2007, Washington enacted legislation creating GHG emission reduction and clean energy goals. Emission performance standards affecting electric utility contracts and power plant projects are included. On September 27, 2006, California's governor signed into law the Global Warming Solutions Act of 2006 (AB32), which established GHG reduction goals and a framework for achieving these goals. On December 11, 2008, the California Air Resources Board (CARB) approved a scoping plan that provides a framework for implementing a cap-and-trade program for the electricity generating sector pursuant to AB 32. The scoping plan subjects the electricity generating sector, including electricity imports from out-of-state generation, to an emissions cap beginning in 2012. Based on the requirements of AB32, regulations to implement that cap-and-trade program need to be developed by January 1, 2011. Other regional and state GHG initiatives appear likely, although the states of Idaho, Nevada, and Wyoming have not adopted GHG legislation.

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 (CO_2) emissions from motor vehicles under the Clean Air Act. The Court held that, with respect to mobile sources, the EPA has authority under the Clean Air Act to regulate CO_2 as a pollutant and that the EPA has a duty to determine whether CO_2 emissions contribute to climate change or provide some reasonable explanation why it will not exercise its authority. 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 CO_2 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 both mobile and stationary sources under the Clean Air Act. On June 26, 2008, the U.S. Court of Appeals for the D.C. Circuit denied the request of Attorneys General from 17 states to require the EPA to rule within 60 days on whether CO_2 is a danger to public health or welfare and, therefore, subject to regulation under the Clean Air Act. 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. Environmental groups contend that CO_2 is subject to regulation under the Clean Air Act and that preconstruction permitting requirements must be applied to CO_2 emissions prior to the construction of new power plants or the modification of existing power plants. Specifically, in *In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, the Sierra Club argued to the EPA's Environmental Appeals Board (EAB) that Best Available Control Technology (BACT) is required to reduce CO_2 emissions from coal-fired power plants prior to the issuance of a preconstruction permit under the Clean Air Act's NSR program. On November 13, 2008 the EAB remanded the appeal back to EPA Region 8 to reconsider whether a CO_2 BACT limit should be imposed in the permit. EPA Region 8 has not yet responded to the EAB's remand. On December 18, 2008, however, the EPA Administrator issued an interpretive memorandum stating that CO_2 is not a regulated pollutant under the EPA's NSR program. Environmental groups filed a request with the EPA to reconsider the conclusions reached in the December 18, 2008 interpretive memorandum, which was granted by the EPA on February 17, 2009.

Information about IDACORP's CO_2 emissions is included in the report *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States – 2008.* This report was released by the Ceres Investor Coalition, the Natural Resources Defense Council, the Public Service Enterprise Group Inc. and PG&E Corporation in May 2008. The report lists IDACORP's 2006 CO_2 emissions at 937.9 lbs/MWh, as compared to the reported average for the 100 largest power producers of 1,343.6 lbs/MWh. IPC's CO_2 emissions on an lbs/MWh basis fluctuate with the amount of hydroelectric generation.

In 2008, IPC's CO_2 emissions from IPC's electric power generation facilities were approximately 7.9 million tons, or 1,097 lbs/MWh (adjusted to reflect IPC's partial ownership in the Jim Bridger, Boardman and Valmy facilities). The EPA is developing a mandatory GHG reporting rule that would require reporting of GHG emissions from large sources. The emission information collected would be used by the EPA to develop comprehensive and accurate data relevant to future climate policy decisions, including potential future regulation of GHG emissions. The final reporting rule is scheduled to be finalized by June 2009.

IPC will continue to monitor and evaluate federal, regional or state GHG programs and proposals and judicial and administrative decisions that would affect electric utilities as these programs could increase IPC's capital expenditures and operating costs and reduce earnings and cash flows. At this time, however, IPC is unable to estimate the costs of compliance with potential national, regional or state GHG emissions reduction legislation, regulations or initiatives because these programs and proposals are in the early stages of development and any final program or programs, if adopted, could vary from current proposals. 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. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal as an economical energy source for new and existing electric generation facilities because new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. 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.

As part of IPC's resource planning protocol, the IRP process considers potential GHG emissions regulation and other environmental factors when evaluating potential portfolios. The 2006 IRP included a risk analysis of the costs associated with the regulation of CO_2 emissions by analyzing low, expected and high cases of $0, $14 and

$50 respectively, per ton of CO_2 emitted. Environmental impacts have been and will continue to be integral components of IPC's resource decisions.

Due to escalating construction costs, potential permitting issues, and continued uncertainty surrounding future GHG laws and regulations, IPC has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a combined-cycle natural gas-fired resource located closer to its load center in southern Idaho. Also, IPC added 101 MW of contracted wind generation in December 2007 bringing IPC's total to 121 MW. Another 69 MW of contracted wind generation is under construction. IPC has added 13 MW of geothermal generation. Additional wind and geothermal generation is anticipated through CSPP and RFP-driven contracts.

Climate Change: IPC's substantial hydroelectric generation resources neither burn nor consume fossil fuels to produce electric energy to meet the needs of its customers. Given the debate concerning climate change, consensus is growing that broad steps should be taken in all sectors of the nation's economy to carefully consider ways of limiting and/or reducing greenhouse gas emissions and mitigating climate change impacts while still providing necessary services in a cost-effective manner. IPC intends to continue to add renewable resources to its resource portfolio and will continue to monitor the climate change debate, current climate change research, and recently enacted as well as proposed legislation to identify the potential impacts of global climate change on all aspects of its business. Long-term climate change could significantly affect IPC's business in a variety of ways, including but not limited to, the following: (a) changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation and extreme weather events could increase service interruptions, outages, and maintenance costs; and (b) legislative and/or regulatory developments related to climate change could affect plans and operations in various ways including placing restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general. IPC cannot, however, quantify the potential impact of climate change on its business at this time.

Renewable Portfolio Standards: IPC's operations in Oregon will be required to comply with a ten percent renewable energy portfolio standard beginning in 2025. The new federal administration has called on Congress to adopt a federal renewable energy portfolio standard and it is possible that Idaho and other states in which IPC operates or sells power could adopt renewable energy portfolio standards in the future. New state or federal renewable energy portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.

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

Endangered Species

In December 1992, the USFWS listed several species of fish and five species of snails living within IPC's operating area as threatened or endangered species under the Endangered Species Act. IPC continues to review and analyze the effect such designation has on its operations and is cooperating with governmental agencies to resolve issues related to these species.

On September 5, 2007, the species of snail that had been listed as the "Idaho Springsnail" was delisted by the USFWS. The delisting decision was based on recent studies that indicated the species was synonymous with another common species. On December 21, 2006, IPC and the Governor of Idaho submitted a petition to the USFWS to de-list the threatened Bliss Rapids snail. The petition was supported with data collected by IPC over the past 14 years. The snail, which lives throughout the middle Snake River, springs, and tributaries between Niagara Springs and King Hill, was listed as threatened under the Endangered Species Act in 1992. As of December 31, 2008, no decision on the delisting petition had been issued by the USFWS.

Pursuant to FERC License 1971, IPC owns and finances the operation of anadromous fish hatcheries and related facilities to mitigate the effects of its hydroelectric dams on fish populations. In connection with its fish facilities, IPC sponsors ongoing programs for the control of fish disease, improvement of fish production, and evaluation of hatchery performance. IPC's anadromous fish facilities at Hells Canyon, Oxbow, Rapid River, Pahsimeroi and Niagara Springs continue to be operated by the Idaho Department of Fish and Game. At December 31, 2008, the investment in these facilities was $24 million and the annual cost of operation was $4 million.

OTHER MATTERS:

Southwest Intertie Project (SWIP)

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

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 FAS 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 FAS 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations. On October 10, 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* which clarifies the application of SFAS 157, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements had not been issued. The adoption of SFAS 157 and its related pronouncements did not have a material effect on IDACORP's or IPC's consolidated 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 consolidated 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 December 31, 2008.

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

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

Inflation
IDACORP and IPC believe that inflation has caused and may continue to cause increases in certain operating expenses and the replacement of assets at higher costs. Inflation affects the cost of labor, products and services required for operations and maintenance and capital expenditures. While inflation has not had a significant impact on IDACORP's or IPC's operations, increases in utility expenses due to inflation could have an adverse effect on earnings because of the need to obtain regulatory approval to recover such increased expenses.

ITEM 7A. 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 December 31, 2008.

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

Variable Rate Debt: As of December 31, 2008, IDACORP and IPC had $337 million and $302 million, respectively, in net floating rate debt. Assuming no change in financial structure for either company, if variable interest rates were one percentage point higher than the rates in effect on December 31, 2008, interest rate expense would increase and pre-tax earnings would decrease by approximately $3.4 million for IDACORP and $3.0 million for IPC.

Fixed Rate Debt: As of December 31, 2008, IDACORP and IPC had outstanding fixed rate debt of $1,083 million and $1,075 million, respectively, and the fair market value of this debt was $1,005 million and $997 million, respectively. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $82 million for IDACORP and IPC if interest rates were to decline by one percentage point from their December 31, 2008 levels.

Commodity Price Risk
Utility: IPC's exposure to changes in commodity price is related to its ongoing utility operations producing electricity to meet the demand of its retail electric customers. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and price of production. The objective of IPC's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

IPC's exposure to commodity price risk is largely offset by the previously discussed PCA mechanism. IPC has adopted a risk management program designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. This program has been reviewed and accepted by the IPUC. IPC's Energy Risk Management Policy (the Policy) describes a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected IPC officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the IPC Board of Directors, and to the CAG.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The Power Supply business unit produces and evaluates projections of the operating plan and orders risk mitigating actions dictated by the limits stated in the Policy. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. IPC representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the Board of Directors for approval. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources.

Credit Risk

Utility: IPC is subject to credit risk based on its activity with market counterparties. IPC is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy or complete financial settlement for market activities. IPC mitigates this exposure by actively establishing credit limits, measuring, monitoring, reporting, using appropriate contractual arrangements and transferring of credit risk through the use of financial guarantees, cash or letters of credit. A current list of acceptable counterparties and credit limits is maintained.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. IPC maintains margin agreements that allow performance assurance collateral to be requested and/or posted with certain counterparties. As of December 31, 2008, IPC had posted approximately $0.9 million of assurance collateral. Should IPC experience a reduction in its credit rating on IPC's unsecured debt to below investment grade, IPC could be subject to additional requests by its wholesale counterparties to post additional performance assurance collateral. Based upon IPC's current energy and fuel portfolio and current market conditions as of December 31, 2008, the approximate amount of additional collateral that could be requested upon a downgrade is approximately $28 million. IPC actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Credit risk for IPC's retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC. IPC is obligated to provide service to all electric customers within its service area. IPC records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. IPC will continue to monitor the impact of the current economic conditions on nonpayment from customers and will make any necessary adjustments to its provision for uncollectible accounts.

Idaho administrative code for utility customer relations rules prohibits IPC from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly or infirm persons. IPC's provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC regulations.

Equity Price Risk

IDACORP and IPC are exposed to price fluctuations in equity markets, primarily through their pension plan assets, a mine reclamation trust fund owned by an equity-method investment of IPC and other equity investments at IPC. As a result of recent market declines, the fair value of the pension plan's assets has decreased resulting in an increase in future amounts required to be contributed to the plan. Based on current laws, IPC estimates that the minimum contribution to IPC's pension plan for 2009, which may be made as late as 2010, will be $24 million.

A hypothetical ten percent decrease in equity prices would result in an approximate $1.4 million decrease in the fair value of financial instruments that are classified as available-for-sale securities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2008	**2007**	**2006**
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 784,311	$ 668,303	$ 636,375
Off-system sales	121,429	154,948	260,717
Other revenues	50,336	52,150	23,381
Total electric utility revenues	956,076	875,401	920,473
Other	4,338	3,993	5,818
Total operating revenues	960,414	879,394	926,291
Operating Expenses:			
Electric utility:			
Purchased power	231,137	289,484	283,440
Fuel expense	149,403	134,322	115,018
Power cost adjustment	(47,413)	(121,131)	(29,526)
Other operations and maintenance	294,029	286,510	264,810
Energy efficiency programs	18,880	13,487	-
Gain on sale of emission allowances	(504)	(2,754)	(8,257)
Depreciation	102,086	103,072	99,824
Taxes other than income taxes	19,083	17,634	18,661
Total electric utility expenses	766,701	720,624	743,970
Other expense	3,046	6,692	12,617
Total operating expenses	769,747	727,316	756,587
Operating Income (Loss):			
Electric utility	189,375	154,777	176,503
Other	1,292	(2,699)	(6,799)
Total operating income	190,667	152,078	169,704
Other Income	11,861	20,524	18,195
Losses of Unconsolidated Equity-Method Investments	(3,997)	(4,824)	(2,913)
Other Expense	7,861	8,434	8,559
Interest Expense:			
Interest on long-term debt	67,251	59,961	56,402
Other interest	5,805	3,380	4,573
Total interest expense	73,056	63,341	60,975
Income Before Income Taxes	117,614	96,003	115,452
Income Tax Expense	19,200	13,731	15,377
Income from Continuing Operations	98,414	82,272	100,075
Income from Discontinued Operations, net of tax	-	67	7,328
Net Income	$ 98,414	$ 82,339	$ 107,403
Weighted Average Common Shares Outstanding - Basic (000's)	45,147	44,151	42,713
Weighted Average Common Shares Outstanding - Diluted (000's)	45,332	44,291	42,874
Earnings Per Share of Common Stock:			
Earnings per share from Continuing Operations-Basic	$ 2.18	$ 1.86	$ 2.34
Earnings per share from Discontinued Operations-Basic	-	-	0.17
Earnings Per Share of Common Stock-Basic	$ 2.18	$ 1.86	$ 2.51
Earnings per share from Continuing Operations-Diluted	$ 2.17	$ 1.86	$ 2.34
Earnings per share from Discontinued Operations-Diluted	-	-	0.17
Earnings Per Share of Common Stock-Diluted	$ 2.17	$ 1.86	$ 2.51
Dividends Paid Per Share of Common Stock	$ 1.20	$ 1.20	$ 1.20

