IDAHO POWER CO
Form 10-K
February 28, 2008

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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, 2007
OR

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

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	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
	Preferred Share Purchase Rights	

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 ( ) No (X) 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 ( )

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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, 2007):

IDACORP, Inc.: $1,410,558,106 Idaho Power Company: None

Number of shares of common stock outstanding at January 31, 2008:

IDACORP, Inc.: 45,069,259
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 2008 Annual Meeting of Shareholders to be held on May 15, 2008.

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.

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COMMONLY USED TERMS

AFDC	-	Allowance for Funds Used During Construction
CAMP	-	Comprehensive Aquifer Management Plan
CEP	-	Continuous Equity Program
cfs	-	Cubic feet per second
EIS	-	Environmental impact statement
Energy Act	-	Energy Policy Act of 2005
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch, Inc.
FPA	-	Federal Power Act
GAAP	-	Generally Accepted Accounting Principles
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDEQ	-	Idaho Department of Environmental Quality
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCO	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
ITI	-	IDACORP Technologies, Inc.
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
maf	-	Million acre feet
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
Moody's	-	Moody's Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NEPA	-	National Environmental Policy Act of 1996
O&M	-	Operations and Maintenance
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
RFC	-	River Forecast Center
RFP	-	Request for Proposal
S&P	-	Standard & Poor's Ratings Services
SFAS	-	Statement of Financial Accounting Standards

SO_2	-	Sulfur Dioxide
SRBA	-	Snake River Basin Adjudication
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

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*Except as indicated in Item 12, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2008 Annual Meeting of Shareholders.

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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 (MD&A) - 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. IPC is experiencing moderate customer growth in its service area, and this corporate strategy recognizes that IPC must make substantial investments in infrastructure to ensure adequate electricity supply and reliable service. IPC's regulatory plans for 2008 include finalizing the 2007 general rate case as well as additional initiatives designed 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, 2007, IDACORP had 2,044 full-time employees, 2,028 of which were employed by IPC.

IDACORP's only reportable business segment is IPC, which contributed $77 million to income from continuing operations in 2007.

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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.idahocorpinc.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 a 24,000 square mile area in southern Idaho and eastern Oregon, with an estimated population of 982,000. 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, 2007, IPC supplied electric energy to approximately 482,000 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.

IPC's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, forest products, beet sugar refining and winter recreation.

Regulation
IPC is under the regulatory jurisdiction (as to rates, service, accounting and other general matters of utility operation) of the FERC, the Idaho Public Utilities Commission (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 is subject to the provisions of the Federal Power Act (FPA) as a "public utility" as therein defined. IPC's retail rates are established under the jurisdiction of the state regulatory commissions and its wholesale and transmission rates are regulated by the FERC (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 FPA as a "licensee" as therein defined. As a licensee under the FPA, IPC and its licensed hydroelectric projects are subject to the provisions of Part I of the FPA. All licenses 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.

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").

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Rates
The rates IPC charges to its general business customers are determined by the IPUC and the OPUC. Significant rate cases and proceedings are discussed in more detail in Part II, Item 7 - "MD&A - REGULATORY MATTERS." 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. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, approximately 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered or over-recovered portion, is then included in the calculation of the next year's PCA. IPC has also applied to the OPUC to implement a PCA mechanism in Oregon similar to the one in Idaho.

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 3,193 megawatts (MW), set on July 13, 2007. The previous hourly system peak of 3,084 MW was set in 2006. 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. IPC expects total system average load to grow 2.1 percent annually over the next three years.

Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by weather conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, 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**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
	(thousands of MWhs)					
Hydroelectric	6,181	9,207	6,199	46%	57%	46%
Thermal	7,367	7,021	7,315	54%	43%	54%
Total system generation	13,548	16,228	13,514	100%	100%	100%

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

The generation from IPC's hydroelectric facilities in 2007 was reduced due to poor stream flow conditions. The observed stream flow data released on August 1, 2007, by the National Weather Service's Northwest River Forecast Center (RFC) indicated that Brownlee reservoir inflow for April through July 2007 was 2.8 million acre-feet (maf), or 44 percent of the RFC average. Brownlee reservoir inflow for 2007 totaled 8.5 maf, or 56 percent of the RFC average.

Streamflow projections for 2008 are somewhat improved. Storage in selected federal reservoirs upstream of Brownlee as of February 10, 2008 was 76 percent of average. The stream flow forecast released on February 14, 2008, by the RFC predicts that Brownlee reservoir inflow for April through July 2008 will be 5.7 maf, or 90 percent of the RFC average.

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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, Avista Corporation, PacifiCorp, NorthWestern Energy and 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 2009 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. As of late February 2008, the longwall was operating at normal production. IPC believes Bridger Coal's overall 2008 production and cost objectives are achievable by modifying the surface mine operation plan to offset the underground mining difficulties. Using coal from both mine and plant stockpiles, planned deliveries to the Jim Bridger power plant continue and generation is not expected to be negatively impacted.

Sierra Pacific Power Company, 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. IPC, 50 percent owner of the plant, is obligated to purchase one-half of the coal, ranging from 515,000 tons to 762,500 tons annually. Sierra Pacific Power Company 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, has an agreement with Buckskin Mining Company to supply all of Boardman's coal requirements through 2008. As 10 percent owner of the plant, IPC is obligated to purchase ten percent of the coal purchased under this agreement, ranging from 230,000 to 270,000 tons annually. A Request for Proposal to secure coal for the period 2009-2013 is in process.

IPC owns and operates the Danskin and Bennett Mountain combustion turbines, which are supplied gas through the 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 as alternate firm basis without incurring a reservation charge on the additional amount. 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 18 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.

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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 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 Snake River Basin Adjudication (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 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): The IRP is IPC's business plan for resource acquisition and is the starting point for demonstrating prudence in IPC's resource decisions. IPC filed its 2006 IRP with the IPUC in September 2006 and with the OPUC in October 2006. 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 generation technologies. The 2006 IRP identified IPC's forecast 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. The OPUC acknowledged the 2006 IRP in September 2007 with the stipulation that IPC not commit to the construction of a 250-MW pulverized coal resource, identified to come on-line in 2013, until IPC presents an update of the 2006 IRP to the OPUC no later than June 2008. With its acceptance of the 2006 IRP, the IPUC requested that IPC align the submittal of its next IRP with those submitted by other utilities. To comply with this request IPC intends to provide an update on the status of the 2006 IRP to both the IPUC and OPUC no later than June 2008 and file a new IRP in June 2009.

In a departure from the 2006 IRP, IPC plans to construct a natural gas-fired combined cycle combustion turbine located close to its load center in southern Idaho. IPC determined that coal-fired generation was not the best technology to meet its resource needs by 2013 due to escalating construction costs, potential permitting issues, and continued uncertainty surrounding future greenhouse gas laws and regulations. See further discussion in Part II - Item 7 - "MD&A - REGULATORY MATTERS - Integrated Resource Plan."

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CSPP Purchases: 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 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 2007 the IPUC issued orders increasing the Published Avoided Cost and requiring differentiation between heavy load and light load hour energy prices. See Part II - Item 7 - "MD&A - REGULATORY MATTERS - Wind Integration Costs and PURPA Avoided Cost Rate Computation."

On August 4, 2005, the IPUC granted a temporary reduction in the eligible CSPP project size to 100 kW for intermittent generation resources (such as wind) only and ordered IPC to study the impacts of integrating this type of resource. IPC completed and filed with the IPUC a wind generation integration study report on February 6, 2007. Public workshops were conducted, comments were filed with the IPUC, and information request responses were submitted to the IPUC. A proposed settlement of this issue has been presented to the IPUC for its consideration.

In 2007, as required by the OPUC, IPC filed new avoided costs for the state of Oregon and new standard contracts. The OPUC has approved the new rates and standard contracts.

As of December 31, 2007, IPC had signed agreements to purchase energy from 94 CSPP facilities with contracts ranging from one to 30 years. Seventy-six of these facilities, with a combined nameplate capacity of 231 MW, were on-line at the end of 2007; the other 18 facilities under contract, with a combined nameplate capacity of 267 MW, are projected to come on-line between 2008 and 2010. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2007, IPC purchased 777,147 megawatt-hours (MWh) from these projects at a cost of $45 million, resulting in a blended price of 5.9 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.

Due to the uncertainty regarding the regulation requirements of anticipated wind generation, IPC terminated the wholesale contract for load following services provided to NorthWestern Energy, effective December 31, 2007. The load following contract required IPC to increase or decrease its generation by up to 30 MW to react to NorthWestern's system load changes.

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 2008; however, Raft River Electric Cooperative has provided notice that it intends to renew the contract, as allowed in the original agreement, through September 2010.

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IPC has one wholesale reserve sales contract. The reserve contract is 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 one firm wholesale purchased power contract. This contract is with PPL Montana, 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.

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 holds rights-of-way from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada, known as the Southwest Intertie Project (SWIP). In 2004, the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500-kilovolt transmission line within the rights-of-way to December 2009. IPC obtained the rights-of-way to construct a transmission line along this corridor, but no longer plans to build the line. On March 31, 2005, IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, which provides White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option may be exercised in part or as a whole and, if fully exercised, will result in a net pre-tax gain to IPC of approximately $6 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 compliance costs will continue to be significant for the foreseeable future.

Based upon present environmental laws and regulations, IPC estimates its 2008 capital expenditures for environmental matters, excluding Allowance for Funds Used During Construction (AFDC), will total $26 million. Studies and measures related to environmental concerns at IPC's hydroelectric facilities account for $15 million, and investments in environmental equipment and facilities at the thermal plants account for $11 million. For 2009 and 2010, environmental-related capital expenditures, excluding AFDC, are estimated to be $65 million. Anticipated expenses related to IPC's hydroelectric facilities account for $29 million, and thermal plant expenses are expected to total $36 million.

IPC anticipates approximately $20 million in annual operating costs for environmental facilities during 2008. Hydroelectric facility expenses and thermal plant expenses account for the majority of the costs at approximately $13 million and $7 million, respectively. For 2009 and 2010, total environmental related operating costs are estimated to be approximately $54 million. Expenses related to the hydroelectric facilities are expected to be $39 million, and thermal plant expenses are expected to be $15 million during this period.

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 North Valmy located in Nevada. Please see Part II, Item 7 - "MD&A - LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Air Quality Issues" for a discussion of these matters.

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.

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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 2007, IPC spent approximately $0.8 million identifying and eliminating PCBs.

For a discussion of other environmental issues, including air quality, endangered species, and climate change, please see Part II, Item 7 - "MD&A - Legal and Environmental Issues - Environmental Issues."

Energy Efficiency

In 2007, IPC spent approximately $15.6 million to promote energy efficiency and summer peak reduction through its Demand Side Management (DSM) programs. Major funding for program development, implementation and administration comes from the Idaho and Oregon tariff riders for DSM. From 2001 to March 2007, when funding was discontinued due to the suspension of investor-owned utilities' participation in the Residential Exchange Program of the Bonneville Power Administration (BPA), IPC also received funding from the Conservation and Renewables Discount Program of the BPA.

Approximately $1.8 million was spent on research, analysis and development, technology evaluation, market transformation, and general overhead expenses. 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 $4.0 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 segment's 2007 spending was approximately $3.3 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 $4.5 million was spent on these programs.

Approximately $2.0 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 2007, IPC's energy efficiency programs reduced energy usage by approximately 91,000 MWh and the targeted demand reduction programs resulted in a summer peak reduction of about 48 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.

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Some state regulatory authorities are in the process of changing utility regulations in response to federal and state statutory changes and evolving competitive markets. These statutory changes and conforming regulations may result in increased 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 - FERC Proceedings."

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,		
	2007	**2006**	**2005**
Revenues (thousands of dollars)			
Residential	$ 308,208	$ 299,594	$ 299,488
Commercial	170,001	162,391	173,268
Industrial	101,409	102,958	118,259
Irrigation	88,685	71,432	76,255
Total general business	668,303	636,375	667,270
Off-system sales	154,948	260,717	142,794
Other	52,150	23,381	27,619
Total	$ 875,401	$ 920,473	$ 837,683
Energy use (thousands of MWh)			
Residential	5,227	5,068	4,760
Commercial	3,937	3,761	3,639
Industrial	3,454	3,475	3,423
Irrigation	1,924	1,635	1,467
Total general business	14,542	13,939	13,289
Off-system sales	2,744	5,821	2,774
Total	17,286	19,760	16,063

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 $15 million, $19 million and $20 million in 2007, 2006 and 2005, respectively. IFS's portfolio also includes historic rehabilitation projects such as, the Empire Building in Boise, Idaho. IFS did not make any new investments during 2007.

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, 2007, the gross amount of IFS's portfolio equaled $175 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.

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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 in both 2007 and 2006, and $7 million in 2005.

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, the weather 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. Through its power cost adjustment in Idaho, Idaho Power Company can expect to recover approximately 90 percent of the increase in its Idaho jurisdictional net power supply costs, which are fuel and purchased power less off-system sales, above the level included in its base rates. The power cost adjustment recovery includes both a forecast and deferrals that are subject to the regulatory process. However, recovery of amounts above forecast in one power cost adjustment year does not occur until the subsequent power cost adjustment year. The non-Idaho net power supply costs are subject to periodic recovery from the Oregon and Federal Energy Regulatory Commission jurisdictional customers.

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 legal actions 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.

o Through its annual power cost adjustment in Idaho, Idaho Power Company can expect to recover approximately 90 percent of the increase in its Idaho jurisdictional net power supply costs, which are fuel and purchased power less off-system sales, above the level included in its base rates. The remaining ten percent is absorbed by Idaho Power Company.

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o 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. In periods of growing load, the marginal energy costs of serving new Idaho retail customers are subtracted from the power cost adjustment leaving Idaho Power Company with no opportunity between general rate case filings to recover these costs. If the Idaho Public Utilities Commission increases the rate or modifies the method used to calculate the load growth adjustment rate, or if customer load is higher than the load used to calculate base rates, Idaho Power Company's earnings and cash flows could be reduced.

o 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. As Idaho Power Company's reliance on purchased power continues to increase, the risks associated with the remaining ten percent not recovered through the power cost adjustment could increase costs and reduce earnings and cash flows.

o 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.

o 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.

