IDAHO POWER CO
Form 10-K
February 22, 2012

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, 2011

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 1221 W. Idaho Street Boise, ID 83702-5627 (208) 388-2200	82-0130980

State of incorporation: Idaho

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 Stock Exchange

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

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.
IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

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

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

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

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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 non-affiliates (June 30, 2011):
IDACORP, Inc.: $1,941,836,645 Idaho Power Company: None
Number of shares of common stock outstanding as of February 17, 2012:
IDACORP, Inc.: 49,947,098
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 2012 annual meeting of shareholders.

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

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

COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are found in multiple locations within this report:

ADITC	-	Accumulated Deferred Investment Tax Credits
AFUDC	-	Allowance for Funds Used During Construction
AMI	-	Advanced Metering Infrastructure
aMW	-	Average Megawatts
APCU	-	Annual Power Cost Update
BCC	-	Bridger Coal Company, a joint venture of IERCo
BLM	-	U.S. Bureau of Land Management
BPA	-	Bonneville Power Administration
CAA	-	Clean Air Act
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
CWA	-	Clean Water Act
DEIS	-	Draft Environmental Impact Statement
DSM	-	Demand-Side Management
DSR	-	Demand-Side Resources
EGUs	-	Electric Utility Steam Generating Units
EIS	-	Environmental Impact Statement
EPA	-	U.S. Environmental Protection Agency
EPS	-	Earnings Per Share
ESA	-	Endangered Species Act
FASB	-	Financial Accounting Standards Board
FCA	-	Fixed Cost Adjustment Mechanism
FERC	-	Federal Energy Regulatory Commission
FPA	-	Federal Power Act
GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse Gas
HCC	-	Hells Canyon Complex
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
Idaho ROE	-	Idaho-jurisdiction return on year-end equity
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.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IRS	-	U.S. Internal Revenue Service
kW	-	Kilowatt
LCAR	-	Load Change Adjustment Rate
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
MW	-	Megawatt
MWh	-	Megawatt-hour
NOx	-	Nitrous Oxide
NSPS	-	New Source Performance Standards
O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission

PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
REC	-	Renewable Energy Certificate
RES	-	Renewable Energy Standard
RPS	-	Renewable Portfolio Standard
SEC	-	U.S. Securities and Exchange Commission
SO_2	-	Sulfur Dioxide
USBR	-	U.S. Bureau of Reclamation
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

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*Except as indicated in Items 12 and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2012 annual meeting of shareholders.

SAFE HARBOR STATEMENT

This Annual Report on 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 I, Item 1A - "Risk Factors" and in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" (including under the heading "Forward-Looking Statements"). 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," "targets," "predicts," "projects," "may result," "may continue," or similar expressions.

PART I
ITEM 1. BUSINESS

OVERVIEW

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

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as successor to a Maine corporation organized in 1915. Idaho Power 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. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

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 that wound down operations in 2003.

Idaho Power is IDACORP’s only reportable business segment, contributing 99 percent of IDACORP’s net income in 2011. Segment data is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2011, IDACORP had 2,058 full-time employees, 2,046 of whom were employed by Idaho Power, and 23 part-time employees, 22 of whom were employed by Idaho Power.

IDACORP and Idaho Power make available free of charge on their websites 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 U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is www.idacorpinc.com and can also be accessed through a link to the IDACORP website on the Idaho Power website at www.idahopower.com. The contents of the above-referenced website addresses are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC’s website, www.sec.gov, or from the SEC’s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

IDACORP’s and Idaho Power’s principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

UTILITY OPERATIONS

Idaho Power’s service territory covers approximately 24,000 square miles in southern Idaho and eastern Oregon, with an estimated population of one million. Idaho Power holds franchises, typically in the form of right-of-way arrangements, 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, 2011, Idaho Power supplied electric energy to approximately 496,000 general business customers. Idaho Power’s principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, forest products, beet sugar refining, and winter recreation. Idaho Power's service territory is illustrated on the following page.

Weather, customer demand, and economic conditions impact electricity sales and costs and, therefore, utility revenues are not earned and associated expenses are not incurred evenly during the year. 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. Idaho Power’s retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter that generally results from demand for electric power for heating purposes.

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. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), and as a regulated electric utility Idaho Power is generally not subject to retail competition. Idaho Power is also under the jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. Further, the FERC has jurisdiction over, among other items, Idaho Power's transmission and wholesale sales of electricity, hydroelectric relicensing, and system reliability.

General Business Strategy

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. Idaho Power continuously evaluates and refines its business strategy to ensure coordination among and integration of all functional areas of the company. Idaho Power’s business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company’s financial stability and flexibility. The strategy includes:

- Responsible Planning: Idaho Power’s planning process is intended to ensure adequate generation and transmission resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power’s regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.

- Responsible Development and Protection of Resources: Idaho Power’s business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural resources Idaho Power and the communities it serves depend upon. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.

- Responsible Energy Use: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards (RPS) legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions.

Rates and Revenues

Retail: Idaho Power periodically evaluates the need to seek changes to its retail electricity price structure to cover its operating costs and provide a reasonable rate of return. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA) mechanism, a pension balancing account, and subject-specific filings to recover its costs of providing service and to earn a return on investment.

Retail prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, public hearings, and the issuance of a final order. Participants in these proceedings, which are conducted under established procedural schedules, include Idaho Power, the IPUC or OPUC, and other interested parties. The IPUC and OPUC are required to ensure that the prices and terms of service are fair, non-discriminatory, and provide Idaho Power an opportunity to recover its costs and earn a fair return on investment. In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific authorization from the IPUC or OPUC. Deferred amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

For additional information on regulatory matters, including significant rate cases and proceedings, see the “Regulatory Matters” section of Part II, Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) and Note 3 – “Regulatory Matters” to the consolidated financial statements included in this report.

Developments in 2011 with Special Customer Electric Service Agreements: Idaho Power is authorized to enter into special electric service arrangements with customers that have an aggregate power requirement that exceeds 20 megawatts (MW). Notable recent developments with respect to one of those arrangements are described below.

In March 2009, the IPUC approved a September 2008 electric service agreement between Idaho Power and Hoku Materials, Inc. (Hoku), to provide electric service to Hoku’s polysilicon production facility being constructed in Pocatello, Idaho. The initial term of the agreement is four years beginning December 1, 2009, with a maximum demand obligation during the initial term of 82 MW. Hoku was still not taking significant service as of December 31, 2011. In December 2011, Idaho Power sent to Hoku a notice of termination of service pursuant to IPUC rules to terminate service as a result of an overdue invoice for electric service. On January 9, 2012, Hoku filed a petition with the IPUC alleging that its contract with Idaho Power was contrary to the public interest and requested that the IPUC reform the contract and sought reparations for previously paid amounts under the electric service agreement. On January 13, 2012, the IPUC ordered Idaho Power and Hoku to enter into negotiations to seek settlement of Hoku's petition. On February 17, 2012, Idaho Power, Hoku, and the IPUC Staff filed with the IPUC a settlement stipulation that would amend the electric service agreement. The stipulation provides for a minimum monthly charge of $0.8 million (compared to the existing minimum monthly charge of approximately $2 million) from January 2012 to July 2013 and the establishment of a balancing mechanism that will track and accrue (up to a maximum balance of approximately $16.5 million) on a monthly basis the difference between (a) the first block minimum energy charges (excluding demand charges) under the existing agreement and (b) the modified minimum billed energy charge (excluding demand charges) under the settlement stipulation. In January 2014, Idaho Power will begin invoicing Hoku for, in addition to applicable demand and energy charges, recovery of the deferred amount over a 12 month period, one-twelfth per month. Further, the stipulation provides that Hoku will pay to Idaho Power $2.0 million upon IPUC approval of the stipulation out of existing funds on deposit with Idaho Power, and $0.1 million per month in cash for

18 months commencing with its January 2012 invoice. The stipulation also extends the term of the electric service agreement through December 1, 2014. During the final year of the agreement, Hoku will pay embedded-cost based rates for service. Hoku agrees in the stipulation to cap its monthly power demand during the January 2012 to July 2013 deferral period to 20 MW, with the option to increase usage to 82 MW following a notice period and payment of applicable deposits. In the event Hoku uses more than 20 MW of energy in any given month, Hoku will be required to pay the minimum billed energy charge amounts set forth in the existing electric service agreement.

Wholesale: As a public utility under Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its Open Access Transmission Tariff (OATT). Idaho Power's OATT is revised each year based on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards, which are applicable to Idaho Power, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power has one low-volume wholesale reserve sales contract, with United Materials of Great Falls, Inc. The agreement requires Idaho Power to carry energy reserves in association with an energy sales agreement between Idaho Power and United Materials from the Horseshoe Bend Wind Farm located in Montana. The term of the agreement runs seasonally through May 2013. Idaho Power had one firm wholesale power sales contract with Raft River Electric Cooperative for up to 15 MW, which expired in September 2011.

Idaho Power participates in the wholesale energy market by buying power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans, which are influenced by customer load, market prices, generating costs, and availability of generating resources. Some of Idaho Power's hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric 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. Wholesale energy market prices and compliance factors, such as allowable river stage elevation changes and flood control requirements, influence these dispatch decisions.

Energy Sales: The table below presents Idaho Power’s revenues and energy use by customer type for the last three years. Approximately 95 percent of Idaho Power’s general business revenue comes from customers located in Idaho, with the remainder coming from customers located in Oregon. Idaho Power’s operations are discussed further in Part II, Item 7 - “MD&A – Results of Operations - Utility Operations.”

	Year Ended December 31,		
	2011	2010	2009
Revenues (thousands of dollars)			
Residential	$405,982	$400,607	$409,479
Commercial	220,962	231,440	232,816
Industrial	140,701	138,394	141,530
Irrigation	104,635	110,555	109,655
Provision for sharing	(27,099)	—	—
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,636)	(10,625)	(9,715)
Total general business	834,545	870,371	883,765
Off-system sales	101,602	78,133	94,373
Other	86,581	84,548	67,858
Total	$1,022,728	$1,033,052	$1,045,996
Energy use (thousands of MWh)			
Residential	5,146	4,967	5,300
Commercial	3,815	3,763	3,858
Industrial	3,100	3,076	3,140
Irrigation	1,673	1,707	1,650
Total general business	13,734	13,513	13,948
Off-system sales	3,635	1,982	2,836
Total	17,369	15,495	16,784

Power Supply

Idaho Power primarily relies on company-owned hydroelectric, coal, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, and economic conditions impact power supply costs. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and purchased power. Economic conditions can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,214 MW, set on June 30, 2008, and the all-time winter peak demand is 2,527 MW, set on December 10, 2009. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. During 2011, the largest peak demand was 2,973 MW, set on July 6, 2011. The following table presents Idaho Power's total power supply for the last three years:

	MWh			Percent of Total Generation		
	2011	2010	2009	2011	2010	2009
	(thousands of MWh)					
Hydroelectric plants	10,937	7,344	8,096	69 %	51 %	53 %
Coal-fired plants	4,820	6,864	6,941	30 %	48 %	45 %
Natural gas fired plants	138	160	242	1 %	1 %	2 %
Total system generation	15,895	14,368	15,279	100 %	100 %	100 %
Purchased power - cogeneration and small power production	1,495	910	970			
Purchased power - other	1,256	1,491	1,942			
Total purchased power	2,751	2,401	2,912			
Total power supply	18,646	16,769	18,191			

Hydroelectric Generation: Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 8.6 million megawatt-hours (MWh) under median water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall, amount and timing of water leases, and other weather and stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced.

The manner in which Idaho Power has optimized operation of its hydroelectric facilities in the past has been impacted by intermittent wind generation and may continue to be impacted in the future as the company is faced with integrating an increasing amount of intermittent wind generation. As additional intermittent wind generation resources are developed in the region and contracted to Idaho Power, the operational impacts will likely increase. For related information on intermittent wind generation see "Purchased Power Agreements" below.

Significantly greater snow accumulation during the winter and the resulting effect on stream flow conditions resulted in above average stream flow in 2011, which resulted in a 3.6 million MWh increase in generation from Idaho Power's hydroelectric facilities compared to 2010. The observed stream flow data released in August 2011 by the U.S. Army Corps of Engineers, Northwest Division indicated that Brownlee Reservoir inflow for April through July 2011 was 10.5 million acre-feet (maf), compared to 4.6 maf in April through July 2010 and 5.6 maf in April through July 2009. Annual Brownlee Reservoir inflow for 2011 was 19.3 maf compared to 10.7 maf in 2010 and 11.3 maf in 2009.

Power generation at the Idaho Power hydroelectric power plants on the Snake River also depends on the state water rights held by Idaho Power 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. Idaho Power continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River. For more information on water management issues see Note 10 - "Contingencies" to the consolidated financial statements included in this report.

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee." As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described 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.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental issues. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex and Swan Falls projects. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power's Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

Coal and Natural Gas-Fired Generation: Idaho Power co-owns three coal-fired power plants and owns two natural gas-fired combustion turbine power plants. The coal-fired plants are:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest; and
- Valmy located in Nevada, in which Idaho Power has a 50 percent interest.

The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The Langley Gulch natural gas-fired combined cycle power plant located in Idaho is currently under construction and is contracted to achieve commercial operation no later than November 1, 2012. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012.

Fuel Supply - Coal: Idaho Power, through its subsidiary IERCo, owns a one-third interest in BCC, which owns the Jim Bridger mine that supplies coal to the Jim Bridger generating plant, which is operated by PacifiCorp. 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. Idaho Power believes that the Jim Bridger mine has sufficient reserves to provide coal deliveries for the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2014 from the Black Butte Coal Company's Black Butte mine 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 provide the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

The Boardman generating plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Portland General Electric Company, as the operator of the Boardman plant, has two agreements to supply coal beginning in 2012. All of the Boardman plant's coal requirements in 2012, approximately 50 percent in 2013, and 33 percent in 2014, are under contract. A portion of the 2013 and 2014 coal used will be low sulfur content as Boardman prepares for the 2015 transition to a lower sulfur fuel content. As a ten percent owner of the plant, Idaho Power is obligated to purchase ten percent of the coal purchased under these agreements. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. For additional information, see Part II, Item 7 – "MD&A – Environmental Matters – Environmental Regulation."

NV Energy, Inc., as the operator of the Valmy generating plant, has agreements with coal suppliers through 2015. Idaho Power's share of these agreements along with existing coal inventory at the plant cover Idaho Power's projected coal supply needs for 2012, 2013, and 2014 and approximately 50 percent in 2015. As a 50 percent owner of the plant, Idaho Power is obligated for one-half of the coal purchased under these contracts.

Fuel Supply - Natural Gas: Idaho Power owns and operates the Danskin and Bennett Mountain combustion turbines, and is constructing its Langley Gulch natural gas-fired combined-cycle power plant. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is supplied through Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. The agreements vary in contract length, with the latest termination date of May 2042, but with extensions at Idaho Power’s discretion. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. As the project is developed, storage capacity will be phased into service and allocated to Idaho Power on a monthly basis. Idaho Power's current storage allotment is approximately 89 percent of its eventual total, with its full allotment expected to be reached by July 2012. This firm storage contract expires in 2043. Natural gas will be purchased and stored with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

Idaho Power estimates that its Langley Gulch plant will be in service by July 1, 2012, in time to contribute to meeting summer loads. Approximately 1.2 million MMBtu's of natural gas has been hedged using financial instruments for future purchases for start-up testing of the plant expected to take place between March 2012 and May 2012. Along with this, approximately 2.9 million MMBtu's of natural gas has been financially hedged for future purchases for the operational dispatch of Langley Gulch from July 2012 to January 2013. Idaho Power plans to manage the procurement of additional natural gas as necessary to meet system requirements and fueling strategies.

Purchased Power Agreements: Idaho Power purchases power in the wholesale market and pursuant to long-term power purchase contracts, as described below:

Wholesale Market Purchases: Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk limits, and unit availability, and from PURPA projects as mandated. Idaho Power seeks to manage its loads efficiently by utilizing its generation resources and long-term purchase power contracts in conjunction with buying and selling opportunities in the wholesale market. Idaho Power has the following notable firm wholesale power purchase contracts and energy exchange agreements:

- PPL Energy Plus, LLC - for 83 MW per hour during heavy load hours, to address increased demand during June, July and August. The contract term is through August 2012;
- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033;
- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027;
- USG Oregon LLC - for 22 MW (estimated average annual output) from the to-be-constructed Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is 25 years with an option to extend. USG Oregon LLC has stated that it expects commercial operation by late 2012; and
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock Project in southern Idaho for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is January 1, 2010 through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

CSPP and PURPA Power Purchase Contracts: Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions having jurisdiction over Idaho Power have each issued orders and rules regulating Idaho Power's purchase of power from cogeneration and small power production (CSPP) facilities. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility's avoided costs. The "published avoided cost" is a price established by the IPUC and OPUC to estimate Idaho Power's cost of developing additional generation resources. The IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost that Idaho Power is required to include in PURPA contracts.

Idaho Power has contracts for the purchase of energy from a number of private developers. For these contracts:

- Idaho Power is required to purchase all of the output from the facilities located inside its service territory, subject to some exceptions such as adverse impacts on system reliability;
- Idaho Power is required to purchase the output of projects located outside its service territory if it has the ability to receive power at the facility's requested point of delivery on the Idaho Power system;
- the IPUC jurisdictional portion of the costs associated with CSPP contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and the PCAM;
-

IPUC jurisdictional regulations allow IPUC published avoided costs for up to a 20-year contract term. Effective December 14, 2010, wind and solar resource projects with a nameplate rating of 100 kW or less are eligible for the IPUC published avoided costs. For all other resource types, a project that generates up to ten average MW of energy monthly is eligible for the IPUC published avoided costs;

- OPUC jurisdictional regulations allow OPUC published avoided costs for up to a 20-year contract term for projects with a nameplate rating of up to ten MW of capacity; and
- if a PURPA project does not qualify for published avoided costs, Idaho Power is required to negotiate the terms, prices, and conditions with the developer. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location, and size) and the benefits to the Idaho Power system and must be consistent with other similar energy alternatives.

Idaho Power believes that published avoided cost rates in effect as of the date of this report provide a favorable climate for PURPA project development. Mandated purchase of intermittent, non-dispatchable energy at published avoided cost rates may result in Idaho Power acquiring energy at above wholesale market prices when a surplus already exists (at times resulting in sale of the surplus energy in the wholesale markets at a loss) and result in additional integration costs, thus increasing costs to its customers. Following a dramatic increase in anticipated PURPA projects, in response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011, the IPUC issued an order temporarily reducing the eligibility cap for projects obtaining published avoided cost rates, effective retroactively to December 14, 2010, to 100 kW for wind and solar PURPA projects only. On June 8, 2011, the IPUC disapproved 13 contracts for pending wind projects with a combined nameplate capacity of 294 MW. If these 13 contracts had all been approved, the amount of wind generation that Idaho Power had under contract would have exceeded 1,000 MW. The IPUC has opened a docket to further investigate PURPA contract terms and conditions and pricing models. This matter is scheduled for hearings in August 2012. For further information on those proceedings, refer to "MD&A - Regulatory Matters - PURPA Power Purchase Contracts."

As of December 31, 2011, Idaho Power had 40 MW of solar power generation under contract for purchase. In December 2011, Idaho Power entered into a PURPA purchase power agreement for a 20-MW waste biomass generation project. Idaho Power has also entered into a number of other PURPA agreements for smaller renewable energy projects.

As of December 31, 2011, Idaho Power had the following signed CSPP-related agreements with terms ranging from one to 35 years:

Status	Number of Contracts	Nameplate Capacity (MW)
On-line at the end of 2011	96	606
Contracted and projected to come on-line by year-end 2014	23	383
Total	119	989

The majority of new facilities will be wind resources that will generate on an intermittent basis. During 2011, Idaho Power purchased 1.5 million MWh of power from CSPP facilities at a cost of $90 million, resulting in a blended price of $60.36 per MWh.

Transmission Services

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located anywhere from a few miles to hundreds of miles from customers. Idaho Power’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. Idaho Power’s transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration (BPA), Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy, Inc. These 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 entities in the Western Power System. Idaho Power provides wholesale transmission service and provides firm and non-firm wheeling services for eligible transmission customers. Idaho Power is a member of the WECC, 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.

Resource Planning and Renewable Energy Projects

Integrated Resource Plan: Idaho Power filed its 2011 Integrated Resource Plan (IRP) with the IPUC and OPUC in June 2011. The IRP forecasts Idaho Power's load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options, and identifies near-term and long-term actions. The 2011 IRP was accepted by the IPUC in December 2011. As of the date of this report the 2011 IRP has not been acknowledged by the OPUC. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

Idaho Power updates the IRP every two years and work on the 2013 IRP will begin in the summer of 2012. Idaho Power expects that the updated plan will be completed and filed in June 2013. During the time between resource plan filings, the public and regulatory oversight of the activities identified in the 2011 IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect changes in technology, economic conditions, anticipated resource development, and regulatory requirements.

The 2011 IRP included the 300-MW Langley Gulch project currently under construction and a 50-MW expansion of the Shoshone Falls hydroelectric facility. The 2011 IRP also identified the Boardman-to-Hemingway transmission line in the preferred resource portfolio. Idaho Power believes the Boardman-to-Hemingway transmission line and the Hemingway substation, together with the Gateway West transmission line, will improve reliability, relieve congestion, and provide system flexibility. Additional information about Idaho Power's significant infrastructure development projects are discussed in Part II, Item 7 – "MD&A – Liquidity and Capital Resources – Capital Requirements – Major Infrastructure Projects."

The expected-case load forecast in the 2011 IRP projects peak-hour load will grow 69 MW annually and average-system load will increase annually 29 average MW (aMW) over the 20-year planning period, with an expected-case, median, average annual system load of 2,362 aMW by 2030. Idaho Power intends to meet the anticipated increase in demand through energy efficiency and demand response programs, the development of transmission capacity and additional generation resources, such as the Langley Gulch and Shoshone Falls projects, and from the purchase of power from third parties, including from renewable energy projects and market power purchases. Idaho Power stated in the 2011 IRP that it expects energy efficiency programs to result in 233 aMW of load reduction by 2030, and that demand response programs are targeted to reduce peak summer load by 351 MW by summer 2016.

The 2011 IRP also included discussion related to geothermal, combined heat and power (CHP), and solar resources, each of which is described below.

Geothermal Resources: Idaho Power has continued to work with geothermal project developers capable of delivering energy to the company's service area. The 2009 IRP included two 20-MW increments of geothermal energy in the preferred portfolio—one in 2012 and one in 2016. The 20-MW increment in 2012 was addressed by a long-term power purchase agreement for the output from the Neal Hot Springs geothermal project located in eastern Oregon. This project is currently under construction and the developer expects it to be operational in late 2012. Idaho Power has contracted to receive the RECs from the project during the term of the agreement. The additional 2016 increment of geothermal energy was evaluated in the 2011 IRP and was found unnecessary with the addition of the Boardman-to-Hemingway transmission line project. The preferred portfolio in the 2011 IRP did include 52 MW of geothermal energy in 2021 and Idaho Power plans to follow the development of geothermal resources in and around Idaho Power's service area in the event a project materializes that could fill this need in 2021.

CHP Resources: CHP, also commonly referred to as "cogeneration," facilities utilize by-product heat (often through steam) to generate electricity. CHP resources were not included in the 2011 IRP preferred portfolio because of the uncertainty in being able to successfully develop a CHP project. However, Idaho Power continues to work with large customers and other parties to explore CHP development opportunities.

In 2009, Idaho Power signed an agreement to jointly investigate a CHP project with the Idaho Office of Energy Resources (IOER) and The Amalgamated Sugar Company (TASCO), one of Idaho Power's large industrial customers. The agreement established the framework for a high-level feasibility study to investigate installing a CHP project at TASCO's Nampa, Idaho facility that could generate as much as 100 MW of electricity. The IOER and Idaho Power jointly funded the study, which confirmed initial estimates of the project's potential benefits. In September 2010, Idaho

Power, IOER, and TASCO agreed to complete a more detailed feasibility study to refine performance and financial modeling of the proposed project. The second feasibility study indicated that the CHP project is technically feasible; however, given the increase in the amount of PURPA power generation Idaho Power now has under contract, current economic and electric power market conditions, the current treatment of CHP projects under federal incentive programs, and TASCO's and IPC's individual needs, proceeding with developing this CHP project does not appear to be the most economic choice for either party.

Solar Resources: On or before January 1, 2020, Idaho Power is required to own or contract to purchase the capacity and output from a qualifying solar photovoltaic (PV) system with a minimum capacity of 500 kW pursuant to the state of Oregon's solar PV capacity standard. The timing of development of this required project in Oregon and the solar demonstration project referenced in Idaho Power's 2011 IRP will depend in large part on Idaho Power's ability to resolve integration, reliability, and cost issues associated with the recent influx of PURPA resources from which Idaho Power is currently mandated to purchase power. However, with the cost of solar PV technology continuing to decrease, Idaho Power believes this technology will become more prevalent in its service area. Idaho Power continues to evaluate the timing for proceeding with solar resource projects.

Energy Efficiency and Demand Response Programs: Idaho Power has 16 energy efficiency and demand response programs targeting energy savings across the entire year and summer system demand reduction. These programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new infrastructure. Idaho Power's programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes, including efficient appliances and HVAC equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes; and
- demand response programs to reduce peak summer demand through the voluntary interruption of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through a third-party demand response aggregator.

In 2011, Idaho Power's energy efficiency programs reduced energy usage by approximately 160,000 MWh. Idaho Power's demand response programs had available capacity of approximately 410 MW; however, because of a relatively mild summer and the restructuring of Idaho Power's irrigation peak rewards program, Idaho Power realized approximately 83 MW in summer peak demand reduction through combined performance.