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 8,828	$ 7,966
Receivables:		
Customer	64,733	69,160
Allowance for uncollectible accounts	(1,724)	(7,505)
Employee notes	179	2,128
Other	10,260	10,957
Taxes receivable	18,111	-
Accrued unbilled revenues	43,934	36,314
Materials and supplies (at average cost)	50,121	43,270
Fuel stock (at average cost)	16,852	17,268
Prepayments	10,059	9,371
Deferred income taxes	37,550	25,672
Refundable income tax deposit	-	46,083
Other	7,381	6,023
Total current assets	266,284	266,707
Investments	198,552	201,085
Property, Plant and Equipment:		
Utility plant in service	4,030,134	3,796,339
Accumulated provision for depreciation	(1,505,120)	(1,468,832)
Utility plant in service - net	2,525,014	2,327,507
Construction work in progress	207,662	257,590
Utility plant held for future use	6,318	3,366
Other property, net of accumulated depreciation	19,171	28,089
Property, plant and equipment - net	2,758,165	2,616,552
Other Assets:		
American Falls and Milner water rights	26,332	29,501
Company-owned life insurance	29,482	30,842
Regulatory assets	696,332	449,668
Long-term receivables (net of allowance of $2,478 and $1,878, respectively)	4,012	3,583
Employee notes	54	2,325
Other	43,632	53,045
Total other assets	799,844	568,964
Total	$ 4,022,845	$ 3,653,308

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

		December 31,		
		2008		2007
Liabilities and Shareholders' Equity		(thousands of dollars)		
Current Liabilities:				
Current maturities of long-term debt	$	86,528	$	11,456
Notes payable		151,250		186,445
Accounts payable		96,785		85,116
Taxes accrued		-		8,492
Interest accrued		16,727		18,913
Uncertain tax positions		4,119		26,764
Other		40,259		38,129
Total current liabilities		395,668		375,315
Other Liabilities:				
Deferred income taxes		515,719		466,182
Regulatory liabilities		276,266		274,204
Other		349,304		173,412
Total other liabilities		1,141,289		913,798
Long-Term Debt		1,183,451		1,156,880
Commitments and Contingencies (Note 7)				
Shareholders' Equity:				
Common stock, no par value (shares authorized 120,000,000; 46,929,203 and 45,063,107 shares issued, respectively)		729,576		675,774
Retained earnings		581,605		537,699
Accumulated other comprehensive loss		(8,707)		(6,156)
Treasury stock (9,022 and 380 shares at cost, respectively)		(37)		(2)
Total shareholders' equity		1,302,437		1,207,315
Total	$	4,022,845	$	3,653,308

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2008	2007	2006
Operating Activities:	(thousands of dollars)		
Net income	$ 98,414	$ 82,339	$ 107,403
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	122,440	120,368	122,641
Deferred income taxes and investment tax credits	4,661	11,026	(17,332)
Changes in regulatory assets and liabilities	(64,068)	(128,089)	(17,133)
Non-cash pension expense	3,513	6,868	-
Undistributed earnings of subsidiaries	(7,423)	(6,273)	(9,553)
Gain on sale of assets	(3,446)	(4,758)	(25,658)
Impairment of long-lived asset	-	-	2,047
Other non-cash adjustments to net income	9,008	(2,915)	(3,395)
Excess tax benefit from share-based payment arrangements	(149)	(68)	(1,411)
Change in:			
Accounts receivable and prepayments	(1,725)	(10,284)	24,304
Accounts payable and other accrued liabilities	16,248	2,206	6,725
Taxes accrued	(26,454)	(9,466)	(24,099)
Other current assets	(14,056)	(11,159)	(4,829)
Other current liabilities	(6,130)	15,551	(3,465)
Other assets	1,498	2,157	3,334
Other liabilities	4,182	13,098	10,199
Net cash provided by operating activities	136,513	80,601	169,778
Investing Activities:			
Additions to property, plant and equipment	(243,544)	(287,219)	(221,840)
Proceeds from the sale of ITI	-	-	21,469
Proceeds from the sale of IDACOMM	-	7,283	-
Proceeds from the sale of non-utility assets	5,847	-	146
Investments in affordable housing	(8,314)	348	(5,059)
Proceeds from the sale of emission allowances	2,959	19,846	11,323
Investments in unconsolidated affiliates	(3,038)	(8,535)	(16,030)
Purchase of available-for-sale securities	-	(24,349)	(17,979)
Proceeds from the sale of available-for-sale securities	-	26,110	20,778
Purchase of held-to-maturity securities	(4,248)	(3,116)	(2,730)
Maturity of held-to-maturity securities	6,060	3,317	4,647
Withdrawal (refundable deposit) for tax related liabilities	44,903	-	(44,903)
Other	(3,449)	(795)	(2,862)
Net cash used in investing activities	(202,824)	(267,110)	(253,040)
Financing Activities:			
Increase in term loans	170,000	-	-
Issuance of long-term debt	120,000	240,000	116,300
Retirement of long-term debt	(11,349)	(95,033)	(132,642)
Purchase of pollution control bonds	(166,100)	-	-
Dividends on common stock	(54,239)	(53,012)	(51,272)
Net change in short-term borrowings	(39,095)	57,445	68,900
Issuance of common stock	50,863	37,181	41,465
Acquisition of treasury stock	(304)	(346)	(213)
Excess tax benefit from share-based payment arrangements	149	68	1,411
Other	(2,752)	(1,720)	(3,151)
Net cash provided by financing activities	67,173	184,583	40,798
Net increase (decrease) in cash and cash equivalents	862	(1,926)	(42,464)
Cash and cash equivalents at beginning of the year	7,966	9,892	52,356
Cash and cash equivalents at end of the year	$ 8,828	$ 7,966	$ 9,892
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 20,407	$ 3,021	$ 54,522
Interest (net of amount capitalized)	$ 67,027	$ 62,031	$ 60,353
Non-cash investing activities			
Additions to property, plant and equipment in accounts payable	$ 14,194	$ 13,210	$ 8,299

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Shareholders' Equity

	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total Amount
				(thousands)			
Balance at January 1, 2006	42,656	$ 598,706	$ 437,284	$ (3,425)	239	$ (7,314)	$ 1,025,251
Net Income	-	-	107,403	-	-	-	107,403
Common stock dividends ($1.20 per share)	-	-	(51,323)	-	-	-	(51,323)
Issued	1,188	41,465	-	-	(11)	348	41,813
Acquired	-	-	-	-	6	(213)	(213)
Other	61	(1,372)	(1)	-	(162)	4,937	3,564
Unrealized loss on securities (net of tax)	-	-	-	(1,414)	-	-	(1,414)
Minimum pension liability adjustment (net of tax)	-	-	-	2,118	-	-	2,118
Adjustment upon adoption of SFAS 158 (net of tax)	-	-	-	(3,016)	-	-	(3,016)
Balance at December 31, 2006	43,905	638,799	493,363	(5,737)	72	(2,242)	1,124,183
Net Income	-	-	82,339	-	-	-	82,339
Common stock dividends ($1.20 per share)	-	-	(53,138)	-	-	-	(53,138)
Issued	1,142	37,181	-	-	(12)	330	37,511
Acquired	-	-	-	-	10	(346)	(346)
Other	16	(206)	(1)	-	(70)	2,256	2,049
Unrealized loss on securities (net of tax)	-	-	-	(743)	-	-	(743)
Unfunded pension liability adjustment (net of tax)	-	-	-	324	-	-	324
Adjustment upon adoption of FIN 48	-	-	15,136	-	-	-	15,136
Balance at December 31, 2007	45,063	675,774	537,699	(6,156)	-	(2)	1,207,315
Net Income	-	-	98,414	-	-	-	98,414
Common stock dividends ($1.20 per share)	-	-	(54,508)	-	-	-	(54,508)
Issued	1,765	50,863	-	-	(15)	99	50,962
Acquired	-	-	-	-	10	(304)	(304)
Other	101	2,939	-	-	14	170	3,109
Unrealized loss on securities (net of tax)	-	-	-	(568)	-	-	(568)
Unfunded pension liability adjustment (net of tax)	-	-	-	(1,983)	-	-	(1,983)
Balance at December 31, 2008	46,929	$ 729,576	$ 581,605	$ (8,707)	9	$ (37)	$ 1,302,437

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2008	**2007**	**2006**
	(thousands of dollars)		
Net Income	$ 98,414	$ 82,339	$ 107,403
Other Comprehensive Income (Loss):			
Unrealized gains (losses) on securities:			
Unrealized holding (losses) gains arising during the year, net of tax of ($3,034), $114 and $1,471	(4,727)	179	2,355
Reclassification adjustment for losses (gains) included in net income, net of tax of $2,670, ($592) and ($2,250)	4,159	(922)	(3,769)
Net unrealized losses	(568)	(743)	(1,414)
Unfunded pension liability adjustment, net of tax of ($1,273), $208 and $1,359	(1,983)	324	2,118
Total Comprehensive Income	$ 95,863	$ 81,920	$ 108,107

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31, 2008	2007	2006
	(thousands of dollars)		
Operating Revenues:			
General business	$ 784,311	$ 668,303	$ 636,375
Off-system sales	121,429	154,948	260,717
Other revenues	50,336	52,150	23,381
Total operating revenues	956,076	875,401	920,473
Operating Expenses:			
Operation:			
Purchased power	231,137	289,484	283,440
Fuel expense	149,403	134,322	115,018
Power cost adjustment	(47,413)	(121,131)	(29,526)
Other	225,390	218,347	200,090
Energy efficiency programs	18,880	13,487	-
Gain on sale of emission allowances	(504)	(2,754)	(8,257)
Maintenance	68,639	68,163	64,720
Depreciation	102,086	103,072	99,824
Taxes other than income taxes	19,083	17,634	18,661
Total operating expenses	766,701	720,624	743,970
Income from Operations	189,375	154,777	176,503
Other Income (Expense):			
Allowance for equity funds used during construction	3,141	5,995	6,092
Earnings of unconsolidated equity-method investments	6,772	5,553	9,347
Other income	8,174	12,636	10,578
Other expense	(6,262)	(8,215)	(8,701)
Total other income	11,825	15,969	17,316
Interest Charges:			
Interest on long-term debt	66,145	58,097	53,744
Other interest	10,420	8,281	6,211
Allowance for borrowed funds used during construction	(7,080)	(7,597)	(4,026)
Total interest charges	69,485	58,781	55,929
Income Before Income Taxes	131,715	111,965	137,890
Income Tax Expense	37,600	35,386	43,961
Net Income	$ 94,115	$ 76,579	$ 93,929

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2008	**2007**
Assets	**(thousands of dollars)**	
Electric Plant:		
In service (at original cost)	$ 4,030,134	$ 3,796,339
Accumulated provision for depreciation	(1,505,120)	(1,468,832)
In service - net	2,525,014	2,327,507
Construction work in progress	207,662	257,590
Held for future use	6,318	3,366
Electric plant - net	2,738,994	2,588,463
Investments and Other Property	106,057	105,074
Current Assets:		
Cash and cash equivalents	3,141	5,347
Receivables:		
Customer	64,433	62,122
Allowance for uncollectible accounts	(1,724)	(1,305)
Employee notes	179	2,128
Other	7,768	8,122
Taxes receivable	41,363	-
Accrued unbilled revenues	43,934	36,314
Materials and supplies (at average cost)	50,121	43,270
Fuel stock (at average cost)	16,852	17,268
Prepayments	9,865	9,120
Deferred income taxes	3,852	4,074
Refundable income tax deposit	-	44,316
Other	4,968	1,067
Total current assets	244,752	231,843
Deferred Debits:		
American Falls and Milner water rights	26,332	29,501
Company-owned life insurance	29,482	30,842
Regulatory assets	696,332	449,668
Employee notes	54	2,325
Other	42,853	51,800
Total deferred debits	795,053	564,136
Total	$ 3,884,856	$ 3,489,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2008	**2007**
Capitalization and Liabilities	**(thousands of dollars)**	
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	618,758	581,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	482,047	442,300
Accumulated other comprehensive loss	(8,707)	(6,156)
Total common stock equity	1,187,878	1,113,682
Long-term debt	1,180,691	1,141,508
Total capitalization	2,368,569	2,255,190
Current Liabilities:		
Long-term debt due within one year	81,064	1,064
Notes payable	112,850	136,585
Accounts payable	96,268	84,457
Notes and accounts payable to related parties	768	724
Taxes accrued	-	2,403
Interest accrued	16,675	18,761
Uncertain tax positions	4,119	26,764
Other	39,155	36,907
Total current liabilities	350,899	307,665
Deferred Credits:		
Deferred income taxes	547,159	488,768
Regulatory liabilities	276,266	274,204
Other	341,963	163,689
Total deferred credits	1,165,388	926,661
Commitments and Contingencies (Note 7)		
Total	$ 3,884,856	$ 3,489,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Capitalization

	December 31, 2008	%	December 31, 2007	%
		(thousands of dollars)		
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	618,758		581,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	482,047		442,300	
Accumulated other comprehensive loss	(8,707)		(6,156)	
Total common stock equity	1,187,878	50	1,113,682	49
Long-Term Debt:				
First mortgage bonds:				
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6.025% Series due 2018	120,000		-	
6 % Series due 2032	100,000		100,000	
5.50% Series due 2033	70,000		70,000	
5.50% Series due 2034	50,000		50,000	
5.875% Series due 2034	55,000		55,000	
5.30% Series due 2035	60,000		60,000	
6.30% Series due 2037	140,000		140,000	
6.25% Series due 2037	100,000		100,000	
Total first mortgage bonds	1,065,000		945,000	
Amount due within one year	(80,000)		-	
Net first mortgage bonds	985,000		945,000	
Pollution control revenue bonds:				
Variable Rate Series 2003 due 2024	49,800		49,800	
Variable Rate Series 2006 due 2026	116,300		116,300	
Variable Rate Series 2000 due 2027	4,360		4,360	
Total pollution control revenue bonds	170,460		170,460	
American Falls bond guarantee	19,885		19,885	
Milner Dam note guarantee	9,573		10,636	
Note guarantee due within one year	(1,064)		(1,064)	
Unamortized premium/discount - net	(3,163)		(3,409)	
Term Loan Credit Facility	166,100		-	
Purchase of pollution control revenue bonds	(166,100)		-	
Total long-term debt	1,180,691	50	1,141,508	51
Total Capitalization	$ 2,368,569	100	$ 2,255,190	100