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 lead to restrictions on generation resources. Long-term climate change could significantly affect Idaho Power Company's business because changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation. In addition, legislative and/or regulatory developments related to climate change could place restrictions on construction of new generation resources, the expansion of existing resources, or operation of generation resources.

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 were to 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 flow 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 possibilities for economic expansion.

Conditions that may be imposed in connection with hydroelectric license renewals may require large capital expenditures 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 reduce earnings and cash flows.

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The cost of complying with environmental regulations can increase capital expenditures and operating costs and reduce earnings and cash flows. 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 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. The effects of mercury and other pollutant emissions from coal-fired plants are also being discussed. Governmental and non-governmental entities closely scrutinize these plants and bring enforcement actions to ensure compliance. The adoption of new statutes, rules and regulations to implement carbon dioxide, mercury or other emission controls could result in increased capital expenditures and could increase the cost of operating coal-fired generating plants, 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, including those that have arisen out of the western energy situation. IDACORP, Inc., IDACORP Energy and Idaho Power Company are involved in a number of proceedings including the California refund proceeding at the Federal Energy Regulatory Commission, which has been settled with the largest portion of the market participants but which has appeals pending at 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, in which the Federal Energy Regulatory Commission directed that no refunds be paid, but in connection with which the United States Court of Appeals for the Ninth Circuit issued a decision remanding the matter to the Federal Energy Regulatory Commission and which is presently the subject of rehearing applications pending before the United States Court of Appeals for the Ninth Circuit; show cause proceedings at the Federal Energy Regulatory Commission, which have been settled but have been appealed; claims pending before the United States Court of Appeals for the Ninth Circuit that the Federal Energy Regulatory Commission ordered refund period should have been expanded to include a longer time period; and the reversal by the United States Court of Appeals for the Ninth Circuit of Federal Energy Regulatory Commission rulings that market-based sellers' transactional reports satisfy the Federal Energy Regulatory Commission's filed-rate doctrine requirements as a means of expanding refunds from all sellers of wholesale power, which rulings have been remanded to the Federal Energy Regulatory Commission. To the extent the companies are required to make payments, earnings and cash flows will be negatively affected. 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.

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.

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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 its ability 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 and increase their cost of borrowing. On January 31, 2008, Standard & Poor's Ratings Services lowered the corporate credit rating and long-term ratings of IDACORP, Inc. and Idaho Power Company. In addition, two series of pollution control bonds issued for Idaho Power Company's benefit are supported by financial guaranty insurance policies. The interest rates on these bonds have increased significantly because of the ratings downgrades of the bond insurer. 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. Current or future 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, and require IDACORP, Inc. and Idaho Power Company to pay a higher interest rate on their debt.

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. Demographic factors in the workplace present challenges to employers nationwide and are of particular concern to the electric utility industry. Approximately one-half of the industry's workforce is age 45 or older, making the median age of utility workers higher than the national average. Idaho Power Company is confronted with the challenge of retaining its skilled workforce while recruiting new talent to offset critical losses due to retirements. 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

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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 4,747 miles of high-voltage transmission lines, 23 step-up transmission substations located at power plants, 20 transmission substations, eight switching stations, 222 energized distribution substations (excluding mobile substations and dispatch centers)and approximately 64,672 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 (4) (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)(3)	261,800	
Salmon (diesel-internal combustion)	5,000	
Bennett Mountain (gas-fired)	172,800	
Total Steam and Other	1,557,801	
Total Generation	3,266,846	

(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.
(3) Includes unit under construction (estimated at 170,000 kW and commercial acceptance on April 1, 2008).
(4) Nameplate capacity has been updated as part of the NERC reliability standards FAC-008 and 009 review process. See discussion of relicensing in Part II, Item 7 - "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

At December 31, 2007, 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, 23 years; and distribution lines and substations, 20 years. IPC considers its properties to be well-maintained and in good operating condition.

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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.

Idaho Energy Resources Co. 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.

See Note 1 to IDACORP's and IPC's Consolidated Financial Statements for a discussion of the property of IDACORP's consolidated Variable Interest Entities.

ITEM 3. LEGAL PROCEEDINGS

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

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

None

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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 55.

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 49.

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 61.

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 53.

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 50.

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 47.

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, and Attorney III from 1996 to June 7, 2003. Age 47.

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 55.

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 47.

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 50.

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GREGORY W. PANTER Vice President - Public Affairs of IDACORP, Inc. and Idaho Power Company, appointed April 1, 2001. Age 59.

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. Ms. Shankel was a member of the Finance Department of Idaho Power Company from April 4, 2001, to July 2003. Age 36.

JOHN R. GALE Vice President - Regulatory Affairs of Idaho Power Company, appointed March 15, 2001. Age 57.

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, and Control Area Operations Leader from October 13, 2001, to March 2, 2002. Age 42.

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 and General Manger of Customer Service and Metering from January 9, 1999, to March 2, 2002. Age 52.

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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 22, 2008, there were 14,839 holders of record and the stock price was $30.80 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 the IDACORP and IPC Credit Facilities 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 of no more than 65 percent at the end of each fiscal quarter. IPC's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would cause their leverage ratios to exceed 65 percent. At December 31, 2007, the leverage ratios for IDACORP and IPC were both 53 percent.

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 $53 million, $51 million and $51 million in 2007, 2006 and 2005, respectively.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2007 and 2006 as reported in the consolidated transaction reporting system.

	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

	2006 Quarters			
Common Stock, without par value:	**1st**	**2nd**	**3rd**	**4th**
High	$33.28	$35.20	$38.81	$40.17
Low	28.97	32.00	34.00	37.61
Dividends paid per share	0.30	0.30	0.30	0.30

Issuer Purchases of Equity Securities:

None

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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, 2002, 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
2002	$ 100.00	$ 100.00	$ 100.00
2003	128.86	128.67	123.48
2004	137.11	142.65	151.68
2005	136.92	149.66	176.02
2006	186.71	173.27	212.56
2007	176.26	182.78	247.76

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.

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ITEM 6. SELECTED FINANCIAL DATA

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

	2007	2006	2005	2004	2003
Operating revenues	$ 879,394	$ 926,291	$ 842,864	$ 827,856	$ 823,002
Operating income	152,078	169,704	154,653	106,233	84,062
Income from continuing operations	82,272	100,075	85,716	80,781	49,732
Diluted earnings per share from continuing operations	1.86	2.34	2.02	2.10	1.30
Dividends declared per share	1.20	1.20	1.20	1.20	1.70
Financial Condition:					
Total assets	$ 3,653,308	$ 3,445,130	$ 3,364,126	$ 3,234,172	$ 3,106,108
Long-term debt	1,168,336	1,023,773	1,039,852	1,058,152	1,013,757
Financial Statistics:					
Times interest charges earned:					
Before tax (1)	2.35	2.78	2.65	1.99	1.48
After tax (2)	2.16	2.54	2.37	2.32	1.77
Market-to-book ratio (3)	131%	151%	121%	128%	132%
Payout ratio (4)	65%	48%	79%	63%	139%
Return on year-end common equity (5)	6.8%	9.6%	6.2%	7.2%	5.4%
Book value per share (6)	$ 26.79	$ 25.65	$ 24.05	$ 23.88	$ 22.62

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 (AFDC), and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFDC credits.

(2) The sum of interest on long-term debt, other interest expense excluding AFDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFDC 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 and in Part II, Item 7 - "MD&A - RESULTS OF OPERATIONS - Non-utility Operations - Discontinued Operations."

IDACORP Energy, a marketer of energy commodities, wound down operations in 2003.

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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.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM, Inc. (IDACOMM) as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144. IDACORP's 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 later in the MD&A and in Note 16 to IDACORP's and IPC's Consolidated Financial Statements.

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

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

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, 2007 and 2006, and the results of operations and cash flows for each company for the years ended December 31, 2007, 2006 and 2005.

FORWARD-LOOKING INFORMATION:

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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:

- Changes in and compliance with governmental policies, including new interpretations of existing policies, and regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission, the Oregon Public Utility Commission, and the Internal Revenue Service with respect to allowed rates of return, industry and rate structure, day-to-day business operations, acquisition and disposal of assets and facilities, operation and construction of plant facilities, provision of transmission services, relicensing of hydroelectric projects, recovery of purchased power expenses, recovery of other capital investments, present or prospective wholesale and retail competition, including but not limited to retail wheeling and transmission costs, and other refund proceedings;
- Changes arising from the Energy Policy Act of 2005;
- Litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability;
- Changes in and compliance with environmental, endangered species and safety laws and policies;
- Climate change affecting customer demand, hydroelectric generation and new legislative policies and enactments, and/or regulatory obligations;
- Weather variations affecting hydroelectric generating conditions and customer energy usage;
- Over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities;
- Construction of power generating, transmission and distribution facilities including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up;
- Operation of power generating facilities including breakdown or failure of equipment, performance below expected levels, competition, fuel supply, including availability, transportation and prices, and availability of transmission;
- Blackouts or other disruptions of Idaho Power Company's or the western interconnected transmission systems;
- Impacts from the formation of a regional transmission organization or the development of another transmission group;
- Population growth rates and other demographic patterns;
- Market demand and prices for energy, including structural market changes;
- Changes in operating expenses and capital expenditures, including costs and availability of materials, fuel, and commodities, and fluctuations in sources and uses of cash;
- Results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by factors such as credit ratings and general economic conditions;

- Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;
- Homeland security, natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire, acts of war or terrorism;
- Market conditions that could affect the operations and prospects of IDACORP's subsidiaries or their competitors;
- Increasing health care costs and the resulting effect on medical benefits paid for employees;
- Performance of the stock market and the changing interest rate environment, which affect the amount of required contributions to pension plans, as well as the reported costs of providing pension and other postretirement benefits;
- Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;
- Changes in tax rates or policies, interest rates or rates of inflation;
- Adoption of or changes in critical accounting policies or estimates; and
- New accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements.

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

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EXECUTIVE OVERVIEW:

2007 Financial Results

A summary of IDACORP's net income and earnings per diluted share for the last three years is as follows:

	2007	**2006**	**2005**
Net income	$ 82,339	$ 107,403	$ 63,661
Average outstanding shares - diluted (000s)	44,291	42,874	42,362
Earnings per diluted share	$ 1.86	$ 2.51	$ 1.50

The key factors affecting the change in IDACORP's net income for 2007 include (amounts shown are net of income taxes):

- Discontinued operations contributed $0.1 million to earnings in 2007 as compared to $7 million in 2006, a decrease of $0.17 per diluted share. 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.
- Net loss at the holding company was $3.5 million, a decrease of $2.5 million, or $0.05 per diluted share, from the prior year. The decrease in net loss is attributable to a decrease in administration expenses resulting from the sale of ITI and IDACOMM.
- IFS contributed $2.4 million less to earnings than in the prior year, a decrease of $0.06 per diluted share. The decline in earnings is attributable to higher investment amortization expense and lower tax benefits due to a reduction in the amount of new investments combined with the continued aging of existing investments.
- IPC's net income for the last three years is as follows:

	2007	**2006**	**2005**
Net income	$ 76,579	$ 93,929	$ 71,839

The key factors affecting IPC's net income for 2007 include (amounts shown are net of income taxes):

- Increased retail sales contributed $12.9 million to earnings in 2007. Warmer and drier conditions in 2007 led to higher residential, commercial and industrial usage, as well as higher irrigation loads as compared to the prior year. IPC continued to experience moderate customer growth, with the average number of general business customers increasing 12,125 over 2006, an increase of 2.6 percent.
- Increased costs to supply power, net of rate adjustments, reduced earnings by $13.0 million in 2007. Poor hydroelectric generating conditions in 2007 increased IPC's reliance on typically more expensive thermal generation and purchased power, and reduced wholesale sales. IPC's hydroelectric generation contributed only 46 percent of total system generation in 2007 as compared to 57 percent in 2006.
- Increases in Other O&M expenses reduced earnings by $12.7 million in 2007 compared to 2006. The increase is primarily the result of increases in third-party transmission costs, regulatory commission expenses, maintenance expenses for IPC's coal-fired generation facilities, hydroelectric license and inspection costs, and the Fixed Cost Adjustment accrual which began in 2007.
- Gain on sales of excess SO_2 emission allowances was $1.7 million in 2007 compared to $5.0 million in 2006.

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Non-GAAP Financial Measures

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

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

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

The calculations of IPC's electric utility margin for the last three years are as follows:

	2007	**2006**	**2005**
General business revenue	$ 668,303	$ 636,375	$ 667,270
PCA amortization	287	2,432	(27,791)
Other revenues amortization			
Irrigation load reduction	-	(5,400)	(8,501)
Rate case tax settlement	-	(4,745)	(2,892)
Total	668,590	628,662	628,086
Power supply costs:			
Off-system sales	154,948	260,717	142,794
Purchased power	(289,484)	(283,440)	(222,310)
Fuel	(134,322)	(115,018)	(103,164)
PCA deferral	120,844	27,094	30,786
Total	(148,014)	(110,647)	(151,894)
Third party transmission expense	(10,470)	(7,639)	(6,292)
Other revenues (excluding DSM)	38,663	33,526	39,012
Electric utility margin	$ 548,769	$ 543,902	$ 508,912
Electric utility margin as a percentage of total general business revenue, PCA amortization and other revenues amortization	82%	87%	81%

The decline in electric utility margin as a percentage of total general business revenue, PCA amortization and other revenues amortization is a result of an increase in the ten percent sharing component of the PCA due to below normal hydroelectric production and the negative impact of the Load Growth Adjustment Rate (LGAR) mechanism.

System load in 2007 was 1.0 million MWh greater than the base loads established in the 2005 general rate case. This represents an increase of 274,000 MWh over 2006 total system loads. The MWh increases, when combined with an increase in the LGAR in April 2007 from $16.84 per MWh to $29.41 per MWh, result in a decline in a component of the PCA deferral as compared to 2006. This decline reduced electric utility margin by $13.0 million.