In 2011, Idaho Power spent approximately $46.3 million on energy efficiency and targeted demand reduction response programs. Approximately $37.7 million of funding for these programs is provided by Idaho and Oregon energy efficiency tariff riders, while the balance of the funding comes from Idaho Power base rates. Beginning in 2011, as approved by the IPUC, Idaho Power capitalized approximately $7 million of custom efficiency program incentives as a regulatory asset.

Approximately $4 million of Idaho Power's 2011 energy efficiency spending was related to research and analysis, education, technology evaluation, and market transformation. Most of this activity was done in conjunction with the Northwest Energy Efficiency Alliance.

Environmental Regulation and Costs

Idaho Power'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 Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, and the modification of system operations to accommodate environmental regulations. In addition to generally applicable regulations, the FERC licenses issued for Idaho Power's hydroelectric generating plants have environmental requirements such as aeration of turbine water to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power co-owns three coal-fired power plants and owns two natural gas combustion turbine power plants that are subject to a broad range of environmental requirements, including air quality regulation. For a more detailed discussion of these and other environmental issues, refer to Part II, Item 7 – "MD&A – Environmental Matters."

Idaho Power's environmental compliance costs will continue to be significant for the foreseeable future, especially with potential additional regulation under discussion at the state and federal levels. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

Environmental expenditures	2012	2013 - 2014
Capital expenditures:		
Studies and measures at hydroelectric facilities	$12	$31
Investments in equipment and facilities at thermal plants	15	99
Total capital expenditures	$27	$130
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$21	$48
Operating costs for environmental facilities - thermal	12	27
Total operations and maintenance	$33	$75

Idaho Power anticipates that a number of new and impending EPA rulemakings and proceedings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs in addition to the amounts set forth above.

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 $6 million, $7 million, and $8 million in 2011, 2010, and 2009, respectively. IFS's portfolio also includes historic rehabilitation projects such as the Empire Building in Boise, Idaho. IFS made no new investments in 2011, but did have $7 million and $14 million in new investments during 2010 and 2009, respectively, and will continue to evaluate new opportunities for investment commensurate with the ongoing needs of IDACORP.

IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk. Over 90 percent of IFS's investments have been made through syndicated funds. At December 31, 2011, the gross amount of IFS's portfolio equaled $198 million in tax credit investments. These investments cover 49 states, Puerto Rico, and the U.S. Virgin Islands. The underlying investments include nearly 700 individual properties, of which all but five are administered through syndicated funds.

IDA-WEST

Ida-West operates and has a 50 percent interest in nine hydroelectric plants with a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $9 million, $8 million, and $9 million in 2011, 2010, and 2009, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below, along with their business experience during at least 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.

Senior Executive Officers (in alphabetical order)

DARREL T. ANDERSON, 53
- President and Chief Financial Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 1, 2009 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - October 1, 2009.

REX BLACKBURN, 56
- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 1, 2009 - present.
- Senior Attorney, Idaho Power Company, January 1, 2008 - March 31, 2009.
- Partner at Blackburn and Jones, LLP, a law firm, January 2003 - December 31, 2007.

LISA A. GROW, 46
- Senior Vice President, Power Supply of Idaho Power Company, October 1, 2009 - present.
- Vice President – Delivery Engineering and Operations of Idaho Power Company, July 20, 2005 - September 30, 2009.

J. LAMONT KEEN, 59
- President and Chief Executive Officer of IDACORP, Inc., July 1, 2006 - present.
- Chief Executive Officer of Idaho Power Company, November 17, 2005 - present.
- President of Idaho Power Company, March 1, 2002 - December 31, 2011.
- Executive Vice President of IDACORP, Inc., March 1, 2002 - July 1, 2006.
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company.

STEVEN R. KEEN, 51
- Senior Vice President, Finance and Treasurer of Idaho Power Company, January 1, 2012 - present.
- Vice President, Finance and Treasurer of IDACORP, Inc., June 1, 2010 - present.
- Vice President, Finance and Treasurer of Idaho Power Company, June 1, 2010 - December 31, 2011.
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 1, 2006 - May 31, 2010.
- President of IDACORP Financial Services, January 15, 1999 - May 31, 2007.

DANIEL B. MINOR, 54
- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President of IDACORP, Inc., May 20, 2010 - present.
- Executive Vice President, Operations of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President – Delivery of Idaho Power Company, July 1, 2004 - October 1, 2009.

Other Executive Officers (in alphabetical order)

DENNIS C. GRIBBLE, 59

•Vice President and Chief Information Officer of Idaho Power Company, June 1, 2006 - present.
•Vice President and Chief Information Officer of IDACORP, Inc., June 1, 2006 - December 31, 2011.
•Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, July 15, 2004 - June 1, 2006.

PATRICK A. HARRINGTON, 51

•Corporate Secretary of IDACORP, Inc. and Idaho Power Company, March 15, 2007 - present.
•Senior Attorney, IDACORP, Inc. and Idaho Power Company, June 7, 2003 - March 15, 2007.

WARREN KLINE, 56

- Vice President, Customer Operations of Idaho Power Company, May 20, 2010 - present.
- Vice President – Customer Service and Regional Operations of Idaho Power Company, July 20, 2005 - May 20, 2010.

JEFFREY MALMEN, 44

- Vice President, Public Affairs of IDACORP, Inc. and Idaho Power Company, October 1, 2008 - present.
- Senior Manager – Governmental Affairs of IDACORP, Inc. and Idaho Power Company, December 10, 2007 - October 1, 2008.
- Chief of Staff of the Office of Idaho Governor C.L. “Butch” Otter, January 2007 - November 2007.
- Chief of Staff of the Office of Idaho Congressman C.L. “Butch” Otter, January 2001 - December 2006.

LUCI K. MCDONALD, 54

- Vice President, Human Resources and Corporate Services of Idaho Power Company, May 20, 2010 - present
- Vice President, Human Resources and Corporate Services of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President – Human Resources of IDACORP, Inc. and Idaho Power Company, December 6, 2004 - May 20, 2010.

KEN W. PETERSEN, 48

- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Corporate Controller of IDACORP and Idaho Power Company, December 29, 2007 - May 20, 2010.
- General Manager Delivery Services and Delivery Business Unit Controller of Idaho Power Company, January 3, 2004 - December 28, 2007.

N. VERN PORTER, 52

- Vice President, Delivery Engineering and Operations, Idaho Power Company, October 1, 2009 - present.
- General Manager of Power Production of Idaho Power Company, April 22, 2006 - October 1, 2009.
- Senior Manager of Power Supply Operations of Idaho Power Company, August 30, 2003 - April 22, 2006.

GREGORY W. SAID, 57

- Vice President, Regulatory Affairs, Idaho Power Company, January 20, 2011 - present.
- General Manager of Regulatory Affairs, Idaho Power Company, April 3, 2010 - January 20, 2011.
- Director, State Regulation, Idaho Power Company, August 23, 2008 - April 3, 2010.
- Manager, Revenue Requirement, Idaho Power Company, November 14, 1998 - August 23, 2008.

NAOMI SHANKEL, 40

- Vice President, Supply Chain of Idaho Power Company, May 20, 2010 - present.
- Vice President, Supply Chain of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, September 21, 2006 - May 20, 2010.
- Director, Audit Services of IDACORP, Inc. and Idaho Power Company, July 19, 2003 - September 21, 2006.

LORI D. SMITH, 51

- Vice President, Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Vice President - Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2008 - May 20, 2010.
- Vice President - Finance and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - January 1, 2008.

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ITEM 1A. RISK FACTORS

In addition to the factors discussed elsewhere in this report, the risk factors set forth below may have a significant impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements.

If the Idaho Public Utilities Commission, the Oregon Public Utility Commission, or the Federal Energy Regulatory Commission grant less rate recovery in regulatory proceedings than Idaho Power needs to cover existing and future costs and earn a rate of return, earnings and cash flows may be reduced. The prices that the Idaho Public Utilities Commission and Oregon Public Utility Commission authorize Idaho Power to charge for its retail services, and the tariff rate that the Federal Energy Regulatory Commission permits Idaho Power to charge for transmission, are generally the most significant factors influencing IDACORP’s and Idaho Power’s financial position, results of operations, and liquidity. The Idaho Public Utilities Commission and Oregon Public Utility Commission have the authority to disallow recovery of any costs that they consider unreasonable or imprudently incurred. Also, the rates allowed by the Federal Energy Regulatory Commission for transmission service may be insufficient for recovery of costs incurred. While the Idaho Public Utilities Commission and Oregon Public Utility Commission have established an authorized rate of return for Idaho Power, the regulatory process does not provide assurance that Idaho Power will be able to achieve the authorized rate of return. Further, while the Idaho Public Utilities Commission and Oregon Public Utility Commission are required to establish rates that are fair, just, and reasonable, they have considerable discretion in applying this standard. The ratemaking process typically involves multiple parties, including governmental bodies, consumer advocacy groups, and customers. While each party has differing concerns, they often have the common objective of limiting rate increases or even reducing rates. Idaho Power cannot predict the outcome of ratemaking proceedings, including the extent to which costs, including the costs of significant capital projects, will be recovered or what rates of return will be authorized. The failure of Idaho Power to recover those costs, or recover them in a timely manner, may decrease IDACORP's and Idaho Power's earnings and adversely impact cash flows.

For additional information relating to Idaho Power's regulatory framework, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report and "Regulatory Matters" in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Idaho Power's cost recovery deferral mechanisms may not function as intended, which may adversely affect cash flows and liquidity. Idaho Power has power cost adjustment mechanisms that provide for periodic adjustments to the rates charged to its Idaho and Oregon retail customers. The power cost adjustment tracks Idaho Power’s actual net power supply costs (primarily fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates. A majority, but not all, of the variance between these two amounts is deferred for future recovery from, or refund to, customers. Accordingly, the power cost adjustment mechanisms only partially offset the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydroelectric generation, and volatile wholesale energy prices. Because of the power cost adjustment mechanisms, the primary financial impact of power supply cost variations is on the timing of cash flows. When costs rise above the level recovered in retail base rates it adversely affects Idaho Power’s operating cash flow and liquidity until those costs are recovered from customers.

Idaho Power also has a fixed cost adjustment, which began as a pilot program for Idaho Power’s Idaho residential and small general service customers, running from 2007 through 2011. The fixed cost adjustment is designed to remove Idaho Power’s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge, and linking it instead to a set amount per customer. In October 2011, Idaho Power filed an application with the Idaho Public Utilities Commission requesting that the fixed cost adjustment pilot program become permanent. As of the date of this report, the Idaho Public Utilities Commission has not issued a determination. If the fixed cost adjustment is not approved as permanent, or if the Idaho Public Utilities Commission modifies the fixed cost adjustment in some manner, Idaho Power may incur fixed costs that may not be recoverable in rates in times of declining usage per residential and small general service customer, or may recover more than the fixed costs incurred in times of increasing usage per residential and small general service customer. This over- or under-collection of fixed costs would likely continue until Idaho Power's next Idaho general rate case when the recovery of fixed costs through base rates can be realigned, which could adversely affect Idaho Power's cash flows and liquidity.

For additional information relating to Idaho Power's regulatory framework and cost recovery mechanisms, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report and "Regulatory Matters" in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Reduced hydroelectric generation can reduce revenues and increase costs, and reduce earnings and cash flows. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. Because of Idaho Power’s heavy reliance on hydroelectric generation, the availability of water can significantly affect its operations. When hydroelectric generation is reduced, Idaho Power must increase its use of generally more expensive thermal generating resources and purchased power; therefore, opportunities for off-system sales are reduced, which reduces revenues. The further integration of wind and other intermittent power sources into Idaho Power's system may also displace lower cost hydroelectric resources. Integration of intermittent power sources may also increase costs at thermal plants due to wear and tear associated with frequent start-up and shut-down of those facilities to balance loads. While Idaho Power expects to recover, as a result of its power cost adjustment mechanisms, the majority of its net power supply costs above current rates (including the power cost adjustment forecast), recovery of the excess amounts may not occur until the subsequent power cost adjustment year, impacting cash flows and liquidity.

Declines in stream flows and over-appropriation of water in Idaho may reduce hydroelectric generation and revenues and increase costs, and reduce earnings and cash flows. The combination of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights may further reduce Snake River flows available for hydroelectric generation. Idaho Power’s January 2010 settlement agreement with the State of Idaho resolves litigation regarding certain Idaho Power water rights on the Snake River and provides for ongoing Snake River water issues to be addressed in a comprehensive aquifer management plan process. However, there is no assurance that this process will lead to increased Snake River stream flows for Idaho Power’s hydroelectric projects. The comprehensive aquifer management plan process and the resolution of pending proceedings relating to the Snake River may affect Snake River flows available for hydroelectric generation and thereby reduce Idaho Power’s revenues and increase costs, and may reduce earnings and cash flows.

Idaho Power’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 relies on coal and natural gas to fuel its generation facilities. As part of its normal business operations, Idaho Power purchases power and natural gas in the open market or under short-term, long-term, or variable-priced contracts. Market prices for coal and natural gas are influenced by factors impacting supply and demand, such as weather conditions, fuel transmission or transportation availability, economic conditions, and changes in technology. Increases in demand for coal or natural gas may result in market price increases, short-term price volatility, and supply availability issues. Any disruption in Idaho Power’s fuel supply may require the company to find alternative fuel sources at higher costs, to produce power from higher cost generation facilities, or to purchase power from other sources at higher costs. Idaho Power may not be able to fully recover these increased costs through ratemaking, which may reduce earnings. Further, Idaho Power's power cost adjustment mechanisms contain a cost-sharing feature that does not in all circumstances provide for full recovery of incurred costs in customer rates.

Idaho Power’s power generating facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, workforce safety matters, the loss of cost-effective disposal options for solid waste, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of Idaho Power's transmission and distribution facilities could result in reduced customer satisfaction and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses. These operational risks may result in plant outages, as well as increased operation and maintenance expenses, power generation costs, and power purchase costs, which could have an adverse impact on earnings and cash flows.

Load changes in Idaho Power's service territory expose Idaho Power to greater market and operational risk and could increase costs and reduce earnings and cash flows. While Idaho Power's customer growth rate has slowed in recent years, 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 peak system demand. While Idaho Power is exploring targeted opportunities for managed load growth, load growth can create planning and operating difficulties for Idaho Power that can negatively impact its ability to reliably serve customers. Through current regulatory mechanisms, Idaho Power can expect to recover the majority of the net power supply costs above the amounts included in its rates, though recovery of the excess amounts does not occur until the subsequent power cost adjustment year, and the remaining amount is absorbed by Idaho Power, which could increase costs and reduce earnings and cash flows. Load growth can also result in the need for additional investments in Idaho Power's infrastructure to serve the new load. For instance, to meet customer demand Idaho Power is currently constructing its Langley

Gulch natural gas-fired generating plant, and has in development a number of transmission projects. If Idaho Power is 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 disconnect between the time investments are made and costs are recovered would have a negative effect on earnings and cash flows. Further, while Idaho Power has experienced a general trend of load growth in its service territory in recent years, increased emphasis on energy efficiency and weak economic conditions could result in a decline in loads, which may decrease Idaho Power's revenues from energy sales. Also, Idaho Power's regulatory mechanisms, including its load change adjustment rate included in its power cost adjustment, may not result in Idaho Power recovering all of its costs associated with load decreases, which would have a negative impact on earnings and cash flows.

Federally mandated purchases of power from PURPA power purchase projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect cash flows, financial condition, and earnings. An abundance of intermittent, non-dispatchable wind power generation at times when Idaho Power has available lower-cost resources to meet load demands has an impact on the operation of Idaho Power's hydroelectric generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Wind power generated from PURPA projects, which Idaho Power is generally obligated to purchase regardless of the then-current load demand or wholesale energy market prices, increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, even when weather conditions have resulted in favorable hydroelectric generation conditions or fuel prices are low. Wind generation in the Pacific Northwest during periods when abundant hydroelectric generation is also available reduces wholesale market prices. This may result in Idaho Power's sale of excess wind power at a significant discount to the price Idaho Power paid for the wind power under PURPA wind power purchase contracts. It may also result in the sale of excess lower-cost hydroelectric or fuel-based power at depressed wholesale market prices. When forecasted wind or other intermittent resources do not materialize, Idaho Power must obtain a substitute source of power to meet load demand, and often must purchase power in the wholesale power markets to balance loads. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its costs will increase as a result of its efforts to integrate intermittent, non-dispatchable power from a large number of PURPA power projects. Idaho Power anticipates that those costs will escalate as the volume of wind and other intermittent power on Idaho Power's system increases, which may adversely affect IDACORP's and Idaho Power's cash flows, financial condition, and earnings.

Weather and climate change could affect customer demand and hydroelectric generation and disrupt transmission and distribution systems, reducing earnings and cash flows. Warmer than normal winters, cooler than normal summers, and increased rainfall during the irrigation seasons reduce retail revenues from power sales and may impact the amount and timing of hydroelectric generation. Changes in the amount and timing of snowpack and stream flows may also adversely affect hydroelectric generation. Extreme weather events and their associated impacts, such as high winds and fires, can disrupt transmission and distribution systems and cause service interruptions and extended outages, increase supply chain costs, potentially interrupt use of generation resources, and limit Idaho Power's ability to meet customer energy demand. Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints or system damage, could adversely impact Idaho Power's costs and ability to meet customer energy demand. Conversely, rapid decreases in load requirements due to unexpected weather events could result in Idaho Power's sale of excess energy at depressed wholesale market prices. Disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses and reduces earnings and cash flows.

Long-term climate change could increase the likelihood and frequency of these adverse weather events. Further, legislative and/or regulatory developments associated with climate change could affect construction plans and operations, including placing restrictions on the construction of new generation resources and the expansion of existing resources, result in closure of generation resources or installation of costly pollution control equipment, or require changes to the operation of generation resources and Idaho Power's power generation portfolio in general. Also, consumer preference for renewable or low greenhouse gas-emitting sources of energy could impact demand from existing sources and require significant investment in new generation and transmission resources. Any of these effects of weather and climate change could decrease revenues, increase operating costs, and reduce IDACORP’s and Idaho Power’s earnings and cash flows.

In Idaho Power's service territory, demand for power peaks during the hot summer months, often concurrent with a seasonal increase in wholesale power market prices. As a result, Idaho Power's operating results fluctuate substantially on a seasonal basis. In addition, Idaho Power will generally sell less power, and correspondingly have lower net income, when weather conditions in its service areas are milder. Unusually mild weather in the future could diminish IDACORP's and Idaho Power's results of operations and adversely affect its financial condition.

Idaho Power’s risk management policy and programs relating to economically hedging power and gas exposures, financial and interest rate risk, and counterparty creditworthiness may not always perform as intended, and as a result Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities. These hedging transactions are impacted by a range of factors, including variations in power demand, fluctuations in market prices, and market prices for alternative commodities. In connection with these hedging transactions, Idaho Power is exposed to the risk that counterparties that owe it money will default on their obligations. A similar risk of non-performance by third parties arises where those parties are obligated to purchase energy from, or sell energy to, Idaho Power, or are parties to commodity price risk management arrangements. Idaho Power actively manages the market risk inherent in its energy related activities and counterparty credit positions by establishing and enforcing risk limits and risk management policies. Idaho Power has procedures that monitor compliance with its risk management policies and programs, including verification of transactions, regular portfolio reporting of various risk management metrics, and daily counterparty credit risk analysis. However, actual hydroelectric and thermal generation, power purchase volumes from intermittent sources, transmission availability, and market prices may be significantly different than those originally planned for when Idaho Power enters into its positions in hedging transactions. This creates uncertainty in the appropriate amount of hedging activity to pursue. Forecasts of future loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. Changes in market prices are also unpredictable and can at times result in Idaho Power’s hedged positions performing less favorably than unhedged positions. In addition, Idaho Power’s counterparty credit policies may not prevent counterparties from failing to perform, forcing the company to replace forward contracts with transactions in the open market, where the price for the particular commodity may at that time be higher. As a result, risk management decisions may adversely affect IDACORP’s and Idaho Power’s financial condition, results of operations, or cash flows.

Also, as part of IDACORP's and Idaho Power's risk management programs, they may use a variety of non-derivative and derivative financial instruments, such as swaps, futures, and forwards, to manage market risks. They may also use interest rate derivative instruments to hedge against interest rate fluctuations related to debt. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of the derivative instruments involves management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of the contracts. IDACORP or Idaho Power could also recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform, which could adversely affect IDACORP's or Idaho Power's results of operations, financial condition, and cash flows.

Idaho Power’s ability to enter into swaps and derivatives and hedge commodity and interest rate risk may be adversely affected by recent federal legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law in July 2010. The Dodd-Frank Act establishes regulatory jurisdiction by the Commodity Futures Trading Commission and the Securities and Exchange Commission for certain swaps and derivative instruments and the users of those instruments. A number of federal agencies, including the Commodity Futures Trading Commission and the Securities and Exchange Commission, must adopt rules to implement the Dodd-Frank Act. As Idaho Power enters into swap and derivative transactions from time to time in connection with its general business operations, these rules, when implemented, could have a significant impact on Idaho Power and will likely increase the costs Idaho Power incurs in connection with its swap and derivative transactions. Under the rules, Idaho Power may be required to post collateral to meet minimum capital and margin requirements. The Dodd-Frank Act also requires a broad category of swaps to be cleared and traded on registered exchanges or special derivatives exchanges. These clearing requirements would result in a significant change from Idaho Power's current practice of bilateral transactions and negotiated credit terms. The Dodd-Frank Act outlines an elective exemption to the clearing requirements for swaps entered into by end users that are not "major swap participants" or "swap dealers" and that enter into hedges to mitigate their own commercial risk. Although Idaho Power expects that its swaps will qualify under the end user exemption, there can be no assurance they will qualify. Further, even if Idaho Power's swaps were to qualify under the end user exemption, it will not be exempt from all swap-related requirements of the Dodd-Frank Act, and counterparties that are swap dealers or major swap participants may seek to pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits. The occurrence of these events could have an adverse effect on IDACORP's and Idaho Power's results of operations, financial condition, and cash flows.

Capital expenditures for power generation and delivery infrastructure and replacement of that infrastructure can significantly affect liquidity. Idaho Power’s business is capital intensive and requires significant investments in energy generation and other infrastructure projects. Long-term increases in both the number of customers and the demand for energy require expansion and reinforcement of transmission and distribution systems, generating facilities, and other infrastructure. For instance, Idaho Power is currently constructing the Langley Gulch power plant and is in the permitting process for two substantial 500-kV transmission line projects. The cost of maintaining existing, aging equipment and infrastructure and developing new infrastructure is substantial, and involves risks relating to, among other things, cost overruns, system outages, price increases in commodities (such as steel and copper), and denial by regulatory bodies of recovery through rates of costs incurred. Idaho Power may not be successful in limiting capital expenditures to planned amounts, particularly in the event of escalating costs for materials and labor. If Idaho Power does not receive timely regulatory recovery of costs associated with those expansion and reinforcement activities, Idaho Power will have to rely more heavily on external debt or equity financing for its future capital expenditures. These large capital expenditures may weaken the consolidated financial profile of IDACORP and Idaho Power. Additionally, a significant portion of Idaho Power’s facilities were constructed many years ago, which could affect reliability, increase repair and maintenance expenses, and increase reliance on market purchases of power.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs could adversely affect cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power’s funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase Idaho Power's funding requirements for the pension and other postretirement benefit plans. Future pension funding requirements, and the timing of funding payments, may also be subject to changes in legislation. Depending on the timing of contributions to the plans and the availability of recovery of costs through rates, cash contributions to the plans could reduce the cash available for operating activities. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

Idaho Power’s business is subject to substantial governmental regulation, including environmental laws and mandatory reliability standards, which could increase costs. Idaho Power is subject to an extensive body of 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.

As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Further, Idaho Power has received notice of violations from, and self-reported reliability standard compliance issues to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council, and has several matters pending. Potential monetary and non-monetary penalties for a violation of Federal Energy Regulatory Commission regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power could have an adverse impact on its and IDACORP’s results of operations, financial condition, and cash flows.

Idaho Power is also 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 and carries with it the risk of penalties and fines. These laws and regulations generally require Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, inspections, and other approvals, and may be enforced by both public officials and private individuals. Idaho Power cannot predict the outcome or effect of any action or litigation that may arise from applicable environmental regulations. In addition, Idaho Power cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs or mitigation measures. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Environmental regulations may also require Idaho Power to install pollution control equipment at, or perform environmental remediation on, its or its co-owned facilities, often at a substantial cost.

Emissions of nitrogen and sulfur oxides, mercury, and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls, and mitigation expenses. Certain federal legislators, environmental advocacy groups, and regulatory agencies in the United States have also been focusing considerable attention on CO_2 and other emissions from power generation facilities and their potential role in climate change and/or regional air quality compliance. Existing environmental regulations regarding air emissions (such as NOx, SO_2, or mercury emissions), water quality, and other toxic pollutants may be revised or new climate change laws or regulations may be adopted or become applicable to Idaho Power. Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of fossil fuel plant emissions. Idaho Power cannot predict the outcome of pending or future legislative and rulemaking proposals. Future changes in environmental laws or regulations governing emissions reduction could make certain electric generating units (especially coal-fired units) uneconomical and subject to shut-down, could require the adoption of new methodologies or technologies that significantly increase costs or delay in-service dates, and may raise uncertainty about the future viability of fossil fuels as an energy source for new and existing electric generation facilities. Modification of existing environmental regulations or adoption of new environmental regulations may result in increased capital expenditures and could increase the cost of operating Idaho Power's generating plants or make them uneconomical to operate and result in reduced earnings and cash flows.

Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its facilities and execution of its long-term strategy, including construction of new transmission and distribution infrastructure. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's owned or co-owned generation and/or transmission facilities could be delayed, halted, or subjected to additional costs.

Complying with state or federal renewable portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows. A number of states have adopted renewable portfolio standards, which require that electricity providers obtain a minimum percentage of their power from renewable energy sources by a specified date. Idaho Power's operations in Oregon will be required to comply with a ten percent renewable portfolio standard beginning in 2025, and it is possible that other states, including Idaho, could adopt renewable portfolio standards that are applicable to Idaho Power in the future. The cost of purchasing or generating power from renewable energy sources is often greater than fossil fuel and hydroelectric generation sources, and construction of renewable energy facilities involves significant capital expenditures. As a result, new state or federal renewable portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.

The listing as threatened or endangered under the Endangered Species Act of fish, wildlife, or plant species that are found in the areas of Idaho Power's generation facilities or transmission lines may require mitigation, affect the location of a project or the ability to construct a project, and increase capital expenditures and operating costs. Relicensing of the Hells Canyon and Swan Falls hydroelectric projects and construction of the Gateway West and Boardman-to-Hemingway transmission lines requires consultation under the Endangered Species Act to determine the effects of these projects on any listed species within the project areas. The listing of species as threatened or endangered, including the relatively recent listing of slickspot peppergrass as a threatened species, will result in an Endangered Species Act consultation for the Gateway West and Boardman-to-Hemingway transmission lines and future transmission projects. Similarly, the presence of sage grouse in the vicinity of the Gateway West and Boardman-to-Hemingway transmission projects has required more extensive, costly, and time consuming evaluation and engineering. These and other requirements of the Endangered Species Act and similar laws may increase costs and reduce earnings and cash flows.

Conditions imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and reduce earnings and cash flows. Idaho Power is currently involved in renewing federal licenses for some of its hydroelectric projects, including its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The listing of various species of marine life, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. In particular, fish and other marine life recovery plans may require major operational changes to the region's hydroelectric projects. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power's energy requirements.

In 2007, the Federal Energy Regulatory Commission Staff issued a final environmental impact statement for the Hells Canyon Complex, which the Federal Energy Regulatory Commission will use in part to determine whether, and under what conditions, to issue a new license for the Hells Canyon Complex. Certain portions of the final environmental impact statement involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act and formal consultations under the Endangered Species Act, which remain unresolved. One significant issue involves water temperature gradients, and certain parties in the Hells Canyon Complex relicensing proceedings have advocated for the installation of water temperature management apparatus which, if required to be installed, would require substantial capital expenditures to construct and maintain. There can be no assurance that recovery through rates would be authorized, particularly given the magnitude of any potential impact on customer rates, which at this time cannot be predicted with certainty. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the economic impact of those requirements, or whether a new multi-year license will ultimately be issued. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs, and reduce hydroelectric generation, which could reduce earnings and cash flows.

IDACORP, Idaho Power, and their subsidiaries are subject to costs and other effects of legal and regulatory proceedings, settlements, investigations, and claims. From time to time in the normal course of business, IDACORP, Idaho Power, and their subsidiaries are subject to various regulatory proceedings, lawsuits, and claims that could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. The final resolution of matters in which IDACORP, Idaho Power, or their subsidiaries are involved could require that they incur costs in a range of amounts that could have an adverse effect on their cash flows and results of operations. Similarly, the terms of resolution could require the companies to change their business practices and procedures, which could also have an adverse effect on their cash flows, financial positions, or results of operations.

IDACORP, IDACORP Energy, and Idaho Power are involved in a number of proceedings, including proceedings arising from the California energy crisis and the energy shortages, high prices, and blackouts in the western United States during 2000 and 2001, and a refund proceeding affecting sellers of wholesale power in the spot market in the Pacific Northwest. Idaho Power may also be subject to costs and other effects of additional legal claims, actions, and complaints, including those related to the Jim Bridger, Valmy, and Boardman coal-fired plants, in which Idaho Power holds an ownership interest. For instance, in September 2010 the Environmental Protection Agency issued a Notice of Violation to Portland General Electric Company, the majority owner of the Boardman plant, alleging violations of the New Source Performance Standards and operating permit requirements under the Clean Air Act as a result of prior modifications made to the plant. Private parties have also brought tort actions against companies relating to their alleged contribution to climate change, including claims relating to the Jim Bridger and Boardman power plants. If IDACORP, Idaho Power, or their subsidiaries are required to make payments in connection with any legal or regulatory proceeding, settlement, investigation, or claim, earnings and cash flows could be negatively affected.

As a holding company, IDACORP 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 is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. Consequently, IDACORP’s ability to pay dividends and to service its debt is dependent upon dividends and other payments received from its subsidiaries. IDACORP’s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other payments. The ability of IDACORP’s subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiaries’ actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which reviews the appropriateness of dividends in light of current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. Any of these factors may result in a reduction or cessation of dividends. See Part II, Item 5 - "Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities" of this report for a description of restrictions on IDACORP's and Idaho Power's payment of dividends.

A downgrade in IDACORP’s and Idaho Power’s credit ratings could affect the companies’ ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Access to capital markets is important to Idaho Power's ability to operate and to complete its capital projects, including its current and planned generation and transmission projects. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power, and these ratings impact access to, and the cost of, borrowing. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source of short-term financing. Downgrades of IDACORP’s or Idaho Power’s credit ratings, or those affecting relationship banks, could limit the companies' ability to access capital, including the commercial paper markets, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Volatility in the financial markets, or denial of regulatory authority to issue debt or equity securities, may negatively affect IDACORP's and Idaho Power's ability to access capital and/or increase their cost of borrowing, or result in losses on investments. IDACORP and Idaho Power require liquidity to pay operating expenses and principal of, and interest on, debt and to finance capital expenditures not satisfied by cash flows from operations. Financial markets have in recent years experienced extreme volatility and disruption, generally resulting in a decrease in the availability of liquidity and credit for borrowers. In a volatile credit environment, one or more of the participating banks in IDACORP's and Idaho Power's credit facilities may default on their obligations to make loans under, or withdraw from, the credit facilities, or IDACORP's and Idaho Power's access to capital may otherwise be inhibited. In addition, at times Idaho Power has a relatively large balance of short-term investments. Volatility in the financial markets may result in a lack of liquidity for short-term investments and declines in value of some investments. The occurrence of any of these events could affect Idaho Power's ability to execute its business plan and adversely affect IDACORP's and Idaho Power's earnings, liquidity, and financial condition. Further, Idaho Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations. Notably, without additional approval from those commissions, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

National and regional economic conditions, in conjunction with increased electric rates, may cause increased late payments and uncollectible customer accounts, or reduce energy consumption, which would reduce earnings and cash flows. Beginning in 2008, economic conditions in Idaho Power's service area have been relatively weak. Unemployment rates are high relative to historic unemployment levels and customer growth has been slow relative to prior years. These factors may reduce the amount of energy Idaho Power's customers consume; result in a loss of customers; increase the likelihood and prevalence of late payments and uncollectible accounts, and reduce the customer growth rate. A resulting decrease in overall customer usage or collections may reduce revenues and earnings.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP's or Idaho Power's financial condition. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. The companies' tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation, and employment-related taxes and ongoing issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by taxing authorities. For instance, recent income tax method changes had a significant impact on financial results in 2011. The outcome of ongoing and future income tax proceedings could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could reduce IDACORP's and Idaho Power's earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho Power anticipate or request from applicable state regulatory commissions. The Idaho Public Utilities Commission or Oregon Public Utility Commission could, for instance, determine that all or a portion of any benefits resulting from tax-related projects be shared with customers in the form of reduced rates or otherwise, which may reduce revenue, earnings, and cash flows.

Employee workforce factors could increase costs and reduce earnings. Idaho Power is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, an aging workforce, and impacts of efforts to organize workforce, including the possible unionization of one or more segments of the workforce. Idaho Power's operations require a skilled workforce to perform specialized, complex utility functions. Idaho Power expects that a significant portion of its skilled workforce will be retiring, at a rate higher than Idaho Power's historical rate, within the next ten years, which places demand on Idaho Power to attract and retain skilled workers. Without a skilled workforce, Idaho Power’s ability to provide quality service to its customers and meet regulatory requirements will be challenged and could affect earnings. Also, the costs associated with attracting and retaining appropriately qualified employees to replace an aging and skilled workforce could reduce earnings and cash flows.

Acts or threats of terrorism, cyber attacks, security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations, or the businesses of third parties, could result in reduced revenues and increased costs. Idaho Power's generation and transmission facilities are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed critical infrastructure, in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, national public health or safety, or any combination of those matters. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power and by delaying the development and construction of new generating and transmission facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure Idaho Power's assets, and could further adversely affect Idaho Power's operations by contributing to disruption of supplies and markets for natural gas or coal used to fuel gas-fired or coal-fired power plants. Because generation and transmission are part of an interconnected system, Idaho Power faces the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system. The events could also impair IDACORP's and Idaho Power's ability to raise capital by contributing to financial instability and lower economic activity. Further, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased compliance costs.

In the normal course of business, Idaho Power collects, processes, and retains sensitive and confidential customer and proprietary information, and operates systems that directly impact the availability of electric power and the transmission of electric power in the electric grid. Idaho Power operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite the security measures in place, Idaho Power's facilities and systems, and those of third-party service providers, could be vulnerable to security breaches, data leakage, or other similar events that could interrupt operations, resulting in a shutdown of service and exposing Idaho Power to liability. Those breaches and events may result from acts of Idaho Power employees, contractors, or third parties. If Idaho Power's technology systems were to fail or be breached and Idaho Power were unable to recover the systems and/or data in a timely manner, Idaho Power may be unable to fulfill critical business functions. Also, confidential and proprietary business, employee, or customer information could be compromised, exposing Idaho Power to liability and causing business disruptions, which could have a material adverse effect on Idaho Power's operations and IDACORP's and Idaho Power's financial results. The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs and impact financial results. In addition, these types of events could require significant management attention and resources, and could adversely affect IDACORP's and Idaho Power's reputation among customers and the public.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power'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. Idaho Power is also constructing a natural gas-fired combined cycle power plant in Idaho with a summer nameplate capacity of 300 MW, expected to be ready for commercial operation by July 1, 2012. As of December 31, 2011, the system also includes approximately 4,828 pole miles of high-voltage transmission lines, 23 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 228 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 26,714 pole miles of distribution lines.

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

Project	Nameplate Capacity (kW)	License Expiration	
Hydroelectric Developments:			
Properties subject to federal licenses:			
Lower Salmon	60,000	2034	
Bliss	75,000	2034	
Upper Salmon	34,500	2034	
Shoshone Falls	12,500	2034	
CJ Strike	82,800	2034	
Upper Malad - Lower Malad	21,770	2035	
Brownlee - Oxbow - Hells Canyon	1,166,900	2005	(1)
Swan Falls	27,170	2010	(1)
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][3]	64,200		
Danskin (gas-fired)	270,900		
Salmon (diesel-internal combustion)	5,000		
Bennett Mountain (gas-fired)	172,800		
Total Steam and Other	1,566,901		
Total Generation	3,275,946		

(1) Licensed on an annual basis while the application for a new multi-year license is pending.
(2) Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.
(3) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations on December 31, 2020.

Relicensing of Idaho Power's hydroelectric projects is discussed in Part II, Item 7 - "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Idaho Power's property is also subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. In addition, Idaho Power'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, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

IERCo owns a one-third interest in BCC and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant. Ida-West holds 50 percent interests in nine operating hydroelectric plants with a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – "Contingencies" to IDACORP's and Idaho Power's consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

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 (NYSE). On February 17, 2012, there were 12,508 holders of record of IDACORP common stock and the closing stock price was $41.85 per share. The outstanding shares of Idaho Power's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

The amount and timing of dividends paid 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, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power 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 Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

A covenant under IDACORP's credit facility and Idaho Power's credit facility described in Part II, Item 7 - "MD&A – Liquidity and Capital Resources - Financing Programs – Credit Facilities" requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined in the respective credit facilities, of no more than 65 percent at the end of each fiscal quarter.

Idaho Power's Revised Code of Conduct approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or Idaho Power's Code of Conduct. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $827 million and $723 million, respectively, at December 31, 2011. Idaho Power must obtain approval of the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding. IDACORP and Idaho Power paid dividends of $60 million, $58 million, and $57 million in 2011, 2010, and 2009, respectively.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to

$0.33 per share of IDACORP common stock, from the prior dividend amount of $0.30 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 - "Common Stock" to the consolidated financial statements included in this report.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2011 and 2010 as reported by the NYSE.

	2011			2010		
Quarter	High	Low	Dividends paid per share	High	Low	Dividends paid per share
1st	$ 38.72	$ 36.14	$ 0.30	$ 35.69	$ 29.98	$ 0.30
2nd	40.38	37.65	0.30	36.93	31.22	0.30
3rd	40.71	33.88	0.30	36.98	32.46	0.30
4th	42.66	37.26	0.30	37.76	35.46	0.30

IDACORP, Inc. did not repurchase any shares of its common stock during the fourth quarter of 2011.

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, 2006, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.

Source: Bloomberg and EEI

	2006	2007	2008	2009	2010	2011
IDACORP	$ 100.00	$ 94.40	$ 82.12	$ 93.25	$ 111.75	$ 132.15
S&P 500	100.00	105.49	66.47	84.06	96.75	98.77
EEI Electric Utilities Index	100.00	116.56	86.37	95.62	102.34	122.80

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 Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

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

	2011		2010		2009		2008		2007	
Operating revenues	$1,026,756		$1,036,029		$1,049,800		$960,414		$879,394	
Operating income	164,248		198,670		203,583		190,667		152,078	
Net income attributable to IDACORP, Inc.	166,693		142,798		124,350		98,414		82,272	
Diluted earnings per share from continuing operations	3.36		2.95		2.64		2.17		1.86	
Dividends declared per share	1.20		1.20		1.20		1.20		1.20	
Financial Condition:										
Total assets	$4,960,609		$4,676,055		$4,238,727		$4,022,845		$3,653,308	
Long-term debt (including current portion)	1,488,614		1,610,859		1,419,070		1,269,979		1,168,336	
Financial Statistics:										
Times interest charges earned:										
Before tax [1]	2.35		2.65		2.88		2.47		2.35	
After tax [2]	2.97		2.66		2.59		2.23		2.16	
Book value per share [3]	$33.18		$31.01		$29.17		$27.76		$26.79	
Market-to-book ratio [4]	128	%	119	%	110	%	106	%	131	%
Payout ratio [5]	36	%	41	%	45	%	55	%	65	%
Return on year-end common equity [6]	10.1	%	9.3	%	8.9	%	7.6	%	6.8	%

The financial statistics listed above are calculated in the following manner:
[1] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
[2] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
[3] Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.
[4] The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (3) above.
[5] Dividends paid per common share divided by diluted earnings per share.
[6] Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

Beginning January 1, 2009, noncontrolling interests (previously known as minority interests) were required to be classified as equity. IDACORP’s consolidated financial statements reflect the reclassification of noncontrolling interests to equity for all periods presented.

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

FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations and, as such, constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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 are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Item 1A - "Risk Factors" of this report and the following important factors:

- the effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission, the Federal Energy Regulatory Commission, and other regulators affecting Idaho Power's ability to recover costs and/or earn a reasonable rate of return;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River basin, which can impact stream flows and the amount of generation from Idaho Power's hydroelectric facilities;
- the cost and availability of materials, fuel, and commodities, and their impact on Idaho Power's infrastructure costs, power costs, and ability to meet required loads, and their impact on the wholesale energy market in the western United States;
- costs and delays associated with construction and maintenance of power generation, transmission, and distribution facilities, including the inability to obtain required governmental permits and approvals, hydroelectric plant licenses under reasonable terms (and the costs resulting from conditions in such licenses), rights-of-way, and siting, and risks related to contracting, construction, and start-up;
- disruptions or outages of Idaho Power's generation or transmission systems or the western interconnected transmission system affecting Idaho Power's ability to deliver power to its customers and requiring the dispatch of more expensive generation resources or purchasing power, which may ultimately increase costs;
- increased costs associated with the legislatively mandated purchase of intermittent power, such as wind, at above-market rates, and the costs and other challenges of integrating intermittent power sources into Idaho Power's resource portfolio;
- population growth and changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, and the associated impact on loads and load growth;
- the continuing effects of the weak economy in Idaho Power's service territory and elsewhere, including decreased demand for electricity, reducing revenue from sales of excess energy during periods of low wholesale market prices, impaired financial soundness of vendors and service providers, and elevated levels of uncollectible customer accounts;
- changes in and costs of compliance with laws, regulations, and policies relating to the environment, natural resources, and endangered species and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies intended to mitigate carbon dioxide, mercury, and other emissions;

- global climate change and regional or national weather variations, which affect customer demand and hydroelectric generation and can impact the ability and cost to procure adequate supplies of natural gas, coal, or purchased power to serve customers;
- inclement weather and other natural phenomena such as earthquakes, floods, droughts, lightning, wind, and fire, which, in addition to affecting customer demand for power, could significantly affect the ability and cost to procure adequate supplies of fuel or power to serve customers, and could increase the costs to repair and maintain Idaho Power's generating facilities, transmission and distribution systems, and other infrastructure;

- transaction risks, including increases in costs, associated with Idaho Power's energy commodity and other derivative instruments, the failure of Idaho Power's energy risk management policies to work as intended, exposure to counterparty credit risk, and potential higher costs of hedging activities due to new regulations pertaining to swaps and derivatives;
- wholesale market conditions, including availability of power on the spot market and the ability to enter into commodity financial hedges with creditworthy counterparties, and the cost of those hedges, which may affect the prices Idaho Power must pay for power as well as the prices at which Idaho Power can sell any excess power;
- deteriorating values in the equity markets, changes in interest rates and credit spreads, reductions in demand for investment-grade commercial paper, inflation, and other financial market conditions, as well as changes in government regulations, which affect, among other things, the cost of capital and the ability to access the capital markets, indebtedness obligations, and the amount and timing of required contributions to benefit plans;
- failure of Idaho Power to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, including, but not limited to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the U.S. Environmental Protection Agency, and Idaho and Oregon state regulatory commissions, which may result in penalties, increase the cost of compliance, the nature and extent of investigations and audits, and costs of remediation;
- the cost and outcome of litigation, dispute resolution, and regulatory proceedings, and penalties, settlements, or awards that influence the companies' business and operations;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to existing power purchase and credit arrangements;
- the ability to obtain debt and equity financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets, the companies' financial performance, and other economic conditions;
- whether the companies will be able to continue to pay dividends under the terms of their respective financing and credit agreements and regulatory limitations, and whether the companies' boards of directors will continue to declare common stock dividends based on the boards of directors’ periodic consideration of factors ordinarily affecting dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and restrictions in applicable agreements;
- changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or state and local taxing jurisdictions, and the availability and use by IDACORP or Idaho Power of tax credits;
- employee workforce factors, including unionization or the attempt to unionize all or part of the companies' workforce, and the ability to adjust the labor cost structure to changes in growth within Idaho Power's service territory;
- the failure of information systems or the failure to secure information system data, security breaches, or the direct or indirect effect on the companies' business resulting from the occurrence of cyber attacks, terrorist incidents or the threat of terrorist incidents, and acts of war;
- adoption of or changes in accounting policies, principles, or estimates, including the potential adoption of all or a portion of International Financial Accounting Standards; and
- new accounting or Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations 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. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

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, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP’s common stock is listed and trades on the New York Stock Exchange under the trading symbol “IDA.” Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power provided electric service to approximately 496,000 general business customers as of December 31, 2011. As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), which determine the rates that Idaho Power charges to its general business customers. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its Federal Energy Regulatory Commission (FERC) tariff and to provide transmission services under its FERC open access transmission tariff (OATT). Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, and to seek to earn a return on investment.

Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power’s revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, availability of water for hydroelectric generation, price changes, customer usage patterns (which are affected in large part by the condition of the local economy), and the availability and price of purchased power and fuel. Idaho Power is a dual peaking utility that typically experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. IDACORP’s and Idaho Power’s financial condition is also affected by regulatory decisions, through which Idaho Power seeks to recover its costs on a timely basis, and to earn an authorized return on investment, and by the ability to obtain financing through the issuance of debt and/or equity securities.

IDACORP’s other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy, a marketer of energy commodities, which wound down operations in 2003. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

EXECUTIVE OVERVIEW

Overview of 2011 Financial Results

IDACORP's earnings were $3.36 per diluted share for the year ended December 31, 2011 compared to $2.95 and $2.64 per diluted share in 2010 and 2009, respectively. IDACORP's earnings in 2011 were impacted by the approval of a tax method change that allowed Idaho Power to recognize during 2011 $56.9 million in tax benefits relating to tax years 2009 and prior. This tax benefit, combined with the results of ongoing operations, triggered sharing mechanisms in Idaho that reduced operating income by $47.4 million, reflecting earnings to be shared with Idaho customers to reduce rates. In addition, 2011 results include the full-year impact of base rate increases implemented in 2010, higher electricity sales volumes, and lower PCA rates.

2011 Accomplishments and 2012 Challenges and Areas of Emphasis

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of Idaho Power's achievements during 2011 under its three-part business strategy include:

- execution of Idaho Power's purposeful regulatory strategy, which resulted in settlement of Idaho Power's 2011 Idaho general rate case with the IPUC (including a base rate increase effective January 1, 2012), a June 1, 2011 base rate

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increase for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan, and several other positive regulatory decisions;

- execution of a settlement agreement with the IPUC extending through 2014 Idaho Power's ability to amortize additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum annual return on year-end equity in the Idaho jurisdiction (Idaho ROE) of 9.5 percent;
- significant progress toward cost-sharing agreements with other parties for the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects, which were ultimately executed in January 2012;
- completion of deployment of smart meters to substantially all customers;
- continued progress on the construction of the Langley Gulch power plant;
- approval by the U.S. Congress Joint Committee on Taxation (Joint Committee) of a tax method change for uniform capitalization, resulting in a significant increase in net income relative to 2010; and
- ranking in the top quartile of the 120 largest utilities in the country for customer satisfaction in the J.D. Power and Associates 2011 Electric Utility Residential Customer Satisfaction Study.

During 2012, IDACORP's and Idaho Power's management will continue to focus on and implement the companies' three-part strategy. Notable matters that the companies expect will require management's focus and attention in 2012 include:

- completion of construction and commencement of commercial operations of the Langley Gulch power plant, and timely and adequate rate recovery of costs for the plant;
- continued efforts toward permitting of the Boardman-to-Hemingway and Gateway West transmission projects;
- seeking a positive outcome in proceedings at the IPUC relating to the pricing models and other terms of PURPA power purchase agreements;
- seeking methods for the integration of intermittent power sources and anticipated increases in intermittent wind generation, which Idaho Power believes could have an adverse impact on system reliability and functionality and on customer rates;
- obtaining IPUC authorization to include Idaho Power's FCA as a permanent component of rates;
- implementation of a new customer and billing system; and
- continued work toward resolution of issues relating to relicensing of Idaho Power's hydroelectric projects, including the Hells Canyon Complex.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by regulatory, economic, and other factors, many of which are described below.

Emphasis on Regulatory Cost Recovery: The prices that Idaho Power is authorized to charge for its electric service is a major factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Because of the significant impact of ratemaking decisions on Idaho Power's business and financial condition, the company continues to focus on timely recovery of its costs through filings with the company's regulators. Effective implementation of Idaho Power's purposeful regulatory strategy is particularly important in an economic climate that puts pressure on regulators to limit rate increases or otherwise take actions to limit the potential adverse impact of rates on customers. Regulatory developments that IDACORP and Idaho Power expect to have an impact on their future results, each of which is discussed in more detail under "Regulatory Matters" in this MD&A or in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, include the following:

- Idaho 2011 General Rate Case and Settlement - On December 30, 2011, the IPUC approved a settlement stipulation resolving most of the issues in the general rate case. The settlement stipulation provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. The settlement stipulation results in a $34 million, or 4.07 percent average, increase in Idaho Power's annual Idaho-jurisdictional base rate revenues, effective January 1, 2012.

Extension of Certain Provisions of the January 2010 Settlement Agreement - On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power's customers, the IPUC Staff, and others, in connection with a general rate case. The settlement agreement included, among other items: (a) a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE in any calendar year from 2009 to 2011; and (b) a provision to allow the additional amortization of ADITC if Idaho Power's actual Idaho ROE was below 9.5 percent in any calendar year from 2009 to 2011. The sharing and amortization provisions of the January 2010 settlement agreement expired on December 31, 2011. On December 27, 2011, the

IPUC issued an order approving a settlement stipulation providing for an extension through 2014, with modifications, of those two provisions of the January 2010 settlement agreement. The extension provides for up to $45 million of additional amortization of ADITC through 2014, with certain annual limits, and additional sharing of annual earnings in excess of specified Idaho ROEs. In consideration for the extension, the settlement stipulation provided that Idaho Power would allocate to customers (as a reduction to Idaho Power's pension regulatory asset) 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. After the combined effect of the 50 percent sharing mechanism in the January 2010 settlement agreement and the December 2011 settlement order that provided for additional sharing, Idaho Power retained 12.5 percent of Idaho-jurisdiction earnings exceeding a 10.5 percent Idaho ROE.

- Idaho PCA Orders - In both its Idaho and Oregon jurisdictions, Idaho Power has power cost adjustment (PCA) mechanisms that address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers. The Idaho PCA mechanism compares Idaho Power's actual net power supply costs to net power supply costs currently being recovered in retail rates, with most of the variance between these two amounts deferred for future recovery from, or refund to, customers. On May 31, 2011, the IPUC approved a $40.4 million PCA decrease, effective June 1, 2011. This followed a May 28, 2010 IPUC order approving a $146.9 million PCA decrease, effective June 1, 2010. These PCA rate decreases were offset by increases in power supply costs in base rates and deferrals and amortization under the PCA mechanism, resulting in a relatively small impact on earnings.