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31, 2008	2007	2006
Operating Activities:	(thousands of dollars)		
Net income	$ 94,115	$ 76,579	$ 93,929
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	109,047	107,500	105,464
Deferred income taxes and investment tax credits	25,614	36,258	(13,473)
Changes in regulatory assets and liabilities	(64,068)	(128,089)	(17,133)
Non-cash pension expense	3,513	6,868	-
Undistributed earnings of subsidiary	(6,772)	(5,553)	(9,347)
Gain on sale of assets	(3,460)	(4,589)	.(11,751)
Impairment of assets	-	-	2,047
Other non-cash adjustments to net income	5,102	(5,660)	(5,853)
Change in:			
Accounts receivables and prepayments	(2,462)	(13,298)	3,596
Accounts payable	16,728	3,654	6,623
Taxes accrued	(43,608)	(12,862)	(30,235)
Other current assets	(14,055)	(11,234)	(4,767)
Other current liabilities	(6,130)	15,751	(2,310)
Other assets	1,492	2,147	3,332
Other liabilities	4,487	14,000	10,997
Net cash provided by operating activities	119,543	81,472	131,119
Investing Activities:			
Additions to utility plant	(243,544)	(287,219)	(221,840)
Proceeds from the sale of non-utility assets	5,785	-	35
Purchase of available-for-sale securities	-	(24,349)	(17,979)
Proceeds from the sale of available-for-sale securities	-	26,110	20,778
Proceeds from sale of emission allowances	2,959	19,846	11,323
Investments in unconsolidated affiliate	(3,210)	(8,675)	(16,030)
Withdrawal (refundable deposit) for tax related liabilities	43,927	(43,927)	-
Other	(3,349)	(263)	462
Net cash used in investing activities	(197,432)	(318,477)	(223,251)
Financing Activities:			
Increase in term loans	170,000	-	-
Issuance of long-term debt	120,000	240,000	116,300
Retirement of long-term debt	(1,064)	(81,064)	(116,300)
Purchase of pollution control bonds	(166,100)	-	-
Dividends on common stock	(54,368)	(53,491)	(51,109)
Net change in short term borrowings	(27,635)	84,385	52,200
Capital contribution from parent	37,000	51,000	47,050
Other	(2,150)	(882)	(2,940)
Net cash provided by financing activities	75,683	239,948	45,201
Net increase (decrease) in cash and cash equivalents	(2,206)	2,943	(46,931)
Cash and cash equivalents at beginning of the year	5,347	2,404	49,335
Cash and cash equivalents at end of the year	$ 3,141	$ 5,347	$ 2,404
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes paid to parent	$ 36,053	$ 2,877	$ 86,311
Interest (net of amount capitalized)	$ 63,448	$ 57,355	$ 55,501
Non-cash investing activities:			
Additions to utility plant in accounts payable	$ 14,194	$ 13,210	$ 8,299

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2008	2007	2006
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 442,300	$ 404,076	$ 361,256
Net Income	94,115	76,579	93,929
Cumulative effect of accounting change (adoption of FIN 48)	-	15,136	-
Dividends on common stock	(54,368)	(53,491)	(51,109)
Retained Earnings, End of Year	$ 482,047	$ 442,300	$ 404,076

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements Comprehensive Income

	Year Ended December 31,		
	2008	2007	2006
	(thousands of dollars)		
Net Income	$ 94,115	$ 76,579	$ 93,929
Other Comprehensive Income (Loss):			
Unrealized gains (losses) on securities:			
Unrealized holding (losses) gains arising during the year, net of tax of ($3,034), $114 and $1,471	(4,727)	179	2,355
Reclassification adjustment for losses (gains) included in net income, net of tax of $2,670, ($592) and ($2,250)	4,159	(922)	(3,769)
Net unrealized losses	(568)	(743)	(1,414)
Unfunded pension liability adjustment, net of tax of ($1,273), $208 and $1,359	(1,983)	324	2,118
Total Comprehensive Income	$ 91,564	$ 76,160	$ 94,633

The accompanying notes are an integral part of these statements.

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

Nature of Business

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

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

IDACORP's other subsidiaries include:

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

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM, Inc. as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Additional information about discontinued operations is presented in Note 16.

Principles of Consolidation

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

The entities that IDACORP and IPC consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West. Marysville has approximately $21 million of assets, primarily a hydroelectric plant, and approximately $17 million of intercompany long-term debt, which is eliminated in consolidation. For this joint venture, Ida-West is considered the primary beneficiary because the ownership of the intercompany note results in it absorbing a majority of the expected losses of the entity.

Prior to October 2008, IDACORP also consolidated IFS' limited partnership investment in Empire Development Company, LLC, (Empire) an entity that earned historic tax credits through the rehabilitation of the Empire Building in Boise, Idaho. In 2008 the partnership agreement for Empire was amended and as a result of the amendment Empire no longer met the criteria to be a VIE. Empire was deconsolidated and is now accounted for under the equity method of accounting, resulting in an increase in investments of $2 million and reductions of $9 million of other property, plant and equipment and $7 million in long-term debt.

Through IFS, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These VIEs are historic rehabilitation and affordable housing developments in which IFS holds limited partnership interests ranging from five to 99 percent. IFS does not absorb a majority of the expected losses of these entities, either because of specific provisions in the partnership agreements or due to not owning a majority interest. These investments were acquired between 1996 and 2008. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $75 million at December 31, 2008.

Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with accounting principles generally accepted in the United States of America. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, litigation, asset impairment, income taxes, unbilled revenues and bad debt. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual results could differ from those estimates.

System of Accounts

The accounting records of IPC conform to the Uniform System of Accounts prescribed by the FERC and adopted by the public utility commissions of Idaho, Oregon and Wyoming.

Regulation of Utility Operations

IPC follows SFAS 71, *Accounting for the Effects of Certain Types of Regulation,* and its financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating IPC. The application of SFAS 71 sometimes results in IPC recording expenses in a different period than when an unregulated enterprise would record the expenses. In these circumstances, the expenses are deferred as regulatory assets on the balance sheet and recorded on the income statement when recovered in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying SFAS 71 are discussed in more detail in Note 6.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly liquid temporary investments with maturity dates at date of acquisition of three months or less.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options and swaps are used to manage exposure to commodity price risk in the electricity market. The objective of the risk management program is to mitigate the risk associated with the purchase and sale of electricity and natural gas. The accounting for derivative financial instruments that are used to manage risk is in accordance with the concepts established by SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended.

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFUDC) and indirect charges for engineering, supervision and similar overhead items. Repair and maintenance costs associated with planned major maintenance are expensed as the costs are incurred, as are maintenance and repairs of property and replacements and renewals of items determined to be less than units of property. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.73 percent in 2008, 2.95 percent in 2007 and 2.75 percent in 2006.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS 144. SFAS 144 requires that if the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no impairments of long-lived assets in 2008.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. IPC's weighted-average monthly AFUDC rates for 2008, 2007 and 2006 were 5.2 percent, 6.8 percent and 7.6 percent, respectively. IPC's reductions to interest expense for AFUDC were $7 million for 2008, $8 million for 2007 and $4 million for 2006. Other income included $3 million, $6 million and $6 million of AFUDC for 2008, 2007 and 2006, respectively.

Revenues

Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense.

Income Taxes

IDACORP and IPC account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction, IPC's deferred income taxes (commonly referred to as normalized accounting) are provided for the difference between income tax depreciation and straight-line depreciation computed using book lives on coal-fired generation facilities and properties acquired after 1980. On other facilities, deferred income taxes are provided for the difference between accelerated income tax depreciation and straight-line depreciation using tax guideline lives on assets acquired prior to 1981. Deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods do not provide for current recovery in rates. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

The state of Idaho allows a three-percent investment tax credit on qualifying plant additions. Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties. Credits earned on non-regulated assets or investments are recognized in the year earned.

Income taxes are discussed in more detail in Note 2.

Earnings Per Share

The following table presents the computation of IDACORP's basic and diluted earnings per common share (in thousands, except for per share amounts):

	Year ended December 31,					
		2008		2007		2006
Numerator:						
Income from continuing operations	$	98,414	$	82,272	$	100,075
Denominator:						
Weighted-average shares outstanding - basic*		45,147		44,151		42,713
Effect of dilutive securities:						
Options		37		45		93
Restricted Stock		148		95		68
Weighted-average shares outstanding – diluted		45,332		44,291		42,874
Basic earnings per share from continuing operations	$	2.18	$	1.86	$	2.34
Diluted earnings per share from continuing operations	$	2.17	$	1.86	$	2.34

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

The diluted EPS computation excluded 556,518 options in 2008, 487,100 options in 2007 and 538,950 options in 2006, because the options' exercise prices were greater than the average market price of the common stock during those years. In total, 783,985 options were outstanding at December 31, 2008, with expiration dates between 2010 and 2015.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). The following table presents IDACORP's and IPC's accumulated other comprehensive loss balance at December 31 (net of tax):

		2008		2007
	(thousands of dollars)			
Unrealized holding gains on available-for-sale securities	$	-	$	568
SMSP		(8,707)		(6,724)
Total	$	(8,707)	$	(6,156)

Other Accounting Policies

Debt discount, expense and premium are deferred and being amortized over the terms of the respective debt issues.

Reclassifications and Revision

Certain items previously reported for years prior to 2008 have been reclassified to conform to the current year's presentation. The reclassifications that were made to prior year amounts are as follows: Non-utility additions were reclassified to other from additions to property, plant and equipment, and proceeds from the sale of non-utility assets were moved from other to their own line in the investing section of IDACORP's consolidated statements of cash flows; other assets was combined with other in the financing section of IDACORP's and IPC's consolidated statements of cash flows; and notes receivable was combined with other receivables in the current assets section of IPC's consolidated balance sheets. The "Demand-side management" line title was changed to "Energy efficiency programs" to reflect the terminology commonly used for these programs. Net income and shareholders' equity were not affected by these reclassifications and revision.

New Accounting Pronouncements

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

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

SFAS 161: In March 2008, the FASB issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*. SFAS 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. The adoption of SFAS 161 did not have a material impact on the consolidated financial statements of IDACORP and IPC.

SFAS 163: In May 2008, the FASB issued SFAS 163, *Accounting for Financial Guarantee Insurance Contracts—an interpretation of FASB Statement No. 60.* SFAS 163 is generally effective for financial statements issued for fiscal years beginning after December 15, 2008. SFAS 163 did not impact the consolidated financial statements of IDACORP and IPC.

FSP EITF 03-6-1: In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method described in SFAS No. 128, *Earnings per Share.* FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. All prior-period earnings per share data presented must be adjusted retrospectively, and early application is not permitted. The adoption of EITF 03-6-1 did not have a material impact on the consolidated financial statements of IDACORP and IPC.

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. The adoption of FSP FAS 142-3 did not have a material impact on the consolidated financial statements of IDACORP and IPC.

2. INCOME TAXES:

The components of the net deferred tax liability are as follows:

	IDACORP		IPC	
	2008	2007	2008	2007
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 44,341	$ 42,968	$ 44,341	$ 42,968
Advances for construction	9,305	10,172	9,305	10,172
Deferred compensation	17,811	17,800	17,052	16,423
Emission allowances	-	6,921	-	6,921
Partnership investments	1,255	572	1,255	572
Tax credits	76,597	53,770	-	-
Retirement benefits	85,034	20,753	85,034	20,753
Other	15,871	10,853	15,029	8,810
Total	250,214	163,809	172,016	106,619
Deferred tax liabilities:				
Property, plant and equipment	246,424	227,337	246,424	227,337
Regulatory assets	333,882	308,290	333,882	308,290
Conservation programs	1,902	3,169	1,902	3,169
PCA	62,820	45,008	62,820	45,008
Partnership investments	13,060	13,006	-	-
Retirement benefits	69,334	6,945	69,334	6,945
Other	961	564	961	564
Total	728,383	604,319	715,323	591,313
Net deferred tax liabilities	$ 478,169	$ 440,510	$ 543,307	$ 484,694

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	IDACORP			IPC		
	2008	2007	2006	2008	2007	2006
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$ 41,165	$ 33,601	$ 40,408	$ 46,100	$ 39,188	$ 48,262
Change in taxes resulting from:						
AFUDC	(3,577)	(4,757)	(3,542)	(3,577)	(4,757)	(3,542)
Capitalized interest	1,729	2,289	1,394	1,729	2,289	1,394
Investment tax credits	(3,490)	(3,578)	(3,513)	(3,490)	(3,578)	(3,513)
Repair allowance	(2,450)	(2,450)	(2,450)	(2,450)	(2,450)	(2,450)
Removal costs	(2,954)	(3,787)	(1,912)	(2,954)	(3,787)	(1,912)
Pension accrual	-	1,022	1,902	-	1,022	1,902
Capitalized overhead costs	(4,200)	(4,200)	(2,940)	(4,200)	(4,200)	(2,940)
Tax accounting method change	-	-	6,122	-	-	6,122
Uncertain tax positions	1,280	(3,586)	-	1,280	(3,586)	-
Settlement of prior years' tax returns	(2,753)	-	(7,465)	(2,761)	-	(8,144)
State income taxes, net of federal benefit	3,842	5,810	6,606	4,601	6,618	7,820
Depreciation	5,562	7,576	5,757	5,562	7,576	5,757
Affordable housing tax credits	(11,437)	(14,541)	(19,218)	-	-	-
Other, net	(3,517)	332	(5,772)	(2,240)	1,051	(4,795)
Total income tax expense	$ 19,200	$ 13,731	$ 15,377	$ 37,600	$ 35,386	$ 43,961
Effective tax rate	16.3%	14.3%	13.3%	28.5%	31.6%	31.9%

The items comprising income tax expense are as follows:

	IDACORP			IPC		
	2008	2007	2006	2008	2007	2006
	(thousands of dollars)					
Income taxes currently payable:						
Federal	$ 13,801	$ 9,573	$ 28,712	$ 16,390	$ 8,916	$ 52,142
State	1,541	(3,105)	4,254	(3,602)	(6,202)	5,293
Total	15,342	6,468	32,966	12,788	2,714	57,435
Income taxes deferred:						
Federal	18,709	8,035	(17,379)	33,224	28,148	(14,161)
State	(3,645)	926	(537)	2,794	6,223	360
Total	15,064	8,961	(17,916)	36,018	34,371	(13,801)
Uncertain tax positions:						
Federal	(12,763)	(3,345)	-	(12,763)	(3,345)	-
State	(712)	(241)	-	(712)	(241)	-
Total	(13,475)	(3,586)	-	(13,475)	(3,586)	-
Investment tax credits:						
Deferred	5,759	5,466	3,840	5,759	5,465	3,840
Restored	(3,490)	(3,578)	(3,513)	(3,490)	(3,578)	(3,513)
Total	2,269	1,888	327	2,269	1,887	327
Total income tax expense	$ 19,200	$ 13,731	$ 15,377	$ 37,600	$ 35,386	$ 43,961

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP.