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The following table reconciles electric utility margin to electric utility operating income (GAAP) for the last three years:

	2007	2006	2005
Electric utility margin	$ 548,769	$ 543,902	$ 508,912
Other operations and maintenance (excluding third party transmission expense)	(276,040)	(257,171)	(236,089)
Gain on sale of emission allowances	2,754	8,257	1,172
Depreciation	(103,072)	(99,824)	(101,485)
Taxes other than income taxes	(17,634)	(18,661)	(20,856)
Operating income - electric utility (GAAP)	$ 154,777	$ 176,503	$ 151,654

Business Strategy

IDACORP is focusing on a strategy that emphasizes IPC as IDACORP's core business. IPC continues to experience moderate customer growth in its service area, and this corporate strategy recognizes that IPC must make substantial investments in infrastructure to ensure adequate supply and reliable service. IPC's regulatory plans in 2008 include finalizing the 2007 general rate case as well as additional initiatives designed to speed recovery of the financial and operating costs of new facilities and system improvements.

The strategy includes seeking timely rate recovery in both the Idaho and Oregon jurisdictions. The 2008 regulatory strategy includes filing for recovery of the investment and operating costs of IPC's new 170- MW natural gas-fired peaking plant expected to go on line in April 2008; pursuing a power cost adjustment mechanism in Oregon; and potential general rate case filings in both Idaho and Oregon.

IFS and Ida-West remain components of the corporate strategy. This strategy also included the sale of non-core businesses. IDACORP completed the sales of ITI on July 20, 2006, and IDACOMM on February 23, 2007.

Regulatory Matters

General rate case settlement: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of approximately 10.35 percent, or $63.9 million annually, for its Idaho customers in order to begin recovery of its capital investments and higher operating costs. IPC also requested a $29.16 per MWh LGAR, which adjusts the power supply costs IPC includes in the PCA for differences between actual load and the load used in calculating base rates. The existing LGAR is $29.41 per MWh. The impact of the new LGAR on IPC will ultimately be determined by future load changes.

The parties to the proceeding reached a settlement that includes an average annual increase of 5.2 percent (approximately $32.1 million annually). The parties also agreed in the settlement to make a good faith effort to develop a mechanism to adjust or replace the current LGAR. As an interim solution, the parties have agreed to use the LGAR of $62.79 per MWh recommended by the IPUC Staff in its testimony filed December 10, 2007, but to apply it to only fifty percent of the load growth occurring during each month within the April 2008 - March 2009 PCA year.

The parties also agreed in the settlement to participate in a good faith discussion regarding a forecast test year methodology that balances the auditing concerns of the IPUC Staff and intervenors with IPC's need for timely rate relief. The parties agreed that such a methodology would begin with auditable numbers from which projections would be made for the test year.

IPC filed a settlement stipulation with the IPUC on January 23, 2008. The settlement is subject to approval by the IPUC. The parties have requested in the stipulation that the new rates become effective no later than March 1, 2008, but IPC is unable to predict what relief the IPUC will grant or when the IPUC will issue its final order.

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

Emission allowances: In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million, after subtracting transaction fees. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). 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 is included in IPC's PCA calculations as a credit to the PCA true-up balance and is currently reflected in PCA rates during the June 1, 2007, through May 31, 2008, PCA rate year.

During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million, after subtracting transaction fees. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $18.5 million ($11.3 million net of tax, assuming a tax rate of approximately 39 percent). On January 15, 2008, a workshop was held to discuss whether the customer share of the Idaho jurisdictional portion of the 2007 sales proceeds should once again be included as a PCA credit or used to reduce investment costs in wind development, green tags, or other options that would provide longer term customer benefits. Because the workshop participants were unable to reach a consensus regarding the use of the SO_2 emission allowance proceeds, the IPUC determined that the case would proceed under modified procedure. Written comments were due February 25, 2008.

The bulk of IPC's accumulated excess emission allowances were sold during the 2005-2007 period. IPC currently has approximately 15,000 excess emission allowances and anticipates accumulating a similar amount of excess 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 allowances.

Record system peaks

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

Integrated Resource Plan

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

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

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The near-term action plan in the 2006 IRP indicated initial commitments to the construction of a coal-fired base load resource would be necessary before the end of 2007 in order for a project to be on-line in 2013. In order to meet this schedule, IPC screened and evaluated coal-fired resources in 2006 and 2007. The results of this evaluation indicated construction costs had escalated substantially since resource cost estimates were prepared for the 2006 IRP. Due to such escalating construction costs, potential permitting issues, and continued uncertainty surrounding future greenhouse gas laws and regulations, IPC determined that coal-fired generation was not the best technology to meet its resource needs in 2013. IPC plans to construct a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho. IPC continues to evaluate coal-fired resource opportunities, including expansion of its jointly-owned facilities, clean coal technologies and potential power purchase agreements for future energy needs.

Transmission Projects

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

IPC is also exploring alternatives for the construction of a 500-kV line between southwestern Idaho and the Northwest, named the Hemingway-Boardman Line (formerly referred to as the Idaho-Northwest Line). If built, the line could run from the proposed Hemingway Station southwest of Boise to a proposed transmission station near Boardman, Oregon and be in service as early as 2012. IPC has received inquiries from other parties about participating in this project.

The proposed Gateway West and Hemingway-Boardman transmission projects will be used both by wholesale transmission customers and to serve IPC's native load consistent with IPC's Open Access Transmission Tariff (OATT). Therefore these facilities will be subject to both the FERC and state public utility commission regulation and rate making policies.

Capital Requirements and Cash Flows

IDACORP estimates that it will spend approximately $900 million on construction expenditures over the next three years, excluding any estimated expenditures for a Nominal 250-MW combined cycle combustion turbine expected to be operational in mid-2012 and the transmission projects discussed above. This amount reflects the need for additional resources in order for IPC to supply power to its growing number of customers.

Forecasts indicate that internal cash generation after dividends will provide less than the full amount of total capital requirements for 2008 through 2010. 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.

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.

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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. This includes active participation in the Snake River Basin Adjudication, a judicial action initiated in 1987 to determine the nature and extent of water use in the Snake River basin, judicial and administrative proceedings relating to the conjunctive management of ground and surface water rights, and management and planning processes intended to reverse declining trends in river, spring, and aquifer levels and address the long-term water resource needs of the state. On occasion, resolution of these water management issues involves litigation. IPC is involved in legal actions regarding not only its water rights but also the water rights of others. One such action, initiated in the Snake River Basin Adjudication, involves IPC's water rights at the Swan Falls project on the Snake River and several other upstream hydroelectric projects that are the subject of a 1984 agreement with the state of Idaho known as the Swan Falls Agreement. IPC also has initiated legal action against the U.S. Bureau of Reclamation (USBR) over the interpretation and effect of a 1923 contract with the USBR on the operation of the American Falls Reservoir and the release of water from that reservoir to be used at IPC's downstream hydroelectric projects. Although IPC intends to continue vigorously defending its water rights and although none of the pending water management issues are expected to impact IPC's hydroelectric generation in the near term, IPC cannot predict the ultimate outcome of these matters or what effect they may have on its consolidated financial positions, results of operations or cash flows. IPC's ongoing participation in such issues will help ensure that water remains available over the long-term for use at IPC's hydroelectric projects on the Snake River.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES:

The preparation of financial statements in accordance with GAAP requires management to apply accounting policies and make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates involve judgment with respect to numerous 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 $450 million of regulatory assets and $274 million of regulatory liabilities at December 31, 2007. 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.

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, and a postretirement medical benefit plan.

The expenses IDACORP and IPC record for these plans depend on a number of factors, including the provisions of the plans, changing employee demographics, actual returns on plan assets and several assumptions used in the actuarial valuations upon which pension expense is based. 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 2008 pension expense will be increased to 6.4 percent from the 5.85 percent used in 2007.

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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 $15 million, $16 million, and $14 million for the three years ended December 31, 2007, 2006 and 2005, respectively, including amounts allocated to capitalized labor and amounts deferred as regulatory assets. For 2008, gross pension expense is expected to total approximately $16 million, which takes into account the increase in the discount rate noted above. 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			
	2008		2007		2008		2007	
	(millions of dollars)							
Effect of 0.5% increase	$	(1.4)	$	(1.7)	$	(2.2)	$	(2.2)
Effect of 0.5% decrease		1.7		2.7		2.2		2.2

No cash contributions were made to the qualified plan from 2005 through 2007, and none are expected in 2008. Under the non-qualified plan, IPC makes payments directly to participants in the plan. Payments are expected to be approximately $2.7 million in 2008 and averaged approximately $2.5 million per year from 2005 to 2007. Gross postretirement plan contributions are expected to be approximately $4.1 million in 2008, and averaged $4.3 million from 2005 to 2007.

Please refer to Note 8 and Note 6 of IDACORP's and IPC's Consolidated Financial Statements, which contains additional information about the pension and postretirement plans and the regulatory treatment of pension expense, respectively.

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.

Impairment of Long-Lived Assets

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, *"Accounting for the Impairment or Disposal of Long-Lived Assets."* 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. Long-lived assets that were evaluated in 2007 include the following:

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Southwest Intertie Project: IPC began developing the Southwest Intertie Project (SWIP) in 1988. IPC's investment consists predominantly of a federal permit for a specific transmission corridor in Nevada and Idaho and also private rights-of-way in Idaho. The SWIP rights-of-way extend from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada. In 2004 the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500kV transmission line within the rights-of-way before December 2009. On March 31, 2005, IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, which provides White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option may be exercised in part or as a whole and, if fully exercised, will result in a net pre-tax gain to IPC of approximately $6 million. Based on management expectations regarding SWIP, no impairment has been identified.

Impairment of Equity-Method Investments

IFS has affordable housing investments with a net book value of $78 million at December 31, 2007, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for two investments 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 2007 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.

Unbilled Revenue

IPC's general business revenues include an estimate of electricity delivered to general business customers that has not been billed at the end of the period. Unbilled revenues estimates are dependent upon a number of inputs that require management's judgment. Unbilled revenue is calculated by taking daily estimates of MWhs delivered and applying information from the meter-reading schedule to estimate the portion of MWhs delivered that have not been billed. These unbilled MWhs are allocated to the general business customer classes based on historical data. IPC then calculates unbilled revenue based on the respective rates of each customer class. Due to the seasonal fluctuations of IPC's load, the amount of unbilled revenue increases during the summer and winter months and decreases during the spring and fall.

Income Taxes

IDACORP and IPC account for income taxes in accordance with SFAS No. 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 2007 are compared to 2006 and the results of 2006 are compared to 2005.

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

		2007		2006		2005
IPC - Utility operations	$	76,579	$	93,929	$	71,839
IDACORP Financial Services		7,112		9,509		10,911
IDACORP Energy		(171)		5		4,881
Ida-West Energy		2,223		2,564		2,381
Holding company expenses		(3,471)		(5,932)		(4,296)
Discontinued operations		67		7,328		(22,055)
Total earnings	$	82,339	$	107,403	$	63,661
Average outstanding shares - diluted (000s)		44,291		42,874		42,362
Earnings per diluted share	$	1.86	$	2.51	$	1.50

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Utility Operations

Operating environment: IPC is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by weather conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, springtime snow pack run-off, river base flows, spring flows, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC's hydroelectric projects are reduced, IPC's hydroelectric generation is reduced. This results in less generation from IPC's resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased 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 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 were much lower in 2007 than 2006 resulting in 6.2 million MWh generated from IPC's hydroelectric facilities, compared to 9.2 million MWh in 2006. The observed stream flow data released on August 1, 2007, by the National Weather Service's Northwest River Forecast Center (RFC) indicated that Brownlee reservoir inflow for April through July 2007 was 2.8 million acre-feet (maf), or 44 percent of the RFC average. Brownlee reservoir inflow for 2007 totaled 8.5 maf, or 56 percent of the RFC average. Storage in selected federal reservoirs upstream of Brownlee as of February 10, 2008 was 76 percent of average. The stream flow forecast released on February 14, 2008 by the RFC predicts that Brownlee reservoir inflow for April through July 2008 will be 5.7 maf, or 90 percent of the RFC average.

Generation from thermal plants during 2007 was higher than 2006 due primarily to increased generation to meet increased load requirements. In addition, the thermal plants were under-utilized in 2006 due to an unanticipated outage at the Boardman plant and a planned outage at the Valmy plant, of which IPC owns a ten percent and 50 percent interest, respectively. Both units returned to service in June 2006. Additionally, the Bennett Mountain combustion turbine suffered a mechanical failure on July 11, 2006. IPC's investigation revealed that during construction a bolt was negligently installed by a third party. The bolt came loose, causing extensive mechanical damage. The plant was down from July 12 through September 6, 2006. Total repair costs were approximately $16 million. In 2007, IPC received reimbursement for the bulk of the total repair costs from its insurance carrier. With regards to the remaining repair costs, IPC has reached an agreement in principle with the third party, which essentially makes IPC whole.

IPC's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,193 MW, set on July 13, 2007. The previous hourly system peak of 3,084 MW was set in 2006. Although IPC was able to meet all of its load requirements during these periods of increased demand, all available resources of IPC's system were fully committed during several heavy load periods in the summer. 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**
2007	6,181	7,367	13,548	5,196	18,744
2006	9,207	7,021	16,228	4,964	21,192
2005	6,199	7,315	13,514	3,894	17,408

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

General Business Revenue: The 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.

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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:

	2007	2006	2005
Revenue			
Residential	$ 308,208	$ 299,594	$ 299,488
Commercial	170,001	162,391	173,268
Industrial	101,409	102,958	118,259
Irrigation	88,685	71,432	76,255
Total	$ 668,303	$ 636,375	$ 667,270
MWh			
Residential	5,227	5,068	4,760
Commercial	3,937	3,761	3,639
Industrial	3,454	3,475	3,423
Irrigation	1,924	1,635	1,467
Total	14,542	13,939	13,289
Customers (average)			
Residential	397,285	387,707	373,602
Commercial	61,640	59,050	57,146
Industrial	126	130	129
Irrigation	18,043	18,081	17,942
Total	477,094	464,968	448,819
Heating degree-days	5,128	5,195	5,437
Cooling degree-days	1,290	1,209	965
Precipitation (inches)	8.1	12.1	13.6

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.