- Idaho FCA Mechanism - The FCA is designed to remove Idaho Power’s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA began as a pilot program in 2007 and expired on December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent. As of the date of this report, a determination and order from the IPUC as to the future of the FCA is pending.

- Oregon 2011 General Rate Case - On July 29, 2011, Idaho Power filed a general rate case for its Oregon jurisdiction with the OPUC, requesting a $5.8 million increase in annual Oregon jurisdictional revenues. On February 1, 2012, Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC that provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the OPUC approves the stipulation, Idaho Power expects that new rates will become effective on March 1, 2012.

Economic Conditions and Customer Growth: Since 2008, economic conditions in Idaho Power's service territory have been relatively weak. Unemployment rates remain high compared to historical levels. After peaking at 10.0 percent in early 2011, the service area unemployment rate has fallen to 8.4 percent in December 2011, according to the Idaho Department of Labor. From 2001 through September 2008, the highest monthly unemployment rate in the service territory was 5.2 percent. The customer growth rate, while still positive, has been low relative to prior years. During 2011, the customer growth rate in Idaho Power's service territory was 0.7 percent. By comparison, for the 20-year period ending 2010 the average annual customer growth rate in Idaho Power's service territory was 2.7 percent. Economic conditions can impact consumer demand for electricity, collectability of accounts, the volume of off-system sales, and Idaho Power's need for purchased power. Management cannot predict the timing of, and pace at which, economic recovery may occur in Idaho Power's service territory. Idaho Power continues to manage costs while executing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use.

Weather Conditions and Associated Impacts: Weather conditions normally have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy usage for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters of each calendar year, irrigation customers use electricity to operate irrigation pumps. A 1.6 percent increase in energy usage by Idaho Power customers during 2011 compared to 2010 is largely attributable to below average temperatures in the winter months offset by above average precipitation in the springtime, resulting in increased heating unit load and lower use of irrigation pumps.

Idaho Power's hydroelectric facilities comprise approximately one-half of Idaho Power's nameplate generation capacity. The actual availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, base flows in the Snake River, spring flows, rainfall, water leases and other water rights, and other weather and stream flow considerations. At the date of this report, Idaho Power expects hydroelectric generation during 2012 in the range of 7.5 to 9.5 million MWh, based on reservoir storage levels and forecasted weather conditions as of February 12, 2012, compared to 10.9 million MWh in 2011 and 7.3 million MWh in 2010.

Median annual hydroelectric generation is 8.6 million MWh. Due largely to favorable hydroelectric generation conditions, hydroelectric generation comprised 69 percent of Idaho Power's total system generation during 2011 and 51 percent during 2010. Where favorable hydroelectric generating conditions exist for Idaho Power, they also may be abundant for other Pacific Northwest hydroelectric facility operators, thus increasing the available supply of lower-cost power and depressing regional wholesale market prices, which impacts the revenue Idaho Power receives from off-system sales of its excess power. Average wholesale power prices per MWh for sales for resale were down 29 percent in 2011 relative to 2010.

Fuel and Purchased Power Expense: In addition to hydroelectric generation and power it purchases in the wholesale markets, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's power generation capacity, the rate of expansion of alternative energy generation sources such as wind energy, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs.

For the year 2011, Idaho Power's weighted average fuel-related cost per MWh for its fossil fuel generation resources increased 17 percent relative to 2010, mainly due to the effect of lower generation output, which spreads fixed costs over lower output, and coal price increases. Notwithstanding the increase in fuel cost per MWh generated, total fuel expense decreased 18 percent relative to 2010, due to a decrease in output from fuel-fired power generating plants resulting from both the abundant hydroelectric generation and increased wind power obtained through mandated power purchases pursuant to PURPA. Looking ahead, operation of the Langley Gulch power plant that Idaho Power is currently constructing will increase Idaho Power's use of natural gas, and thus its exposure to volatility in natural gas prices.

Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind energy, and wholesale energy market prices. Idaho Power is generally obligated to purchase power from PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss. Integration of intermittent, non-dispatchable resources into Idaho Power's portfolio also creates a number of operational risks, which Idaho Power is working to address.

The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts of fluctuations in Idaho Power's power supply costs. Idaho Power also uses physical and financial forward contracts for both electricity and fuel in order to manage the risks relating to fuel and power price exposures.

Regulatory and Environmental Compliance Costs and Expenditures: Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits. Compliance with these requirements directly influences Idaho Power's operating environment and may significantly increase Idaho Power's operating costs. Further, potential monetary and non-monetary penalties for a violation of applicable laws or regulations may be substantial. Accordingly, Idaho Power has in place numerous compliance policies and initiatives, and frequently evaluates, updates, and supplements those policies and initiatives. In particular, environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power shut down certain power generation plants. For instance, the Boardman coal-fired power plant, in which Idaho Power owns a 10 percent interest, was recently the subject of proceedings with Oregon regulators relating to the installation of costly emission controls and a cessation of coal-fired operations in 2020, and in September 2010 the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation relating to the Boardman plant, alleging

Clean Air Act (CAA) violations. As legislation and regulations concerning greenhouse gas emissions develop, Idaho Power will assess the potential impact on the costs to operate its power generation facilities, as well as the willingness or ability of power plant participants to fund any required pollution control equipment upgrades.

Other Notable Matters and Areas of Focus

Pension Plans: In 2010, Idaho Power contributed $60 million to its defined benefit pension plan, and in 2011 Idaho Power contributed an additional $18.5 million to the plan. On May 19, 2011, the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. Idaho Power expects to make additional significant cash contributions to its defined benefit pension plan through at least 2016.

Water Management and Relicensing of Hydroelectric Projects: Because of Idaho Power's reliance on streamflow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for use at its hydroelectric projects. Also, Idaho Power is involved in renewing federal licenses for the Hells Canyon Complex (HCC), its largest hydroelectric generation source, and the Swan Falls hydroelectric project. Relicensing involves numerous environmental issues and substantial costs. Idaho Power is working with the states of Idaho and Oregon, regulatory authorities, and interested parties to address concerns and take appropriate measures relating to the relicensing of Idaho Power's hydroelectric projects. Given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial.

Transmission Projects: Idaho Power continues to focus on expansion of its transmission system in an effort to improve system reliability and resource adequacy through the proposed Boardman-to-Hemingway and Gateway West transmission projects. Construction of these projects cannot commence until all federal, state, and local regulatory requirements are met. In January 2012, Idaho Power entered into cost-sharing arrangements with third parties for the permitting phases of both projects. To further mitigate the risks associated with these projects, at least in part, Idaho Power plans to seek regulatory support for cost recovery from the IPUC and OPUC for the projects prior to construction.

2011 Tax-Related Projects: In September 2011, the U.S. Internal Revenue Service (IRS) notified Idaho Power that Idaho Power's uniform capitalization tax method agreement had been approved, resulting in the recognition of $56.9 million of its previously unrecognized tax benefits in 2011.

Summary of 2011 Financial Results

The following is a summary Idaho Power's net income, net income attributable to IDACORP, Inc., and IDACORP's earnings per diluted share for the years ended December 31, 2011, 2010, and 2009 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2011	2010	2009
Idaho Power net income	$ 164,750	$ 140,634	$ 122,559
Net income attributable to IDACORP, Inc.	$ 166,693	$ 142,798	$ 124,350
Average outstanding shares – diluted (000’s)	49,558	48,340	47,182
IDACORP, Inc. earnings per diluted share	$ 3.36	$ 2.95	$ 2.64

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for 2010 to 2011 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2010			$ 142.8
Change in Idaho Power net income before taxes:			
Rate and other regulatory changes, including power cost, pension expense recovery, and fixed cost adjustment mechanisms		$ 26.3	
Changes in sales volumes		9.8	
Increased transmission service revenues		7.4	
Increased other operating and maintenance expenses:			
Pension and payroll related expenses (excluding pension impact of settlement stipulation below)		(17.2)	
Thermal plant expenses		(5.0)	
Other		(2.2)	
Increased depreciation expense		(3.9)	
Increased property taxes		(4.8)	
Other changes in operating income, net		1.1	
Increase in Idaho Power operating income prior to sharing mechanisms		11.5	
Additional pension expense as a result of settlement stipulation	(20.3)		
Decrease in revenues as a result of sharing mechanism	(27.1)		
Decrease in operating income as a result of sharing mechanisms		(47.4)	
Change in Idaho Power operating income		(35.9)	
Increase in AFUDC		11.6	
Other net decreases		(3.7)	
Increases due to tax method changes and related examination settlements		27.8	
Change in other income tax benefit		24.3	
Total increase in Idaho Power net income			24.1
Other net decreases (net of tax)			(0.2)
Net income attributable to IDACORP, Inc. - December 31, 2011			$ 166.7

Idaho Power net income increased by $24.1 million in 2011 compared to 2010, largely as a result of approval by the U.S. Congress Joint Committee on Taxation of the uniform capitalization method agreement with the IRS, which allowed for recognition in 2011 of $56.9 million of previously unrecognized tax benefits for tax years 2009 and prior. This benefit was partially offset by $47.4 million due to Idaho-jurisdictional sharing mechanisms.

The uniform capitalization method approval contributed to triggering of the sharing mechanism under Idaho Power's January 2010 settlement agreement with the IPUC and other parties. Under this sharing mechanism, Idaho Power recorded a $27.1 million reduction in revenues to be refunded to or to otherwise benefit customers, reflecting the equal sharing of Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE.

Additionally, Idaho Power recorded $20.3 million of additional pension expense as a result of an IPUC order approving a 2011 settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power. The settlement stipulation provided that Idaho Power would allocate to customers 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. As agreed to with the IPUC, this allocation was used to reduce Idaho Power's pension regulatory asset (reducing a portion of Idaho customers' future obligation), resulting in the corresponding recognition of additional pension expense.

Other items influencing the change in Idaho Power's operating income and annual earnings as compared to 2010 include:

- Several rate orders went into effect in 2010 and 2011 that impacted current year revenues and had a net positive impact on operating income. A June 1, 2010 base rate increase benefited 2011 with an additional five months of increased base rate revenue. A pension expense recovery rate increase occurred on June 1, 2010 and was further increased on June 1, 2011. Also included in the rate orders were PCA-related customer rate decreases on June 1 of both years. However, concurrent with each PCA rate decrease was a corresponding reduction in PCA expense. These rate changes, combined with lower power supply costs net of PCA mechanisms, improved operating income by approximately $26.3 million for the year.
- Increased sales volumes improved operating income by $9.8 million. Cooler temperatures early in the year contributed to an $8.0 million increase in electricity demand from residential customers, many of whom rely on electric power for heating systems during the winter months. This increase was partially offset by a $3.3 million decrease in irrigation revenues due to a wetter, cooler spring reducing the need to use irrigation pumps. A 17.7 percent increase in cooling degree days when compared with the prior year, particularly an increase in temperature in the late summer months, drove the remaining increase.
- Transmission system revenues, a component of other revenues, increased $7.4 million, principally resulting from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases.
- O&M expenses increased, primarily due to an $11.5 million increase in pension expense associated with the pension recovery rate orders, an increase in payroll-related costs of $5.7 million, and increased maintenance expense of $5.0 million at the thermal plants. These increases were partially offset by lower legal expenses of $2.3 million.
- Depreciation expense increased $3.9 million for the year due to increased plant in service.
- Property tax increased $4.8 million in 2011, primarily due to lower residential and commercial values in other property classes shifting tax costs to centrally assessed property.

Prior to the effects of the sharing mechanisms described above, Idaho Power operating income increased $11.5 million compared to 2010. After the effects of the sharing mechanism, operating income decreased $35.9 million compared to 2010. Also contributing to increased earnings at Idaho Power were increases of $11.6 million in AFUDC, which represents the cost of financing construction projects with borrowed funds and equity funds.

Key Operating and Financial Metrics

IDACORP's and Idaho Power's outlook for 2012 full year metrics is as follows:

	2012 Estimate	2011 Actual
Idaho Power Operating & Maintenance Expense (millions)	$325-$335	$339
Idaho Power Capital Expenditures, excluding AFUDC (millions)	$230-$240	$338
Idaho Power Hydroelectric Generation (million MWh)	7.5-9.5	10.9
Non-regulated subsidiary earnings and holding company expenses (millions)	$0.0-$3.0	$1.9

The 2012 range for capital expenditures includes the completion of the Langley Gulch power plant and expenditures for the siting and permitting of major transmission expansions for the Boardman-to-Hemingway and Gateway West transmission projects, net of ongoing payments from third parties participating as joint funders in the permitting project for future expenditures.

The estimated hydroelectric generation range is based on reservoir storage levels and forecasted weather conditions as of February 12, 2012.

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and Idaho Power's earnings during the year ended December 31, 2011. In this analysis, the results for 2011 are compared to 2010 and the results for 2010 are compared to 2009.

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

Utility Operations

The table below presents Idaho Power's energy sales, in MWh, and supply for the last three years.

	Year Ended December 31,		
	2011	2010	2009
General business sales	13,734	13,513	13,948
Off-system sales	3,635	1,982	2,836
Total energy sales	17,369	15,495	16,784
Hydroelectric generation	10,937	7,344	8,096
Coal generation	4,820	6,864	6,941
Natural gas and other generation	138	160	242
Total system generation	15,895	14,368	15,279
Purchased power	2,751	2,401	2,912
Line losses	(1,277)	(1,274)	(1,407)
Total energy supply	17,369	15,495	16,784

For the year 2011, general business sales increased by 0.2 million MWh, mostly related to increased residential customer usage over the prior year. Off-system sales increased by 1.7 million MWh in 2011 as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. Due largely to favorable hydroelectric generating conditions, hydroelectric generation comprised 69 percent of Idaho Power's total system generation during 2011. Hydroelectric generation in 2011 was 127 percent of the annual median generation of 8.6 million MWh, which is based on hydrologic conditions for the period 1928 through 2010 and adjusted to reflect the current level of water resource development. The 0.8 million MWh reduction in hydroelectric generation in 2010 compared to 2009 was primarily due to reduced precipitation during the snow accumulation period.

The increase in hydroelectric generation during 2011 led to a decreased reliance on coal-fired generation, and also contributed to the availability of additional surplus power available for off-system sales. Most of the decrease in power supply costs that typically results from increased hydroelectric generation is returned to customers through the PCA mechanisms.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. To reduce the magnitude of peak demands, Idaho Power has implemented a demand response program and a number of energy efficiency programs. The 2011 summer peak demand was 2,973 MW, set on July 6, 2011. The record summer peak demand of 3,214 MW was set on June 30, 2008, and the highest winter peak demand of 2,527 MW was set on December 10, 2009. During these and other similar heavy load periods, Idaho Power's system is fully committed to serve loads and meet required operating reserves. When loads exceed Idaho Power's generation capacity, Idaho Power must rely on power obtained from purchase contracts (some power from which may not be available when required if the source is intermittent power such as wind) and may be required to purchase power in the wholesale energy spot market.

General Business Revenues: The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the past three years.

	Year Ended December 31,		
	2011	2010	2009
Revenue			
Residential	$405,982	$400,607	$409,479
Commercial	220,962	231,440	232,816
Industrial	140,701	138,394	141,530
Irrigation	104,635	110,555	109,655
Total	872,280	880,996	893,480
Provision for sharing	(27,099)	—	—
Deferred revenues [1]	(10,636)	(10,625)	(9,715)
Total general business revenues	$834,545	$870,371	$883,765
MWh			
Residential	5,146	4,967	5,300
Commercial	3,815	3,763	3,858
Industrial	3,100	3,076	3,140
Irrigation	1,673	1,707	1,650
Total	13,734	13,513	13,948
Customers (year end)			
Residential	411,487	408,754	406,631
Commercial	65,226	64,647	64,349
Industrial	121	125	129
Irrigation	18,736	18,547	18,818
Total	495,570	492,073	489,927

[1] As part of its February 1, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the Hells Canyon Complex relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power expects to collect approximately $10.7 million annually in the Idaho jurisdiction, but will defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service.

Changes in customer demand and changes in rates are the primary causes of fluctuations in general business revenue. The table below presents the most significant rate increases and decreases, shown on an annualized basis, which impacted revenues over the last three years.

Description	Effective Date	Percentage Rate Increase (Decrease)	Annualized $ Impact (millions)
2009 Idaho PCA	6/1/2009	10.2%	84
2009 Idaho AMI	6/1/2009	1.8%	11
2009 Oregon general rate case settlement	3/1/2010	15.4%	5
2010 Idaho settlement agreement	6/1/2010	9.9%	89
2010 Idaho PCA	6/1/2010	(16.4%)	(147)
2010 Idaho pension expense recovery	6/1/2010	0.8%	5
2011 Idaho PCA	6/1/2011	(4.8%)	(40)
2011 Idaho pension expense recovery	6/1/2011	1.4%	12

The Idaho general rate case settlement stipulation approved by the IPUC on December 30, 2011, resulted in a 4.2 percent overall, or $34 million annual, increase in Idaho-jurisdictional base rates, effective January 1, 2012. For more information related to the December 2011 settlement stipulation, see "Regulatory Matters" later in this MD&A.

The primary influences on customer demand are weather 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, with increased precipitation reducing electricity usage. Boise, Idaho weather impacts for the last three years are included in the table below.

	Year Ended December 31,			
	2011	2010	2009	Normal
Heating degree-days [(1)]	5,554	5,078	5,612	5,727
Cooling degree-days [(1)]	1,076	914	1,188	807

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

General Business Revenues - 2011 Compared to 2010: General business revenue decreased $35.8 million in 2011 compared to 2010. Most of the decrease is a result of recording a regulatory liability of $27.1 million to be refunded to, or otherwise be used to benefit, customers, reflecting the equal sharing of Idaho-jurisdiction earnings exceeding the authorized return on year-end equity of 10.5 percent, pursuant to a January 2010 Idaho settlement agreement. The offset to this liability was recorded as a reduction to general business revenue during the third and fourth quarters of 2011. The remaining changes in general business revenue, a decrease of $8.7 million for 2011, are primarily attributable to the effects of rate changes and usage. These factors are discussed in more detail below.

• Rates. Rate changes combined to reduce general business revenue by $38.8 million in 2011 compared to 2010. The revenue impact of several of these changes was directly offset by associated changes in operating expenses. For example, Idaho PCA amortization expense was reduced $56.3 million due to decreases in the corresponding Idaho PCA rates. The decrease in PCA rates were partially offset by an increase in base retail rates of $38.5 million for the year.

The $10.5 million decline in revenue from commercial customers in 2011 relative to 2010, notwithstanding an increase in usage, is largely due to the disproportionate impact of the PCA rate reductions that went into effect in 2010 and 2011. Commercial customer rates are typically subject to a greater adjustment when PCA rates increase or decrease.

• Customers. Changes related to a special industrial customer contract, along with small increments in customer count, increased general business revenues by $16.6 million. Customer growth from 2010 to 2011 was 0.7 percent.

• Usage. For 2011, higher usage increased general business revenue $13.5 million compared to 2010. The increase was due primarily to colder first quarter temperatures, which increased power demand for residential heating purposes, as well as a 17.7 percent increase in cooling degree-days during the year, which increased power demand for air conditioning purposes. This increase was partially offset by a 2.3 percent decrease in irrigation usage resulting from the cooler spring weather and the timing and level of precipitation during the second quarter of 2011.

General Business Revenues - 2010 Compared to 2009:

• Rates. Rate increases positively impacted general business revenue by $16.9 million in 2010 as compared to 2009, due to increases in base rates of $73.5 million, partially offset by PCA rate decreases of $56.6 million.

- Customers. Growth in customer count contributed to a modest increase in general business revenues of $2.9 million. Customer growth from 2009 to 2010 was 0.5 percent.

- Usage. A decrease in usage reduced general business revenue by $33.4 million. Idaho Power believes the decline in total MWh sales was due primarily to mild temperatures, which decreased power demand for heating and cooling purposes, and partially due to the continued weakness of the economy and energy conservation practices in its service area.

Off-System Sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years.

	Year Ended December 31,		
	2011	2010	2009
Revenue	$ 101,602	$ 78,133	$ 94,373
MWh sold	3,635	1,982	2,836
Revenue per MWh	$ 27.95	$ 39.42	$ 33.28

Off-System Sales - 2011 Compared to 2010: Off-system sales revenue increased by $23.5 million, or 30 percent, in 2011 as compared to 2010. Sales volumes nearly doubled, as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. This increase was partially offset by a 29 percent decrease in average prices due in part to abundant hydroelectric generation in the region.

Off-System Sales - 2010 Compared to 2009: Off-system sales revenue decreased $16.2 million in 2010 as compared to 2009. Hydroelectric generation decreased nine percent, which reduced surplus power available for sale. This decrease was partially offset by an 18 percent increase in revenue per MWh due to lower hydro generation in the region which drove wholesale power prices higher.

Other Revenues: The table below presents the components of other revenues for the last three years.

	Year Ended December 31,		
	2011	2010	2009
Transmission services, facility rental and other	$ 48,918	$ 40,364	$ 36,037
Energy efficiency	37,663	44,184	31,821
Total	$ 86,581	$ 84,548	$ 67,858

Other Revenues - 2011 Compared to 2010: Other revenues increased $2.0 million in 2011 as compared to 2010, due mainly to:

- an increase of $7.4 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases; and
- a decrease in energy efficiency revenues of $6.5 million, due in part to an IPUC order that moved custom efficiency payments to a regulatory asset that will be amortized over time and recovered through general rate cases rather than through the energy efficiency rider. The remaining decrease relates to lower customer incentives paid versus the prior year. Energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected. As of December 31, 2011, Idaho Power's energy efficiency rider balance was a regulatory asset of $8.9 million.

Other Revenues - 2010 Compared to 2009: Other revenues increased $16.7 million in 2010 as compared to 2009, due mainly to:

- an increase of $4.3 million in transmission system revenues. Transmission system revenues increased $2.8 million primarily due to new transmission facilities, as well as rate changes. Wheeling revenue increased $2.1 million primarily due to increases in the FERC formula rate that took effect on October 1, 2009 and October 1, 2010; and

- an increase in energy efficiency revenues of $12.4 million, due to increased program activity. Energy efficiency activities are funded through rider mechanisms on customer bills.

Purchased Power: The table below presents Idaho Power’s purchased power expenses and volumes for the last three years.

	Year Ended December 31,		
	2011	2010	2009
Expense			
PURPA contracts	$ 90,251	$ 56,022	$ 59,606
Other purchased power (including wheeling)	73,085	87,747	107,592
Total purchased power expense	$ 163,336	$ 143,769	$ 167,198
MWh purchased			
PURPA contracts	1,495	910	970
Other purchased power	1,256	1,491	1,942
Total MWh purchased	2,751	2,401	2,912
Cost per MWh from PURPA contracts	$ 60.36	$ 61.56	$ 61.45
Cost per MWh from other sources	$ 58.19	$ 58.85	$ 55.40
Weighted average - all sources	$ 59.37	$ 59.88	$ 57.42

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase power during heavy load periods, which is higher priced energy, than during light load periods, which is lower priced energy, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Also, in accordance with Idaho Power’s risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transactions prices.

Purchased Power - 2011 Compared to 2010: Purchased power expense increased $19.6 million, or 14 percent, in 2011 as compared to 2010. This increase was driven by MWh purchased from PURPA contracts, which increased 64 percent due to new PURPA wind generation facilities coming on-line. The increase was partially offset by reduced wholesale market purchases resulted from Idaho Power's above average hydroelectric generation in 2011, and continued reliance on financial hedges to mitigate potential changes in forecasted hydrologic conditions. Wholesale market purchases were also down due to lower system loads resulting from relatively mild weather.

Purchased Power - 2010 Compared to 2009: Purchased power expense decreased $23.4 million in 2010 as compared to 2009, due to lower system loads that resulted from mild weather, relatively weak economic conditions, energy conservation practices, and a greater reliance on financial hedges to mitigate potential changes in forecasted hydrologic conditions.

Fuel Expense: Idaho Power’s fuel expenses and generation at its thermal generating plants for the last three years are included in the table below.

	Year Ended December 31,		
	2011	2010	2009
Expense			
Coal	$ 119,845	$ 146,927	$ 130,234
Natural gas and other	11,697	12,746	19,332
Total fuel expense	$ 131,542	$ 159,673	$ 149,566
MWh generated			
Coal	4,820	6,864	6,941
Natural gas and other	138	160	242
Total MWh generated	4,958	7,024	7,183
Cost per MWh			

Coal	$24.86	$21.41	$18.76
Natural gas and other	84.76	79.66	79.88
Weighted average, all sources	26.53	22.73	20.82

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh are noticeably impacted by these fixed charges when generation output is substantially different between the two periods.

Fuel Expense - 2011 Compared to 2010: In 2011, fuel expense decreased $28.1 million, or 18 percent, compared to 2010, due to lower generation at Idaho Power's thermal plants. The output at these plants was down 2.0 million MWh, or 30 percent in 2011 compared to 2010. The reduced dispatch was primarily caused by lower regional power prices due to higher regional hydroelectric and wind generation. The impact of lower thermal generation was partially offset by higher coal prices. During parts of 2010, the Bridger and Valmy generating plants received fuel from prior lower-cost contracts.

Fuel Expense - 2010 Compared to 2009: In 2010, fuel expense increased $10.1 million compared to 2009 due to new higher-priced contracts with Black Butte Coal Company for supplying the Valmy and Jim Bridger plants that took effect in early 2010. BCC, which also supplies coal to the Jim Bridger plant, experienced higher labor-related costs due to a tight labor market in the southwest Wyoming area and higher materials and supplies expense related to the underground mining operation. Fuel expense also increased due to a 31 percent increase in generation at the Boardman plant due to an extended outage in 2009 that did not recur in 2010, increasing fuel expense $1.8 million. These increases were partially offset by a $6.6 million decrease in fuel expense at the natural gas-fired peaking plants.