Tax Credits Carryforwards

As of December 31, 2008, IDACORP had $57.9 million of general business credit carryforward for federal income tax purposes, and $18.7 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2025 to 2028, and the Idaho investment tax credit expires from 2019 to 2022.

FIN 48

IDACORP and IPC adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48) on January 1, 2007, as required. IPC recorded an increase of $15.1 million to 2007 opening retained earnings for the cumulative effect of adopting FIN 48. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands of dollars):

	2008	2007
Balance at January 1,	$ 17,594	$ 21,180
Additions for tax positions of prior years	1,280	848
Reductions for tax positions of prior years	(10,426)	(4,434)
Settlements with taxing authorities	(4,329)	-
Balance at December 31,	$ 4,119	$ 17,594

If recognized, the $4.1 million balance of unrecognized tax benefits would affect IDACORP's and IPC's effective tax rates.

Since 2006, IPC has been disputing the Internal Revenue Service's (IRS) disallowance of IPC's use of the simplified service cost method (SSCM) of uniform capitalization for tax years 2001-2004. The dispute has been under review with the IRS Appeals Office. In December 2008, the Appeals Office informed IDACORP that the SSCM settlement computations were complete. IDACORP reviewed the final computations and agreed to the result. The settlement was submitted to the U.S. Congress Joint Committee on Taxation (JCT) for review in January 2009.

In November 2006, IDACORP made a $44.9 million refundable tax deposit with the IRS related to the disputed income tax assessment for SSCM. In May 2008, IDACORP withdrew $20 million from the deposit. Approximately $21 million from the deposit was applied to the settled income tax deficiency and interest charges with the remaining balance refunded to IDACORP.

The IRS completed its examination of IDACORP's 2004 tax year in August 2008 and its 2005 tax year in October 2008. The 2004 examination report was submitted for JCT review as part of the SSCM settlement and the 2005 report was submitted in November 2008. IDACORP expects the JCT review process for 2001-2005 to be completed in 2009. As of December 31, 2008, all uncertain tax positions related to tax years 2001-2005 were considered effectively settled.

The IRS began examining IPC's current method of uniform capitalization in December 2008. IDACORP expects that the examination will be completed during 2009. Resolution would result in a decrease to IPC's unrecognized tax benefits of $4.1 million.

IDACORP and IPC recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. During the years ended December 31, 2008 and 2007, IPC recognized a net reduction in interest expense of $0.1 million and $1 million, respectively. IPC had accrued interest of $0.2 million and $5.5 million as of December 31, 2008 and 2007, respectively. No penalties are accrued.

IDACORP and IPC are subject to examination by their major tax jurisdictions – U.S. federal and state of Idaho. The open tax years for federal and Idaho are 2006-2008 and 2005-2008, respectively. The IRS began its examination of 2006 in December 2008. IDACORP and IPC are unable to predict the outcome of this examination.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

IDACORP Common Stock
The following table summarizes common stock issued and reserved:

	Shares issued			Shares reserved at
	2008	**2007**	**2006**	**December 31, 2008**
Dividend reinvestment and stock purchase plan	169,229	150,458	145,508	3,113,319
Employee savings plan	111,021	99,562	99,248	1,970,716
Restricted stock plan	16,149	-	-	297,965
Long-term incentive and compensation plan	115,730	26,292	467,791	2,403,404
Continuous equity program	1,453,967	881,337	536,518	2,628,178
Total	1,866,096	1,157,649	1,249,065	10,413,582

On December 15, 2005, IDACORP entered into a Sales Agency Agreement (2005 Agency Agreement) with BNY Capital Markets, Inc. (BNYCM), as IDACORP's agent, for the offer and sale by IDACORP of up to 2,500,000 shares of its common stock from time to time in at-the-market offerings. IDACORP issued 881,337 shares under the 2005 Agency Agreement in 2007 for proceeds of $28.5 million. In 2008, IDACORP sold the remaining 1,082,145 shares of common stock under the 2005 Agency Agreement at an average price of $28.56, including 879,145 shares in the fourth quarter 2008 at an average price of $28.11 per share.

On December 5, 2008, IDACORP entered into a new Sales Agency Agreement (2008 Agency Agreement) with BNY Mellon Capital Markets, LLC (BNYMCM), as IDACORP's agent, for the offer and sale of up to 3,000,000 shares of its common stock from time to time in at-the-market offerings. In December 2008, IDACORP sold 371,822 shares under the 2008 Agency Agreement at an average price of $29.18 per share.

Dividend Restrictions: 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 outstanding preferred stock. Also, certain provisions of credit facilities contain restrictions on the ratio of debt to total capitalization.

IPC must obtain the approval of the Oregon Public Utility Commission (OPUC) before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

IPC Common Stock
In 2008, 2007 and 2006, IDACORP contributed $37 million, $51 million and $47 million respectively, of additional equity to IPC. No additional shares of IPC common stock were issued.

Rights Agreement
On September 10, 2008, the Rights Agreement between IDACORP and Wells Fargo Bank, N. A., as successor to The Bank of New York, as rights agent, dated as of September 10, 1998, as amended (Rights Agreement), and the preferred share purchase rights (rights) issued thereunder expired in accordance with their terms. As a result, shares of IDACORP common stock are no longer accompanied by a right to purchase, under certain circumstances, one one-hundredth of a share of IDACORP's A Series Preferred Stock. IDACORP common shareholders were not entitled to any payment as a result of the expiration of the Rights Agreement and the rights issued thereunder.

Stock-Based Compensation
IDACORP has three share-based compensation plans. IDACORP's employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 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 Director Stock 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 December 31, 2008, the maximum number of shares available under the LTICP and RSP were 1,568,551 and 68,027, respectively.

The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC's employees (in thousands of dollars):

	IDACORP			IPC		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Compensation cost	$ 3,897	$ 2,745	$ 2,692	$ 3,683	$ 2,473	$ 1,458
Income tax benefit	$ 1,524	$ 1,073	$ 1,053	$ 1,440	$ 967	$ 570

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 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.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. For awards granted prior to 2006, dividends were paid to recipients at the time they were paid on the common stock. Beginning with the 2006 awards, dividends are accumulated and will be paid out only on shares that eventually vest.

The performance goals for the 2008 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.

A summary of restricted stock and performance share activity is presented below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	IDACORP		IPC	
	Number of Shares	Weighted-average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2008	263,642	$ 28.17	243,496	$ 28.20
Shares granted	127,538	25.35	124,031	25.35
Shares forfeited	(40,619)	29.12	(40,024)	29.11
Shares vested	(24,768)	31.21	(24,246)	31.21
Nonvested shares at December 31, 2008	325,793	$ 26.72	303,257	$ 26.68

The total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006 was $0.8 million, $0.9 million and $0.6 million, respectively. At December 31, 2008, IDACORP had $2.7 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. IPC's share of this amount was $2.5 million. These costs are expected to be recognized over a weighted-average period of 1.70 years. IDACORP uses original issue and/or treasury shares for these awards.

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. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

The fair values of all stock option awards have been estimated as of the date of the grant by applying a binomial option pricing model. The application of this model involves assumptions that are judgmental and sensitive in the determination of compensation expense. The following key assumptions were used in determining the fair value of options granted:

	2008	2007	2006
Dividend yield, based on current dividend and stock price on grant date	-	-	3.7%
Expected stock price volatility, based on IDACORP historical volatility	-	-	18%
Risk-free interest rate based on U.S. Treasury composite rate	-	-	4.92%
Expected term based on the SEC "simplified" method	-	-	6.50 years

The following table presents information about options granted and exercised (in thousands of dollars, except for weighted-average amounts):

	IDACORP			IPC		
	2008	2007	2006	2008	2007	2006
Weighted-average grant-date fair value	$ -	$ -	$ 9.96	$ -	$ -	$ -
Fair value of options vested	435	737	2,191	353	579	1,275
Intrinsic value of options exercised	182	79	3,771	182	11	2,883
Cash received from exercises	707	281	11,937	707	40	9,614
Tax benefits realized from exercises	71	31	1,474	71	4	1,127

As of December 31, 2008, there was less than $0.1 million of total unrecognized compensation cost related to stock options. These costs are expected to be recognized over a weighted average period of 0.6 years. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

IDACORP's and IPC's stock option transactions are summarized below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
IDACORP				
Outstanding at December 31, 2007	818,232	$ 34.37	4.61	$ 2,690
Exercised	(30,700)	23.04		
Forfeited	(3,547)	30.14		
Outstanding at December 31, 2008	783,985	$ 34.84	3.57	$ 641
Vested or expected to vest at December 31, 2008	782,207	$ 34.85	3.57	$ 641
Exercisable at December 31, 2008	722,487	$ 35.24	3.39	$ 638
IPC				
Outstanding at December 31, 2007	611,243	$ 33.75	4.71	$ 2,310
Exercised	(30,700)	23.04		
Forfeited	(3,547)	30.14		
Outstanding at December 31, 2008	576,996	$ 34.34	3.67	$ 611
Vested or expected to vest at December 31, 2008	575,420	$ 34.35	3.66	$ 611
Exercisable at December 31, 2008	526,105	$ 34.75	3.46	$ 611

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31:

	2008	2007
	(thousands of dollars)	
First mortgage bonds:	$	$
7.20% Series due 2009	80,000	80,000
6.60% Series due 2011	120,000	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	-
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
Total first mortgage bonds	1,065,000	945,000
Pollution control revenue bonds:		
Variable Rate Series 2003 due 2024[(1)]	49,800	49,800
Variable Rate Series 2006 due 2026[(1)]	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	9,573	10,636
Unamortized discount - net	(3,163)	(3,409)
Debt related to investments in affordable housing	8,224	18,438
Other subsidiary debt	-	7,326
Term Loan Credit Facility	166,100	-
Purchase of pollution control revenue bonds	(166,100)	-
Total	1,269,979	1,168,336
Current maturities of long-term debt	(86,528)	(11,456)
Total long-term debt	$ 1,183,451	$ 1,156,880

(1) Humboldt County and Sweetwater County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2008, to $1.231 billion.

At December 31, 2008, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2009	2010	2011	2012	2013	Thereafter
IPC	$ 81,064	$ 1,064	$ 121,064	$ 101,064	$ 71,064	$ 886,435
Other subsidiary debt	5,464	2,760	-	-	-	-
Total	$ 86,528	$ 3,824	$ 121,064	$ 101,064	$ 71,064	$ 886,435

At December 31, 2008 and 2007, the overall effective cost of IPC's outstanding debt was 5.59 percent and 5.72 percent, respectively.

Long-Term Financing
On November 20, 2008, IDACORP filed a registration statement for debt securities and common stock. In this filing, the Company was not registering additional securities, but rather was replacing two prior shelf registration statements that had been effective for more than three years. IDACORP has approximately $588

million remaining on the new shelf registration statement that can be used for the issuance of debt securities 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 December 31, 2008, IPC has $230 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

In January 2007, the IPC Board of Directors approved an increase of the maximum amount of first mortgage bonds issuable by IPC to $1.5 billion. The amount issuable is also restricted by property, earnings and other provisions of the mortgage and supplemental indentures to the mortgage. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. The indenture requires that IPC's net earnings must be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that IPC may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

As of December 31, 2008, IPC could issue under the mortgage approximately $528 million of additional first mortgage bonds based on unfunded property additions and $532 million of additional first mortgage bonds based on retired first mortgage bonds. These amounts are further limited by the $1.5 billion restriction discussed above. At December 31, 2008, unfunded property additions were approximately $880 million.

The mortgage requires IPC to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement or amortization of its properties. IPC may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

The mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority or distinction. IPC may issue additional first mortgage bonds in the future, and those first mortgage bonds will also be secured by the mortgage. The lien of the indenture constitutes a first mortgage on all the properties of IPC, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of IPC are subject to easements, leases, contracts, covenants, workmen's compensation awards and similar encumbrances and minor defects and clouds common to properties. The mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The mortgage creates a lien on the interest of IPC in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger or sale of all or substantially all of the assets of IPC.

At December 31, 2008, IFS had $8 million of debt related to investments in affordable housing. This debt had interest rates ranging from 3.65 percent to 8.17 percent and is due between 2009 and 2010. This debt is collateralized by investments in affordable housing developments with a net book value of $36 million at December 31, 2008. Of this $8 million in debt, $5 million is non-recourse to both IFS and IDACORP and the remainder is recourse only to IFS.

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. The pollution control bonds remain outstanding and have not been retired or cancelled. The maximum interest rate is 14 percent for the Sweetwater bonds and at specified rates capped at 12 percent for the Humboldt bonds.

The regularly scheduled principal and interest payments on the Series 2006 bonds and principal and interest payments on the bonds upon mandatory redemption on determination of taxability are insured by a financial guaranty insurance policy issued by Ambac Assurance Corporation.