2007 vs. 2006:

- **Rates:** Rate increases positively impacted general business revenue by $3.0 million in 2007 as compared to prior year. 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:** General business customer growth improved general business revenue $11.7 million for the year, as IPC continues to experience 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 is 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.

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2006 vs. 2005:

- **Rates:** Rate decreases negatively impacted general business revenue by $66.6 million in 2006 as compared to prior year. A PCA reduction on June 1, 2006, decreased rates by an average of 19.3 percent but was moderated by a net base rate increase of one percent on June 1, 2006 (3.2 percent base rate increase effective June 1, 2006, less a one-time base rate increase of 2.2 percent related to a rate case tax settlement which expired on the same date). Prior year revenues also included amounts related to a rate case tax settlement and an irrigation load reduction rate adjustment, both of which were recovered from June 2005 to May 2006 (with a corresponding reduction to other revenues);
- **Customers:** General business customer growth improved revenue $18.6 million for 2006, as IPC continued to experience customer growth in its service territory. The residential customer base (12-month average) increased 3.8 percent over prior year; and

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- **Usage:** Weather variations positively impacted sales by $17.1 million. Conditions were unusually warm in May, June and July compared to the prior year, which had an abnormally cool and wet spring.

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:

	2007	2006	2005
Revenue	$ 154,948	$ 260,717	$ 142,794
MWh sold	2,744	5,821	2,774
Revenue per MWh	$ 56.47	$ 44.79	$ 51.48

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 sales volumes were moderated by higher prices. Prior year prices were lower due to the abundance of energy in the region.

2006 vs. 2005: In 2006, the MWh volume sold more than doubled and revenues grew 83 percent. Improved stream flow conditions increased total system generation and electricity available for surplus sales. Revenue increases from higher sales volumes were moderated by lower prices caused by abundant energy in the region. The volume increase was also impacted by early water year indications suggesting continued drought conditions for 2006, prompting IPC to make forward purchases in conformance with its risk management policy that were subsequently sold. Additional sales activities are the result of conforming to IPC's risk management policy, managing IPC's energy portfolio to meet customer load, and IPC reacting to changes in market conditions to minimize net power supply costs.

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

	2007	2006	2005
Transmission services and property rental	$ 39,739	$ 34,737	$ 39,012
Provision for rate refund	(1,076)	(1,211)	-
DSM	13,487	-	-
Rate case tax settlement	-	(4,745)	(2,892)
Irrigation lost revenues	-	(5,400)	(8,501)
Total	$ 52,150	$ 23,381	$ 27,619

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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 DSM expenses. The $13.5 million of DSM costs are recorded in Other operations and maintenance expenses and are offset by the same amount recorded in Other revenues resulting in no net effect on earnings. See "Other operations and maintenance expenses."

- Other revenues 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.
- Transmission revenues increased $4.1 million primarily due to an increase in rates that began in June 2006.

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2006 vs. 2005: Other revenues decreased $4 million due mainly to the following:

- In 2006, IPC recorded a $1 million provision for rate refund associated with a revised OATT filing with the FERC requesting an increase in transmission rates. This matter is discussed further in "REGULATORY MATTERS;"
- In December 2006, IPC recorded a $3 million revenue reduction related to estimated refundable transmission revenues and a true up of transmission use-of-facility rates from 1998 through 2005.

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

		2007		2006		2005
Expense	$	289,484	$	283,440	$	222,310
MWh purchased		5,196		4,964		3,894
Cost per MWh purchased	$	55.71	$	57.10	$	57.09

2007 vs. 2006: Purchased power expense grew two percent in 2007. Deteriorated system generation, due to poor hydrologic 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. Hydrologic 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.

2006 vs. 2005: Purchased power expense grew 27 percent in 2006. Record high temperatures and electricity demand, particularly in July 2006, led to increased purchases during a period of high market prices. The increase was also impacted by early water year indications suggesting continued drought conditions for 2006, which prompted IPC to make forward purchases in conformance with its risk management policy. Additional purchase activities were the result of 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:

		2007		2006		2005
Fuel expense	$	134,322	$	115,018	$	103,164
Thermal MWh generated		7,367		7,021		7,315
Cost per MWh	$	18.23	$	16.38	$	14.10

2007 vs. 2006: Fuel expense increased $19.3 million in 2007, as compared to 2006. The increase is largely due to an 11 percent rise in average prices accompanied by a five percent increase in MWh volume. Coal fuel expense was up $7.3 million compared to 2006. The increase in coal prices was due to higher market demand and higher rail transportation costs. Generation from the coal fired power plants was up three percent in 2007. The increase in generation is attributed to fewer planned and unplanned outages at Valmy and Boardman than the previous year. Additional generation from combustion turbine plants contributed $12 million to the overall increase in fuel expense in 2007. The combustion turbine 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.

2006 vs. 2005: The increase in fuel expense was due primarily to a $12.7 million increase in expense from higher coal and rail transportation costs. The increased cost of coal was due primarily to higher market demand, and the increased rail transportation costs are primarily driven by higher diesel fuel costs, including an adjustable fuel surcharge. Higher natural gas costs of $3 million also contributed to the increase. Generation from the coal fired power plants was down four percent due to unplanned outages at Valmy and Boardman. This decrease resulted in a $4 million decrease in fuel expense.

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PCA: PCA expense represents the effects of the Idaho PCA and Oregon deferrals of net power supply costs, which are discussed in more detail below in "REGULATORY MATTERS - Deferred (Accrued) Net Power Supply Costs." In 2007, net power supply costs (fuel and purchased power less off-system sales) were higher than the amounts reflected in the annual PCA forecast. This resulted in the deferral of costs which will be recovered in subsequent rate years. As the deferred costs are being recovered in rates, the deferred balances are amortized. In 2006 and 2005 actual net power supply costs also exceeded the amounts anticipated in the annual PCA forecast.

The following table presents the components of PCA expense:

		2007		2006		2005
Current year net power supply cost deferral	$	(120,844)	$	(27,094)	$	(30,786)
Amortization of prior year authorized balances		(287)		(2,432)		27,791
Total power cost adjustment	$	(121,131)	$	(29,526)	$	(2,995)

Other operations and maintenance expenses:

2007 vs. 2006: Other operations and maintenance 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.

2006 vs. 2005: Other operations and maintenance expenses increased $22 million due mainly to the following:

- An increase in labor-related expenses of $8.5 million due to higher salaries and incentive-based compensation, partially triggered by improved streamflow conditions and the sale of ITI;
- An increase of $6.3 million in hydroelectric and distribution O&M expenses attributable to better generation conditions and the growth in general business customers;
- An increase of $3.5 million in thermal O&M expense resulting primarily from costs due to an extended outage in 2006 at the Valmy plant; and
- A write off of $2 million in the fourth quarter of 2006 for deferred development costs associated with the attempted formation of Grid West.
- These increases were partially offset by a $3 million reversal of accrued FERC fees. IPC and several other utilities contested whether certain federal agency charges could be passed on to utilities through FERC fees. A judgment in favor of IPC and the other utilities was finalized in September 2006.

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

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

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Gain on the sale of emission allowances: Gain on sale of emission allowances in 2007 decreased $5.5 million as compared to 2006 due to recording the gain on the sale of 35,000 SO_2 emission allowances in 2007 as compared to 78,000 in 2006. Gains in 2006 increased $7.1 million over 2005, which had minimal emission allowance sale activity.

Non-utility Operations

IFS: IFS contributed $7 million, $10 million, and $11 million to net income in 2007, 2006 and 2005, 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.

IFS did not make any new investments during 2007 and generated tax credits of $15 million, $19 million and $20 million during 2007, 2006 and 2005, respectively. IFS expects to make future investments in line with the ongoing needs of IDACORP.

Ida-West: Ida-West recorded net income of $2 million, $3 million and $2 million in 2007, 2006 and 2005, respectively. Ida-West continues to manage its independent power projects.

In 2003 a $2.6 million bad debt reserve was established on a note receivable from a partner in one of Ida-West's joint ventures. No adjustments were made to this reserve in 2007 or 2006, but in 2005 the reserve was reduced by $0.7 million based on updated estimates of collectability.

Energy Marketing: IE recorded net income of $0 million in 2007 and 2006 and $5 million in 2005. 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. 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 the second quarter of 2006, IDACORP management designated the operations of ITI and IDACOMM as assets held for sale. The operations of these entities are presented as discontinued operations in IDACORP's financial statements.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. IDACORP recorded a gain of $11.5 million, net of tax, or $0.27 per diluted share from this transaction in the third quarter of 2006.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. for proceeds of $10 million. The sale of IDACOMM did not have a material effect on

IDACORP's financial position, results of operations or cash flows.

Income from discontinued operations was not material in 2007. A loss on disposal of IDACOMM of $3 million was offset by an income tax benefit of $3 million. Income from discontinued operations was $7 million in 2006 and consisted of a loss from operations of $8 million, gain on disposal of ITI of $14 million and an income tax benefit of $1 million. The loss from discontinued operations of $22 million for 2005 consisted of a loss from operations of $27 million and an income tax benefit of $5 million. The 2005 results also included a $10 million goodwill impairment charge recorded at IDACOMM.

Income Taxes

FIN 48: In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*" (FIN 48), to create a single model to address accounting for uncertainty in tax positions. FIN 48 prescribes a minimum recognition threshold that a tax position is required to meet before being recognized in a company's financial statements and also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure, and transition. IDACORP and IPC adopted FIN 48 on January 1, 2007, as required. IPC recorded an increase of $15.1 million to opening retained earnings for the cumulative effect of adopting FIN 48.

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Status of audit proceedings: IPC is 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 2001-2003. The dispute is under review with the IRS Appeals Office. In December 2007, the Appeals Office informed IDACORP that the IRS had completed their review of IPC's SSCM settlement computations. After evaluating the IRS review findings, IPC adjusted its measurement for the SSCM uncertain tax position which resulted in a $4.4 million reduction of the accrued liability for this item. IDACORP expects that the appeals process and the U.S. Congress Joint Committee on Taxation review process will be completed during 2008.

In November 2007 the IRS began its examination of IDACORP's and IPC's 2004-2006 tax years. 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 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:

- Power supply costs deferred for future recovery under IPC's PCA mechanism and other changes in regulatory assets and liabilities decreased operating cash flows by $128 million.
- 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 and IPC's operating cash flows for 2006 were $170 million and $131 million, respectively. These amounts were an increase of $8 million and a decrease of $35 million compared to 2005. The following are significant items that affected operating cash flows in 2006:

- Income tax payments increased in 2006 due to the timing of and increases in taxable income, including the timing effect of cash received in the fourth quarter of 2005 from the sale of approximately $70 million of excess SO_2 emission allowances.
- In 2006, IE collected $13 million of amounts receivable from the Cal ISO and CalPX, and collected $10 million that it had deposited on margin with a counterparty in 2005.

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 $287 million in 2007, $222 million in 2006 and $186 million in 2005. IPC is experiencing a cycle of heavy infrastructure investment needed to address continued customer growth, peak demand growth, and aging plant and equipment.

Net proceeds from the sales of emission allowances provided investing cash of approximately $20 million, $11 million and $71 million in 2007, 2006 and 2005, respectively. The changes were primarily caused by changes in the number of allowances sold each year as well as changes in market prices. See further discussion 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. See Note 2 to IDACORP's and IPC's Consolidated Financial Statements for more information about the income tax assessment.

Financing Cash Flows
Debt issuances: On June 22, 2007, IPC issued $140 million of its 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15, 2037. IPC used the net proceeds to pay down outstanding commercial paper, which had increased to $164 million in June 2007 because of increased capital expenditures.

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

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Equity issuances: On December 15, 2005, IDACORP entered into a Sales Agency Agreement with BNY Capital Markets, Inc. (BNYCMI). Under the terms of the Sales Agency Agreement, IDACORP may offer and sell up to 2,500,000 shares of its common stock, from time to time in at-the-market offerings through BNYCMI, as IDACORP's agent for such offer and sale. Under this program IDACORP received $28 million from the issuance of 881,337 shares in 2007 and $21 million from the issuance of 536,518 shares in 2006. The average prices of the shares issued in 2007 and 2006 were $32.32 and $39.24, respectively. As of December 31, 2007, there were 1,082,145 shares available to be issued through this program.

In April 2005, with the goal of adding additional common equity to its capital structure, IDACORP began using original issue common stock in its Dividend Reinvestment and Stock Purchase Plan, rather than purchasing this stock on the open market. Beginning in August 2005, IDACORP also began using original issue common stock for its 401(k) plan. Under these plans, IDACORP issued 250,020 shares in 2007 and 244,756 shares in 2006, for proceeds of $8.4 million and $8.7 million, respectively.

IDACORP issued 10,070 shares in 2007 and 406,623 shares in 2006 in connection with the exercise of stock options, for proceeds of $0.3 million and $12 million, respectively.

IDACORP made capital contributions of $51 million and $47 million to IPC in 2007 and 2006, 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 is expected to positively impact liquidity and capital resources in future periods.

Financing Programs

IDACORP's consolidated capital structure consisted of common equity of 47 percent and debt of 53 percent at December 31, 2007.

Shelf Registrations: IDACORP currently has $629 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. IPC currently has in place one shelf registration statement that can be used for the issuance of an aggregate principal amount of $350 million of first mortgage bonds (including medium-term notes) and unsecured debt. 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, 2007 and 2006.

	IDACORP	IPC

	2007	2006	2007	2006
Revolving credit facility	$ 100,000	$ 150,000	$ 300,000	$ 200,000
Commercial paper outstanding	(49,860)	(76,800)	(136,585)	(52,200)
Identified for other use (a)	-	-	(24,245)	(24,245)
Net balance available	$ 50,140	$ 73,200	$ 139,170	$ 123,555

(a) 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 IDACORP Facility amended and restated a $150 million five-year facility that would have expired on March 31, 2010.

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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, 2007, no loans were outstanding on IDACORP's Facility and $49.9 million of commercial paper was outstanding. At February 27, 2008, $55 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 IPC Facility amended and restated a $200 million five-year facility that would have expired on March 31, 2010.

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, 2007, no loans were outstanding on IPC's Facility and $137 million of commercial paper was outstanding. At February 27, 2008, $164 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 1/2 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 and 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, 2007, 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, 2007, the facility fee under the IDACORP and IPC Facilities was 0.09 percent and 0.07 percent, respectively.