PCA Mechanisms: Idaho Power's power supply costs can vary significantly from year to year, primarily because of the impacts of weather, system loads, and commodity markets. To address the volatility of power supply costs, Idaho Power has PCA mechanisms for both the Idaho and Oregon jurisdictions. These mechanisms allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. Because of these mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers, resulting in fluctuations in operating cash flows from year to year.

PCA expense represents the effects of the Idaho and Oregon PCA mechanisms. The table below presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2011	2010	2009
Idaho power supply cost accrual (deferral)	$ 27,768	$ (14,324)	$ (42,533)
Oregon power supply cost accrual	1,523	—	184
Oregon excess power cost order	—	—	(6,358)
Amortization of prior year authorized balances	9,206	65,550	115,417
Total power cost adjustment expense	$ 38,497	$ 51,226	$ 66,710

The power supply accruals or deferrals represent the portion of that periods' power supply cost fluctuations accrued or deferred under the PCA mechanisms. If actual power supply costs are greater than the amount forecasted in PCA rates, most of the excess is deferred. Accruals represent additional costs recorded because actual power supply costs were less than the amount forecasted in PCA rates, as was the case for both jurisdictions in 2011. The amortization of the prior year’s balances represents the amounts being collected (refunded) in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2011 Compared to 2010: Actual net power supply costs decreased in 2011 relative to 2010 while base net power supply costs increased, resulting in a change of $43.6 million—from a deferral of $14.3 million to an accrual of $29.3 million. For 2011, collections on deferred amounts have decreased due to lower PCA true-up rates, reducing the PCA amortization by $56.3 million.

PCA Mechanisms - 2010 Compared to 2009: A combination of changes in base power supply costs, elements of the PCA mechanism, and a decrease in PCA rates reduced PCA expenses $15.5 million in 2010 as compared to 2009. The $49.9 million decrease in the amortization of the prior year's deferral balance resulted from lower PCA true-up rates in effect in 2010. The $28.2 million decrease in the Idaho deferral is due to changes in base and actual power supply costs and forecast rates. In addition, in 2009 Idaho Power recorded the effect of an order from the OPUC that allows Idaho Power to defer for future recovery $6.4 million of costs incurred in prior years.

Other Operations and Maintenance Expenses: The $44.7 million increase in other O&M expense in 2011 as compared to 2010 was principally due to:

- $20.3 million of increased pension expenses relating to the settlement stipulation that reduced a portion of Idaho customers' future obligation through a reduction in the pension regulatory asset;
- increased pension and other benefit expenses of $11.5 million, primarily due to pension expense amortization that began in June 2010 and was increased in June 2011 in conjunction with recovery of deferred pension costs in rates;
- $5.0 million in higher thermal O&M due to maintenance outages at the Valmy plant, partially offset by an equipment impairment taken in 2010 at the Bridger plant that did not recur in 2011; and
- an increase in other payroll related costs of $5.7 million.

These increases were partially offset by a combination of lower meter reading expense and the completed amortization of certain DSM expenses of $3.5 million, and lower outside service fees of $2.3 million.

Other O&M expense increased $1.3 million from 2010 to 2009, an increase of less than one percent.

Income Taxes

Income Tax Expense: IDACORP's and Idaho Power's income tax expense for 2011 decreased significantly relative to 2010, primarily as a result of an IRS examination settlement in 2011 related to Idaho Power's uniform capitalization tax accounting method. Income tax expense in 2010 was down significantly from 2009, principally as a result of Idaho Power's tax accounting method change for repair-related expenditures and lower pre-tax earnings at IDACORP and Idaho Power. For additional information relating to IDACORP's and Idaho Power's income taxes, see Note 2 - “Income Taxes” to the consolidated financial statements included in this report.

Status of Audit Proceedings and Tax Method Changes: In September 2010, Idaho Power adopted a tax accounting method change for capitalized repair expenditures on utility assets concurrent with the filing of IDACORP's 2009 consolidated federal income tax return. Also in 2010, Idaho Power reached an agreement with the IRS, subject to subsequent review by the Joint Committee, regarding the allocation of mixed service costs in its method of uniform capitalization. Both methods were subject to audit under IDACORP's 2009 IRS examination.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 examination and submitted its report on the 2009 tax year to the Joint Committee for review. Idaho Power considers the capitalized repairs method effectively settled and believes that no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in the second quarter of 2011.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in the third quarter of 2011.

Completion of the Joint Committee review allowed the IRS to finalize its 2009 examination, process the income tax changes, and close the case in September 2011. In the fourth quarter, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010. In early 2011, IDACORP requested and received the return of $13 million of previously made estimated tax payments for the 2010 tax year.

In December 2011, the IRS completed its examination of IDACORP's 2010 tax year. There were no unresolved income tax issues as a result of the IRS examination. Accordingly, the examination had no impact on IDACORP or Idaho Power's 2011 financial position, results of operations, or cash flows.

Bonus Depreciation Legislation: The Small Business Jobs Act (Jobs Act) and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) includes provisions for the extension and increase of bonus depreciation. Bonus depreciation provides for the accelerated deduction of current capital expenditures from certain asset classes. The Jobs Act extended 50 percent bonus depreciation to 2010 and the Tax Relief Act extended bonus depreciation to 2011-2012 and increased it to 100 percent for a portion of 2010 and 2011. Idaho Power has included an estimated bonus deprecation deduction in its current income tax provision. The estimated deduction would reduce Idaho Power's 2011 federal income tax liability by approximately $36 million. The State of Idaho did not conform to the federal bonus depreciation rules for 2010-2012.

LIQUIDITY AND CAPITAL RESOURCES

Overview

IDACORP's and Idaho Power's operating cash flows are driven principally by Idaho Power's sales of electricity and transmission capacity. General business revenues and the costs to supply power to general business customers, and the timing of income tax payments, are factors that have the greatest impact on Idaho Power's operating cash flows and are subject to risks and uncertainties relating to power generation conditions and Idaho Power's ability to obtain rate relief to cover its operating costs and provide a return on investment.

Significant uses of cash flows from Idaho Power's utility operations include the purchase of electricity, the purchase of fuel for power generation, and payment of other operating expenses, taxes, and interest, with any excess amount being available for other uses such as capital expenditures and the payment of dividends. Idaho Power is in a period of significant infrastructure investment, adding capacity to its baseload generation, transmission system, and distribution facilities in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's aging hydroelectric and thermal generation facilities require continuing upgrades and component replacement, and the costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Idaho Power expects that total capital expenditures will be between $720 million and $740 million over the period from 2012 through 2014.

Idaho Power's operating cash flows usually do not fully support the amount required for utility capital expenditures during periods of significant infrastructure development. Idaho Power uses operating and capital budgets to control operating costs and optimize capital expenditures, and funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. Idaho Power seeks to recover its operating costs and earn a return on its capital expenditures through rates, periodically filing for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators.

IDACORP and Idaho Power expect to continue financing capital requirements with a combination of internally generated funds and externally financed capital, and expect minimal need for external financing in 2012. However, IDACORP and Idaho Power monitor debt market conditions and may issue debt securities when they determine that, under the circumstances and in light of the timing and extent of financing needs, conditions are favorable for issuance of debt securities. Idaho Power has $100 million in principal amount of medium-term notes due in November 2012 and expects to fund retirement of those notes with cash from operations or some combination of cash from operations and the issuance of debt securities. IDACORP plans to continue to issue common stock under the pre-existing dividend reinvestment and employee-related stock purchase plans in 2012. While not expected in 2012, IDACORP may also determine to issue IDACORP common stock from time to time under its continuous equity program, depending on market conditions and capital needs. IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2011, IDACORP's capital structure consisted of approximately 52 percent equity and 48 percent debt, which decreases the likelihood that IDACORP will issue equity securities during 2012. A significant focus for 2012 will be to control costs and generate sufficient cash from operations to meet operating needs and contribute to capital expenditure requirements.

On October 26, 2011, IDACORP and Idaho Power entered into agreements that amended and restated their respective credit agreements. IDACORP's new credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's new credit facility consists of a revolving line of credit, through issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IDACORP and Idaho Power each have the right to request an increase in the aggregate principal amount of the new credit facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

As of February 17, 2012, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $125 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement, which can be used for the issuance of debt securities and common stock, including up to 3.0 million shares of IDACORP common stock available for issuance under its continuous equity program. Approximately $539 million of debt and equity securities issuances remained available under the shelf registration statement;
- Idaho Power's shelf registration statement, which can be used for the issuance of first mortgage bonds and debt securities. $300 million remained available under the shelf registration statement; and
- IDACORP's and Idaho Power's issuance of commercial paper, which can be used to meet short-term liquidity requirements.

The conditions of the capital markets and the weak economy have in recent years caused a general concern regarding access to sufficient capital at a reasonable cost. Notwithstanding these concerns, IDACORP and Idaho Power have not been significantly affected by this disruption in the credit environment, including in the commercial paper markets, and currently expect to continue to be able to access the capital markets to meet anticipated short- and long-term borrowing needs.

Idaho Power has PCA mechanisms in place that provide for the deferral of fluctuations in purchased power and fuel costs. However, if costs rise above the level currently recovered in retail rates, deferral balances will increase, which will negatively affect cash flow and liquidity until those costs are recovered from customers.

Operating Cash Flows

IDACORP’s and Idaho Power’s operating cash inflows for the year ended December 31, 2011 were $310 million and $292 million, respectively. IDACORP's operating cash flows increased by $5 million and Idaho Power's decreased by $38 million compared to the year ended December 31, 2010. With the exception of cash flows related to income taxes, IDACORP’s operating cash flows are principally derived from the operating cash flows of Idaho Power. Significant items that affected the companies' operating cash flows in 2011 relative to 2010 included:

- income before income taxes decreased by $27 million for IDACORP and $28 million for Idaho Power;
- in 2011, Idaho Power recorded a $27 million regulatory liability in addition to a $20 million reduction to pension-related regulatory assets as a result of sharing mechanisms, which reduced income before income taxes but did not reduce operating cash flows. No sharing was recorded during 2010;
- cash outflows related to the pension and postretirement benefit plans decreased by $44 million. Idaho Power made an $18.5 million cash contribution to its defined benefit pension plan in 2011, compared with a $60 million cash contribution in 2010;
- cash inflows related to income taxes decreased by $15 million and $57 million for IDACORP and Idaho Power, respectively. IDACORP received income tax refunds of $12 million in 2011 compared with $27 million in 2010. Idaho Power’s net refunds from IDACORP for income tax were $1 million for the year, compared with $57 million for the same period in 2010;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $13 million, as Idaho Power collected $56 million less of previously deferred costs due to decreases in PCA rates, partially offset by a $44 million increase in the current year PCA accrual, as compared with 2010;
- changes in fuel inventories reduced operating cash flows by $18 million, as fuel on hand increased by $20 million during 2011 due to decreased thermal plant operation, compared with $2 million during the same period in 2010; and
- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances decreased cash flows by $10 million, as Idaho Power collected more during 2010 than it recorded as revenues while collecting less during 2011 than it recorded as revenues.

IDACORP's and Idaho Power's operating cash inflows for the year ended December 31, 2010 were $305 million and $330 million, respectively. These amounts were an increase of $21 million and $58 million, respectively, compared to the year ended December 31, 2009. Significant items that affected operating cash flows in 2010 included:

- IDACORP's net refunds for income taxes were $27 million in 2010, as compared with $21 million in 2009. Idaho Power's net refunds from IDACORP for income tax were $57 million in 2010, as compared with $14 million in 2009;
- changes in accounts payable balances increased operating cash flows $32 million. Changes in amounts owed for

purchased power and for coal contributed $14 million and $8 million, respectively, to the change;

- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances increased cash flows by $32 million as Idaho Power collected less during 2009 than it recorded as revenues while collecting more during 2010 than it recorded as revenues;
- in the first quarter of 2009, $13 million of refunds were made to Idaho Power's transmission customers upon a final order from the FERC on Idaho Power's OATT; and
- Idaho Power made a $60 million contribution to its defined benefit pension plan in 2010, decreasing operating cash flows. Idaho Power did not make a contribution to its defined benefit pension plan in 2009.

Investing Cash Flows

Investing activities are predominantly related to capital expenditures for new construction and improvements to Idaho Power's generation, transmission, and distribution facilities. These capital expenditures address peak demand growth, aging plant and equipment, and customer growth. Idaho Power's construction expenditures were $338 million, $338 million, and $252 million in 2011, 2010 and 2009, respectively. In 2010, construction expenditures were partially offset by proceeds from the sale of $19 million of transmission-related assets to PacifiCorp. IDACORP cash flows relating to investments in affordable housing through IFS were $2 million, $13 million, and $6 million in 2011, 2010, and 2009, respectively.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, energy and price hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, credit facilities, and contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho Power, and non-utility expenses allocated to IDACORP, through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities.

Debt: On March 2, 2011, Idaho Power repaid at maturity $120 million of its 6.60% first mortgage bonds (secured notes) using a portion of the proceeds from the first mortgage bonds issued in August 2010 discussed in the next paragraph. Idaho Power's next upcoming material long-term debt principal repayment obligation is its $100 million of 4.75% first mortgage bonds that mature in November 2012.

On August 30, 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, Series I due 2020 and $100 million of 4.85% first mortgage bonds, Series I due 2040 under a shelf registration statement.

On December 1, 2009, Idaho Power repaid at maturity $80 million of its 7.2% first mortgage bonds. On November 20, 2009, Idaho Power issued $130 million of its 4.5% first mortgage bonds, Series H, due March 1, 2020. On August 20, 2009, Idaho Power completed the remarketing of its $166.1 million pollution control revenue refunding bonds and on August 25, 2009, Idaho Power used the proceeds from the remarketed bonds plus other funds to prepay its $170 million term loan credit agreement. On March 30, 2009, Idaho Power issued $100 million of its 6.15% first mortgage bonds, Series H due April 1, 2019. During 2009, IDACORP and Idaho Power reduced short-term debt by $94 million and $109 million, respectively.

Equity: IDACORP has entered into sales agency agreements as a means of selling its common stock from time to time in at-the-market offerings. IDACORP did not issue any shares under these agreements in 2011. In 2010, IDACORP received $34 million, net of agent's fees, from the issuance of 973,585 shares of IDACORP common stock at an average price of $35.47. In 2009, IDACORP received $14 million, net of agent's fees, from the issuance of 489,360 shares of IDACORP common stock at an average price of $28.79. IDACORP entered into a new sales agency agreement with BNY Mellon Capital Markets, LLC on December 16, 2011, replacing a December 2008 sales agency agreement that provided for the sale of up to 3 million shares of IDACORP common stock. At the time of expiration of the December 2008 sales agency agreement, 1,165,233 shares were unissued. As of February 17, 2012, there were 3 million shares available for issuance under the current sales agency agreement.

IDACORP issues common stock under its Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan (a 401(k) plan), which provides additional common equity to IDACORP's capital structure. Under these plans, IDACORP issued 211,276 shares in 2011, 250,030 shares in 2010, and 366,673 shares in 2009, for proceeds of $8.2 million, $8.6 million, and $9.6 million, respectively.

IDACORP issued 255,746 shares of IDACORP common stock in 2011, 194,860 shares in 2010, and 25,800 shares in 2009, in connection with the exercise of stock options, for proceeds of $9.4 million, $5.4 million, and $0.6 million, respectively.

IDACORP and Idaho Power paid dividends of $60 million, $58 million, and $57 million in 2011, 2010, and 2009, respectively. IDACORP made capital contributions of $16 million, $50 million, and $20 million to Idaho Power in 2011, 2010, and 2009, respectively.

Financing Programs

Shelf Registrations: IDACORP has an effective shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) that, as of the date of this report, can be used for the issuance of up to $539 million of debt securities and common stock. Idaho Power has an effective shelf registration statement on file with the SEC that, as of the date of this report, can be used for the issuance of up to $300 million of first mortgage bonds and unsecured debt. Refer to Note 4 - "Long-Term Debt" to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture of Mortgage and Deed of Trust, market conditions, and regulatory authorizations, and satisfaction of covenants and tests contained in other financing agreements. The Indenture of Mortgage and Deed of Trust limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture of Mortgage and Deed of Trust. As of December 31, 2011, Idaho Power could issue approximately $1.3 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. However, the Indenture of Mortgage and Deed of Trust further limits the maximum amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2011 was limited to approximately $539 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust.

Credit Facilities: As described above, on October 26, 2011, IDACORP and Idaho Power executed new credit agreements that amended and restated their existing $100 million and $300 million credit facilities, respectively. Each of the new credit facilities mature on October 26, 2016, and may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $125 million at any one time outstanding, including swingline loans not to exceed $15 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. Each company may request up to two one-year extensions of the then-existing maturity date. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 0.65 as of the end of each fiscal quarter. In determining the leverage ratio, “consolidated indebtedness” broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). “Consolidated total capitalization” is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities, which could limit the ability of the companies to issue first mortgage bonds and debt securities. There are additional covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments, restrict the creation of certain liens, and prohibit entering into any agreements restricting dividend payments from any material subsidiary. At February 17, 2012, IDACORP and Idaho Power were in compliance with all facility covenants.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurrence of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and 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 greater than 50 percent of the outstanding loans or greater than 50 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 to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percent per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

Without additional approval from the IPUC, the OPUC, and the Public Service Commission of Wyoming, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

The following table outlines available short-term borrowing liquidity as of the dates specified:

	December 31, 2011		December 31, 2010	
	IDACORP[2]	Idaho Power	IDACORP[2]	Idaho Power
Revolving credit facility	$125,000	$300,000	$100,000	$300,000
Commercial paper outstanding	(54,200)	—	(66,900)	—
Identified for other use[1]	—	(24,245)	—	(24,245)
Net balance available	$70,800	$275,755	$33,100	$275,755

(1) Port of Morrow and American Falls bonds that holders may put to Idaho Power

(2) These amounts represent the IDACORP facility only.

At February 17, 2012, IDACORP had no amounts outstanding under its credit facility and $51.5 million of commercial paper outstanding, and Idaho Power had no amounts outstanding under its credit facility and no commercial paper outstanding.

The following table presents additional information about short-term borrowing during the years ended December 31, 2011 and 2010:

	December 31, 2011		December 31, 2010	
	IDACORP [1]	Idaho Power	IDACORP[1]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$54,200	$—	$66,900	$—
Weighted average interest rate	0.47 %	— %	0.43 %	— %
Daily average amount outstanding during the year	$65,574	$—	$19,754	$348
Weighted average interest rate during the year	0.41 %	— %	0.40 %	0.43 %

Maximum month-end balance	$ 74,400	$ —	$ 66,900	$ 5,500

(1) These amounts represent IDACORP only.

Impact of Credit Ratings on Liquidity

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on their respective credit ratings. The following table outlines the ratings of Idaho Power's and IDACORP's securities, and the ratings outlook, by Standard & Poor's Ratings Services and Moody's Investors Service as of the date of this report:

	S&P Idaho Power	IDACORP	Moody's Idaho Power	IDACORP
Corporate Credit Rating/Long-Term Issuer Rating	BBB	BBB	Baa 1	Baa 2
Senior Secured Debt	A-	None	A2	None
Senior Unsecured Debt	BBB	None	Baa 1	None
Short-Term Tax-Exempt Debt	BBB/A-2	None	Baa 1/ VMIG-2	None
Commercial Paper	A-2	A-2	P-2	P-2
Senior Unsecured Credit Facility	None	None	Baa 1	Baa 2
Rating Outlook	Stable	Stable	Stable	Stable

These security ratings reflect the views of the ratings 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 agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2011, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade Idaho Power could be subject to additional requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2011, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Capital Requirements

Idaho Power's construction expenditures were $338 million during the year ended December 31, 2011. The following table presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2012 through 2014 (in millions of dollars):

	2012	2013-2014
Ongoing capital expenditures	$200-205	$490-500
Langley Gulch Power Plant (detailed below)	30-35	-
Total	$230-240	$490-500

Major Infrastructure Projects: Idaho Power is undertaking a number of significant infrastructure projects, described below.

Langley Gulch Power Plant: The Langley Gulch Power Plant is a natural gas-fired combined cycle combustion turbine generating plant with a summer nameplate capacity of approximately 300 MW and a winter capacity of approximately 330 MW. Construction of the plant, substation, and transmission lines is in process. The plant is being constructed near New Plymouth, Idaho and is contracted to achieve commercial operation by November 1, 2012. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012. The commitment estimate for the project is $427.4 million, $355 million of which Idaho Power incurred from inception in 2009 through December 31, 2011. AFUDC is included in both amounts. As of the date of this report, the overall project remains on schedule and Idaho Power expects the total project cost to be below the commitment estimate. Throughout 2011, significant progress was made constructing the plant and most equipment, facilities, and systems are complete. The construction contractor is preparing for commissioning of the plant, with testing planned to start in the first quarter of 2012. The step-up transformers were commissioned and energized from the substation in the fourth quarter of 2011. The plant will be connected to Idaho Power's existing grid through a new substation and two new transmission lines. The substation and one of the transmission lines have been completed. The second transmission line is under construction and is expected to be completed by May 2012.

Transmission Projects: As described in its 2011 Integrated Resource Plan (IRP), Idaho Power continues to focus on expansion of its existing transmission system in an effort to improve system reliability and resource adequacy. Idaho Power is involved in two significant transmission projects -- the Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, and the Gateway West project, a joint development with PacifiCorp to build transmission lines between a station located near Douglas, Wyoming and the Hemingway station.

Boardman to Hemingway Line. The Boardman-to-Hemingway line will provide transmission service to meet needs identified in the 2011 IRP and other requests pursuant to Idaho Power's OATT. The Oregon Department of Energy's Energy Facility Siting Council (EFSC) process and the National Environmental Policy Act (NEPA) process are under way. Idaho Power is working with the EFSC to develop a phased approach to the EFSC's process so it can run concurrently with the NEPA process. Idaho Power expects to receive the EFSC project order in the first quarter of 2012. Idaho Power is preparing the preliminary application for site certificate pursuant to that process and anticipates filing the application in December 2012. The U.S. Bureau of Land Management (BLM) is in the process of publishing the draft environmental impact statement (DEIS) that Idaho Power expects will include both Idaho Power's proposed route and other alternative routes. Idaho Power anticipates the DEIS will be published in February 2013. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA, described below, to jointly pursue the permitting of the project. Idaho Power's estimated share of the cost of the permitting phase of the project, after reflecting the terms of the joint funding agreement, is $11 million, including AFUDC. Total cost estimates for the project are approximately $820 million, including AFUDC. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the initial phase are not included in the table above. The preferred portfolio in the 2011 IRP provides for a 2016 in-service date for the transmission line, as immediate system reliability benefits could be realized by construction of the transmission line by that date. However, the actual completion date of the project is subject to siting, permitting, regulatory approvals, individual participant's in-service requirements, the terms of any resulting joint construction agreements, and other conditions. Idaho Power will continue to work with the BLM, Oregon Department of Fish and Wildlife, and other agencies to address environmental issues, which could delay the project, alter the proposed siting, and result in significantly higher costs.

Gateway West Line. Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project. In January 2012, Idaho Power and PacifiCorp entered a new joint funding agreement for permitting the project as described below. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $24 million, including AFUDC. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $150 million and $300 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs are not included in the table above. Timing of the construction of each segment of the project is subject to siting, permitting, regulatory approvals, individual participant's in-service requirements, the terms of any resulting joint construction agreements, and other conditions.

On July 29, 2011, the BLM issued for public review and comment a DEIS for the Gateway West project. The DEIS did not identify a preferred route for the project. Idaho Power provided input for comments relating to the DEIS that PacifiCorp submitted to the BLM in October 2011. As of the date of this report, the BLM continues to work through its NEPA process to address the lack of an agency preferred route and to address sage grouse and other resource issues.

Rapid Response Team for Transmission. The Obama Administration announced on October 5, 2011 the Rapid Response Team for Transmission (RRTT) pilot program to streamline federal permitting and increase cooperation at the federal, state, and tribal levels for several transmission projects. The Boardman-to-Hemingway and Gateway West projects are included in the RRTT pilot projects. Idaho Power is participating in the RRTT process for both the Boardman-to-Hemingway and Gateway West projects, but is unable to predict whether the RRTT will have a positive impact on the timing or ultimate cost of either project.

Agreements Relating to Transmission Projects:

March 2010 Memorandum of Understanding. In March 2010, Idaho Power and PacifiCorp entered into a Memorandum of Understanding (2010 MOU) under which Idaho Power and PacifiCorp agreed to negotiate in good faith to reach arrangements pertaining to, among other items, the sale by the parties to one another of an undivided ownership interest in certain transmission facilities, and joint development and construction of three transmission projects, including the Boardman-to-Hemingway and Gateway West projects. In April 2010, Idaho Power and PacifiCorp entered into an arrangement pursuant to which they agreed to sell to one another interests in certain high-voltage transmission-related and interconnection equipment, and in May 2010 executed agreements pertaining to the joint ownership and operation of portions of those facilities. In subsequent months, Idaho Power and PacifiCorp sought to negotiate the terms and conditions of the other arrangements contemplated by the 2010 MOU, including the Boardman-to-Hemingway and Gateway West transmission projects, but were unable to reach agreement on those arrangements, and the 2010 MOU was ultimately terminated in April 2011. However, on January 12, 2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into arrangements pertaining to the Boardman-to-Hemingway project and meeting BPA's eastern Idaho load service obligations, described below. Idaho Power and PacifiCorp also entered into an arrangement pertaining to the Gateway West project, as described below.