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

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

The loans bear interest at either a floating rate or a Eurodollar rate. The floating rate is equal to (i) the highest of (a) the prime rate announced by JPMorgan Chase Bank on such day, (b) the sum of (1) the federal funds effective rate in effect on such day plus (2) 0.5 percent per annum and (c) an amount equal to (1) the LIBO Reference Rate on such day plus (2) 1 percent plus (ii) the applicable margin. The Eurodollar rate is (i) the rate published on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) for dollar deposits with a comparable maturity plus (ii) the applicable margin. The LIBO Reference Rate is the rate appearing on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) as the rate for United States dollar deposits for a one month interest period. The applicable margin is currently 2 percent for Eurodollar advances and 1 percent for floating rate advances, but may be increased or decreased based upon the ratings assigned to IPC's senior unsecured debt by Moody's and S&P.

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

5. NOTES PAYABLE:

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

At December 31, 2008, $25 million in loans were outstanding on IDACORP's facility and no loans were outstanding on IPC's facility.

At December 31, 2008, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of IDACORP's short-term borrowings were as follows at December 31 (in thousands of dollars):

	IDACORP		IPC		Total	
	2008	2007	2008	2007	2008	2007
			(thousands of dollars)			
Balances:						
At the end of year	$38,400	$49,860	$112,850	$136,585	$151,250	$186,445
Average during the year	$57,734	$44,773	$151,192	$96,890	$208,927	$141,663
Weighted-average interest rate:						
At the end of year	4.29%	5.45%	4.89%	5.56%	4.74%	5.53%
Average during the year	3.70%	5.44%	3.97%	5.54%	3.90%	5.51%

6. REGULATORY MATTERS:

Regulatory Assets and Liabilities

The following is a breakdown of IPC's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortizatio n Period	Earning a Return	Not Earning a Return	Total as of December 31, 2008	Total as of December 31, 2007
Regulatory Assets:					
Income Taxes		$ -	$ 335,644	$ 335,644	$ 309,902
Benefit Plans(1)		-	177,348	177,348	17,765
Deferred Pension Costs(1)		-	10,583	10,583	2,797
Conservation	2010	3,942	4,864	8,806	8,107
PCA Deferral	2009	140,821	-	140,821	92,323
FCA Deferral		2,721	-	2,721	-
Oregon Deferral(2)		2,878	-	2,878	5,100
Oregon PCAM Deferral(3)		5,400	-	5,400	-
Asset Retirement Obligations(4)		-	10,907	10,907	12,188
Grid West Loans	2013	65	922	987	1,108
Mark-to-Market Liabilities		-	3,074	3,074	171
Other	2010	77	160	237	379
Total(5)		$ 155,904	$ 543,502	$ 699,406	$ 449,840
Regulatory Liabilities:					
Income Taxes		$ -	$ 46,102	$ 46,102	$ 44,580
Conservation		197	2	199	1,893
FCA Accrual (prior year)	2009	-	1,105	1,105	2,145
Removal Costs(4)		-	156,837	156,837	155,314
Deferred ITC		-	73,270	73,270	71,001
Mark-to-Market Assets		-	652	652	586
Other		-	514	514	851
Total(6)		$ 197	$ 278,482	$ 278,679	$ 276,370

(1) See Note 8.
(2) Amortization capped at 10 percent of gross Oregon revenue per year.
(3) Amortization capped at 6 percent of gross Oregon revenue per year beginning after the Oregon Deferral amortization is completed.
(4) See Note 12.
(5) Includes $3,074 and $172 for 2008 and 2007, respectively, reported in other current assets on the balance sheets.
(6) Includes $2,413 and $2,166 for 2008 and 2007, respectively, reported in other current liabilities on the balance sheets.

In the event that recovery of costs through rates becomes unlikely or uncertain, SFAS 71 would no longer apply. If IPC were to discontinue application of SFAS 71 for some or all of its operations, then these items may represent stranded investments. If IPC is not allowed recovery of these investments, it would be required to write off the applicable portion of regulatory assets and the financial effects could be significant.

Idaho Rate Cases

2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four areas having a Idaho jurisdictional combined revenue requirement impact of approximately $8 million annually. Included in these areas is an item that relates to a $3.3 million expense credit received in 2006 as a result of successful litigation with the FERC and other federal agencies (FERC Credit). In the order, the IPUC directed IPC to refund the FERC Credit to customers over a five year period, thereby reducing IPC's annual revenue requirement by approximately $0.7 million during such period. IPC believes that this was contrary to Idaho law. If IPC is unsuccessful in its challenge of the IPUC's ruling on FERC fees, it will recognize a loss for some or all of this amount.

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 in base rates of 5.2 percent (approximately $32.1 million annually), effective March 1, 2008. The settlement did not specify an overall rate of return or a return on equity.

Danskin CT1 Power Plant Rate Case: On March 7, 2008, IPC filed an application with the IPUC requesting recovery of construction costs associated with the gas-fired Danskin CT1 plant located near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. IPC requested adding to rate base approximately $65 million attributable to the cost of constructing the generating facility and the related transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or approximately $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 related facilities, 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 at December 31 (in thousands of dollars):

	2008	2007
Idaho PCA current year:		
Deferral for the 2008-2009 rate year[1]	$ -	$ 85,732
Deferral for the 2009-2010 rate year	93,657	-
Idaho PCA true-up awaiting recovery:		
Authorized May 2007	-	6,591
Authorized May 2008	47,164	-
Oregon deferral:		
2001 costs	1,663	2,993
2006 costs	1,215	2,107
2008 PCAM	5,400	-
Total deferral	$ 149,099	$ 97,423

(1) 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.

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

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

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

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

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and was 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" (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon's jurisdictional share of excess power supply costs of $5.7 million. A hearing is set for April 16, 2009.

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. A settlement agreement was reached with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million, which 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 of gross Oregon revenue 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 "Note 7 - 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.

<u>Oregon Power Cost Recovery Mechanism:</u> 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 stipulation and OPUC order established a power cost recovery mechanism with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

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

On October 29, 2007, IPC filed the October Update portion of its 2008 APCU 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 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.69 percent, increase in Oregon revenues.

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

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

On October 6, 2008, the OPUC provided an order clarifying that the PCAM is a deferral under the Oregon statute. IPC expects that deferrals under the PCAM component will be subject to the six percent limitation on annual amortization discussed above. IPC had $5.4 million deferred under the PCAM as of December 31, 2008.

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 deferred $2.5 million of FCA net under-recovery of fixed costs during 2008.

Idaho Energy Efficiency Rider (Rider) Prudency Review

IPC's Rider is the chief funding mechanism for IPC's investment in conservation, energy efficiency and demand response programs. Effective June 1, 2008, IPC collects 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

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

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. IPC and the IPUC Staff agreed to continue to exchange information and discuss settlement with regard to the remaining $14.7 million, and IPC will file a pleading with the IPUC by April 1, 2009 seeking a prudency determination on the remainder. If resolution with respect to the remaining $14.7 million cannot be reached in the proceedings stemming from the April 1 filing, IPC and the IPUC Staff will recommend a procedure to allow the IPUC to make such a determination.

Open Access Transmission Tariff (OATT)

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

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

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

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

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

Pension Expense
In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the pension plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, *Employers' Accounting for Pensions*, as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. 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 2008, $7.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations:
As of December 31, 2008, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Seventy-nine of these facilities, with a combined nameplate capacity of 267 megawatts (MW), were on-line at the end of 2008; the other 13 facilities under contract, with a combined nameplate capacity of 190 MW, are projected to come on-line during 2009 and 2010. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2008, IPC purchased 756,014 megawatt-hours (MWh) from these projects at a cost of $45.9 million, resulting in a blended price of 6.1 cents per kilowatt hour. IPC purchased 777,147 megawatt-hours at a cost of $45 million in 2007 and 911,132 MWh at a cost of $54 million in 2006.

At December 31, 2008, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2009	2010	2011	2012	2013	Thereafter
			(thousands of dollars)			
Cogeneration and small power production	$ 73,684	$ 76,150	$ 95,579	$ 97,234	$ 94,888	$ 1,334,434
Power and transmission rights	84,040	19,013	15,035	2,655	2,655	10,455
Fuel	65,808	27,179	26,891	6,895	9,664	90,320

In addition, IDACORP has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees.

	2009	2010	2011	2012	2013	Thereafter
			(thousands of dollars)			
Operating leases	$ 3,132	$ 2,785	$ 2,327	$ 1,799	$ 1,795	$ 24,054
Equipment, maintenance, and service agreements	82,075	23,284	21,820	1,783	1,724	6,896
FERC and other industry related fees	3,922	3,922	3,922	3,922	3,922	19,612

IDACORP's expense for operating leases was approximately $3 million in 2008, $3 million in 2007 and $4 million in 2006.

Guarantees

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2008. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company and IPC expect 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

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

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

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

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

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, and required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds.

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

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

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 and severed the three cases from the remainder of the consolidated cases. On December 2, 2008, the Ninth Circuit filed an order dismissing the Port of Seattle petitions for review. That dismissal order is now final.

<u>Market Manipulation:</u> As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming ("gaming") or other forms of proscribed market behavior in concert with another party ("partnership") in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the "partnership" show cause proceeding against IPC. The order dismissing IPC from the "partnership" proceedings was not the subject of rehearing requests and is now final. Later in 2004, the FERC approved a settlement of the "gaming" proceeding without finding of wrongdoing by IPC. The Port of Seattle was the only party to appeal the FERC orders approving the "gaming" settlement. On December 8, 2008, the Ninth Circuit issued an order dismissing that appeal. The dismissal order is now final.

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

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

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. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court's decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court.

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

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

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

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 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." On November 19, 2008, the plaintiffs filed a motion to refer the pending motions for summary judgment to magistrate judge for recommendation decision. On December 2, 2008, PacifiCorp filed an opposition to plaintiff's motion. The court has yet to rule on either motion filed by plaintiffs. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit – Boardman: On September 30, 2008, Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired power plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE's construction and operation of the plant. The complaint seeks a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, injunctive relief requiring PGE to remediate alleged environmental damage and ongoing impacts, civil penalties of up to $32,500 per day per violation and the plaintiffs' cost of litigation, including reasonable attorney fees. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent and is the operator of the plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs' response to the motion is due March 6, 2009, and PGE's reply is due April 3, 2009. IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Snake River Basin Adjudication: IPC is engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC. 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 State of Idaho and IPC filed summary judgment motions on the recharge issue and completed briefing on the issue. The court held a hearing on December 4, 2008 on the summary judgment motions. After argument, the court took the matter under advisement. 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 the 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 and while many believe that groundwater recharge is a very high-priority issue, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrogeology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards. IPC is currently engaged in a 3 to 5 year pilot study, in cooperation with IDWR and water users, to determine the temporal and spatial impacts and/or benefits of recharging, a maximum of 30,000 acre-feet of water downstream of American Falls Reservoir on the ESPA Aquifer and the Snake River.

IPC has also filed an action 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 United States on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acrefeet 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 United States has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. on October 15, 2007 to recover damages from the United States for the lost generation resulting from the reduced flows. On September 30, 2008, IPC filed an amended complaint in which IPC seeks, in addition to damages for breach of the 1923 contract, a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On October 2, 2008, the court set a discovery schedule requiring that discovery be completed and pre-trial motions filed by October 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy in Canyon County, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho against IDACORP and IPC. The plaintiffs' complaint asserts claims for negligence, negligence *per se*, gross negligence, nuisance, and fraud. The claims are based on allegations that from 1972 until at least March 2005, IPC discharged "stray voltage" from its electrical facilities that caused physical harm and injury to the plaintiffs' dairy herd. Plaintiffs seek compensatory damages of not less than $1 million.

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 motion to dismiss was argued and submitted on September 25, 2008. On October 30, 2008, the court issued a decision granting the motion to dismiss. On November 13, 2008, plaintiffs filed a motion to reconsider the court's decision. On December 22, 2008, the court denied the plaintiffs motion to reconsider. On February 20, 2009, plaintiffs filed a notice of appeal of the court's dismissal of the action. 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.

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

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

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

8. BENEFIT PLANS:

SFAS 158

In December 2006, IDACORP and IPC adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

The measurement provisions of SFAS 158 were adopted as of January 1, 2008 and require that IPC measure its plan assets and benefit obligations as of its balance sheet date. IPC already used a December 31 measurement date for its plans, so adoption of the measurement provisions of SFAS 158 did not have any effect on IDACORP's or IPC's results of operations or cash flows.

Pension Plans

IPC has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. IPC's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2008, 2007 or 2006. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2008 and 2007, approximately $39.9 million and $48.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

The following table summarizes the changes in benefit obligations and plan assets of these plans:

	Pension Plan		SMSP	
	2008	2007	2008	2007
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 420,526	$ 425,599	$ 43,153	$ 41,866
Service cost	14,920	15,213	1,278	1,409
Interest cost	26,393	24,457	2,669	2,372
Actuarial loss (gain)	19,547	(29,585)	3,376	(87)
Benefits paid	(16,970)	(15,158)	(2,644)	(2,700)
Plan amendments	-	-	561	293
Benefit obligation at December 31	464,416	420,526	48,393	43,153
Change in plan assets:				
Fair value at January 1	407,970	400,924	-	-
Actual return on plan assets	(95,676)	22,204	-	-
Benefits paid	(16,970)	(15,158)	-	-
Fair value at December 31	295,324	407,970	-	-
Funded status at end of year	$ (169,092)	$ (12,556)	$ (48,393)	$ (43,153)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ -	$ -	$ (2,883)	$ (2,596)
Noncurrent liabilities [(1)]	(169,092)	(12,556)	(45,510)	(40,557)
Net amount recognized	$ (169,092)	$ (12,556)	$ (48,393)	$ (43,153)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 155,289	$ 5,954	$ 12,088	$ 9,200
Prior service cost	3,155	3,805	2,209	1,841
Subtotal	158,444	9,759	14,297	11,041
Less amount recorded as regulatory asset	(158,444)	(9,759)	-	-
Net amount recognized in accumulated other comprehensive income	$ -	$ -	$ 14,297	$ 11,041
Accumulated benefit obligation	$ 385,002	$ 346,477	$ 44,275	$ 39,851

(1) Noncurrent liabilities are contained in IDACORP's and IPC's Consolidated Balance Sheets under "Other liabilities" and "Other deferred credits," respectively.