As a result of the S&P ratings downgrade discussed below, as of January 31, 2008, the credit facility fees changed for IPC. The margin for Eurodollar rate advances increased from 0.28 percent to 0.36 percent, and the facility fee increased from 0.07 percent to 0.09 percent. All of the other fees discussed above stayed the same for IPC. IDACORP's fees remain unchanged.

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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. In an order issued May 6, 2005, the IPUC clarified that IPC's authority will not terminate but will continue for a period of 364 days from any downgrade below investment grade.

Debt Covenants: The IDACORP Facility and the IPC Facility 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, 2007, the leverage ratio for both IDACORP and IPC was 53 percent. At December 31, 2007, IDACORP was in compliance with all other covenants of the IDACORP Facility and IPC was in compliance with all other covenants of the IPC Facility. Both the IDACORP Facility and the IPC Facility contain additional covenants including:

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(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

On January 31, 2008, Standard & Poor's Rating Services lowered its corporate credit rating on IDACORP and IPC to 'BBB' from 'BBB+'. The outlook for both companies changed to stable from negative. S&P stated that its decision reflected a gradual deterioration of cash flow coverage as well as a failure to sufficiently address long-term ratemaking issues in the proposed Idaho general rate case settlement. Specifically, S&P indicated that the proposed settlement fails to resolve issues such as the use of a forecasted test year or the appropriate level of load growth adjustment credit.

Access to capital markets at a reasonable cost is determined in large part by credit quality. These downgrades are expected to increase the cost of new debt issuances and outstanding variable rate debt issuances within the downgraded ratings categories. The following table outlines the current S&P, Moody's and Fitch ratings of IDACORP's and IPC's securities:

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

Rating Outlook	Stable	Stable	Stable	Stable	Stable	Stable

These security ratings and the ratings discussed below 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.

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). The pollution control bonds currently bear interest at an auction interest rate reset every 35 days for the Humboldt bonds and every seven days for Sweetwater bonds.

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The Humboldt bonds and Sweetwater bonds are each rated "AAA" by S&P and "Aaa" by Moody's, respectively. Fitch also rated each series of bonds.

On January 18, 2008, Fitch announced that it had downgraded Ambac's insurer financial strength rating to "AA" from "AAA" and was keeping the rating on negative watch. Fitch also downgraded the Humboldt bonds and the Sweetwater bonds to "AA" from "AAA." S&P's and Moody's ratings for the bonds remain unchanged. However, Moody's placed Ambac's insurance financial strength rating on review for possible downgrade on January 16, 2008, and, as a result of this review, Moody's-rated securities that are guaranteed by Ambac were also placed under review for possible downgrade, except those with higher public underlying ratings. S&P also placed Ambac's financial strength, financial enhancement and issuer credit ratings on CreditWatch with negative implications on January 18, 2008. On February 25, 2008, S&P affirmed Ambac's "AAA" financial strength and financial enhancement ratings, but retained the negative watch.

The downgrade of Ambac and the pollution control bonds has resulted in higher interest rates on the pollution control bonds. Such downgrades could also result in a "failed auction", where there are no purchasers for the bonds. A "failed auction" would result in the existing holders having to hold the pollution control bonds at the maximum interest rate of 14 percent for the Sweetwater bonds and at a specified rate capped at 12 percent for the Humboldt bonds. If a "failed auction" occurs, new auctions will continue to be every 35 days for the Humboldt bonds and every seven days for the Sweetwater bonds. On February 27, 2008, auctions were held for both series of pollution control bonds. The Sweetwater bonds had a successful auction establishing a new interest rate of 7.95 percent. The Humboldt bonds experienced a "failed auction" which resulted in a new interest rate of 5.464 percent (currently based on LIBOR multiplied by 1.75) and the Humboldt bonds continuing to be held by the current holders. IPC may exercise certain options available with respect to these bonds to lessen interest rate costs and volatility going forward. IPC may redeem the bonds at par plus accrued and unpaid interest or convert them from the auction rate mode to another interest rate mode.

Capital Requirements

Utility Construction Program: IPC's construction program and related expenditures are subject to on-going review and are revised to include changes in load growth, construction costs, location of generation sources, transmission capacity, adequacy of rate recovery and environmental concerns. Variations in the timing and amounts of capital expenditures will result from regulatory and environmental factors, load growth, other resource acquisition needs and the timing of relicensing expenditures.

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. Continuing load growth also requires that IPC add to its transmission system and distribution facilities to provide new service and to maintain reliability. As a result, IPC expects to spend approximately $900 million in construction expenditures from 2008 to 2010, which excludes any estimated expenditures for a Nominal 250-MW combined cycle combustion turbine expected to be operational in mid-2012, the Gateway West Project expected to be in service between 2012 and 2014, and the proposed Hemingway-Boardman Line that could be in service as early as 2012. IPC expects 2008 capital expenditures to be between $280 and $300 million.

IPC and PacifiCorp are jointly exploring a project, called the Gateway West Project, to build two 500-kV lines between the Jim Bridger plant and Boise. If built, it is expected that the majority of the project would be completed between 2012 and 2014, depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. IPC estimates that its share of project costs would be between $800 million and $1.2 billion. IPC is exploring the construction of a 500-kV line referred to as the Hemingway-Boardman Line. IPC and a number of other utilities with proposed regional transmission projects in the Northwest have begun to coordinate technical studies. See further discussion in "REGULATORY MATTERS - Gateway West Project and Hemingway-Boardman Line."

Other Capital Requirements: IDACORP's non-regulated capital expenditures are expected to be $25 million in 2008 and an aggregate of $25 million for 2009-2010. These expenditures primarily relate to IFS's tax advantaged investments.

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Internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2008 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	**2008**	**2009-2010**	**2011-2012**	**Thereafter**

		(millions of dollars)			
IPC:					
Long-term debt (a)	$ 1,146	$ 1	$ 82	$ 222	$ 841
Future interest payments (b)	1,173	64	124	104	881
Operating leases (c)	19	3	7	3	6
Uncertain tax positions (d)	6	2	4	-	-
Purchase obligations:					
Cogeneration and small power production	1,993	76	199	207	1,511
Fuel supply agreements	210	54	69	32	55
Purchased power & transmission (e)	65	38	10	5	12
Other (f)	113	63	17	10	23
Total purchase obligations	4,725	301	512	583	3,329
Pension and postretirement plans (h)	64	6	14	15	29
Other long-term liabilities - IPC	6	4	2	-	-
Total IPC	$ 4,795	$ 311	$ 528	$ 598	$ 3,358
Other:					
Long-term debt (a)(g)	26	10	9	1	6
Future interest payments (b)(g)	7	1	1	1	4
Operating leases (g)	2	1	-	-	1
Total IDACORP	$ 4,830	$ 323	$ 538	$ 600	$ 3,369

(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, 2007.

(c) Approximately $8 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) In addition to the amounts listed, approximately $17 million of federal income tax is estimated to be due in 2008, but would be fully offset by the $45 million tax deposit IDACORP made in 2006.

(e) 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.

(f) Approximately $40 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.

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

(h) Based on current assumptions, no pension contributions will be required during the next five years. IPC cannot estimate contributions beyond 2012 at this time. Amounts include 10 years of postretirement and non-qualified pension contributions.

Environmental Regulation Costs: IPC anticipates approximately $20 million in annual operating costs for environmental facilities during 2008. Hydroelectric facility expenses and thermal plant expenses account for the majority of the costs at approximately $13 million and $7 million, respectively. From 2009 through 2010, total environmental related operating costs are estimated to be approximately $54 million. Expenses related to the hydroelectric facilities are expected to be $39 million and thermal plant expenses are expected to total $15 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 global warming and mercury and other pollutant emissions from coal-fired generation plants.

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

LEGAL AND ENVIRONMENTAL ISSUES:

Legal and Other Proceedings

Wah Chang: On May 5, 2004, Wah Chang, a division of TDY Industries, Inc., filed two lawsuits in the U.S. District Court for the District of Oregon against numerous defendants. IDACORP, IE and IPC are named as defendants in one of the lawsuits. The complaints allege violations of federal antitrust laws, violations of the Racketeer Influenced and Corrupt Organizations Act, violations of Oregon antitrust laws and wrongful interference with contracts. Wah Chang's complaint is based on allegations relating to the western energy situation. These allegations include bid rigging, falsely creating congestion and misrepresenting the source and destination of energy. The plaintiff seeks compensatory damages of $30 million and treble damages.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley sitting by designation in the U.S. District Court for the Southern District of California. The companies filed a motion to dismiss the complaint, which the court granted on February 11, 2005. Wah Chang appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit on March 10, 2005. On November 20, 2007, the Ninth Circuit affirmed the dismissal. On December 10, 2007, Wah Chang filed Petitions for Rehearing and Rehearing En Banc with the Ninth Circuit, which were denied on January 15, 2008. If Wah Chang decides to seek Supreme Court review, time for filing its petition for certiorari will expire on April 14, 2008. The companies cannot predict whether Wah Chang will seek certiorari or whether the Supreme Court will grant it. 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.

Western Energy Proceedings at the FERC: IE and IPC are involved in a number of FERC proceedings arising out of the western energy situation in California and claims that dysfunctions in the organized California markets contributed to or caused unjust and unreasonable prices in Pacific Northwest spot markets, and may have been the result of manipulations of gas or electric power markets. The following proceedings are included.

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(1) California Refund: This proceeding originated with an effort by the state of California to obtain refunds for a portion of the spot market sales from sellers of electricity into California from October 2, 2000, through June 20, 2001. California is claiming that the sales prices were not just and reasonable and were not in compliance with the FPA. The FERC issued an order on refund liability on March 26, 2003 on which multiple parties, including IE, sought rehearing. On October 16, 2003, the FERC denied the requests for rehearing and required the California Independent System Operator (Cal ISO) to make a compliance filing regarding refund amounts within five months, which has been delayed on a number of occasions and has not yet been filed with the FERC. On May 12, 2004, the FERC issued an order clarifying its earlier refund orders. The FERC denied requests for rehearing on November 23, 2004. On December 2, 2003, IE and others petitioned the United States Court of Appeals for 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, including by IE, and have been consolidated with the appeals already pending before the Ninth Circuit. On September 21, 2004, the Ninth Circuit convened the first of its case management proceedings, a procedure reserved to help organize complex cases, staying action on all of the consolidated cases. On October 22, 2004, the Ninth Circuit severed several issues related to the FERC's refund jurisdiction, established a schedule for briefing and held oral argument on April 12 and 13, 2005. On September 6, 2005, the Ninth Circuit issued a decision in one of the severed cases concluding that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. On August 2, 2006, the Ninth Circuit issued its decision on a second severed case ruling that all transactions that occurred within or as a result of the CalPX and the Cal ISO were the proper subject of the refund proceeding; refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000 but required FERC to reconsider based upon claims that some market participants had violated governing tariff obligations (the California Parties are seeking a refund effective date of May 1, 2000); and effectively expanded the scope of the refund proceeding to transactions within the CalPX and Cal ISO markets outside the 24-hour spot market and energy exchange transactions. On August 8, 2005 the FERC issued an order establishing a framework for those sellers wanting to make a cost filing to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC along with others made a cost filing on September 14, 2005. During the next two months, the California entities on the one hand and IE and IPC on the other submitted filings that argued the merits of the cost filings. On March 27, 2006, the FERC rejected the IE/IPC cost filing and on April 26, 2006, IE and IPC sought rehearing of the rejection. 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.

Before the rejection of the cost filing, 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 including IE's and IPC's cost filing and refund obligation. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement.

On May 12, 2006, the FERC issued an order determining the method that should be used to allocate amounts approved in cost filings, approving the methodology that IE and IPC and others had advocated prior to the time IE and IPC entered into the February 17, 2006 settlement - allocating cost offsets to buyers in proportion to the net refunds they are owed through the Cal ISO and CalPX markets. On June 12, 2006, the California Parties requested rehearing, urging the FERC to allocate the cost offsets to all purchasers from the Cal ISO and CalPX markets and not just to that limited subset of purchasers who are net refund recipients. On July 12, 2006, the FERC tolled the time to act on the request for rehearing and has not issued orders on rehearing since that time. IDACORP and IPC are unable to predict how or when the FERC might rule on the request for rehearing.

The FERC approved the February 17, 2006 Offer of Settlement on May 22, 2006. 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.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the settlement. On July 10, 2006, IPC and IE and the California Parties filed a response to Port of Seattle's request for rehearing. On October 5, 2006, the FERC issued an order denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC orders approving the settlement. The Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it. On October 25, 2007, the Ninth Circuit severed the appeal of the FERC's orders approving the settlement with the California Parties (along with appeals of two other similar cases) from the remainder of the consolidated cases. The Ninth Circuit established a briefing schedule for the three cases which currently concludes in late June 2008. A date for argument has not yet been scheduled. IPC and IE are unable to predict when or how the Ninth Circuit might rule on Port of Seattle's petition for review.

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A provision of the CalPX participation agreement referred to as the chargeback provision was triggered when a participant defaulted on a payment to the CalPX requiring other market participants to pay their allocated share of the default amount to the CalPX. This provision was triggered initially by the Southern California Edison and Pacific Gas and Electric Company defaults. The FERC ordered the CalPX to hold the chargeback funds until the conclusion of the California Refund proceeding. Based upon the settlement between the California Parties and IE and IPC discussed above, the FERC directed the return of IE's chargeback amounts, totaling $2.27 million. On June 1, 2006, IE received approximately $2.5 million from the CalPX representing the return of $2.27 million in chargeback funds plus interest.