Boardman to Hemingway Transmission Project Joint Permit Funding Agreement, dated January 12, 2012, among Idaho Power, PacifiCorp, and the Bonneville Power Administration (B2H Funding Agreement). The B2H Funding Agreement provides that the parties will seek to jointly fund and support the process of completing environmental studies, including an environmental impact statement pursuant to the National Environmental Policy Act, and obtaining governmental authorizations and permits for rights-of-way over public lands, necessary to develop the project. The planning, design, procurement, and acquisition of private rights-of-way, private easements, and similar private property interests are not within the scope of the B2H Funding Agreement. Idaho Power is designated as the project manager under the B2H Funding Agreement, responsible for administering and overseeing the project and for the day-to-day activities involved in advancing the project. The B2H Funding Agreement assigns each party a permitting interest based on each party's specified capacity ownership interests. The agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 for PacifiCorp in the Boardman-to-Hemingway transmission project. The agreement further provides that during future negotiations pertaining to development and construction agreements, the parties will seek to retain interests in the project equal to their respective permitting interests. PacifiCorp or BPA may withdraw from the B2H Funding Agreement at any time. Idaho Power has no right to withdraw from the B2H Funding Agreement.

Gateway West Transmission Project Development Agreement, dated January 12, 2012, between Idaho Power and PacifiCorp (Gateway Funding Agreement). The Gateway Funding Agreement outlines the terms under which the parties will jointly own, develop, design, permit, site, and acquire rights-of-way for the Gateway West transmission project. Idaho Power's interest in the Gateway West project applies to four of ten segments involved in the project, referred to as segments 6 (which Idaho Power had previously constructed and is included only for purposes of federal permitting related to the Gateway West project), 8, 9, and 10. PacifiCorp is designated as the project manager under the agreement. The Gateway Funding Agreement provides that the project manager may seek to reconfigure portions of the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations. Further, PacifiCorp retains the right to remove specified segments from the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations and Idaho Power's ability to continue with the permitting and construction of certain removed segments.

Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement. Idaho Power's state permitting interest in its segments is 100 percent for segment 6 and 33 percent for each of segments 8, 9, and 10, with a federal permitting interest in the project of 11 percent. PacifiCorp has a 100 percent state permitting interest in segments 1, 2, 3, 4, 5, and 7, and a 67 percent state permitting interest in segments 8, 9, and 10, and has a federal permitting interest of 89 percent in the project. Information on the segments in which Idaho Power has an interest is as follows:

Segment No.	Connected Substations	Length of Line (Miles)	Size of Line	State
6	Borah to Midpoint	88	500-kV	Idaho
8	Midpoint to Hemingway	126	500-kV	Idaho
9	Cedar Hill to Hemingway	152	500-kV	Idaho
10	Midpoint to Cedar Hill	34	500-kV	Idaho

The Gateway Funding Agreement provides for the parties to subsequently meet to negotiate the terms and conditions of one or more definitive development and construction agreements for the Gateway West transmission line. The agreement specifies that the parties intend that the terms of any construction agreement would provide that Idaho Power is entitled to one-third of the anticipated bi-directional transmission capacity on segments 8, 9, and 10, and one-third of any total incremental system capacity on those segments, and that PacifiCorp is entitled to the remaining two-thirds interest. A party may withdraw from the federal permitting project, all or a portion of the state permitting project (relating to one or two of segments 8, 9, and 10), or the agreement in its entirety. Upon withdrawal, the withdrawing party forfeits its rights, title, and interest in the agreement and associated tangible and intangible property rights or, if withdrawing from less than all segments, its rights, title, and interest in those segments.

Idaho Power was previously a party to an existing memorandum of understanding, dated May 7, 2007, relating to transmission project development, and a permitting cost sharing agreement, dated September 5, 2008, to share with PacifiCorp the costs of certain Gateway West project permitting activities. The prior memorandum of understanding and permitting agreement terminated upon execution of the Gateway Funding Agreement.

Memorandum of Understanding, dated January 12, 2012, among Idaho Power, PacifiCorp, and BPA (2012 MOU). The 2012 MOU provides that the parties will negotiate in good faith the terms of mutually satisfactory definitive agreements that would allow BPA to meet its load service obligations in southeast Idaho. It provides that the parties will explore opportunities to establish eastern Idaho load service from the Hemingway substation in exchange for similar service from the Federal Columbia River Transmission System, and will consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission or other arrangements. The 2012 MOU outlines at least two potential alternatives for further negotiation, including a network service option and an asset ownership rights option on certain of Idaho Power's and PacifiCorp's transmission systems. Any party may terminate the 2012 MOU at any time, without penalty, and the 2012 MOU automatically expires on December 31, 2014.

AMI/Smart Grid and American Recovery and Reinvestment Act of 2009 (ARRA): The advanced metering infrastructure (AMI) project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In December 2011, Idaho Power completed the installation of this technology for approximately 99 percent of its customers, installing approximately 488,000 AMI meters at a cost of $71.8 million.

Under the ARRA, Idaho Power was awarded a grant of $47 million from the U.S. Department of Energy (DOE). This grant matches a $47 million investment by Idaho Power in Smart Grid technology, including AMI. The grant was signed by the DOE on April 2, 2010 and applies to project costs incurred beginning in August 2009 for a three-year term. As of December 31, 2011, Idaho Power had invoiced approximately $33.2 million from the DOE, of which $32.8 million had been received, and expects to continue billing and collecting monthly over the remaining term of the award. The costs to be reimbursed by the grant are not included in the Capital Requirements table above.

Environmental Regulation Costs: As of the date of this report, Idaho Power estimates incurring approximately $60 million in capital and operating costs for environmental facilities during 2012. Hydroelectric facility expenses, including costs for relicensing the HCC, and thermal plant expenses account for approximately $33 million and $27 million, respectively. From 2013 through 2014, total environmental-related operating and capital costs are estimated to be approximately $205 million. Expenses related to the hydroelectric facilities during that period are expected to be $79 million and include costs associated with the relicensing of the HCC. Thermal plant expenses are expected to total $126 million during this period. The capital portion of these amounts are included in the Capital Requirements table above but do not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

Other Capital Requirements: IDACORP's non-regulated capital expenditures have primarily related to IFS's tax-structured investments. As of the date of this report, IDACORP does not anticipate any significant expenditures for 2012 through 2014.

Retirement Benefit Plans

Idaho Power made a $60 million contribution in 2010 and an $18.5 million contribution in 2011 to its defined benefit pension plan. In 2012 and beyond, Idaho Power expects significant contribution obligations under its retirement benefit plans. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and to the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations.

Contractual Obligations

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

	Payment Due by Period				
	Total	2012	2013-2014	2015-2016	Thereafter
Idaho Power:	(millions of dollars)				
Long-term debt[1]	$1,492	$101	$72	$2	$1,317
Future interest payments[2]	1,268	79	145	141	903
Operating leases	27	2	6	3	16
Purchase obligations:					
Cogeneration and small power production	4,673	147	405	433	3,688
Large power production[3]	19	19	—	—	—
Fuel supply agreements	340	79	131	32	98
Purchased power & transmission[4]	27	11	8	4	4
Other[5]	160	51	43	25	41
Pension and postretirement benefit plans[6]	286	41	103	100	42
Other long-term liabilities - Idaho Power	1	—	—	—	1
Total Idaho Power	8,293	530	913	740	6,110
Other	1	—	1	—	—
Total IDACORP	$8,294	$530	$914	$740	$6,110

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.
(2) 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, 2011.
(3) Large power production relates to the Langley Gulch power plant and includes two contracts with Siemens Energy, Inc. relating to the purchase of a gas turbine and the purchase of a steam turbine, and an Engineering, Procurement and Construction Services Agreement with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for design, engineering, procurement, construction management, and construction services for Langley Gulch.
(4) Approximately $9 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 has been included in the table for presentation purposes.
(5) Approximately $81 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, has been included in the table for presentation purposes.
(6) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2016 with any level of precision, and amounts through 2016 are estimates only. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP's common stock are within the discretion of IDACORP's board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power 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 Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the foregoing factors, among others.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to $0.33 per share of IDACORP common stock, from the prior quarterly dividend amount of $0.30 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP’s and Idaho Power’s payment of dividends, see Note 6 – “Common Stock” to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future earnings and financial condition. Certain legal proceedings to which IDACORP or Idaho Power are parties or are otherwise involved are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Off-Balance Sheet Arrangements

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2011, the value of the reclamation trust fund totaled $80 million. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

REGULATORY MATTERS

Overview

Idaho Power continues to focus on timely recovery of its costs through filings with the IPUC, OPUC, and the FERC. The discussion below highlights certain notable regulatory determinations and pending matters or issues that may have a material impact on IDACORP's and Idaho Power's business or results. Regulatory matters, and in many cases their financial impact on IDACORP and Idaho Power, are also discussed in Note 3 - “Regulatory Matters” to the consolidated financial statements included in this report, which should be read in conjunction with the discussion below.

Idaho and Oregon Significant Rate Changes

As a regulated utility, the prices that the IPUC and OPUC authorize Idaho Power to charge for its retail services is a major factor in determining IDACORP’s and Idaho Power’s results of operations and financial condition. The table below summarizes notable rate increases and decreases, shown on an annualized basis, in recent years. Certain of the regulatory actions that resulted in the rate increases and decreases are described in more detail in this section of MD&A or in Note 3 - “Regulatory Matters” to the consolidated financial statements included in this report.

Description	Effective Date	Percentage Rate Increase (Decrease)		Estimated Annualized $ Impact (millions)
2008 Idaho general rate case	2/1/2009	3.1	%	$21
2008 Idaho general rate case	3/19/2009	0.9	%	6
2009 Idaho PCA	6/1/2009	10.2	%	84
2009 Idaho AMI	6/1/2009	1.8	%	11
2009 Oregon APCU	6/1/2009	11.5	%	4
2009 Oregon general rate case settlement	3/1/2010	15.4	%	5

2010 Idaho settlement	6/1/2010	9.9	%	89	
2010 Idaho PCA	6/1/2010	(16.4	)%	(147	)
2010 Idaho pension expense recovery	6/1/2010	0.8	%	5	
2011 Idaho PCA	6/1/2011	(4.8	)%	(40	)
2011 Idaho pension expense recovery	6/1/2011	1.4	%	12	
2011 Idaho general rate case settlement	1/1/2012	4.1	%	34	

Change in Deferred (Accrued) Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual estimates of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. The table below summarizes the change in deferred net power supply costs over the last two years.

	Idaho	Oregon[1]	Total
Balance at December 31, 2009	$71,412	$13,221	$84,633
Costs deferred through PCA and PCAM	14,324	—	14,324
Prior costs expensed and recovered through rates	(63,757)	(1,792)	(65,549)
SO_2 allowances credited to account	(4,504)	79	(4,425)
Interest and other	84	686	770
Balance at December 31, 2010	17,559	12,194	29,753
Current period net power supply costs accrued	(27,768)	(1,523)	(29,291)
Prior costs expensed and recovered through rates	(6,849)	(2,357)	(9,206)
Transfer of energy efficiency expenditures	10,000	—	10,000
SO_2 allowance and renewable energy certificate (REC) sales	(5,884)	(447)	(6,331)
Interest and other	(179)	623	444
Balance at December 31, 2011	$(13,121)	$8,490	$(4,631)

[1] Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $2 million). Deferrals are amortized sequentially.

2011 Idaho General Rate Case Settlement

On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. In its general rate case application, Idaho Power requested an additional $82.6 million in annual revenues in Idaho-jurisdictional base rates, comprised of approximately $71.3 million related to revenue requirement categories other than net power supply expenses (non-NPSE) and $11.3 million associated with net power supply expenses (NPSE).

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. The settlement stipulation provided for a reduction of approximately $25.8 million to the requested non-NPSE recovery, resulting in a $45.5 million increase in the non-NPSE components of Idaho-jurisdictional base rates. The settlement stipulation also provided that approximately $22.8 million of Idaho-jurisdictional revenue associated with the recovery of NPSE associated with PURPA power costs would not be included in base rates, but would instead be eligible for 100 percent recovery through the Idaho PCA mechanism if the costs are incurred. Idaho Power's requested Idaho jurisdictional base rate increase and the adjustments reflected in the settlement stipulation are summarized in the table below (in millions).

	Non-NPSE	NPSE	Total
As filed in general rate case	$71.3	$11.3	$82.6
Adjustments in settlement stipulation	(25.8)	(22.8)	(48.6)
Total settlement stipulation	$45.5	$(11.5)	$34.0

The settlement stipulation provided for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. On December 30, 2011, the IPUC issued an order approving the settlement stipulation, with new rates effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity. Additional details relating to the 2011 Idaho general rate case and settlement are included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

December 2011 Idaho Settlement Agreement

On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others, in connection with a general rate case. Significant elements of the January 2010 settlement agreement included, among other items:

- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho ROE is below 9.5 percent in any calendar year from 2009 to 2011 in its Idaho jurisdiction. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, with specified annual limits.

Because Idaho Power's Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and accelerated amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's 2011 Idaho ROE and contributed to the triggering of the sharing mechanism. In accordance with the January 2010 settlement agreement, Idaho Power recorded a $27.1 million regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdictional earnings above a 10.5 percent Idaho ROE required to be shared with Idaho customers. The sharing and amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011.

On December 27, 2011, the IPUC issued an order approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power and filed with the IPUC on December 12, 2011.
The settlement stipulation provides that:

- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more that $25 million in 2012;
- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.0 percent but less than a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; and
- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers and 25 percent to Idaho Power.

In consideration of these terms, the settlement stipulation provided that Idaho Power will allocate to customers 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded a pre-tax charge to pension expense of approximately $20.3 million in 2011, representing the additional amount to be allocated to Idaho customers. After the combined effect of the 50 percent sharing mechanism in the January 2010 settlement agreement and the December 2011 settlement order that provided for additional sharing, Idaho Power retained 12.5 percent of Idaho-jurisdiction earnings exceeding a 10.5 percent Idaho ROE.

OPUC Deferral Request: On November 17, 2011, the OPUC Staff filed an application seeking authorization from the OPUC to defer in the Oregon jurisdiction $2.9 million of the benefit resulting from the uniform capitalization tax method change. Idaho Power is opposing the application, and hearings and briefs are scheduled for mid-2012.

Idaho Defined Benefit Pension Plan Contribution Recovery

In September 2010, Idaho Power made a $60 million contribution to its defined benefit pension plan. To provide for timely recovery in rates of that contribution, on March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective June 1, 2011. Idaho Power also expects to continue to make additional significant cash contributions to its defined benefit pension plan through at least 2016. For estimated defined benefit pension plan funding obligations, refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and "Critical Accounting Policies and Estimates - Pension and Other Postretirement Benefits" in this MD&A.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

Langley Gulch Power Plant Ratemaking

On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power's rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012. Idaho Power plans to time the filing of its applications with the IPUC and OPUC for recovery of construction costs such that regulatory authority for collection of those costs is issued, and customer rates adjusted, as near as practicable to the project's commercial in-service date.

Oregon General Rate Case

On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2011 Integrated Resource Plan

As a public utility under the jurisdiction of the FERC, the IPUC, and the OPUC, Idaho Power is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, to construct and place in service sufficient generation and transmission capacity to reliably deliver resources to network customers and the company's retail customers, and otherwise take actions to fulfill its obligation to provide safe and reliable electric service. As part of its resource planning, and in accordance with regulatory requirements, Idaho Power prepares and publishes an IRP every two years. The IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and near-term and long-term action plans.

Idaho Power filed its 2011 IRP with the IPUC and OPUC on June 30, 2011. In developing its 2011 IRP, Idaho Power forecast the number of customers in Idaho Power's service area will increase approximately 1.5 percent per year, from approximately 492,000 at the end of 2010 to over 650,000 by the end of the IRP's 20-year planning period in 2030. The 2011 IRP expected-case load forecast projects peak-hour load will grow 69 MW annually and average-system load will increase annually 29 average MW (aMW) over the 20-year planning period, with an expected-case, average annual system load of 2,362 aMW by 2030.

Idaho Power intends to meet the anticipated increase in demand through energy efficiency and demand response programs, the development of transmission capacity and additional generation resources, such as its 300 MW Langley Gulch natural gas-fired power plant currently under construction, and from the purchase of power from third parties, including from renewable energy projects and market power purchases. Idaho Power stated in the 2011 IRP that it expects energy efficiency programs to result in 233 aMW of load reduction by 2030, and that demand response programs are targeted to reduce peak summer load by 351 MW by summer 2016. The 2011 IRP also identifies transmission constraints as a significant issue for Idaho Power. Idaho Power is in the process of developing the Boardman-to-Hemingway transmission project in an effort to alleviate in part its transmission capacity constraint from the Pacific Northwest.

On December 30, 2011, the IPUC issued an order accepting Idaho Power's 2011 IRP. The order directed Idaho Power to continue to address a number of items, including: (a) comparing the risk, cost, and environmental benefits of strategies that directly reduce emissions from its resource mix to the purchase of emission offsets or offset options, (b) redoubling its efforts to realize the achievable potential for savings from efficiency and DSM programs, and (c) addressing the risks of reliance on natural gas in its resource portfolio. The order also directs Idaho Power to provide as part of its 2013 IRP additional information and/or analyses related to the Gateway West transmission project involvement, Idaho Power's proposed solar demonstration project, HCC relicensing efforts, early retirement of existing coal plants, and the quantification of transmission siting and market price risks.

PURPA Power Purchase Contracts

Pursuant to the requirements of Section 210 of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from cogeneration and small power production facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements may result in Idaho Power acquiring energy it does not need at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's power supply cost mechanisms, and thus the primary impact of the PURPA agreements is on customer rates.

Idaho Proceedings: In response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011, the IPUC issued an order temporarily reducing the eligibility cap for PURPA projects entitled to published avoided cost rates from 10 aMW to 100 kW for wind and solar PURPA projects while the IPUC further investigated the implications of large projects disaggregating into smaller projects to qualify for higher published avoided cost rates and other benefits. On June 8, 2011, the IPUC issued an order maintaining the 100 kW eligibility cap for published avoided cost rates for wind and solar PURPA projects, and initiating additional proceedings to allow the parties to investigate and analyze the methodologies used in determining the appropriate power purchase price for PURPA projects. On that same date, the IPUC issued orders disapproving 13 wind power purchase agreements. Idaho Power estimates that the payments over the lives of the disapproved agreements would have totaled approximately $1.3 billion.

Idaho Power remains engaged in proceedings at the IPUC relating to the determination of appropriate power purchase prices and other terms of PURPA power purchase agreements. The IPUC has established a timeline for various informational filings by all parties to the case, with hearings scheduled for August 2012. On January 31, 2012, Idaho Power submitted written testimony in the PURPA proceedings, in support of Idaho Power's request that the IPUC (a) change the methodology used to establish power purchase prices for PURPA projects, (b) reduce the maximum authorized PURPA power purchase agreement term from the existing 20 years to a maximum of five years, and (c) authorize a curtailment strategy that would allow Idaho Power to optimize use of its cost-effective resources.

Oregon Proceedings: In response to two filings Idaho Power made with the OPUC in January 2012, on February 14, 2012 the OPUC issued an order effectively imposing a 60 day prohibition on Idaho Power's entering into standard contracts with qualified PURPA facilities, allowing Idaho Power time to update its avoided cost rate through the IRP process prior to executing standard PURPA contracts. In the same order, the OPUC declined to reduce the eligibility cap for standard contracts from its current level of 10 MW to 100 kW. Idaho Power expects to be engaged in proceedings at the OPUC to resolve the same or similar issues being presented in the IPUC PURPA matters.

Bonneville Power Administration Residential Exchange Program

The Pacific Northwest Electric Power Planning and Conservation Act of 1980, through the Residential Exchange Program (REP), provides for 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 BPA. Pursuant to agreements between the BPA and Idaho Power, benefits from the REP were passed through to Idaho Power's Idaho and Oregon residential and small farm customers in the form of electricity bill credits. However, 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 Idaho Power) were inconsistent with the Northwest Power Act. As a result, on May 21, 2007, the BPA notified Idaho Power and six other IOUs that it was immediately suspending the REP payments. Subsequently, Idaho Power worked with other northwest IOUs and consumer-owned utilities, Pacific Northwest public utility commissions, and the BPA to craft an agreement so that residential and small farm customers of Idaho Power can resume sharing in the benefits of the federal Columbia River power system. The BPA approved an REP settlement agreement in a Record of Decision dated July 26, 2011 and committed the BPA to perform its obligations under the settlement agreement in accordance with its terms. Updated rates became effective January 1, 2012. Since any benefits will pass directly through to Idaho Power's eligible residential and small farm customers, the settlement is not expected to have a material effect on Idaho Power's financial condition or results of operations.

FERC Compliance Programs

The FERC has approved an extensive number of reliability standards developed by the North American Electric Reliability Corporation and the WECC, including critical infrastructure protection (CIP) standards and regional standard variations. As part of its compliance program, Idaho Power periodically reviews its operations for compliance with FERC rules, orders, and standards and self-reports compliance issues to the FERC and the WECC. Recent reports Idaho Power has submitted to the FERC have generally focused on Standards of Conduct and Idaho Power’s FERC OATT. Consistent with prior years, during the year ended December 31, 2011, Idaho Power self-reported to the FERC and received notices of alleged violations from the FERC and the WECC. Idaho Power has also received notification that the FERC intends to take no further action regarding several issues previously reported by Idaho Power.

Consistent with its historical practice, Idaho Power is working with the FERC and the WECC to resolve alleged violations and items it self-reported to the FERC and the WECC. Idaho Power is unable to predict what action, if any, the WECC or the FERC will take on those unresolved matters, but based on the nature of the potential violations Idaho Power does not expect any material adverse effect from currently alleged violations on its financial position, results of operations, or cash flows. Idaho Power plans to continue its efforts to reduce potential violations through its compliance program and its approach of self-reporting compliance issues to, and working with, the FERC and the WECC.

Relicensing of Hydroelectric Projects

Idaho Power, 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. Idaho Power is actively pursuing the relicensing of the HCC and the Swan Falls project (SFP). In addition, in July 2010 Idaho Power received a license amendment to expand the Shoshone Falls hydroelectric project and to potentially extend the term of the license beyond its 2034 expiration date.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 36 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application for a new license in anticipation of the July 2005 expiration of the then-existing license. In connection with the relicensing process, in August 2007 the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under section 401 of the Clean Water Act (CWA) and formal consultations under the Endangered Species Act (ESA), which remain unresolved.

Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, Idaho Power has filed Water Quality Certification Applications, required under section 401 of the CWA, with the States of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Water quality issues are of interest to various federal and state agencies, Native American tribes, and other parties who may provide input to the states' certification process. Section 401 of the CWA requires that a state either approve or deny a 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

On September 13, 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed. Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns.

Idaho Power expects the FERC to issue a license order for the HCC once the ESA consultation and the state water quality certification processes are completed. Idaho Power is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until a new multi-year license is issued.

Swan Falls Project: The existing license for the SFP expired in June 2010. Idaho Power is currently operating the SFP under an annual license while its application for a multi-year license is pending before the FERC. In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail, a species listed as endangered under the ESA, was found in the area during the EIS review. In February 2012, the USFWS issued a biological opinion to address the project's effects on the Snake River physa snail. The biological opinion includes a provision for the incidental take of the snail for purposes of licensing and continued operation of the project. Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license, which Idaho Power anticipates will be between 30 and 50 years. Idaho Power expects the FERC to issue a license for the SFP in the second quarter of 2012.

Treatment of Relicensing Costs: Relicensing costs are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $145 million and $5 million for HCC and SFP, respectively, were included in construction work in progress at December 31, 2011. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho-jurisdictional rates approximately $6.5 million annually ($10.7 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project, and collecting these amounts will reduce the relicensing amount submitted to regulators for recovery through the ratemaking process. Through December 31, 2011, Idaho Power has collected $31 million of AFUDC related to the HCC relicensing project through customer rates.

Shoshone Falls Expansion: On July 1, 2010, the FERC amended the license for the Shoshone Falls project to expand its generating capacity to approximately 61 MW. The amended license has an expiration date of 2034, but provides that the license will be extended to 2044 following completion of the proposed generation capacity expansion project. Idaho Power filed a request for a two-year schedule extension with the FERC in January 2012 as it continues to evaluate the project and the associated license requirements, costs, and operating issues, which if granted would change Idaho Power's estimated in-service date for the upgrades (if ultimately undertaken) from 2015 to 2017.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to regulations by federal, state, and local authorities governing the protection of the environment, including at the federal level the CAA; the CWA; the Comprehensive Environmental Response, Compensation and Liability Act; the Emergency Planning and Community Right-to-Know Act; the ESA; the Federal Land Policy and Management Act; the National Environmental Policy Act; and the Resource Conservation and Recovery Act. These laws and regulations are continuously changing and are generally becoming more restrictive. Idaho Power monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to alter the operation and productivity of power generating plants and other assets. Environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities; require that Idaho Power install additional pollution control devices at existing generating plants; or require that Idaho Power discontinue operating certain power generation plants. While there can be no assurance of recovery, Idaho Power intends to seek recovery of any such costs through the ratemaking process.

Idaho Power co-owns three coal-fired power plants and owns two natural gas combustion turbine power plants that are subject to air quality regulation. Additionally, Idaho Power is in the process of construction and start-up of the Langley Gulch power plant, a natural gas-fired generating plant. The CAA establishes controls on the emissions from stationary sources like those owned by Idaho Power. The EPA adopts many of the standards and regulations under the CAA, while states have the primary responsibility for implementation and administration of these air quality programs. Also, the FERC licenses issued for Idaho Power's hydroelectric generating plants impose numerous environmental requirements, such as aeration of water discharged through turbines to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power continues to actively monitor, evaluate, and work on water quality and air quality issues. These items are discussed in greater detail below.