The following table shows the components of net periodic benefit cost for these plans:

	Pension Plan			SMSP		
	2008	2007	2006	2008	2007	2006
	(thousands of dollars)					
Service cost	$ 14,920	$ 15,213	$ 14,476	$ 1,278	$ 1,409	$ 1,473
Interest cost	26,393	24,457	22,340	2,669	2,372	2,327
Expected return on assets	(34,112)	(33,387)	(30,817)	-	-	-
Amortization of net loss	-	-	129	489	566	844
Amortization of prior service cost	650	650	664	192	173	245
Net periodic pension cost	$ 7,851	$ 6,933	$ 6,792	$ 4,628	$ 4,520	$ 4,889

Prior to the adoption of SFAS 158, changes in the SMSP minimum liability increased other comprehensive income by $2 million in 2006.

In 2009, IDACORP and IPC expect to recognize as components of net periodic benefit cost $10 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2008, relating to the pension and SMSP plans. This amount consists of $8.5 million of net loss and $0.6 million of prior service cost for the pension plan and $0.7 million of net loss and $0.2 million of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans:

	2009	2010	2011	2012	2013	2014-2017
			(thousands of dollars)			
Pension Plan	$ 17,616	$ 18,968	$ 20,525	$ 22,464	$ 24,655	$ 157,832
SMSP	$ 2,963	$ 3,122	$ 3,165	$ 3,276	$ 3,473	$ 19,863

Postretirement Benefits
IPC maintains a defined benefit postretirement plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Benefits for employees who retire after December 31, 2002, are limited to a fixed amount, which will limit the growth of IPC's future obligations under this plan.

The net periodic postretirement benefit cost was as follows (in thousands of dollars):

	2008	2007	2006
Service cost	$ 1,154	$ 1,368	$ 1,463
Interest cost	3,498	3,512	3,426
Expected return on plan assets	(2,899)	(2,777)	(2,523)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Amortization of prior service cost	(535)	(535)	(535)
Amortization of net loss	-	403	812
Net periodic postretirement benefit cost	$ 3,258	$ 4,011	$ 4,683

The following table summarizes the changes in benefit obligation and plan assets (in thousands of dollars):

	2008	2007
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 56,826	$ 62,913
Service cost	1,154	1,368
Interest cost	3,498	3,512
Actuarial (gain) loss	1,656	(7,431)
Benefits paid(1)	(3,486)	(3,536)
Benefit obligation at December 31	59,648	56,826
Change in plan assets:		
Fair value of plan assets at January 1	35,096	32,627
Actual return on plan assets	(7,834)	3,129
Employer contributions	1,507	2,876
Benefits paid(1)	(3,486)	(3,536)
Fair value of plan assets at December 31	25,283	35,096
Funded status at end of year (included in noncurrent liabilities)(2)	$ (34,365)	$ (21,730)

(1) Benefits paid are net of $1,927 and $1,646 of plan participant contributions, and $421 and $405 of Medicare Part D subsidy receipts for 2008 and 2007, respectively.
(2) Noncurrent liabilities are contained in "Other liabilities" for IDACORP, and "Other deferred credits" for IPC.

Amounts recognized in accumulated other comprehensive income consist of:

	2008	2007
Net loss	$ 16,289	$ 3,900
Prior service cost (credit)	(2,072)	(2,607)
Transition obligation	8,160	10,200
Subtotal	22,377	11,493
Less amount recognized in regulatory assets	(18,904)	(8,006)
Less amount included in deferred tax assets	(3,473)	(3,487)
Net amount recognized in accumulated other comprehensive income	$ -	$ -

In 2009, IDACORP and IPC expect to recognize as components of net periodic benefit cost $2.3 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2008 relating to the postretirement plan. This amount consists of ($0.5) million of prior service cost, $0.8 million of net loss and $2.0 million of transition obligation.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and established a prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2009	2010	2011	2012	2013	2014-2018
Expected benefit payments[1]	$ 4,100	$ 4,300	$ 4,400	$ 4,500	$ 4,700	$ 24,800
Expected Medicare Part D subsidy receipts	$ 500	$ 600	$ 600	$ 700	$ 800	$ 4,000

(1)Expected benefit payments are net of expected Medicare Part D subsidy receipts.

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the plan was 10 percent and 6.75 percent in 2008 and 2007, respectively. The assumed health care cost trend rate for 2008 is assumed to decrease gradually to 5 percent over ten years, and remain at that level. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5 percent and 6.75 percent in 2008 and 2007, respectively. A 1-percentage point change in the assumed health care cost trend rate would have the following effect (in thousands of dollars):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of cost components	$ 245	$ (187)
Effect on accumulated postretirement benefit obligation	$ 2,136	$ (1,700)

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all IPC-sponsored pension and postretirement benefits plans:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.1%	6.4%	6.1%	6.4%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	10.0%	6.75%
Dental trend rate	-	-	5.0%	6.75%
Measurement date	12/31/08	12/31/07	12/31/08	12/31/07

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all IPC-sponsored pension and postretirement benefit plans:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.4%	5.85%	6.4%	5.85%
Expected long-term rate of return on assets	8.5%	8.5%	8.5%	8.5%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	10.0%	6.75%
Dental trend rate	-	-	5.0%	6.75%

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2008 and 2007, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	**2008**	**2007**	**2008**	**2007**
Equity securities	58%	65%	-%	-%
Debt securities	28	22	-	-
Real estate	12	10	-	-
Other[(1)]	2	3	100	100
Total	100%	100%	100%	100%

(1) The postretirement benefit plan assets are primarily life insurance contracts.

Pension Asset Allocation Policy: The target allocations for the portfolio by asset class are as follows:

Large-Cap Growth Stocks	10%	International Growth Stocks	7%
Large-Cap Core Stocks	11%	International Value Stocks	7%
Large-Cap Value Stocks	10%	Intermediate-Term Bonds	13%
Small-Cap Growth Stocks	5%	Short-Term Bonds	10%
Small-Cap Value Stocks	5%	Core Real Estate	9%
Micro-Cap Stocks	3%	Absolute Return	4%
Cash and Cash Equivalents	3%	Private Equity	3%

Assets are rebalanced as necessary to keep the portfolio close to target allocations.

The plan's principal investment objective is to maximize total return (defined as the sum of realized interest and dividend income and realized and unrealized gain or loss in market price) consistent with prudent parameters of risk and the liability profile of the portfolio. Emphasis is placed on preservation and growth of capital along with adequacy of cash flow sufficient to fund current and future payments to pensioners.

There are three major goals in IPC's asset allocation process:

- Determine if the investments have the potential to earn the rate of return assumed in the actuarial liability calculations.
- Match the cash flow needs of the plan. IPC sets cash allocations sufficient to cover the current year benefit payments and bond allocations sufficient to cover at least five years of benefit payments. IPC then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan.
- Maintain a prudent risk profile consistent with ERISA fiduciary standards.

Allowable plan investments include stocks and stock funds, investment-grade bonds and bond funds, core real estate funds, private equity funds, and cash and cash equivalents. With the exception of real estate holdings and private equity, investments must be readily marketable so that an entire holding can be disposed of quickly with only a minor effect upon market price.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst–case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

IPC's asset modeling process also utilizes historical market returns to measure the portfolio's exposure to a "worst-case" market scenario, to determine how much performance could vary from the expected "average" performance over various time periods. This "worst-case" modeling, in addition to cash flow matching and diversification by asset class and investment style, provides the basis for managing the risk associated with investing portfolio assets.

Employee Savings Plan
IPC has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. IPC matches specified percentages of employee contributions to the plan. Matching contributions amounted to $5 million, $5 million, and $4 million in 2008, 2007 and 2006, respectively.

Postemployment Benefits
IPC provides certain benefits to former or inactive employees, their beneficiaries and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under IPC's disability plans and health care for surviving spouses and dependents. IPC accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and IPC's consolidated balance sheets at December 31, 2008 and 2007 are $3.7 million and $3.5 million, respectively.

Pension Protection Act
In 2006, the Pension Protection Act of 2006 (the Act), which affects the manner in which many companies, including IDACORP and IPC, administer their pension plans was signed into law. The Act made changes to a variety of rules that apply to employee benefit plans, including those dealing with minimum funding requirements of defined benefit pension plans and plan investments of defined contribution pension plans. The Act also permanently extended the pension law changes made by the Economic Growth and Tax Relief Reconciliation Act of 2001, which had been scheduled to sunset on December 31, 2010. This legislation became effective on January 1, 2008.

In accordance with the Act, companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009, in order to avoid a scheduled series of required annual contributions. As of December 31, 2007, qualified pension liabilities were nearly fully funded; however, recent stock market performance has reduced the value of pension assets during 2008. Therefore, under current provisions of the Act, IPC will need to make additional contributions to become fully funded over a period of seven years. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated contributions would be approximately $45 million in 2010 and $33 million for each of 2011, 2012, and 2013. These estimates reflect the initial relief measures as passed by Congress; however, additional measures are being proposed, which may impact immediate funding requirements.

9. PROPERTY PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS:

The following table presents the major classifications of IPC's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2008 and 2007 (in thousands of dollars):

	2008		2007	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,736,670	2.34%	$ 1,639,710	2.52%
Transmission	742,871	2.11	684,399	2.13
Distribution	1,254,048	2.50	1,175,429	2.58
General and Other	296,545	7.53	296,801	8.29
Total in service	4,030,134	2.73%	3,796,339	2.95%
Accumulated provision for depreciation	(1,505,120)		(1,468,832)	
In service - net	$ 2,525,014		$ 2,327,507	

IPC has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. IPC's proportionate share of direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income.

These facilities, and the extent of IPC's participation, were as follows at December 31, 2008 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW[(1)]
Jim Bridger Units 1-4	Rock Springs, WY	$ 495,321	$ 16,403	$ 279,296	33	771
Boardman	Boardman, OR	70,924	477	50,914	10	64
Valmy Units 1 and 2	Winnemucca, NV	336,783	8,041	212,791	50	284

(1)IPC share of nameplate capacity

IPC's wholly-owned subsidiary IERCo, is a joint venturer in Bridger Coal Company, which operates the mine supplying coal to the Jim Bridger generating plant. IPC's coal purchases from the joint venture were $63 million, $51 million and $52 million in 2008, 2007 and 2006, respectively.

IPC has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. IPC's power purchases from these facilities were $8 million in 2008, 2007 and 2006.

See Note 1 for a discussion of the property of IDACORP's consolidated VIE.

10. INVESTMENTS:

The following table summarizes IDACORP's and IPC's investments as of December 31 (in thousands of dollars):

	2008	2007
IPC Investments:		
Equity method investment	$ 86,433	$ 76,451
Available-for-sale equity securities	14,451	21,445
Executive deferred compensation	4,679	6,627
Other investments	948	5
Total IPC investments	106,511	104,528
Investments in affordable housing	74,951	77,608
Equity method investments	10,030	9,550
Held-to-maturity debt securities	9,424	11,248
Executive deferred compensation	1,225	3,431
Other investments	66	-
Total IDACORP investments	$ 202,207	$ 206,365

Equity Method Investments

IPC, through its subsidiary IERCo, is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. Ida-West, through separate subsidiaries, owns 50 percent of each of the following electric generation projects: South Forks Joint Venture; Hazelton/Wilson Joint Venture and Snow Mountain Hydro LLC.

IFS invests in affordable housing developments that are accounted for in accordance with APB 18, *The Equity Method of Accounting for Investments in Common Stock,* and Emerging Issues Task Force Issue 94-1, *Accounting for Tax Benefits Resulting from Investments in Affordable Housing Projects,* and are presented as Investments on the Consolidated Balance Sheets. All projects are reviewed periodically for impairment.

The following table presents IDACORP's and IPC's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

	2008	2007	2006
Bridger Coal Company (IPC)	$ 6,772	$ 5,553	$ 9,347
Ida-West projects	1,830	1,820	2,341
IFS affordable housing projects	(12,599)	(12,197)	(14,601)
Total	$ (3,997)	$ (4,824)	$ (2,913)

The following table presents summarized income statement information for Bridger Coal Company (in thousands of dollars):

	2008		2007		2006	
Operating revenues	$	187,560	$	153,126	$	154,910
Operating expenses		167,245		136,468		126,869
Net Income	$	20,315	$	16,658	$	28,041

The following table presents summarized balance sheet information for Bridger Coal Company (in thousands of dollars):

	2008		2007	
Assets				
Current assets	$	64,569	$	58,672
Noncurrent assets		318,266		330,583
Total Assets	$	382,835	$	389,255
Liabilities				
Current liabilities	$	25,182	$	25,372
Noncurrent liabilities		98,355		134,529
Total Liabilities		123,537		159,901
Joint venture capital		259,298		229,353
Total Liabilities and Joint Venture Capital	$	382,835	$	389,254

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

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities have maturities ranging from 2009 through 2025.

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

	2008			2007		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities (IPC)	$ -	$ -	$ 14,451	$ 1,059	$ 128	$ 21,445
Held-to-maturity debt securities (IFS)	3	25	9,448	15	5	11,245

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

	2008		2007		2006	
Proceeds from sales	$	-	$	26,110	$	20,778
Gross realized gains from sales		-		2,093		3,774
Gross realized losses from sales		-		762		280

Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IDACORP and IPC analyze securities in loss positions as of the end of each reporting period. Due to recent market conditions IDACORP and IPC reviewed securities in a loss position and determined that due to the severity of the losses and the volatility of the market an other-than-temporary impairment should be recorded. At December 31, 2008, four available-for-sale and six held-to-maturity securities were in an unrealized loss position. The available-for-sale equity securities in unrealized loss positions are in broadly diversified index funds used to fund IPC's SMSP. The held-to-maturity debt securities in unrealized loss positions are bonds, whose market values fluctuate based on the interest rate environment. The available-for-sale securities were in unrealized loss positions of at least 32 percent and were deemed other-than-temporarily impaired and written down $6.8 million to fair market value at December 31, 2008. IDACORP and IPC did not recognize any other-than-temporary impairments in 2007 or 2006.