On December 31, 2005, with respect to the CalPX chargeback and the California Refund proceedings discussed above, the CalPX and the Cal ISO owed $14 million and $30 million, respectively, for energy sales made to them by IPC in November and December 2000. In the fourth quarter of 2005, IE reduced by $9.5 million to $32 million its reserve against these receivables. This reserve was calculated taking into account the uncertainty of collection, given the California energy situation. Following payment of the $10.25 million to IE and IPC in June 2006, IE further reduced the reserve by $24.9 million to $7.1 million. This reserve was calculated taking into account several unresolved issues in the California refund proceeding. Based on the reserve recorded as of December 31, 2007, IDACORP believes that the future collectability of these receivables or any potential refunds ordered by the FERC would not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

(2) Pacific Northwest Refund: These proceedings involved arguments that the spot market in the Pacific Northwest was affected by the dysfunction in the California market, warranting refunds. The FERC rejected this claim on June 25, 2003, and denied rehearing on November 11, 2003 and February 9, 2004. The FERC orders were appealed to the Ninth Circuit. Oral argument was held on January 8, 2007. On August 24, 2007, the court filed an opinion in the appeal, remanding to the FERC the orders that declined to require refunds. The court's opinion instructed the FERC to consider whether evidence of market manipulation submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources in the proceeding. On September 18, 2007, the court extended until November 16, 2007 the time for filing petitions for rehearing to allow the parties' time to assess settlement prospects and directed Senior Judge Edward Leavey of the Ninth Circuit to initiate mediation efforts. The Ninth Circuit did not renew the extension of time and a number of parties have sought rehearing of the Ninth Circuit's decision. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters. The settlement in the California Refund proceeding resolves all claims the California Parties have against IE and IPC in the Pacific Northwest proceeding.

(3) Market Manipulation: These proceedings include two FERC show cause orders which resulted from a ruling of the Ninth Circuit that the FERC permit the California parties in the California refund proceeding to submit materials to the FERC demonstrating market manipulation by various sellers of electricity into California. On June 25, 2003, the FERC ordered a large number of parties including IPC to show cause why certain trading practices did not constitute gaming ("gaming") or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IPC reached agreement with the FERC Staff on the show cause orders. The "gaming" settlement was approved by the FERC on March 3, 2004. The FERC approved the motion to dismiss the "partnership" proceeding on January 23, 2004. Although the orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit, the order dismissing IPC from the "partnership" proceedings was not the subject of rehearing requests. Originally, eight parties requested rehearing of the FERC's March 3, 2004 order approving the "gaming" settlement. The settlement between the California Parties and IE and IPC discussed above in the California refund proceeding approved by the FERC on May 22, 2006, results in the California Parties and other settling parties withdrawing their requests for rehearing of the settlement with the FERC Staff regarding allegations of "gaming." On October 11, 2006, the FERC issued an order denying rehearing of its earlier approval of the "gaming" allegations, thereby effectively terminating the FERC investigations as to IPC and IE regarding bidding behavior, physical withholding of power and "gaming" without finding of wrongdoing. On October 24, 2006, the Port of Seattle appealed the FERC order to the U.S. Court of Appeals for the Ninth Circuit. That appeal was consolidated with the other cases currently before the Ninth Circuit respecting Western energy matters. IE and IPC are unable to predict when or how the Ninth Circuit will rule on the petitions for review.

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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 review evidence of economic withholding of generation. IPC, along with over 60 other market participants, responded to the FERC data requests and the FERC terminated its investigations as to IPC on May 12, 2004. Numerous parties have appealed the FERC's termination of this investigation as to IPC and over 30 other market participants. IE and IPC are unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

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

The U.S. District Court has set this matter for trial commencing in April 2008. Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity permit violations. The Court has not yet ruled on those motions. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

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

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

Environmental Issues

Idaho Water Management Issues: From 2000 through 2005, and throughout 2007, below normal precipitation and stream flows have exacerbated a developing water shortage in Idaho, manifested by a number of water issues including declining Snake River base flows and declining levels in the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer that has been estimated to hold between 200 - 300 maf of water. These issues are of interest to IPC because of their potential impacts on generation at IPC's hydroelectric projects.

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

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

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

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

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

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

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

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On July 23, 2007, the court issued an Order granting in part and denying in part the State's motion to dismiss, consolidating the issues into a consolidated subcase before the court, providing for discovery during the objection period and setting a scheduling conference for December 18, 2007. In its Order, the court denied the majority of the State's motion to dismiss, refusing to dismiss the complaint and finding that the court has jurisdiction to hear and determine virtually all the issues raised by IPC's complaint that relate to IPC's water rights and the effect of the Swan Falls Agreement upon those water rights. This includes the issues of ownership, whether IPC's water rights are subordinated to recharge and how those water rights are to be administered relative to other water rights on the same or connected resources. The court did find that by virtue of a state statute the IDWR, and its director, could not be parties to the SRBA and therefore stayed IPC's claims against the IDWR and its director pending resolution of the issues to be litigated in the SRBA, or until further order of the court.

Consistent with IPC's motion to consolidate and stay proceedings, the court consolidated all of the issues associated with IPC's water rights before the court and stayed that proceeding to allow other parties that may be affected by the litigation to file responses or intervene in the consolidated proceedings by December 5, 2007. On December 18, 2007, the court held a status and scheduling conference in the consolidated proceedings. Subsequently, the court issued a scheduling order on December 20, 2007, with a trial scheduled to begin on February 2, 2009. IPC is unable to predict the outcome of the consolidated proceedings.

IPC has also recently filed two actions in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the U.S. on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the U.S. has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, on October 15, 2007, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. to recover damages from the U.S. for the lost generation resulting from the reduced flows. On October 15, 2007, IPC filed a second action in the United States District Court for the District of Idaho in Boise, Idaho, to compel the U.S. to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. The U.S. Bureau of Reclamation filed an answer in the case filed with the U.S. District Court for the District of Idaho on February 15, 2008. No answer has been filed in the case filed in the U.S. Court of Claims. IPC is unable to predict the outcome of this litigation.

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

Technology (RH BART). Low nitrogen oxide (NO_x) burner technology and mercury continuous emission monitoring systems (mercury CEMS) installations are progressing at all three coal-fired power plants.

National Ambient Air Quality Standards: EPA-adopted NAAQS for fine particulate matter became effective in December 2006. This new standard has been challenged by a number of groups in the U.S. Court of Appeals for the District of Columbia Circuit. All of the counties in Idaho, Nevada, Oregon, and Wyoming where IPC's power plants operate are currently designated as meeting attainment with federal air quality standards, including the new particulate matter standard. Nevertheless, under the new fine particulate standards, three years of data are being collected to determine the attainment status of all U.S. counties. In July 2007, the EPA proposed to revise the NAAQS for 8-hour ozone. For the primary (health-based) standard, EPA is proposing that the standard be lowered from 0.08 parts per million (ppm) to between 0.070 and 0.075 ppm. The EPA received public comment for 90 days and held 4 public hearings. The impact of these new standards will not be known until these data are collected, analyzed, and released to the public and the associated regulatory programs are promulgated and implemented.

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 could appeal this decision but, in the absence of an appeal, the impact of this decision will not be known until such time as the EPA develops a new report in response to the court's decision.

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In response to the CAMR, the Idaho Department of Environmental Quality (IDEQ) proposed two new rules to the Idaho Environmental Quality Commission: a rule to opt out of the federal mercury cap-and-trade program, and a rule to prohibit the construction and operation of a coal-fired power plant in Idaho. In April 2006, the governor of Idaho signed House Bill 791, which placed a two-year moratorium on applying for or issuance of permits, licenses or construction of certain coal-fired power plants in Idaho. The moratorium expires on April 7, 2008. During the 2007 Idaho state legislative session, the state did not reject the proposal to opt out of the cap-and-trade program, therefore accepting the opt-out rule. In January 2008, Senate Bill 1314 was introduced which, if enacted, would extend the current moratorium for an additional two years. IPC has no current plans impacted by the moratorium or opting out of the CAMR cap-and-trade program.

On October 10, 2006, the Wyoming Environmental Quality Council (WEQC) approved the Wyoming Department of Environmental Quality's (WDEQ) recommended Wyoming regulation to implement CAMR. This rule will allocate mercury allowances to each plant based on heat-input and hold back ten percent of the allocated allowances for new sources. This rule will also allow plants to participate in the national cap-and-trade program. Mercury CEMS are planned to be installed at the Jim Bridger plant in 2008 at an estimated cost of $0.2 million (IPC share). Until the mercury CEMS are installed and operational, the amount of mercury emissions is not definitively known. It is not possible at this time to determine the effect of the allowance allocation rule on future operations and costs at the plant.

On December 15, 2006, the Oregon Environmental Quality Commission adopted the Oregon Department of Environmental Quality (ODEQ)-proposed utility mercury rule. IPC estimates that capital expenditures for mercury controls at Boardman will be $9.2 million (IPC share) with an annual incremental operations and maintenance cost of up to $0.8 million (IPC share). The mercury rule will provide a limited number of mercury allowances to Boardman that may be used for trading.

The Nevada Department of Environmental Protection has adopted a state CAMR that will provide mercury allowances to each plant based on actual emissions until 2018, at which time the allowance allocations will be reduced to meet the federal cap. To meet the reduced allocations in the year 2018, mercury controls are expected to be installed. Mercury CEMS are planned to be installed at the North Valmy plant in 2008 at an estimated cost of $0.1 million (IPC share).

At this time, it is uncertain how state mercury rules or requirements might be impacted by the vacated CAMR and any resulting impacts to IPC.

Regional Haze - Best Available Retrofit Technology: In accordance with federal regional haze rules, the WDEQ and 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 and Boardman plants. The two units at the North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule.

PacifiCorp submitted the RH BART application for the Jim Bridger plant in January 2007. The WDEQ is still evaluating the application and will go out for public comment. If there are no appeals to the application, the WDEQ will prepare a State Implementation Plan to present to the WEQC for approval and submittal to the EPA. The plant is already in the process of installing low NO_x burners and scrubber upgrades that are proposed in the application. Over the next four years, these upgrade expenditures are currently estimated at $27.7 million (IPC share), with a total upgrade expenditures estimated at $34.3 million (IPC share).

PGE completed the RH BART analysis for the Boardman plant and submitted it to the ODEQ on November 15, 2007. This analysis includes proposed emission control upgrades for the Boardman plant to comply with RH BART requirements. Capital upgrade costs required to meet RH BART standards could vary significantly depending on the technology utilized. Because of the combined benefit of emission equipment that reduces multiple pollutants simultaneously, upgrade plans under consideration will also meet CAMR standards. Upgrade cost estimates to meet both standards range from $30 million to $62 million (IPC share). Depending on what pollution control equipment is required to meet the standards, an extended maintenance outage may be necessary. No commitments are in place at this time and the cost estimates are preliminary and subject to change. More detailed information will be available after completion of the analysis for the Boardman plant and approval of the RH BART proposals by state and federal environmental regulators.

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Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) regulations and judicial decisions that would affect electric utilities. At the national level, numerous GHG bills have been introduced in the U.S. Senate and House of Representatives during 2006 and 2007. Debate continues in Congress on the direction and scope of U.S. policy on regulation of GHGs. IPC anticipates new developments to occur in 2008.

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

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

Information about IDACORP's carbon dioxide emissions is included in the report *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States - 2004*. This report was released by the Ceres Investor Coalition, the Natural Resources Defense Council and the Public Service Enterprise Group Inc. in April 2006. The report lists IDACORP's 2004 carbon dioxide emissions at 1,222.0 lbs/MWh, as compared to the reported average for the 100 largest power producers of 1,341.8 lbs/MWh. IPC's carbon dioxide emissions on a lbs/MWh basis fluctuate with the amount of hydroelectric generation. Even during a low water year like 2004, IPC's emissions from electricity generation were below the average of the 100 largest power producers. During 2007, IPC's carbon dioxide emissions were approximately 1,153 lbs/MWh.

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

Due to escalating construction costs, 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 is in the process of adding 45.5 MW of geothermal generation by 2011. Additional wind and geothermal generation is anticipated through CSPP and RFP-driven contracts.

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In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. Environmental Protection Agency*, a case involving the EPA's authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. The Court held that, with respect to mobile sources, the EPA has authority under the Clean Air Act to regulate carbon dioxide as a pollutant and that the EPA has a duty to determine whether carbon dioxide 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 carbon dioxide emissions from stationary sources, including electricity generators. IPC will continue to monitor developments with respect to the possible regulation of GHG emissions from stationary sources under the Clean Air Act.

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

Endangered Species

In December 1992, the U.S. Fish and Wildlife Service (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, 2007, 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, 2007, the investment in these facilities was $24 million and the annual cost of operation was $3 million.

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

Renewable Portfolio Standards: Legislation to adopt a national renewable portfolio standard (RPS) has been introduced into but not yet adopted by Congress. IPC expects debate to continue on a national RPS and anticipates new developments in 2008.

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A number of states in which IPC operates or sells power into have enacted RPS legislation. For example, Oregon law requires the state's largest utilities to meet 25 percent of their electric load with renewable energy by 2025. Because of its relatively small presence in the state, IPC is not currently subject to the Oregon RPS. It is possible that Idaho and other states in which IPC operates or sells power into could adopt similar RPS initiatives.

IPC will continue to monitor RPS developments but cannot, at this time, predict the impacts of state and federal RPS legislation on its business.

REGULATORY MATTERS:

General Rate Case
Idaho: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of approximately 10.35 percent for its Idaho customers in order to begin recovery of its capital investments and higher operating costs. IPC's proposal would increase its revenues $63.9 million annually. The application included a requested return on equity of 11.5 percent and an overall rate of return of 8.561 percent. IPC filed its case based upon a 2007 forecast test year, a first for IPC in the Idaho jurisdiction. Since IPC's last general rate case filing in 2005, IPC projected that it will have placed in service an additional $300 million of investment in its electrical system during 2006 and 2007. IPC also requested a $29.16 per MWh LGAR, which adjusts the power supply costs IPC includes in the PCA for differences between actual load and the load used in calculating base rates. The existing LGAR is $29.41 per MWh. The impact of the new LGAR on IPC will ultimately be determined by future load changes.

IPUC Staff and intervenor testimony was filed December 10, 2007. The parties to the proceeding reached a settlement that includes an average annual increase of 5.2 percent (approximately $32.1 million annually). Neither an overall rate of return nor a return on equity is specified in the settlement. The currently authorized rate of return would remain at 8.1 percent.