Idaho Power continues to actively monitor pollution control standards as they are promulgated and their associated costs to Idaho Power as they relate to the economic and operational feasibility of generation plants. In its order acknowledging Idaho Power’s 2009 IRP, the OPUC directed Idaho Power to analyze (a) any potential EPA, state, and other federal agency regulations associated with air quality, fly ash, and water that may affect Idaho Power’s generation facilities, and (b) coal curtailment and the costs associated with coal plant retirement, and include the results of this analysis in its 2011 IRP. Idaho Power filed its 2011 IRP in June 2011 with the IPUC and OPUC, and the IRP contains the analysis requested by OPUC. While not currently quantifiable, Idaho Power anticipates that a number of impending EPA rulemakings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs.

In addition to the items below, also refer to Note 10 - "Contingencies" to the consolidated financial statements included in this report for additional information regarding certain environmental proceedings affecting Idaho Power's properties and Item 1- "Business - Environmental Regulation and Costs" in this report.

Global Climate Change and GHG Emission Intensity Reduction Goal

There is concern nationally and internationally about climate change and the possible contribution of greenhouse gas (GHG) emissions to climate change. Long-term climate change could significantly affect Idaho Power’s business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plans and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general; and
- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Idaho Power does not currently operate in coastal areas and, while there may be secondary impacts, it is not directly exposed to the effects of potential sea level rises that some experts predict may result from global climate change.

Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce the CO_2 emission intensity of Idaho Power's utility operations. Idaho Power's goal is to reduce its resource portfolio's average CO_2 emission intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh. The guidelines are intended to reduce Idaho Power's average CO_2 emission intensity in a manner that minimizes the costs of those reductions to Idaho Power's customers. In May 2010 and May 2011, Idaho Power submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated CO_2 emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2010, 2009, 2008, and 2007 respectively.

In 2008, Idaho Power and Ida-West together ranked as the 32nd lowest emitter of CO_2 per MWh produced and the 31st lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a June 2010 collaborative report from Ceres, the Natural Resources Defense Council, Public Service Enterprise Group, Constellation Energy, and Entergy using publicly reported 2008 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the 55th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

Environmental Regulation

Regulation of Greenhouse Gas Emissions: In recent years, there have been a number of bills introduced in the U.S. Congress relating to GHG emissions, renewable energy, energy efficiency, carbon capture and sequestration, and other matters. However, given the complexities of this form of legislation and other competing legislative priorities, the timing and elements of any future legislation addressing GHG emission reduction requirements are uncertain. There are also state and regional initiatives (including the Western Regional Climate Action Initiative) considering market-based mechanisms to reduce GHG emissions. Further, in support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. However, any international treaty creating mandatory GHG emission reduction requirements in the United States would require Congressional approval.

In June and December 2010, the EPA issued final rules regulating GHG emissions through its pre-construction and operating permit programs under the CAA. These rules are referred to as the "Tailoring Rule" and GHG Permitting Rules. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, existing major sources were required to include applicable requirements relating to GHGs in their operating permits when the permits are renewed or the major source is modified. Idaho Power believes that its owned and co-owned generation plants are in compliance with the new GHG emission regulations.

In August 2007, the Oregon legislature enacted legislation establishing goals for the reduction of GHG emissions, which sought to cease the growth of Oregon GHG emissions by 2010, and seek to (a) by 2020, reduce GHG levels to 10 percent below 1990 levels; and (b) by 2050, reduce GHG levels to at least 75 percent below 1990 levels. The legislation also calls for state government-developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

Idaho Power will continue to monitor and evaluate proposed international, federal, state, and regional GHG legislation or initiatives as well as judicial decisions that could affect its generating facilities and operations. Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. The regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of older, less-efficient coal-fired units.

There are financial, regulatory, and logistical uncertainties related to GHG reductions and the implementation of renewable energy mandates. The impact on Idaho Power of currently proposed legislation relating to GHG emissions would depend on a variety of factors, including the specific GHG emissions limits or renewable energy requirements, the timing of implementation of these limits or requirements, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot meaningfully predict the effect on its results of operations, financial position, or cash flows of any GHG emission, renewable energy mandate, or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. Idaho Power would seek to recover these costs and expenditures from customers as costs of doing business but is unable to predict whether it would be permitted to recover some or all of the increased costs and expenditures from customers through rates.

In its 2011 IRP, Idaho Power did not include any new conventional coal resources in the resource portfolio due to the uncertainty regarding future GHG regulations. IDACORP and Idaho Power's boards of directors continue to review environmental issues on a regular basis and in connection with the review of the companies' strategic plans. The boards of directors are also periodically informed of any new material environmental issues, including updates on any proposed legislation.

Renewable Portfolio Standards: Legislation has been introduced in the U.S. Congress that would require utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal RPS is in effect. Idaho Power will be required to comply with a 10 percent RPS in Oregon beginning in 2025, and Idaho Power expects to meet these requirements with the RECs from the Elkhorn Valley wind project. No RPS requirement currently exists in Idaho. Idaho Power continues to monitor proposed federal RPS legislation and the possibility of additional state RPS legislation.

Utility Maximum Achievable Control Technology (MACT): In April 2010, the U.S. District Court for the District of Columbia approved a timetable that required the EPA to finalize a standard to control mercury emissions from coal-fired power plants by November 2011. In March 2011, the EPA released the proposed Utility Maximum Achievable Control Technology rule (Utility MACT Rule) to control emissions of mercury and other hazardous air pollutants (HAPs) from coal- and oil-fired electric utility steam generating units (EGUs) under the federal CAA. In the same notice, the EPA further proposed to revise the NSPS for fossil fuel-fired EGUs. In December 2011, the EPA finalized the Utility MACT Rule. The final Utility MACT Rule remains largely the same as the proposal. The final regulation imposes maximum achievable control technology and NSPS standards on all coal-fired EGUs and replaces the former Clean Air Mercury Rule. Specifically, the final regulation sets numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrogen chloride, and mercury. In addition, the final regulation imposes a work practice standard for organic HAPs, including dioxins and furans. The final regulation also sets work-practice standards to reduce emissions during start-up and shut-down. For the revised NSPS, for EGUs commencing construction of a new source after publication of the regulation, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. Mercury continuous emission monitoring systems have been installed on all of the coal-fired units at the Jim Bridger, Boardman, and Valmy generating plants. However, Idaho Power is in the process of determining how these regulations will impact the Bridger, Boardman, and Valmy generating plants and what additional controls, if any, will need to be installed in order to comply with the regulations. Based on its evaluation as of the date of this report, Idaho Power does not foresee any plant closures due to the Utility MACT Rule and expects related compliance costs will not be substantial.

National Ambient Air Quality Standards (NAAQS): In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). In December

2006, the EPA revised the NAAQS for PM2.5. This new standard is the subject of a legal challenge by a number of groups. However, all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power's power plants are currently located were designated as meeting attainment with the revised PM2.5 NAAQS. In January 2010, the EPA adopted a new NAAQS for NO2 at a level of 100 parts per billion averaged over a 1-hour period. In addition, in June 2010 the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. The various states and the EPA have not yet completed the designation of areas as attaining or not attaining these new NAAQS. As a result, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations.

Regional Haze – Best Available Retrofit Technology (RH BART): In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not, as of the date of this report, subject to the federal regional haze rule. The Wyoming Department of Environmental

Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) have conducted assessments of the Jim Bridger and Boardman plants pursuant to an RH BART process. These states have also evaluated the need for additional controls at Jim Bridger and Boardman to achieve reasonable progress toward a long term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

Jim Bridger Plant: In December 2009, the WDEQ issued a RH BART permit to PacifiCorp for the Jim Bridger plant. The WDEQ determined that low NOx burners with over-fire air is RH BART for NOx for all four Bridger units and that RH BART is not required for SO_2 for the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install selective catalytic reduction (SCR) for NOx control at Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by January 15, 2015 to install add-on NOx controls at Jim Bridger Units 1 and 2 by December 31, 2023. PacifiCorp is already in the process of installing low NOx burners and SO_2 scrubber upgrades at the Jim Bridger plant. The SO_2 scrubber upgrade project has been completed on all four Jim Bridger units. Idaho Power expects to spend approximately $2 million in 2012 to complete these pollution control projects. Idaho Power's estimated share of the cost to install SCR on Jim Bridger Units 3 and 4 is $120 million. Installation of SCR also could require extended maintenance outages. Design and cost estimates for add-on NOx controls at Jim Bridger Units 1 and 2 are not yet available.

In February 2010, PacifiCorp filed an administrative appeal of the Jim Bridger RH BART permit with the Wyoming Environmental Quality Council (WEQC). PacifiCorp argued that the WDEQ lacked the legal and technical basis to require the SCR and add-on NOx controls required by the permit. In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp has agreed to install SCR, alternative add-on NOx controls, or otherwise achieve a 0.07 lb/mmBtu 30-day rolling average NOx emission rate by December 31, 2015 for Unit 3 and December 31, 2016 for Unit 4. In addition, PacifiCorp has agreed to install SCR, alternative add-on NOx controls, or otherwise achieve a 0.07 lb/mmBtu 30-day rolling average NOx emission rate by December 31, 2021 for Unit 2 and December 31, 2022 for Unit 1. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan (RH SIP) that are consistent with the terms of the settlement agreement. In light of the settlement agreement, PacifiCorp received a revised RH BART permit for Jim Bridger on November 24, 2010. In September 2011, a federal district court in Colorado approved a consent decree in the case of Wildearth Guardians v. Jackson pursuant to which the EPA must either propose to approve the Wyoming RH SIP or propose an alternate Federal Implementation Plan (FIP) by April 15, 2012. In addition, the EPA must either grant final approval to the Wyoming RH SIP or finalize an RH FIP for Wyoming by October 15, 2012.

Boardman Power Plant: Following the introduction of various plans and an extensive public process, in December 2010 the OEQC approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The rules implementing the plan were approved by the EPA and published in the Federal Register in July 2011, and require the installation of a number of emissions controls. The new rules repeal the OEQC's 2009 Best Available Retrofit Technology rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more extensive suite of emissions controls. The estimated combined total capital cost of the required controls under the plan approved by the OEQC is approximately $60 million. Idaho Power is a 10 percent owner of the Boardman plant, and thus Idaho Power's estimated share of the capital cost is $6 million, which is in addition to normal capital expenditures and maintenance costs. As of December 31, 2011, Idaho Power had paid $2.8 million of its total estimated share of the capital cost.

In September 2011, the federal district court in Oregon approved a consent decree that settled a citizen suit brought by the Sierra Club against PGE alleging certain violations of the requirements of the CAA at the Boardman plant. Under the terms of the settlement, beginning in 2015 through 2020 PGE has agreed to cap and reduce annual sulfur dioxide emissions to levels lower than those specified in the OEQC plan described above and further agreed to pay certain public interest groups a total of $2.5 million for various air quality projects.

The scheduled 2020 shutdown of coal-fired operations at the Boardman plant results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. As a result, in response to an application Idaho Power filed in September 2011, on February 14, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On February 15, 2012, Idaho Power filed an application with the IPUC requesting a $1.6 million annual increase in Idaho jurisdiction base rates to recover the incremental Idaho jurisdictional annual revenue deficiency associated with early shut-down. As of December 31, 2011, Idaho Power's net book value in the Boardman plant was approximately $25.9 million with annual depreciation of approximately $1.3 million.

New Source Review (NSR): Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS of the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. The EPA sent information requests under the CAA, requesting information relevant to NSR and NSPS compliance, to the Jim Bridger plant in 2003, the Valmy plant in 2009, and the Boardman plant in 2008 with a follow up request for information in 2009. In September 2010, the EPA issued a Notice of Violation to PGE, alleging that PGE has violated the NSPS under Section III of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. See Note 10 - "Contingencies" to the consolidated financial statements included in this report for a discussion of the Boardman EPA Notice of Violation.

Coal Combustion Residuals (CCRs): In December 2008, the breach of a dike at the Tennessee Valley Authority’s Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties. In June 2010, the EPA proposed regulations pursuant to the Resource Conservation and Recovery Act governing the disposal and management of CCRs. The EPA requested comments on two options for regulating CCRs. The first would regulate CCRs as a new “special waste” subject to many of the requirements for hazardous waste, while the second would regulate CCRs in a manner similar to typical solid waste, subject to fewer and less stringent environmental requirements. The EPA initiated a public comment period and held public hearings, which ended in November 2011. Either of the EPA’s proposed options represents a shift toward more comprehensive and potentially more expensive requirements for CCRs disposal and management. If this or other new legislation or regulations increase the cost of managing and disposing of CCRs or create additional liability with respect to historic disposal practices, they could have an adverse impact on Idaho Power’s consolidated financial position, results of operations, or cash flows. However, the financial and operational consequences cannot be determined until final legislation is passed or regulations are enacted.

Polychlorinated Biphenyls (PCBs): In April 2010, the EPA issued an advance notice of proposed rulemaking pursuant to the Toxic Substances Control Act regarding the use of PCBs. The EPA is considering revisiting the use authorization allowing the continued use of PCBs in equipment. If new regulations require the replacement of existing equipment, they could have an adverse effect on Idaho Power’s consolidated financial position, results of operations, or cash flows. However, the financial and operational consequences cannot be determined until final regulations are enacted. Idaho Power currently records asset retirement obligation liabilities and associated regulatory assets for the estimated retirement costs of equipment containing PCBs. Proposed regulations could accelerate Idaho Power’s estimated timing of the retirements of equipment with PCBs.

Clean Water Act Section 316(b): In March 2011, the EPA issued a proposed rule that would establish requirements under section 316(b) of the CWA for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rules would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact. The existing facility may choose one of two options for meeting BTA requirements for impingement mortality under this proposed rule. The owner or operator may monitor to show the specified performance standards for impingement mortality of fish and shellfish have been met, or they may demonstrate that the intake velocity meets specified design criteria. For entrainment mortality, this proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the BTA for entrainment mortality would be implemented at each facility. Idaho Power expects the draft rule to be issued in the first half of 2012. Based on the qualification criteria, Idaho Power expects that the new requirements would apply to the Jim Bridger plant, but is unable to determine the potential increased costs that may result from implementation of the rule until final rules are issued and it has performed cost studies.

Public Nuisance-Related Suits for GHGs

In December 2010, the U.S. Supreme Court granted certiorari in Connecticut v. American Electric Power, Inc., to review the opinion from the U.S. Court of Appeals for the Second Circuit granting plaintiffs standing to bring climate change-related public nuisance suits against six major emitters of greenhouse gases (GHGs). In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions, because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. Even though the Court rejected the merits of the plaintiffs' claim, the Court nevertheless held that the plaintiffs had the requisite legal standing to bring the claims. Finally, the Court remanded to the Second Circuit the issue of whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the decision of the Supreme Court in this case does not eliminate the potential for future nuisance-related suits based on GHG emissions.

Renewable Energy Certificates and Emission Allowances

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the year ended December 31, 2011, Idaho Power's REC sales totaled $6.5 million. Idaho Power has sold all of its 2010 and earlier vintage RECs. Idaho Power has sold a portion of its 2011 RECs and intends to continue selling its 2011 and later RECs as they are generated and become available for sale. Ordinarily, Idaho Power does not receive the RECs associated with PURPA projects.

Endangered Species

The listing of a species as threatened or endangered may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or to relicense its hydroelectric projects. Several notable matters pertaining to threatened or endangered species and affecting Idaho Power are discussed below.

Slickspot Peppergrass: This southwestern Idaho plant species was listed as threatened by the USFWS in 2009. While critical habitat for the plant was not designated at the time of listing, approximately 98 percent of the plant species is located on federal land owned by the BLM and the U.S. Department of Defense. Parts of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines will cross BLM land. This listing will add an additional requirement and species for consideration in the ESA Section 7 consultation. A Section 7 consultation is a process used to determine a proposed action's effects on any ESA-listed species that may be within the project area. This listing may increase the expense and delay the timing of permitting for these projects.

Sage Grouse: The sage grouse is considered a "candidate species" under the ESA, which allows land management agencies to implement additional conservation measures in an effort to prevent a formal ESA listing. In March 2010, the USFWS announced that listing of the greater sage grouse as threatened or endangered under the ESA is warranted, but precluded by higher priority listing actions. On February 2, 2012, a federal district court in Idaho issued an order denying a request to expedite the listing of the sage grouse under the ESA. As a result, the USFWS has until 2015 to make a final listing determination under the ESA. On February 6, 2012, the same court issued an order holding that the BLM had violated the National Environmental Policy Act and other federal laws in connection with the granting of livestock grazing permit renewals in sage grouse habitat. Due to the presence of sage grouse in the vicinity, siting of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines has required more extensive, costly, and time consuming evaluation, permitting, and engineering. Any required additional conservation measures may increase the costs of existing operations and impact the cost and timing of siting, permitting, and construction of the Boardman-to-Hemingway and Gateway West transmission lines and other construction and transmission projects. Listing of the greater sage grouse as threatened or endangered under the ESA would add an additional requirement and species for consideration in ESA Section 7 consultations for those projects, and may increase the expense and adversely affect the cost and timing of those projects.

Hells Canyon Project: In 2007, the FERC requested initiation of formal consultation under the ESA with the National Marine Fisheries Service (NMFS) and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has not yet been initiated and NMFS and USFWS continue to gather and consider information relative to the effects of relicensing on relevant species. Idaho Power continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns. Idaho Power may be required to modify operations pursuant to the biological opinion that will result from formal consultation. However, the issuance of a final biological opinion during 2012 is unlikely.

Bliss and Lower Salmon Falls Projects: As part of a settlement agreement, Idaho Power has finalized a snail protection plan for the Bliss and Lower Salmon Falls projects in cooperation with the USFWS. Idaho Power has filed applications with the FERC to amend the licenses for the projects that will maintain operating flexibility at both projects for the remainder of their licenses. The FERC and USFWS are conducting an ESA Section 7 consultation on two ESA listed snails, the Bliss Rapids snail and the Snake River physa snail. Idaho Power has been working closely with USFWS to develop the necessary biological information to complete the consultation. A biological assessment for the Snake River physa snail, jointly developed between the USFWS and Idaho Power, was filed with the FERC in September 2011. The biological assessment evaluates the potential impacts of the license amendment on the Snake River physa snail. Idaho Power anticipates that the FERC will request formal consultation with the USFWS during the second half of 2012. The USFWS will then develop a biological opinion on the effects of load-following on both types of snails.

Swan Falls Project: In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail, a species listed as endangered under the ESA, was found in the area during the EIS review. While the biological opinion includes a provision for the incidental take of the snail, Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (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.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power has recorded $987 million of regulatory assets and $362 million of regulatory liabilities at December 31, 2011. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power 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 Idaho Power's results of operations and financial position.

Income Taxes

IDACORP and Idaho Power use judgment and estimation 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.

Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

In September 2009, the IRS issued IDD #5, which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Since that time, the IRS and Idaho Power agreed to a method consistent with the IDD guidance and changed Idaho Power's uniform capitalization method. In 2010, Idaho Power provided a current uncertain tax position liability equal to the net tax benefit recorded for the method change until the agreement with the IRS was approved by the Joint Committee. This approval occurred in the third quarter of 2011, which effectively settled the issue for financial reporting purposes. No material uncertain tax positions remained at December 31, 2011.

Asset Impairment

Available-for-sale Securities: Idaho Power is required to evaluate available-for-sale securities periodically to determine whether a decline in fair value below cost is other than temporary. If the decline in fair value is other than temporary, the cost of the investment is written down to fair value and the loss is recorded as a realized loss. Two significant factors that are considered when evaluating investments for impairment are the length of time and the extent to which the market value has been less than cost.

Idaho Power has investments in four mutual funds that experienced a significant decline in fair value in 2008. Idaho Power's investments had lost between 32 percent and 43 percent of their value, primarily during the stock market downturn in September and October 2008, and had been in loss positions from 6 to 12 months at December 31, 2008. Because of the severity of the declines in value, Idaho Power determined that the loss in value was other-than-temporary and recorded a pre-tax loss of $6.8 million in the fourth quarter of 2008. At December 31, 2011 and 2010, the fair values of these investments were at or above their new cost bases and no impairment was recorded.

Equity-Method Investments: IFS has affordable housing investments with a net book value of $63 million at December 31, 2011, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for one investment which is consolidated, these investments are accounted for under the equity method of accounting. The standard for determining whether impairment must be recorded for these investments is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses are performed on these investments when indicators of impairment are noted. An immaterial impairment was recorded on one of the Ida-West joint ventures in 2011, and no impairments were recorded in 2010 or in 2009. These estimates required IDACORP to make assumptions about future revenues, cash flows, and other items that are inherently uncertain. Actual results could vary significantly from the assumptions used, and the impact of such variations could be material.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future stock market performance, changes in interest rates, and other factors used to develop the actuarial assumptions are uncertain, and 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 Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2011, with maturities matching the projected cash outflows of the plans. The discount rate used to calculate the 2012 pension expense will be decreased to 4.9 percent from the 5.4 percent used in 2011.

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. The long-term rate of return used to calculate the 2012 pension expense will be 7.75 percent, compared to the 8.25 percent rate used for 2011.

Gross pension and other postretirement benefit expense for these plans totaled $39 million, $39 million, and $40 million for the years ended December 31, 2011, 2010, and 2009, respectively, including amounts allocated to capitalized labor and amounts deferred as regulatory assets. For 2012, gross pension and other postretirement benefit costs are expected to total approximately $52 million, which takes into account the change in the discount rate noted above, as well as a decrease in expected return on plan assets. 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	
	2012	2011	2012	2011
	(millions of dollars)			
Effect of 0.5% increase on net periodic benefit cost	$(5.7)	$(4.8)	$(2.2)	$(2.1)
Effect of 0.5% decrease on net periodic benefit cost	6.6	5.2	2.2	2.1

Additionally a 0.5 percent increase in the plans' discount rates would have resulted in a $55 million decrease in the combined benefit obligations of the plans as of December 31, 2011. A 0.5 percent decrease in the plans' discount rates would have resulted in a $61 million increase in the combined benefit obligations of the plans as of December 31, 2011.

No cash contributions were made to the defined benefit pension plan in 2009. Contributions of $60 million and $18.5 million were made in 2010 and 2011, respectively. Contributions required to be made during 2012 are estimated to be $34 million. Payments of $44 million, $44 million, $42 million, and $42 million are estimated to be due in 2013, 2014, 2015, and 2016, respectively. Under the SMSP, Idaho Power makes payments directly to participants in the plan. Benefit payments are expected to be $3.6 million in 2012 and averaged $3.3 million per year from 2009 to 2011. Postretirement benefit plan contributions are expected to be $3.7 million in 2012, and averaged $2.3 million from 2009 to 2011.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2011, $58 million of expense was deferred as a regulatory asset. Approximately $22 million is expected to be deferred in 2012. Idaho Power recorded pension expense in 2011, 2010, and 2009 of $34 million, $5 million, and $1 million, respectively.

Refer to Note 11 – “Benefit Plans” of the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that 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 Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria 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.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

There have been no recently issued accounting pronouncements that have had or are expected to have a material impact on IDACORP's or Idaho Power's results of operations or financial condition. See Note 1 - “Summary of Significant Accounting Policies” to the consolidated financial statements included in this report for a summary of significant accounting policies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power 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, 2011.

Interest Rate Risk

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

Variable Rate Debt: As of December 31, 2011, IDACORP and Idaho Power had $78.3 million and $24.1 million, respectively, in net floating-rate debt. The fair market value of this debt was $78.3 million and $24.1 million, respectively. Assuming no change in financial structure, if variable interest rates were to average one percentage-point higher than the average rate on December 31, 2011, interest rate expense would increase and pre-tax earnings would decrease by approximately $0.8 million for IDACORP and $0.2 million for Idaho Power.

Fixed Rate Debt: As of December 31, 2011, IDACORP and Idaho Power each had $1.5 billion in fixed rate debt, with a fair market value equal to $1.7 billion. 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 $193 million for both IDACORP and Idaho Power if interest rates were to decline by one percentage point from their December 31, 2011 levels.

Commodity Price Risk

Idaho Power's exposure to changes in commodity prices is related to its ongoing utility operations that produce electricity to meet the demand of its retail electric customers. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. Idaho Power anticipates that the additional volume of natural gas needed to operate the Langley Gulch power plant will increase its exposure in the future to natural gas commodity price risk. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of production. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

Idaho Power’s exposure to commodity price risk is largely offset by the PCA mechanisms in Idaho and Oregon. Therefore, the primary objectives of Idaho Power’s energy purchase and sale activity are 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. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power’s Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power’s Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power’s strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power does not engage in trading activities for non-retail purposes.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The Power Supply business unit produces and evaluates projections of the operating plan based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. Idaho Power 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.