The following table summarizes information regarding securities that were in an unrealized loss position at the end of each year, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	**Aggregate Related Fair Value**	**Aggregate Unrealized Loss**	**Aggregate Related Fair Value**
2008:				
Held to maturity debt securities (IFS)	$ -	$ -	$ 25	$ 3,975
2007:				
Available-for-sale equity securities (IPC)	$ 128	$ 1,059	$ -	$ -
Held to maturity debt securities (IFS)	-	-	5	642

11. 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, *Effective Date of FASB Statement No. 157* (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 Board of Directors 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 following tables present information about IDACORP's and IPC's assets and liabilities measured at fair value on a recurring basis as of December 31, 2008 (in thousands of dollars). IDACORP's and IPC's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
IDACORP				
Assets:				
Derivatives	$ 652	$ -	$ -	$ 652
Money market funds	4,610	-	-	4,610
Trading securities	5,904	-	-	5,904
Available-for-sale securities	14,451	-	-	14,451
Liabilities:				
Derivatives	$ -	$ (2,653)	$ -	$ (2,653)
IPC				
Assets:				
Derivatives	$ 652	$ -	$ -	$ 652
Money market funds	1,224	-	-	1,224
Trading securities	4,679	-	-	4,679
Available-for-sale securities	14,451	-	-	14,451
Liabilities:				
Derivatives	$ -	$ (2,653)	$ -	$ (2,653)

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 Consolidated Balance Sheets are categorized based on the inputs to the valuation techniques as follows:

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

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

a) Quoted prices for similar assets or liabilities in active markets;
b) Quoted prices for identical or similar assets or liabilities in non-active markets;
c) Pricing models whose inputs are observable for substantially the full term of the asset or liability;
d) Pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

IDACORP and IPC Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data.

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

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

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

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable	$ 5,703	$ 5,726	$ 8,073	$ 8,121
Liabilities:				
Long-term debt	$ 1,277,042	$ 1,199,699	$ 1,171,745	$ 1,348,944
IPC				
Assets:				
Notes receivable	$ 259	$ 282	$ 4,859	$ 4,907
Liabilities:				
Long-term debt	$ 1,268,818	$ 1,191,476	$ 1,145,981	$ 1,272,627

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 reports 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, but may consider the fair value option on a case-by-case basis in the future.

12. ASSET RETIREMENT OBLIGATIONS (ARO):

SFAS 143, *Accounting for Asset Retirement Obligations,* as amended and interpreted, requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under SFAS 143, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, IPC records regulatory assets or liabilities instead of accretion, depreciation and gains or losses, as approved by Order No. 29414 from the IPUC. The regulatory assets recorded under this order do not earn a return on investment.

IPC's recorded AROs relate to the removal of Polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2008, changes in estimates for both of these facilities resulted in a net decrease of $2.6 million in the recorded ARO.

IPC also has AROs associated with its transmission system and hydroelectric facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of IPC also collect removal costs in rates for certain assets that do not have associated AROs. The adoption of SFAS 143 required IPC to redesignate these removal costs as regulatory liabilities. Costs recorded as regulatory liabilities on IDACORP's and IPC's Consolidated Balance Sheets as of December 31, 2008 and 2007, were $157 million and $155 million, respectively.

The following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	IDACORP		IPC	
	2008	**2007**	**2008**	**2007**
Balance at beginning of year	$ 14,515	$ 13,388	$ 14,515	$ 12,911
Accretion expense	701	695	701	692
Revisions in estimated cash flows	(2,627)	920	(2,627)	920
Liability settled	(174)	(488)	(174)	(8)
Balance at end of year	$ 12,415	$ 14,515	$ 12,415	$ 14,515

13. SEGMENT INFORMATION:

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of IPC. IPC's regulated operations include the generation, transmission, distribution, purchase and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of IPC that is also subject to regulation and is a one-third owner of Bridger Coal Company, an unconsolidated joint venture.

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

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

	Utility Operations	All Other	Eliminations [1]	Consolidated Total [1]
2008				
Revenues	$ 956,076	$ 4,338	$ -	$ 960,414
Operating income	189,375	1,292	-	190,667
Other income (loss)	2,124	(1,743)	-	381
Interest income	2,929	1,582	(892)	3,619
Equity method income (loss)	6,772	(10,769)	-	(3,997)
Interest expense	69,485	4,463	(892)	73,056
Income (loss) before income taxes	131,715	(14,101)	-	117,614
Income tax expense (benefit)	37,600	(18,400)	-	19,200
Income from continuing operations	94,115	4,299	-	98,414
Total assets	3,884,856	164,339	(26,350)	4,022,845
Expenditures for long-lived assets	243,544	273	-	243,817
2007				
Revenues	$ 875,401	$ 3,993	$ -	$ 879,394
Operating income (loss)	154,777	(2,699)	-	152,078
Other income	7,436	101	-	7,537
Interest income	2,980	3,126	(1,553)	4,553
Equity method income (loss)	5,553	(10,377)	-	(4,824)
Interest expense	58,781	6,113	(1,553)	63,341
Income (loss) before income taxes	111,965	(15,962)	-	96,003
Income tax expense (benefit)	35,386	(21,655)	-	13,731
Income from continuing operations	76,579	5,693	-	82,272
Total assets	3,489,516	235,636	(71,844)	3,653,308
Expenditures for long-lived assets	287,219	46	-	287,265
2006				
Revenues	$ 920,473	$ 5,818	$ -	$ 926,291
Operating income (loss)	176,503	(6,799)	-	169,704
Other income	5,060	1,176	(490)	5,746
Interest income	2,909	2,694	(1,713)	3,890
Equity method income (loss)	9,347	(12,260)	-	(2,913)
Interest expense	55,929	7,250	(2,204)	60,975
Income (loss) before income taxes	137,890	(22,438)	-	115,452
Income tax expense (benefit)	43,961	(28,584)	-	15,377
Income from continuing operations	93,929	6,146	-	100,075
Total assets	3,177,725	273,742	(6,337)	3,445,130
Expenditures for long-lived assets	221,930	5,093	-	227,023

[1] 2006 includes the assets of IDACOMM which are presented as assets held for sale.

14. RELATED PARTY TRANSACTIONS (IPC):

IDACORP

IPC performs corporate functions such as financial, legal and management services for IDACORP and its subsidiaries. IPC charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services IPC billed IDACORP $1 million, $2 million and $4 million in 2008, 2007 and 2006, respectively.

Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. IPC paid $8 million in 2008, 2007 and 2006.

15. OTHER INCOME AND EXPENSE:

The following table presents the components of Other income and Other expense (in thousands of dollars):

	2008	2007	2006
Other income:			
Allowance for funds used during construction-equity	$ 3,141	$ 5,995	$ 6,092
Investment income, net	(5,273)	6,855	8,489
Carrying charges	6,709	3,437	1,040
Other	7,284	4,237	2,574
Total	$ 11,861	$ 20,524	$ 18,195
Other expense:			
SMSP expense	$ 4,628	$ 4,520	$ 4,889
Other	3,233	3,914	3,670
Total	$ 7,861	$ 8,434	$ 8,559

16. DISCONTINUED OPERATIONS:

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

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

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

	2008	2007	2006
Revenues	$ -	$ 1,278	$ 12,882
Operating expenses	-	(1,309)	(21,369)
Other (expense) income	-	(25)	354
(Loss) gain on disposal	-	(2,877)	14,476
Pre-tax (losses) income	-	(2,933)	6,343
Income tax benefit	-	3,000	985
Income from discontinued operations	$ -	$ 67	$ 7,328

The results of operations for the years ended December 31, 2007 and 2006 do not include depreciation expense of approximately $0.3 million and $1.2 million, respectively, that would be recorded if the related assets were classified as held and used.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the consolidated financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No.* 109, on January 1, 2007 and as discussed in Note 8 to the consolidated financial statements, the Company adopted 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),* as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Idaho Power Company and subsidiary (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the consolidated financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No.* 109, on January 1, 2007 and as discussed in Note 8 to the consolidated financial statements, the Company adopted 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),* as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 25, 2009

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA:

The following unaudited information is presented for each quarter of 2008 and 2007 (in thousands of dollars except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
IDACORP, Inc.				
2008				
Revenues	$ 213,440	$ 230,226	$ 299,716	$ 217,032
Operating income	44,756	40,529	81,577	23,805
Net income	21,716	17,515	51,739	7,444
Basic earnings per share	0.48	0.39	1.15	0.16
Diluted earnings per share	0.48	0.39	1.14	0.16
2007				
Revenues	$ 206,711	$ 213,772	$ 261,463	$ 197,446
Operating income	43,779	36,572	47,930	23,795
Income from continuing operations	24,580	18,465	28,931	10,295
Income from discontinued operations, net	67	-	-	-
Net income	24,647	18,465	28,931	10,295
Basic and diluted earnings per share	0.56	0.42	0.65	0.23
Idaho Power Company				
2008				
Revenues	$ 212,796	$ 228,945	$ 298,107	$ 216,228
Income from operations	45,160	40,388	81,112	22,715
Net income	21,271	17,728	47,405	7,711
2007				
Revenues	$ 205,928	$ 212,526	$ 260,516	$ 196,431
Income from operations	45,584	35,908	48,596	24,689
Net income	23,331	16,164	24,108	12,976

Operating income and Net income were decreased in the fourth quarter of 2008 by $7.4 million following a decision received from the FERC increasing the OATT refund, and $6.8 million other-than-temporary impairment of diversified index funds used to fund IPC's Senior Management Security Plan due to the decline in market value.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:

The Chief Executive Officer and 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 December 31, 2008, have concluded that IDACORP's disclosure controls and procedures are effective.

IPC:
The Chief Executive Officer and 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 December 31, 2008, have concluded that IPC's disclosure controls and procedures are effective.

Internal control over financial reporting:

IDACORP:

Management's Annual Report on Internal Control Over Financial Reporting
The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2008. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management believes that, as of December 31, 2008 IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2008 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2008.

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2008 of the Company and our report dated February 25, 2009 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's adoption of Statement of Financial Accounting Standards No. 158 and Financial Accounting Standards Board Interpretation No. 48.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 25, 2009

Idaho Power Company:

Management's Annual Report on Internal Control Over Financial Reporting
The management of Idaho Power Company (IPC) is responsible for establishing and maintaining adequate internal control over financial reporting of IPC. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IPC's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2008. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management believes that, as of December 31, 2008, IPC's internal control over financial reporting is effective based on those criteria.

IPC's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2008 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IPC's internal control over financial reporting as of December 31, 2008.

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2008 of the Company and our report dated February 25, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of Statement of Financial Accounting Standards No. 158 and Financial Accounting Standards Board Interpretation No. 48.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 25, 2009

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 December 31, 2008, requiring disclosure that have materially affected, or are reasonably likely to materially affect, IDACORP's or IPC's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The portion of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors - Nominees for Election - Terms Expire 2012," "Nominee for Election - Term Expires 2011," "Continuing Directors – Terms Expire 2011," "Continuing Directors - Terms Expire 2010," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance - Corporate Governance Committee Report - Process for Shareholders to Recommend Candidates for Director" paragraph 1, "Corporate Governance - Audit Committee," paragraph 1 and "Corporate Governance - Code of Ethics," to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009 is hereby incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009 is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers and Five Percent Shareholders" to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009 is hereby incorporated by reference.

The following table includes information as of December 31, 2008, with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP), the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP) and the Non-Employee Director Stock Compensation Plan (DSP).

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders [1]	783,985	$ 34.84	1,636,578 [2][3]
Equity compensation plans not approved by shareholders[4]	-	$ -	26,863
Total	783,985	$ 34.84	1,663,441

(1) Consists of the RSP and the LTICP.
(2) In addition to being available for future issuance upon exercise of options, 1,568,551 shares under the LTICP may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares or other equity-based awards.
(3) 68,027 shares remain available for future issuance under the RSP.
(4) Consists of shares available for future issuance under the DSP.

Equity Compensation Plans Not Approved by IDACORP Shareholders:
The DSP was adopted by the Board of Directors effective May 17, 1999. The purpose of the DSP is to increase directors' stock ownership through stock-based compensation. The DSP provides for an annual stock grant valued at $45,000.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portion of IDACORP's definitive proxy statement appearing under the captions "Related Person Transaction Disclosure" and "Corporate Governance – Director Independence" paragraphs 1 and 2 to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009 is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP:
The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2009 Annual Meeting of Shareholders to be held on May 21, 2009 is hereby incorporated by reference.

IPC:
The following table presents fees billed for professional services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, Deloitte Entities), for IPC for the fiscal years ended December 31, 2008 and 2007.

	2008	2007
Audit fees	$ 1,037,923	$ 1,148,354
Audit-related fees (1)	59,800	62,520
Tax fees (2)	138,606	114,486
All other fees (3)	2,000	-
Total	$ 1,238,329	$ 1,325,360

(1) Includes fees for audits of IPC's benefit plans and agreed upon procedures at a subsidiary.
(2) Includes fees for tax consulting in connection with 263A settlement guidelines, uniform capitalization issues and benefit plan filings.
(3) Accounting research tool subscription.

Policy on Audit Committee Pre-Approval
IPC and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, on February 4, 2004, the Audit Committee established a pre-approval policy in accordance with applicable securities rules. All fees were pre-approved by the Audit Committee in 2007 and 2008.

In addition to the audits of IPC's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed audit and audit-related services. The Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to IPC's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations and whether the nature of the engagement and the related fees are consistent with the following principles, as stated in the SEC's adopting release for the rules on auditor independence:

- the independent public accounting firm cannot function in the role of management of IPC;
- the independent public accounting firm cannot audit its own work; and
- the independent public accounting firm cannot serve in any advocacy role on behalf of IPC.

The appendices to the pre-approval policy describe the specific audit, audit related, tax and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of all consolidated financial statements and financial statement schedules.

(3) 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	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.1.
*4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.2.