The parties to the proceeding also agreed in the settlement to make a good faith effort to develop a mechanism to adjust or replace the current LGAR. As an interim solution, the parties have agreed to use the LGAR of $62.79 per MWh recommended by the IPUC Staff on December 10, 2007, but to apply it to only 50 percent of the load growth occurring during each month within the April 2008 - March 2009 PCA year.

The parties also agreed to participate in a good faith discussion regarding a forecast test year methodology that balances the auditing concerns of the IPUC Staff and intervenors with IPC's need for timely rate relief. The parties agreed that such a methodology would begin with auditable numbers from which projections would be made for the test year.

IPC filed a settlement stipulation with the IPUC on January 23, 2008. The settlement is subject to approval by the IPUC. The parties have requested in the settlement stipulation that the new rates become effective no later than March 1, 2008, but IPC is unable to predict what relief the IPUC will grant or when the IPUC will issue its final order.

Deferred (Accrued) Net Power Supply Costs

IPC's deferred (accrued) net power supply costs consisted of the following at December 31 (in thousands of dollars):

		2007	2006
Idaho PCA current year:			
	Accrual for the 2007-2008 rate year (1)	$ -	$ (3,484)
	Deferral for the 2008-2009 rate year (2)	85,732	-
Idaho PCA true-up awaiting recovery (refund):			
	Authorized May 2006	-	(11,689)
	Authorized May 2007	6,591	-
Oregon deferral:			
	2001 costs	2,993	6,670
	2005 costs	-	2,889
	2006 costs	2,107	-
	Total deferral (accrual)	$ 97,423	$ (5,614)

(1) The 2007-2008 PCA reflected $69 million of emission allowance sales to be credited to customers.

(2) The 2008-2009 PCA deferral balance reflects $17 million of emission allowance sales in 2007.

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

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

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

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

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

As discussed above in "General Rate Case - Idaho", a settlement stipulation before the IPUC in that rate case would reset the LGAR to $62.79 per MWh, but would apply that rate to only 50 percent of the load growth occurring each month within the April 2008 - March 2009 PCA year. In the current 2007 general rate, IPC filed normalized firm base load of 15.6 million MWh as compared with 14.8 million MWh in the 2005 general rate case. Because the LGAR is reset in general rate cases, IPC expects to update its filed base load on a more frequent basis during periods of high load growth.

Emission Allowances: During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million, after subtracting transaction fees. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $18.5

million ($11.3 million net of tax, assuming a tax rate of approximately 39 percent). On January 15, 2008, a workshop was held to discuss whether the customer share of the Idaho jurisdictional portion of the 2007 sales proceeds should once again be included as a PCA credit or used to reduce investment costs in wind development, green tags, or other options that would provide longer term customer benefits. Because the workshop participants were unable to reach a consensus regarding the use of the SO_2 emission allowance proceeds, the IPUC determined that the case would proceed under modified procedure. Written comments were due February 25, 2008.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million, after subtracting transaction fees. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). 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 is included in IPC's PCA calculations as a credit to the PCA true-up balance and is currently reflected in PCA rates during the June 1, 2007, through May 31, 2008, PCA rate year.

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The bulk of IPC's accumulated excess emission allowances were sold during the 2005-2007 period. IPC has approximately 15,000 excess emission allowances currently and anticipates realizing a similar amount annually into the near future. Tighter emission restrictions are expected in the long term which may cause IPC to use more emission allowances for its own requirements and reduce the annual amount of excess emission allowances.

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

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. On April 25, 2007, a tentative settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

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

Oregon Power Cost Adjustment Mechanism (PCAM)
On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost adjustment mechanism similar to the Idaho PCA. If the application is approved, it will allow IPC to recover excess net power supply costs or distribute benefits to customers in a more timely fashion than through the existing deferral process. The proposed mechanism differs from the Idaho PCA in that is reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case. Settlement conferences were held and the interested parties reached a verbal agreement. A stipulation has been drafted by IPC and is being reviewed by the parties to the settlement.

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

Fixed Cost Adjustment Mechanism (FCA)

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

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IPC and the IPUC Staff agreed in concept to a three-year pilot program beginning January 1, 2007, and a stipulation was filed on December 18, 2006. The stipulation called for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of DSM activities. The IPUC approved the stipulation on March 12, 2007. The pilot program began retroactively on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. IPC accrued $2.1 million of FCA expense in 2007.

Pension Expense
In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current contributions being made to the plan. On March 20, 2007, IPC filed a request with the IPUC to clarify that IPC can consider future contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued its order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for accrued pension expense under SFAS 87, *"Employers' Accounting for Pensions,"* as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The order did not determine the method of recovery. 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 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. IPC did not request a carrying charge to be applied to the deferral of the accrued SFAS 87 expense.

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

Federal Regulatory Matters
The Bonneville Power Administration Residential Exchange Program: The Pacific Northwest Electric Power Planning and Conservation Act of 1980, through the Residential Exchange Program, provides access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of the region's investor-owned utilities (IOUs). The program is administered by the Bonneville Power Administration (BPA). IPC entered into settlement agreements with the BPA that settled IPC's rights under the Residential Exchange Program (REP) for the fiscal year 2002-2006 rate period and for the fiscal year 2007-2011 rate period. Pursuant to these agreements between the BPA and IPC, benefits from the BPA were passed through to IPC's Idaho and Oregon residential and small-farm customers in the form of electricity bill credits.

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 REP payments that the utilities pass through to their residential and small-farm customers in the form of electricity bill credits. IPC took action with both the IPUC and the OPUC to reduce the level of credit on its customers' bill to zero, effective June 1, 2007. From October 1, 2001 to June 1, 2007, IPC had passed through to its REP customers approximately $90 million in benefits pursuant to the settlement agreements.

Since that time IPC has been working with the other northwest IOUs, 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 is the WP-07 supplemental rate case. IPC will fully participate in this proceeding, which is expected to be completed prior to October 1, 2008. At issue is the REP calculation and allocation of benefits to IOUs, and IPC specifically, and resolution of claims of overpayment in past periods.

Since these REP benefits were passed through to IPC's customers, the outcome of this matter is not expected to have a significant effect on IPC's financial condition or results of operations.

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

FERC Proceedings:
Open Access Transmission Tariff (OATT): On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. The proposed rates would have produced an annual revenue increase for the FERC jurisdiction of approximately $13 million based on 2004 test year data. The FERC accepted IPC's rates, effective June 1, 2006, subject to adjustment to conform to SFAS 109 tax accounting requirements, which lowered the estimated annual increase in revenues to approximately $11 million.

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

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

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which is on file and publicly available at FERC Docket No. ER06-787. In the Initial Decision, the ALJ concluded that (i) the Legacy Agreements should be included in the load divisor of the rate formula and (ii) the revenue IPC receives under the Legacy Agreements should not be credited against the total transmission revenue requirement attributed to OATT customers. If the Initial Decision is implemented, IPC estimates that this ruling will reduce the estimated FERC jurisdictional annual revenue increase (based on 2004 test year data) to $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $2.4 million for the June 1, 2006, through December 31, 2007, period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process. IPC is awaiting a final FERC order.

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

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

On December 28, 2007, the FERC issued Order No. 890-A, an order on Rehearing and Clarification of Order 890. Order No. 890-A primarily affirms and clarifies Order No. 890. Order No. 890-A will become effective 60 days after its publication in the Federal Register.

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

FERC Order 693: Pursuant to section 215 of the FPA, on March 16, 2007, the FERC issued Order No. 693 in which it approved 83 of the 107 reliability standards proposed by the North American Electric Reliability Corporation (NERC). Previously, the FERC certified the NERC as the electric reliability organization responsible for developing and enforcing mandatory reliability standards. Collectively, the reliability standards define overall acceptable performance with regard to operation, planning and design of the North American bulk power system. As the FERC recognized in Order No. 693, most of these reliability standards were already being adhered to on a voluntary basis. Compliance with these standards became mandatory and subject to the FERC's penalty authority in June 2007. Since then, additional reliability standards have been submitted, and will continue to be submitted, by the NERC to the FERC for approval. IPC reviewed all requirements, procedures and documentation to ensure compliance with these standards and submitted all necessary information by the effective date of June 18, 2007. IPC certified its compliance with a subset of these standards (the WECC Actively Monitored Standards) prior to the January 10, 2008 deadline. IPC is subject to compliance spot-checks beginning in 2008. Order No. 693 substantially impacts documentation requirements, but is not expected to have a material impact on operations.

Northern Tier Transmission Group

IPC, along with four other transmission-owning entities covering all or parts of the transmission system in six western states, has formed the Northern Tier Transmission Group (NTTG). The goal of the group is to improve overall operation and expansion of the high-voltage transmission network. The group continues to make progress on four major initiatives: improving generation control performance (the first generation control became operational in March 2007); compliance with FERC Order 890 through cooperative efforts in developing process and information exchange; providing improved information on available transmission capacity; and conducting open, participatory transmission planning processes which will result in identifying specific transmission projects. Several projects have been identified for the "fast-track" planning process and work has begun on engineering analysis. One of these projects is IPC's joint project with PacifiCorp (MidAmerican) to evaluate building two high voltage transmission lines as discussed below (Gateway West Project). FERC Order No. 890 required jurisdictional utilities to establish planning procedures, to which IPC responded by submitting its Attachment K filing with the FERC on December 7, 2007. To date, the FERC has yet to accept or issue orders regarding any Attachment K filings, including IPC's. In addition to other activities, the NTTG fulfills a significant portion of the sub-regional and regional planning requirements specified in Order 890, including the commencement of the NTTG biennial planning process with a public stakeholder meeting held in January 2008.

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

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

The proposed Gateway West and Hemingway-Boardman transmission projects will be used both by wholesale transmission customers and to serve IPC's native load consistent with our OATT. Therefore these facilities will be subject to both the FERC and state public utility commission regulation and rate-making policies.

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 Published Avoided Cost is a price established by the IPUC and the OPUC to estimate IPC's cost of developing additional generation resources. As discussed more fully in "Wind Integration Costs" below, on August 4, 2005, the IPUC granted a temporary reduction in the eligible project size to 100 kW for intermittent generation resources only and ordered IPC to study the impacts of integrating this type of resource.

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 OPUC jurisdictional portion of the costs associated with CSPP contracts is recovered through general rate case filings. The Oregon provisions are currently being reviewed in an OPUC proceeding. 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.

Recent activities, including the extension of the Federal Production Tax Credit and the expansion of the tax credit eligibility to solar, geothermal and other forms of generation, resolution of IPUC and OPUC PURPA-related hearings and a December 1, 2004, order by the IPUC increasing the Published Avoided Costs, create a favorable climate for PURPA project development, which 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, 2007, IPC had signed agreements to purchase energy from 94 CSPP facilities with contracts ranging from one to 30 years. Of these facilities, 76 were on-line at the end of 2007; the other 18 facilities under contract are due to come on-line in 2008 and 2009. During 2007, IPC purchased 777,147 MWh from these projects at a cost of $45 million, resulting in a blended price of 5.9 cents per kilowatt hour.

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

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

In an attempt to settle the case, IPC entered into a settlement stipulation with Renewable Northwest Project and the NW Energy Coalition on October 2, 2007. The settlement stipulation prescribed, among other things, a methodology for calculating a wind integration charge that will be applied to PURPA wind projects. The integration charge will be calculated as a percentage of the current 20-year, levelized, avoided cost rate, subject to a cap of $6.50/MWh. On February 20, 2008, the IPUC issued an order approving the settlement stipulation and increasing the PURPA cap back to ten aMW.

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

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

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

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

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Avista Corporation, Rocky Mountain Power, and the IPUC Staff filed comments supporting IPC's position but recommending that the fuel cost component be tied to each year in the NWPCC forecast rather than using an average of the twenty years. The IPUC approved the application including the IPUC Staff's recommended modification on December 28, 2007.

Integrated Resource Plan

IPC filed its 2006 IRP with the IPUC in September 2006 and with the OPUC in October 2006. The 2006 IRP previewed IPC's load and resource situation for the next 20 years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions.

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

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 2006 IRP.

Peaking Resource: Construction of a new simple cycle combustion turbine resource at the Danskin plant near Mountain Home, Idaho is expected to be complete in the first quarter of 2008. The combustion turbine will provide approximately 166 MW of capacity during summer load peaks and up to 200 MW during winter. IPC received a Certificate of Public Convenience and Necessity for this project on December 15, 2006, that included a construction cost commitment estimate of $60 million and approval to include in rate base the prudent capital costs for construction and operating fuel. The project is ahead of schedule and under the commitment estimate. Related transmission interconnection and line requirements are being completed by IPC at an estimated cost of $24 million.

Wind Agreement: In February 2007, the IPUC approved a power purchase agreement with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW (nameplate) of wind generation from the Elkhorn Valley Wind Project located in eastern Oregon. The project was constructed during 2007 and became commercially operational on December 28, 2007.

Geothermal Agreement: An RFP for geothermal-powered generation was released on June 2, 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. On January 9, 2008, the IPUC approved a power purchase agreement for 13 MW (nameplate generation) from the Raft River Geothermal Power Plant Unit #1 located in southern Idaho. This project began operating in October 2007. Contract negotiations for the remaining 32.5 MW will take place over the next several months and will include an additional unit at the Raft River site (on-line 2009) and two units at the Neal Hot Springs site located in eastern Oregon (on-line 2010 and 2011).

Coal-fired Resource (Shift to Natural Gas-fired Resource): The near-term action plan in the 2006 IRP indicated initial commitments to the construction of a coal-fired resource would be necessary before the end of 2007 in order for a project to be on-line in 2013. In order to meet this schedule, IPC screened and evaluated coal-fired resources in 2006 and 2007. This evaluation concluded in August 2007 and the results indicated construction costs had escalated substantially since resource cost estimates were prepared for the 2006 IRP. Due to escalating construction costs and continued uncertainty surrounding future GHG laws and regulations, IPC decided not to pursue the development of a coal-based resource at this time. However, IPC continues to evaluate other coal-fired resource opportunities, including expansion of its jointly-owned facilities, clean coal technologies and potential power purchase agreements. In order to meet baseload deficiencies identified 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.

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Additional RFPs: On January 22, 2008, IPC released an RFP for 50 to 100 MW of geothermal energy. While additional geothermal resources were not included in the 2006 IRP for this time frame, the development of PURPA wind and combined heat and power projects has been slower than anticipated. If competitively priced geothermal resources are available, they may help to meet future resource needs. IPC also anticipates releasing an RFP in 2008 for 50 MW from one or more combined heat and power projects.

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 and Swan Falls projects.

Hells Canyon Complex: The most significant ongoing relicensing effort is the Hells Canyon Complex (HCC), which provides approximately two-thirds of IPC's hydroelectric generating capacity and 40 percent of its total generating capacity. The current license for the HCC expired at the end of July 2005. Until the new multi-year license is issued, IPC operates the project under an annual license issued by the FERC. The license application was filed in July 2003 and accepted by the FERC for filing in December 2003. The FERC is now processing the application consistent with the requirements of the FPA, the National Environmental Policy Act of 1969, as amended (NEPA), the Energy Policy Act and other applicable federal laws.

Consistent with the requirements of NEPA, the FERC Staff prepared and issued on August 31, 2007, a final environmental impact statement (EIS) for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, the federal and state agencies, Native American tribes and the public about the environmental effects of IPC's proposed operation of the HCC. The final EIS also considers reasonable alternatives to that proposed operation. In this latter context, the FERC Staff reviewed the comments and alternative proposals submitted by the agencies, tribes and the private interests and evaluated those alternatives as compared to measures proposed by IPC. The final EIS also contains a "Staff Alternative," reflecting those instances where some modification to IPC's proposal is deemed advisable by the Staff to address environmental impacts or concerns. The FERC will consider the findings and proposals contained in the final EIS, together with the other information and material filed in the relicensing proceeding, in the development of a license order for the HCC. IPC's initial review of the final EIS indicates that, in large measure, the findings and recommendations (the Staff Alternative) in the final EIS are consistent with the draft EIS issued by the FERC in July 2006 and that the final EIS generally accepts the science, analysis and the proposed measures contained in IPC's license application and supporting documents. IPC is continuing to review the final EIS and expects to file comments on the final EIS with the FERC in the first quarter of 2008.

In conjunction with the issuance of the final EIS, on September 13, 2007, the FERC requested formal consultation with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) pursuant to section 7 of the Endangered Species Act (ESA) with regard to the effect of relicensing the HCC on several aquatic and terrestrial species listed as threatened under the ESA. In subsequent correspondence these entities, the USFWS and the NMFS advised the FERC that outstanding issues remain with regard to the licensing of the HCC and they did not have sufficient information to complete formal ESA consultation on the project. The agencies further advised that they were working with IPC and other state and federal agencies to address these outstanding issues. IPC continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns associated with the relicensing of the HCC. The FERC is not expected to issue a license order for the HCC until ESA consultation is completed.

On January 31, 2007, IPC filed Water Quality Certification Applications, under section 401 of the Clean Water Act (CWA), with the States of Oregon and Idaho. Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, section 401 of the CWA requires as a prerequisite to the licensing of the project by the FERC that each state certify that any discharge from the project complies with applicable state water quality standards. IPC worked with the ODEQ and the IDEQ through 2007 on proposed water quality measures that would address water quality issues at the project. However, because the CWA requires that a state agency act on a pending application within one year of its filing date, IPC found it necessary to withdraw its pending section 401 applications on November 2, 2007 and re-file new applications on that same date. IPC filed supplemental information to the applications on February 1, 2008. IPC continues to work with the ODEQ and the IDEQ to ensure that state water quality standards will be met at the HCC so that the project can be appropriately certified.

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At December 31, 2007, $96 million of HCC relicensing costs were included in construction work in progress. The relicensing costs are recorded and will be held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. On March 10, 2005, IPC issued a Formal Consultation Package (FCP) to natural resource agencies, Native American tribes and the public relating to environmental studies designed to determine project effects for the relicensing of the Swan Falls project. Based upon the results of those studies and the consultation with the agencies, tribes and the public, on September 21, 2007, IPC submitted its draft license application to FERC for public review and comment. The draft contains project-specific information and the results of the studies developed in the FCP. Comments were received from the agencies and one tribe and on February 19, 2008 a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. IPC will file a final license application with the FERC in June 2008.

At December 31, 2007, $3 million of Swan Falls project relicensing costs were included in construction work in progress. The relicensing costs are recorded and will be held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

Shoshone Falls Expansion: On August 17, 2006, IPC filed a license amendment application with the FERC, which would allow IPC to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. In March 2007, IPC received from the FERC a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis, which provided for a 60-day comment period for interested entities. The FERC issued a supplemental EA on December 4, 2007. The license amendment could be issued in the first quarter 2008.

In conjunction with the license amendment application, IPC has filed a water rights application which is currently being reviewed by the 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 a review of the conditions under which this market-based rate authority is granted to ensure that the rates charged thereunder are just and reasonable. On April 14, 2004, the FERC issued an order indicating that is was reconsidering the rules, procedures and methodologies associated with such "triennial filings." In September 2004, IPC filed a revision to its market power analysis (based on 2003 historical data), which it supplemented in September and October 2004. On March 3, 2005, the FERC issued an order accepting IPC's market power analysis. On June 21, 2007, the FERC issued a final rule, Order No. 697, revamping its market-based rate program. Under Order No. 697, IPC's next triennial filing is not due until June 30, 2010.

On December 9, 2005, the FERC Staff requested that IPC perform a complete generation market power study for the IPC control area using 2004 historical data. IPC filed a revised study with the FERC on February 3, 2006. The FERC accepted IPC's notice on June 20, 2006, confirming that IPC passed the market power analysis screens and maintained market-based rate authority.

Because IPC's new generating unit at its Danskin plant, which has a capacity greater than 100 MW, will soon be operational, IPC anticipates filing a "Notice of Change in Status" with the FERC during the first quarter of 2008.

OTHER MATTERS:

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Adopted Accounting Pronouncements
FIN 48: In 2007, IDACORP and IPC adopted FASB Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*" (FIN 48), which creates a single model to address accounting for uncertainty in tax positions. FIN 48 prescribes a minimum recognition threshold that a tax position is required to meet before being recognized in a company's financial statements and also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The cumulative effect of adopting FIN 48 was recorded as a $15.1 million increase in the 2007 opening balance in retained earnings.

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 will 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, 2007.

Interest Rate Risk
IDACORP and IPC manage interest expense and short- and long-term liquidity though 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, 2007, IDACORP and IPC had $325 million and $374 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, 2007, interest rate expense would increase and pre-tax earnings would decrease by approximately $3.2 million for IDACORP and $3.7 million for IPC.

Fixed Rate Debt: As of December 31, 2007, IDACORP and IPC had outstanding fixed rate debt of $981 million and $956 million, respectively, and the fair market value of this debt was $972 million and $946 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 $96 million for IDACORP and $95 million for IPC if interest rates were to decline by one percentage point from their December 31, 2007 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 IDACORP Board of Directors, and to the CAG.

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The Policy requires monitoring monthly volumetric electricity position and total 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 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.

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. A hypothetical ten percent decrease in equity prices would result in an approximate $2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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IDACORP, Inc.

Consolidated Statements of Income

	Year Ended December 31,		
	2007	2006	2005
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 668,303	$ 636,375	$ 667,270
Off-system sales	154,948	260,717	142,794
Other revenues	52,150	23,381	27,619
Total electric utility revenues	875,401	920,473	837,683
Other	3,993	5,818	5,181
Total operating revenues	879,394	926,291	842,864
Operating Expenses:			
Electric utility:			
Purchased power	289,484	283,440	222,310
Fuel expense	134,322	115,018	103,164
Power cost adjustment	(121,131)	(29,526)	(2,995)
Other operations and maintenance	286,510	264,810	242,381
Demand-side management	13,487	-	-
Gain on sale of emission allowances	(2,754)	(8,257)	(1,172)
Depreciation	103,072	99,824	101,485
Taxes other than income taxes	17,634	18,661	20,856
Total electric utility expenses	720,624	743,970	686,029
Other expense	6,692	12,617	2,182
Total operating expenses	727,316	756,587	688,211
Operating Income (Loss):			
Electric utility	154,777	176,503	151,654
Other	(2,699)	(6,799)	2,999
Total operating income	152,078	169,704	154,653
Other Income	20,524	18,195	17,121
Losses of Unconsolidated Equity-Method Investments	(4,824)	(2,913)	(713)
Other Expense	8,434	8,559	8,006
Interest Expense:			
Interest on long-term debt	59,961	56,402	56,930
Other interest	3,380	4,573	2,799
Total interest expense	63,341	60,975	59,729
Income Before Income Taxes	96,003	115,452	103,326
Income Tax Expense	13,731	15,377	17,610
Income from Continuing Operations	82,272	100,075	85,716
Income (Losses) from Discontinued Operations, net of tax	67	7,328	(22,055)
Net Income	$ 82,339	$ 107,403	$ 63,661
Weighted Average Common Shares Outstanding - Basic (000's)	44,151	42,713	42,279
Weighted Average Common Shares Outstanding - Diluted (000's)	44,291	42,874	42,362

Earnings Per Share of Common Stock:						
Earnings per share from Continuing Operations-Basic	$	1.86	$	2.34	$	2.03
Earnings (loss) per share from Discontinued Operations-Basic		-		0.17		(0.52)
Earnings Per Share of Common Stock-Basic	$	1.86	$	2.51	$	1.51
Earnings per share from Continuing Operations-Diluted	$	1.86	$	2.34	$	2.02
Earnings (loss) per share from Discontinued Operations-Diluted		-		0.17		(0.52)
Earnings Per Share of Common Stock-Diluted	$	1.86	$	2.51	$	1.50
Dividends Paid Per Share of Common Stock	$	1.20	$	1.20	$	1.20

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Balance Sheets

	December 31, 2007	December 31, 2006
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 7,966	$ 9,892
Receivables:		
Customer	69,160	62,131
Allowance for uncollectible accounts	(7,505)	(7,168)
Employee notes	2,128	2,569
Other	10,957	11,855
Energy marketing assets	-	12,069
Accrued unbilled revenues	36,314	31,365
Materials and supplies (at average cost)	43,270	39,079
Fuel stock (at average cost)	17,268	15,174
Prepayments	9,371	9,308
Deferred income taxes	25,672	28,035
Refundable income tax deposit	46,083	44,903
Other	6,023	3,993
Assets held for sale	-	3,326
Total current assets	266,707	266,531
Investments	201,085	202,825
Property, Plant and Equipment:		
Utility plant in service	3,796,339	3,583,694
Accumulated provision for depreciation	(1,468,832)	(1,406,210)
Utility plant in service - net	2,327,507	2,177,484
Construction work in progress	257,590	210,094
Utility plant held for future use	3,366	2,810
Other property, net of accumulated depreciation	28,089	28,692
Property, plant and equipment - net	2,616,552	2,419,080
Other Assets:		
American Falls and Milner water rights	29,501	30,543
Company-owned life insurance	30,842	34,055
Regulatory assets	449,668	423,548
Long-term receivables (net of allowance of $1,878)	3,583	3,802
Employee notes	2,325	2,411
Other	53,045	41,259
Assets held for sale	-	21,076
Total other assets	568,964	556,694
Total	$ 3,653,308	$ 3,445,130

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Balance Sheets

Liabilities and Shareholders' Equity	December 31, 2007	2006
	(thousands of dollars)	
Current Liabilities:		
Current maturities of long-term debt	$ 11,456	$ 95,125
Notes payable	186,445	129,000
Accounts payable	85,116	86,440
Energy marketing liabilities	-	13,532
Taxes accrued	8,492	47,402
Interest accrued	18,913	12,657
Uncertain tax positions	26,764	-
Other	38,129	23,572
Liabilities held for sale	-	2,606
Total current liabilities	375,315	410,334
Other Liabilities:		
Deferred income taxes	466,182	498,512
Regulatory liabilities	274,204	294,844
Other	173,412	179,836
Liabilities held for sale	-	8,773
Total other liabilities	913,798	981,965
Long-Term Debt	1,156,880	928,648
Commitments and Contingencies (Note 7)		
Shareholders' Equity:		
Common stock, no par value (shares authorized 120,000,000; 45,063,107 and 43,905,458 shares issued, respectively)	675,774	638,799
Retained earnings	537,699	493,363
Accumulated other comprehensive loss	(6,156)	(5,737)
Treasury stock (380 and 71,570 shares at cost, respectively)	(2)	(2,242)
Total shareholders' equity	1,207,315	1,124,183
Total	$ 3,653,308	$ 3,445,130

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2007	**2006**	**2005**
Operating Activities:	(thousands of dollars)		
Net income	$ 82,339	$ 107,403	$ 63,661
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	120,368	122,641	124,124
Deferred income taxes and investment tax credits	11,026	(17,332)	(31,769)
Changes in regulatory assets and liabilities	(128,089)	(17,133)	7,275
Non-cash pension expense	6,868	-	-
Undistributed earnings of subsidiaries	(6,273)	(9,553)	(16,762)
Gain on sale of assets	(4,758)	(25,658)	(2,128)
Impairment of goodwill	-	-	10,270
Impairment of long-lived asset	-	2,047	-
Other non-cash adjustments to net income	(2,915)	(3,395)	(15,073)
Excess tax benefit from share-based payment arrangements	(68)	(1,411)	-
Change in:			
Accounts receivable and prepayments	(10,284)	24,304	(6,436)
Accounts payable and other accrued liabilities	2,206	6,725	1,821
Taxes accrued	(9,466)	(24,099)	26,412
Other current assets	(11,159)	(4,829)	(14,360)
Other current liabilities	15,551	(3,465)	794
Other assets	2,157	3,334	(514)
Other liabilities	13,098	10,199	14,181
Net cash provided by operating activities	80,601	169,778	161,496
Investing Activities:			
Additions to property, plant and equipment	(287,751)	(225,048)	(193,314)
Proceeds from the sale of ITI	-	21,469	-
Proceeds from the sale of IDACOMM	7,283	-	-
Investments in affordable housing	348	(5,059)	(4,992)
Proceeds from the sale of emission allowances	19,846	11,323	70,757
Investments in unconsolidated affiliates	(8,535)	(16,030)	-
Purchase of available-for-sale securities	(24,349)	(17,979)	(85,334)