*4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.
*10.1	Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).
*10.6	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7 filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10.13	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).
10.15[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008.

10.16[1] Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 20, 2008.

*10.17 [1] IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).

*10.18 [1] IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).

*10.19 [1] IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vii).

*10.20 [1] Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).

10.21 [1] IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2008.

*10.22[1] 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).

*10.23[1] 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).

10.24[1] Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), approved November 20, 2008.

10.25 [1] Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), approved November 20, 2008.

10.26[1] IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 20, 2008.

*10.27[1] IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).

*10.28[1] IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).

*10.29[1] IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).

10.30[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (November 20, 2008).
10.31[1]	IDACORP, Inc. Executive Incentive Plan, as amended November 20, 2008.
10.32[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008.
10.33[1]	IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors, as amended November 20, 2008.
*10.34	Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC's Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.35	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.36	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.37	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).
*10.38	Guaranty Agreement, dated February 10, 1992, between IPC and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).
*10.39	Power Purchase Agreement between IPC and PPL Montana, LLC, dated March 1, 2003 and Revised Confirmation Agreement dated May 9, 2003. File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 10(k).
*10.40	$100 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among IDACORP, Inc., various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-14465, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(l).
*10.41	$300 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among Idaho Power Company, various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(m).

10.42	$170 Million Term Loan Credit Agreement, dated as of February 4, 2009, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders.
*10.43	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.
*10.44	Power Purchase Agreement between IPC and PPL EnergyPlus, LLC, dated June 2, 2008. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2008, filed on 8/7/08, as Exhibit 10.46.
*10.45	Electric Service Agreement, dated September 17, 2008, between IPC and Hoku Materials, Inc. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2008, filed on 11/6/08, as Exhibit 10.47.
10.46[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008.
10.47[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 20, 2008).
10.48[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008.
10.49[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008.
10.50[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008.
10.51[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 20, 2008).
10.52[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008.
10.53[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008.
10.54[1]	Form of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008.
10.55[1]	Form of Letter Agreement to Amend Outstanding IDACORP Financial Services, Inc. Director Deferred Compensation Agreement (November 20, 2008).
10.56[1]	Form of Amendment to IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008.
10.57[1]	Form of Termination of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 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 Fixed Charges. (IPC)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
*21	Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on 2/28/08, as Exhibit 21.
23	Consent of Independent Registered Public Accounting Firm.
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.

[1] Management contract or compensatory plan or arrangement

IDACORP, Inc.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF INCOME

	Year Ended December 31,		
	2008	**2007**	**2006**
	(thousands of dollars)		
Income:			
Equity in income from continuing operations of subsidiaries	$ 100,303	$ 85,742	$ 106,006
Investment income (losses)	(131)	1,363	854
Total income	100,172	87,105	106,860
Expenses:			
Operating expenses	1,088	3,253	7,080
Interest expense	3,250	4,143	4,225
Other expense	126	70	120
Total expenses	4,464	7,466	11,425
Income from Continuing Operations Before Income Taxes	95,708	79,639	95,435
Income Tax Benefit	(2,706)	(2,633)	(4,640)
Income from Continuing Operations	98,414	82,272	100,075
Income from Discontinued Operations, net of tax	-	67	7,328
Net income	$ 98,414	$ 82,339	$ 107,403

The accompanying note is an integral part of these statements.

IDACORP, Inc.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED BALANCE SHEETS

	December 31,	
	2008	**2007**
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 3,541	$ 1,300
Receivables	3,211	2,741
Refundable income tax deposit	-	45,695
Deferred income taxes	33,693	53,770
Other	755	773
Total current assets	41,200	104,279
Investment in subsidiaries	1,305,873	1,227,981
Other Assets		
Deferred income taxes	44,500	1,828
Other	1,094	2,541
Total other assets	45,594	4,369
Total	$ 1,392,667	$ 1,336,629
Liabilities and Shareholders' Equity		
Current Liabilities:		
Notes payable	$ 38,400	$ 49,860
Accounts payable	5,701	4,478
Taxes accrued	22,485	47,733
Other	541	177
Total current liabilities	67,127	102,248
Other Liabilities:		
Intercompany notes payable	19,855	22,652
Other	3,247	4,414
Total other liabilities	23,102	27,066
Shareholders' Equity	1,302,438	1,207,315
Total	$ 1,392,667	$ 1,336,629

The accompanying note is an integral part of these statements.

IDACORP, Inc.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	**2007**	**2006**
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 56,912	$ 39,332	$ 41,196
Investing Activities:			
Contributions to subsidiaries	(37,000)	(51,000)	(64,533)
Change in intercompany notes receivable	-	880	4,196
Purchase of investments	(364)	-	-
Sale of investments	287	-	-
Sale of ITI	-	-	21,548
Sale of IDACOMM	-	7,858	-
Reimbursement by subsidiary of refundable tax deposit	-	43,927	-
Net cash provided by (used in) investing activities	(37,077)	1,665	(38,789)
Financing Activities:			
Issuance of common stock	50,863	37,181	41,465
Dividends on common stock	(54,240)	(53,012)	(51,272)
Increase (decrease) in short-term borrowings	(11,460)	(26,940)	16,700
Change in intercompany notes payable	(2,092)	(626)	(6,814)
Other	(665)	(1,024)	1,004
Net cash provided by (used in) financing activities	(17,594)	(44,421)	1,083
Net increase (decrease) in cash and cash equivalents	2,241	(3,424)	3,490
Cash and cash equivalents at beginning of year	1,300	4,724	1,234
Cash and cash equivalents at end of year	$ 3,541	$ 1,300	$ 4,724

The accompanying note is an integral part of these statements.

IDACORP, Inc.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2008 Form 10-K, Part II, Item 8.

Accounting for subsidiaries
IDACORP has accounted for the earnings of its subsidiaries under the equity method in the unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends of $56,868, $58,990, and $74,609 that IDACORP subsidiaries paid to IDACORP in 2008, 2007 and 2006, respectively.

IDACORP, Inc.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007 and 2006

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Period	Charged to Income	Charged (Credited) to Other Accounts	Deductions (1)	Balance at End of Period
		(thousands of dollars)			
2008:					
Reserves Deducted From					
Applicable Assets:					
Reserve for uncollectible accounts	$ 7,505	$ 3,661	$ (5,947)	$ 3,495	$ 1,724
Reserve for uncollectible notes	1,879	-	-	-	1,879
Other Reserves:					
Rate refunds	2,397	10,948	-	-	13,345
Injuries and damages reserve	661	1,437	-	133	1,965
Miscellaneous operating reserves	4	-	-	4	-
2007:					
Reserves Deducted From					
Applicable Assets:					
Reserve for uncollectible accounts	$ 7,168	$ 2,093	$ -	$ 1,756	$ 7,505
Reserve for uncollectible notes	1,879	-	-	-	1,879
Deferred tax assets	1,565	-	-	1,565	-
Other Reserves:					
Rate refunds	1,227	2,893	-	1,723	2,397
Injuries and damages reserve	666	2,457	-	2,462	661
Miscellaneous operating reserves	6	3	-	5	4
2006:					
Reserves Deducted From					
Applicable Assets:					
Reserve for uncollectible accounts	$ 33,078	$ 3,079	$ -	$ 28,989	$ 7,168
Reserve for uncollectible notes	1,879	-	-	-	1,879
Deferred tax assets	1,565	-	-	-	1,565
Other Reserves:					
Rate refunds	-	1,227	-	-	1,227
Injuries and damages reserve	1,638	1,914	-	2,886	666
Miscellaneous operating reserves	36	-	-	30	6

Notes: (1) Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts and notes reserves, includes reversals of amounts previously written off.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007, 2006

Column A		Column B		Column C			Column D		Column E
				Additions					
Classification		Balance at Beginning of Period		Charged to Income		Charged (Credited) to Other Accounts		Deductions (1)		Balance at End of Period
				(thousands of dollars)					
2008:									
Reserves Deducted From									
Applicable Assets:									
Reserve for uncollectible accounts	$	1,305	$	3,661	$	253	$	3,495	$	1,724
Other Reserves:									
Rate refunds		2,397		10,948		-		-		13,345
Injuries and damages reserve		661		1,437		-		133		1,965
Miscellaneous operating reserves		4		-		-		4		-
2007:									
Reserves Deducted From									
Applicable Assets:									
Reserve for uncollectible accounts	$	968	$	2,093	$	-	$	1,756	$	1,305
Other Reserves:									
Rate refunds		1,227		2,893		-		1,723		2,397
Injuries and damages reserve		665		1,210		-		1,214		661
Miscellaneous operating reserves		6		3		-		5		4
2006:									
Reserves Deducted From									
Applicable Assets:									
Reserve for uncollectible accounts	$	833	$	3,079	$	-	$	2,944	$	968
Other Reserves:									
Rate refunds		-		1,227		-		-		1,227
Injuries and damages reserve		1,191		1,445		-		1,971		665
Miscellaneous operating reserves		36		-		-		30		6

Notes: (1) Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts includes reversals of amounts previously written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IDACORP, Inc.
(Registrant)

February 26, 2009

By: */s/J. LaMont Keen*
J. LaMont Keen
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By:	*/s/Jon H. Miller* Jon H. Miller		Chairman of the Board	February 26, 2009
By:	*/s/J. LaMont Keen* J. LaMont Keen		President and Chief Executive Officer and Director (Principal Executive Officer)	"
By:	*/s/Darrel T. Anderson* Darrel T. Anderson		Senior Vice President - Administrative Services and Chief Financial Officer (Principal Financial Officer) (Principal Accounting Officer)	"
By:	*/s/Richard J. Dahl* Richard J. Dahl Director	By:	*/s/Jan B. Packwood* Jan B. Packwood Director	"
By:	*/s/Judith A. Johansen* Judith A. Johansen Director	By:	*/s/Richard G. Reiten* Richard G. Reiten Director	"
By:	*/s/Christine King* Christine King Director	By:	*/s/Joan H. Smith* Joan H. Smith Director	"
By:	*/s/Gary G. Michael* Gary G. Michael Director	By:	*/s/Robert A. Tinstman* Robert A. Tinstman Director	"
By:	*/s/Peter S. O'Neill* Peter S. O'Neill Director	By:	*/s/Thomas J. Wilford* Thomas J. Wilford Director	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IDAHO POWER COMPANY
(Registrant)

February 26, 2009

By: /s/J. LaMont Keen
J. LaMont Keen
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By:	/s/Jon H. Miller Jon H. Miller	Chairman of the Board	February 26, 2009
By:	/s/J. LaMont Keen J. LaMont Keen	President and Chief Executive Officer and Director (Principal Executive Officer)	"
By:	/s/Darrel T. Anderson Darrel T. Anderson	Senior Vice President - Administrative Services and Chief Financial Officer (Principal Financial Officer) (Principal Accounting Officer)	"

By:	/s/Richard J. Dahl Richard J. Dahl Director	By:	/s/Jan B. Packwood Jan B. Packwood Director	"
By:	/s/Judith A. Johansen Judith A. Johansen Director	By:	/s/Richard G. Reiten Richard G. Reiten Director	"
By:	/s/Christine King Christine King Director	By:	/s/Joan H. Smith Joan H. Smith Director	"
By:	/s/Gary G. Michael Gary G. Michael Director	By:	/s/Robert A. Tinstman Robert A. Tinstman Director	"
By:	/s/Peter S. O'Neill Peter S. O'Neill Director	By:	/s/Thomas J. Wilford Thomas J. Wilford Director	

FORESIGHT · DILIGENCE · PREPARATION · TRADITION · COURAGE

IDACORP and Idaho Power Board of Directors

Richard J. Dahl
(2008) Santa Rosa Valley, California
Chairman of the Board, International Rectifiers Corp; director, Dine Equity, Inc.; and formerly President and Chief Operating Officer of Dole Food Company

Judith A. Johansen
(2007) Lake Oswego, Oregon
President of Marylhurst University; director, Cascade BanCorp and Schnitzer Steel; formerly President and Chief Executive Officer of PacifiCorp; and formerly Chief Executive Officer and Administrator of Bonneville Power Administration

J. LaMont Keen
(2004) Boise, Idaho
President and Chief Executive Officer of IDACORP, Inc. and Idaho Power

Christine King
(2006) Hauppague, New York
President and Chief Executive Officer of Standard Microsystems Corporation; director, Atheros Communications, Inc. and Open-Silicon, Inc.; and formerly President and Chief Executive Officer of AMI Semiconductor

Gary G. Michael
(2001) Boise, Idaho
Director, The Clorox Co., Questar Corporation, Questar Gas, Questar Pipeline and Graham Packaging Co.; and formerly Chief Executive Officer of Albertsons, Inc.

Jon H. Miller
(1988) Boise, Idaho
Chairman of the Board, IDACORP, Inc. and Idaho Power; private investor; and formerly President and Chief Operating Officer of Boise Cascade Corporation

Peter S. O'Neill
(1995) Boise, Idaho
Director, Building Materials Holding Corp.; and formerly Chairman of O'Neill Enterprises LLC

Jan B. Packwood
(1997) Boise, Idaho
Formerly President and Chief Executive Officer of IDACORP, Inc.

Richard G. Reiten
(2004) Portland, Oregon
Director, U.S. Bancorp; Building Materials Holding Corp., and National Fuel Gas Co.; formerly President and Chief Executive Officer of Northwest Natural Gas Company; and formerly President and Chief Operating Officer of Portland General Electric

Joan H. Smith
(2004) Portland, Oregon
Self-employed consultant, consulting on regulatory strategy and telecommunications; affiliate director with Wilk & Associates/LECG LLP; and formerly Oregon Public Utility Commissioner

Robert A. Tinstman
(1999) Boise, Idaho
Director, Home Federal Bancorp, Inc. and CNA Surety Corp.; and formerly President and Chief Executive Officer of Morrison Knudsen Corporation

Thomas J. Wilford
(2004) Boise, Idaho
President of Alscott, Inc.; Chief Executive Officer of J.A. and Kathryn Albertson Foundation, Inc.; director, K12, Inc.

( ) Year elected to board

IDACORP®

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Boise, ID 83707-0070

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