Credit Risk

Idaho Power is subject to credit risk based on its activity with market counterparties. Idaho Power 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. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2011, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade, Idaho Power could be subject to requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2011, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

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

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

Equity Price Risk

IDACORP and Idaho Power are exposed to price fluctuations in equity markets, primarily through their defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity investments at Idaho Power. During 2011, the fair value of the defined benefit pension plan's assets decreased slightly; however, increases in the benefit liabilities were greater than the increases in the plan's assets, therefore resulting in an increase in future amounts required to be contributed to the plan. Based on current laws, Idaho Power estimates that the minimum contribution to the defined benefit pension plan in 2012 will be approximately $36 million. A hypothetical ten percent decrease in equity prices would result in an approximate $2.2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities as of December 31, 2011.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$834,545	$870,371	$883,765
Off-system sales	101,602	78,133	94,373
Other revenues	86,581	84,548	67,858
Total electric utility revenues	1,022,728	1,033,052	1,045,996
Other	4,028	2,977	3,804
Total operating revenues	1,026,756	1,036,029	1,049,800
Operating Expenses:			
Electric utility:			
Purchased power	163,336	143,769	167,198
Fuel expense	131,542	159,673	149,566
Power cost adjustment	38,497	51,226	66,710
Other operations and maintenance	338,640	293,925	292,813
Energy efficiency programs	37,663	44,184	31,821
Depreciation	119,789	115,921	110,626
Taxes other than income taxes	28,895	24,046	21,069
Total electric utility expenses	858,362	832,744	839,803
Other	4,146	4,615	6,414
Total operating expenses	862,508	837,359	846,217
Operating Income	164,248	198,670	203,583
Other Income, Net	21,209	15,165	16,997
Earnings (Losses) of Unconsolidated Equity-Method Investments	798	3,008	(1,033)
Interest Expense:			
Interest on long-term debt	79,349	80,490	73,371
Other interest, net of AFUDC	(7,823)	(5,376)	(561)
Total interest expense, net	71,526	75,114	72,810
Income Before Income Taxes	114,729	141,729	146,737
Income Tax (Benefit) Expense	(52,133)	(731)	22,362
Net Income	166,862	142,460	124,375
Adjustment for (income) loss attributable to noncontrolling interests	(169)	338	(25)
Net Income Attributable to IDACORP, Inc.	$166,693	$142,798	$124,350
Weighted Average Common Shares Outstanding - Basic (000’s)	49,457	48,193	47,124
Weighted Average Common Shares Outstanding - Diluted (000’s)	49,558	48,340	47,182
Earnings Per Share of Common Stock:			

Earnings Attributable to IDACORP, Inc. - Basic	$3.37	$2.96	$2.64
Earnings Attributable to IDACORP, Inc. - Diluted	$3.36	$2.95	$2.64
Dividends Declared Per Share of Common Stock	$1.20	$1.20	$1.20

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Net Income	$ 166,862	$ 142,460	$ 124,375
Other Comprehensive Income:			
Net unrealized holding (losses) gains arising during the year, net of tax of ($257), $738, and $1,169	(400)	1,149	1,820
Unfunded pension liability adjustment, net of tax of ($1,062), ($1,573), and ($885)	(1,654)	(2,450)	(1,380)
Total Comprehensive Income	164,808	141,159	124,815
Comprehensive (income) loss attributable to noncontrolling interests	(169)	338	(25)
Comprehensive Income Attributable to IDACORP, Inc.	$ 164,639	$ 141,497	$ 124,790

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2011	2010
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$27,813	$228,677
Receivables:		
Customer (net of allowance of $1,239 and $1,499, respectively)	66,296	62,114
Other (net of allowance of $196 and $1,471, respectively)	8,197	10,157
Income taxes receivable	421	12,130
Accrued unbilled revenues	46,441	47,964
Materials and supplies (at average cost)	46,490	45,601
Fuel stock (at average cost)	47,865	27,547
Prepayments	12,405	11,063
Deferred income taxes	16,159	10,715
Current regulatory assets	34,279	6,216
Other	4,606	1,854
Total current assets	310,972	464,038
Investments	199,931	202,944
Property, Plant and Equipment:		
Utility plant in service	4,466,873	4,332,054
Accumulated provision for depreciation	(1,677,609)	(1,614,013)
Utility plant in service - net	2,789,264	2,718,041
Construction work in progress	591,475	416,950
Utility plant held for future use	6,974	7,076
Other property, net of accumulated depreciation	18,877	19,315
Property, plant and equipment - net	3,406,590	3,161,382
Other Assets:		
American Falls and Milner water rights	20,015	22,120
Company-owned life insurance	24,060	26,672
Regulatory assets	953,068	753,172
Long-term receivables (net of allowance of $2,743 and $1,861, respectively)	5,621	3,965
Other	40,352	41,762
Total other assets	1,043,116	847,691
Total	$4,960,609	$4,676,055

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2011	2010
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 101,064	$ 122,572
Notes payable	54,200	66,900
Accounts payable	100,432	103,100
Income taxes accrued	505	—
Interest accrued	21,797	23,937
Uncertain tax positions	—	74,436
Current regulatory liabilities	29,738	8,011
Other	60,511	50,103
Total current liabilities	368,247	449,059
Other Liabilities:		
Deferred income taxes	772,047	566,473
Regulatory liabilities	332,057	298,094
Pension and other postretirement benefits	363,209	263,688
Other	75,805	74,470
Total other liabilities	1,543,118	1,202,725
Long-Term Debt	1,387,550	1,488,287
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 49,964,172 and 49,419,452 shares issued, respectively)	828,389	807,842
Retained earnings	840,916	733,879
Accumulated other comprehensive loss	(11,622)	(9,568)
Treasury stock (12,177 and 14,302 shares at cost, respectively)	(29)	(40)
Total IDACORP, Inc. shareholders' equity	1,657,654	1,532,113
Noncontrolling interests	4,040	3,871
Total equity	1,661,694	1,535,984
Total	$ 4,960,609	$ 4,676,055

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Operating Activities:			
Net income	$166,862	$142,460	$124,375
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	124,659	121,849	118,600
Deferred income taxes and investment tax credits	(52,913)	41,742	19,035
Changes in regulatory assets and liabilities	68,045	46,510	57,836
Pension and postretirement benefit plan expense	45,223	14,728	11,594
Contributions to pension and postretirement benefit plans	(22,088)	(65,601)	(7,569)
(Earnings) losses of unconsolidated equity-method investments	(798)	(3,008)	1,033
Distributions from unconsolidated equity-method investments	2,500	6,530	12,477
Allowance for equity funds used during construction	(25,484)	(16,551)	(7,555)
Other non-cash adjustments to net income, net	4,487	3,061	10,207
Change in:			
Accounts receivable and prepayments	(2,232)	14,243	(15,749)
Accounts payable and other accrued liabilities	5,428	4,014	(28,038)
Taxes accrued/receivable	15,113	(14,216)	28,535
Other current assets	(19,684)	3,848	(14,053)
Other current liabilities	2,171	13,682	(7,485)
Other assets	4,330	(3,662)	1,621
Other liabilities	(5,376)	(4,229)	(20,439)
Net cash provided by operating activities	310,243	305,400	284,425
Investing Activities:			
Additions to property, plant and equipment	(337,765)	(338,252)	(251,937)
Proceeds from the sale of utility assets	—	18,982	—
Proceeds from the sale of non-utility assets	—	—	2,250
Proceeds from the sale of emission allowances and RECs	6,314	6,408	2,382
Proceeds from sale of available-for-sale securities	—	—	9,006
Investments in affordable housing	(1,558)	(13,390)	(5,802)
Investments in unconsolidated affiliates	(2,645)	—	—
Purchase of available-for-sale securities	—	(7,000)	—
Maturity of held-to-maturity securities	—	—	425
Other	3,296	4,918	1,271
Net cash used in investing activities	(332,358)	(328,334)	(242,405)
Financing Activities:			
Issuance of long-term debt	—	200,000	230,000
Remarketing of pollution control bonds	—	—	166,100
Decrease in term loans	—	—	(170,000)
Retirement of long-term debt	(121,064)	(1,064)	(89,174)
Dividends on common stock	(59,668)	(57,872)	(56,820)
Net change in short-term borrowings	(12,700)	13,150	(93,600)
Issuance of common stock	17,501	48,644	24,328
Acquisition of treasury stock	(1,933)	(869)	(1,441)
Other	(885)	(3,365)	(7,254)

Net cash (used in) provided by financing activities	(178,749)	198,624	2,139
Net (decrease) increase in cash and cash equivalents	(200,864)	175,690	44,159
Cash and cash equivalents at beginning of the year	228,677	52,987	8,828
Cash and cash equivalents at end of the year	$27,813	$228,677	$52,987
Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$(12,405)	$(27,112)	$(21,401)
Interest (net of amount capitalized)	$70,969	$69,049	$67,039
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$26,331	$33,949	$19,075
Investments in affordable housing	$—	$1,509	$8,276

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$807,842	$756,475	$729,576
Issued	17,501	48,644	24,328
Other	3,046	2,723	2,571
Balance at end of year	828,389	807,842	756,475
Retained Earnings:			
Balance at beginning of year	733,879	649,180	581,605
Net income attributable to IDACORP, Inc.	166,693	142,798	124,350
Common stock dividends ($1.20 per share)	(59,656)	(58,099)	(56,775)
Balance at end of year	840,916	733,879	649,180
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(9,568)	(8,267)	(8,707)
Net unrealized holding (loss) gain on securities (net of tax)	(400)	1,149	1,820
Unfunded pension liability adjustment (net of tax)	(1,654)	(2,450)	(1,380)
Balance at end of year	(11,622)	(9,568)	(8,267)
Treasury Stock:			
Balance at beginning of year	(40)	(53)	(37)
Issued	1,944	882	1,425
Acquired	(1,933)	(869)	(1,441)
Balance at end of year	(29)	(40)	(53)
Total IDACORP, Inc. shareholders' equity at end of year	1,657,654	1,532,113	1,397,335
Noncontrolling Interests:			
Balance at beginning of year	3,871	4,209	4,434
Net income (loss) attributable to noncontrolling interests	169	(338)	25
Other	—	—	(250)
Balance at end of year	4,040	3,871	4,209
Total equity at end of year	$1,661,694	$1,535,984	$1,401,544

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Operating Revenues:			
General business	$834,545	$870,371	$883,765
Off-system sales	101,602	78,133	94,373
Other revenues	86,581	84,548	67,858
Total operating revenues	1,022,728	1,033,052	1,045,996
Operating Expenses:			
Operation:			
Purchased power	163,336	143,769	167,198
Fuel expense	131,542	159,673	149,566
Power cost adjustment	38,497	51,226	66,710
Other operations and maintenance	338,640	293,925	292,813
Energy efficiency programs	37,663	44,184	31,821
Depreciation	119,789	115,921	110,626
Taxes other than income taxes	28,895	24,046	21,069
Total operating expenses	858,362	832,744	839,803
Income from Operations	164,366	200,308	206,193
Other Income (Expense):			
Allowance for equity funds used during construction	25,484	16,551	7,555
Earnings of unconsolidated equity-method investments	9,018	11,281	8,256
Other (expense) income, net	(4,462)	(2,868)	8,008
Total other income	30,040	24,964	23,819
Interest Charges:			
Interest on long-term debt	79,349	80,490	73,270
Other interest	5,039	4,110	4,060
Allowance for borrowed funds used during construction	(13,333)	(10,675)	(5,398)
Total interest charges	71,055	73,925	71,932
Income Before Income Taxes	123,351	151,347	158,080
Income Tax (Benefit) Expense	(41,399)	10,713	35,521
Net Income	$164,750	$140,634	$122,559

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Net Income	$164,750	$140,634	$122,559
Other Comprehensive Income:			
Net unrealized holding (losses) gains arising during the year, net of tax of ($257), $738, and $1,169	(400)	1,149	1,820
Unfunded pension liability adjustment, net of tax of ($1,062), ($1,573), and ($885)	(1,654)	(2,450)	(1,380)
Total Comprehensive Income	$162,696	$139,333	$122,999

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$4,466,873	$4,332,054
Accumulated provision for depreciation	(1,677,609)	(1,614,013)
In service - net	2,789,264	2,718,041
Construction work in progress	591,475	416,950
Held for future use	6,974	7,076
Electric plant - net	3,387,713	3,142,067
Investments and Other Property	128,674	120,641
Current Assets:		
Cash and cash equivalents	19,316	224,233
Receivables:		
Customer (net of allowance of $1,239 and $1,499, respectively)	66,296	62,114
Other (net of allowance of $196 and $142, respectively)	8,011	8,835
Income taxes receivable	4,644	21,063
Accrued unbilled revenues	46,441	47,964
Materials and supplies (at average cost)	46,490	45,601
Fuel stock (at average cost)	47,865	27,547
Prepayments	12,274	10,910
Deferred income taxes	14,099	7,334
Current regulatory assets	34,279	6,216
Other	4,606	1,238
Total current assets	304,321	463,055
Deferred Debits:		
American Falls and Milner water rights	20,015	22,120
Company-owned life insurance	24,060	26,672
Regulatory assets	953,068	753,172
Other	38,988	40,666
Total deferred debits	1,036,131	842,630
Total	$4,856,839	$4,568,393

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31, 2011	2010
	(thousands of dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$97,877	$97,877
Premium on capital stock	704,758	688,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	735,304	630,259
Accumulated other comprehensive loss	(11,622)	(9,568)
Total common stock equity	1,524,220	1,405,229
Long-term debt	1,387,550	1,488,287
Total capitalization	2,911,770	2,893,516
Current Liabilities:		
Long-term debt due within one year	101,064	121,064
Accounts payable	99,716	102,474
Accounts payable to related parties	1,512	1,110
Interest accrued	21,797	23,930
Uncertain tax positions	—	74,436
Current regulatory liabilities	29,738	8,011
Other	59,785	48,733
Total current liabilities	313,612	379,758
Deferred Credits:		
Deferred income taxes	863,044	661,165
Regulatory liabilities	332,057	298,094
Pension and other postretirement benefits	363,209	263,688
Other	73,147	72,172
Total deferred credits	1,631,457	1,295,119
Commitments and Contingencies		
Total	$4,856,839	$4,568,393

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Capitalization

	December 31,	
	2011	2010
	(thousands of dollars)	
Common Stock Equity:		
Common stock	$97,877	$97,877
Premium on capital stock	704,758	688,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	735,304	630,259
Accumulated other comprehensive loss	(11,622)	(9,568)
Total common stock equity	1,524,220	1,405,229
Long-Term Debt:		
First mortgage bonds:		
6.60% Series due 2011	—	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50 % Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	100,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
Total first mortgage bonds	1,295,000	1,415,000
Amount due within one year	(100,000)	(120,000)
Net first mortgage bonds	1,195,000	1,295,000
Pollution control revenue bonds:		
5.15% Series due 2024	49,800	49,800
5.25% Series due 2026	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	6,382	7,446
Note guarantee due within one year	(1,064)	(1,064)
Unamortized premium/discount - net	(3,113)	(3,440)
Total long-term debt	1,387,550	1,488,287
Total Capitalization	$2,911,770	$2,893,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Operating Activities:			
Net income	$164,750	$140,634	$122,559
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	124,028	121,219	117,878
Deferred income taxes and investment tax credits	(57,929)	78,631	15,082
Changes in regulatory assets and liabilities	68,045	46,509	57,836
Pension and postretirement benefit plan expense	45,223	14,728	11,594
Contributions to pension and postretirement benefit plans	(22,088)	(65,601)	(7,569)
Earnings of unconsolidated equity-method investments	(9,018)	(11,281)	(8,256)
Distributions from unconsolidated equity-method investments	—	4,755	10,720
Allowance for equity funds used during construction	(25,484)	(16,551)	(7,555)
Other non-cash adjustments to net income	1,159	(576)	5,649
Change in:			
Accounts receivables and prepayments	(2,468)	13,118	(14,828)
Accounts payable	5,357	4,080	(28,212)
Taxes accrued/receivable	19,217	(9,392)	38,003
Other current assets	(19,684)	3,848	(14,053)
Other current liabilities	2,169	13,674	(7,438)
Other assets	4,330	(3,662)	1,475
Other liabilities	(5,117)	(3,711)	(20,521)
Net cash provided by operating activities	292,490	330,422	272,364
Investing Activities:			
Additions to utility plant	(337,765)	(338,252)	(251,937)
Proceeds from the sale of utility assets	—	18,982	—
Proceeds from the sale of non-utility assets	—	—	2,250
Proceeds from the sale of emission allowances and RECs	6,314	6,408	2,382
Investments in unconsolidated affiliates	(2,645)	—	—
Purchase of available for sale securities	—	(7,000)	—
Other	2,665	4,366	1,171
Net cash used in investing activities	(331,431)	(315,496)	(246,134)
Financing Activities:			
Issuance of long-term debt	—	200,000	230,000
Retirement of long-term debt	(121,064)	(1,064)	(81,064)
Remarketing of pollution control revenue bonds	—	—	166,100
Decrease in term loans	—	—	(170,000)
Dividends on common stock	(59,705)	(58,070)	(56,911)
Net change in short term borrowings	—	—	(108,950)
Capital contribution from parent	16,000	50,000	20,000
Other	(1,207)	(3,184)	(6,921)
Net cash (used in) provided by financing activities	(165,976)	187,682	(7,746)
Net (decrease) increase in cash and cash equivalents	(204,917)	202,608	18,484
Cash and cash equivalents at beginning of the year	224,233	21,625	3,141
Cash and cash equivalents at end of the year	$19,316	$224,233	$21,625

Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$(759)	$(57,378)	$(13,756)
Interest (net of amount capitalized)	$70,491	$67,868	$66,231
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$26,331	$33,949	$19,075

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$630,259	$547,695	$482,047
Net Income	164,750	140,634	122,559
Dividends on Common Stock	(59,705)	(58,070)	(56,911)
Retained Earnings, End of Year	$735,304	$630,259	$547,695

The accompanying notes are an integral part of these statements.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Nature of Business

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

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

Principles of Consolidation

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

The entities that IDACORP and Idaho Power consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2011, Marysville had approximately $20 million of assets, primarily a hydroelectric plant, and approximately $15 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is the primary beneficiary because the ownership of the intercompany note and the EEC note result in it controlling the entity. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

Through IERCo, Idaho Power holds a variable interest in BCC, a VIE for which it is not the primary beneficiary. IERCo is not the primary beneficiary because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner. The carrying value of BCC was $102 million at December 31, 2011, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $63 million guarantee for mine reclamation costs, which is discussed further in Note 9.

Through IFS, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These VIEs are affordable housing developments and other real estate investments in which IFS holds limited partnership interests ranging from 5 to 99 percent. As a limited partner, IFS does not control these entities and they are not consolidated. These investments were acquired between 1996 and 2010. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $63 million at December 31, 2011.

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Other receivables, primarily notes receivable from business transactions, are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that IDACORP or Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2011 and 2010. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options, and swaps are used to manage exposure to commodity price risk in the electricity and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet. Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements with the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities. The objective of the risk management program is to mitigate the price risk associated with the purchase and sale of electricity and natural gas. Because of Idaho Power's regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue, but is instead recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.83 percent in 2011, 2.84 percent in 2010, and 2.81 percent in 2009.

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. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no material impairments of these assets in 2011, 2010, or 2009.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. Idaho Power’s weighted-average monthly AFUDC rates for 2011, 2010, and 2009 were 7.8 percent, 8.0 percent, and 6.7 percent, respectively. Idaho Power’s reductions to interest expense for AFUDC were $13 million for 2011, $11 million for 2010, and $5 million for 2009. Other income included $25 million, $17 million, and $8 million of AFUDC for 2011, 2010, and 2009, respectively.

Income Taxes

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

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction over Idaho Power’s Idaho service territory, Idaho Power’s deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impact currently for rate making and financial reporting. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

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

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

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

	2011	2010
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$2,569	$2,969
Senior Management Security Plan	(14,191)	(12,537)
Total	$(11,622)	$(9,568)

Other Accounting Policies

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

Reclassifications

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

- Certain amounts related to regulatory assets and liabilities that were included in noncurrent regulatory assets and liabilities were reclassified as current regulatory assets and liabilities in the consolidated balance sheets.
- Pension and other postretirement benefits of $264 million were reclassified from other noncurrent liabilities to a separate line in the consolidated balance sheets.

New Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued the following accounting guidance, which is effective for years beginning after December 15, 2011:

- In May 2011, the FASB issued guidance to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between generally accepted accounting principles in the United States and International Financial Reporting Standards. The guidance changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. IDACORP and Idaho Power are currently assessing the impact of the guidance but do not believe that the adoption of this guidance will have a material effect on their consolidated financial statements.

2. INCOME TAXES

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

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$40,096	$49,723	$51,349	$43,173	$52,972	$55,328
Change in taxes resulting from:						
AFUDC	(13,586)	(9,529)	(4,533)	(13,586)	(9,529)	(4,533)
Capitalized interest	6,465	3,674	1,529	6,465	3,674	1,529
Investment tax credits	(3,355)	(3,378)	(3,404)	(3,355)	(3,378)	(3,404)
Repair allowance	—	—	(3,500)	—	—	(3,500)
Removal costs	(2,244)	(2,850)	(3,810)	(2,244)	(2,850)	(3,810)
Capitalized overhead costs	(5,950)	(3,500)	(3,500)	(5,950)	(3,500)	(3,500)
Capitalized repair costs	(14,000)	(10,500)	—	(14,000)	(10,500)	—
Tax method change – uniform capitalization	—	(65,333)	—	—	(65,333)	—
Tax method change – capitalized repairs	—	(44,466)	—	—	(44,466)	—
Uncertain tax positions – established	—	74,436	1,138	—	74,436	1,138
Uncertain tax positions – settled	(63,138)	(1,138)	(4,119)	(63,138)	(1,138)	(4,119)
State income taxes, net of federal benefit	1,375	4,565	1,216	1,846	5,074	1,903
Depreciation	14,100	13,138	3,895	14,100	13,138	3,895
Affordable housing tax credits	(6,438)	(7,309)	(7,870)	—	—	—
Other, net	(5,458)	1,736	(6,029)	(4,710)	2,113	(5,406)
Total income tax (benefit) expense	$(52,133)	$(731)	$22,362	$(41,399)	$10,713	$35,521
Effective tax rate	(45.5)%	(0.5)%	15.2%	(33.6)%	7.1 %	22.5%

The items comprising income tax (benefit) expense are as follows:

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
	(thousands of dollars)					
Income taxes currently payable:						
Federal	$(10)	$(39,518)	$6,199	$9,234	$(62,338)	$21,035
State	790	(5,960)	108	7,296	(5,580)	2,385
Total	780	(45,478)	6,307	16,530	(67,918)	23,420
Income taxes deferred:						
Federal	23,940	(22,582)	23,309	24,559	10,902	20,638
State	(1,285)	(4,436)	(4,509)	(6,920)	(4,036)	(5,792)
Total	22,655	(27,018)	18,800	17,639	6,866	14,846
Uncertain tax positions:						
Federal	(66,225)	65,222	(2,496)	(66,225)	65,222	(2,496)
State	(8,211)	8,076	(485)	(8,211)	8,076	(485)
Total	(74,436)	73,298	(2,981)	(74,436)	73,298	(2,981)
Investment tax credits:						
Deferred	2,223	1,845	3,640	2,223	1,845	3,640
Restored	(3,355)	(3,378)	(3,404)	(3,355)	(3,378)	(3,404)
Total	(1,132)	(1,533)	236	(1,132)	(1,533)	236
Total income tax (benefit) expense	$(52,133)	$(731)	$22,362	$(41,399)	$10,713	$35,521

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

	IDACORP		Idaho Power	
	2011	2010	2011	2010
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$45,473	$46,199	$45,473	$46,199
Advances for construction	5,118	7,061	5,118	7,061
Deferred compensation	22,172	21,299	22,067	21,045
Advanced payments	12,958	8,292	12,958	8,292
Power cost adjustments	1,711	—	1,711	—
Tax credits	119,310	120,229	8,571	6,471
Revenue sharing	10,594	—	10,594	—
Retirement benefits	122,445	88,827	122,445	88,827
Other	5,380	8,617	3,758	4,422
Total	345,161	300,524	232,695	182,317
Deferred tax liabilities:				
Property, plant and equipment	333,335	284,794	333,335	284,794
Regulatory assets	599,992	422,216	599,992	422,216
Conservation programs	3,464	7,611	3,464	7,611
Power cost adjustments	—	11,833	—	11,833
Partnership investments	19,749	18,380	6,181	4,551
Retirement benefits	122,712	93,997	122,712	93,997
Other	21,797	17,451	15,956	11,146
Total	1,101,049	856,282	1,081,640	836,148
Net deferred tax liabilities	$755,888	$555,758	$848,945	$653,831

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

Tax Credits Carryforwards

As of December 31, 2011, IDACORP had $94.1 million of general business credit carryforward for federal income tax purposes and $25.2 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2031, and the Idaho investment tax credit expires from 2019 to 2025.

Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits for IDACORP and Idaho Power is as follows (in thousands of dollars):

	2011	2010	2009
Balance at January 1,	$74,436	$1,138	$4,119
Additions for tax positions of the current year	—	2,822	—
Additions for tax positions of prior years	—	71,614	1,138
Reductions for tax positions of prior years	(66,379)	(1,138)	(4,119)
Settlements with taxing authorities	(8,057)	—	—
Balance at December 31,	$—	$74,436	$1,138

IDACORP and Idaho Power recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Both companies recognized a net reduction in interest expense of $0.2 million in 2011, interest expense of $0.2 million in 2010, and a net reduction in interest expense of $0.2 million in 2009. Accrued interest at both companies was zero as of December 31, 2011, $0.2 million as of December 31, 2010, and zero as of December 31, 2009. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years are 2011 for federal and 2008-2011 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items.

With the resolution of Idaho Power's capitalized repairs and uniform capitalization tax accounting methods examinations (discussed below), the 2009 tax year is now closed for federal purposes. In 2011, the IRS also completed its examination of IDACORP's 2010 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no remaining material tax uncertainties for 2011 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

In June 2010, Idaho Power completed its evaluation of a tax accounting method change for its 2009 tax year that allows a current income tax deduction for repair-related expenditures on its utility assets that are currently capitalized for financial reporting and tax purposes. In September 2010, Idaho Power adopted this method following the automatic consent procedures with the filing of IDACORP's 2009 consolidated federal income tax return. The method was subject to audit under IDACORP's 2009 CAP examination.

For the year ended December 31, 2010, Idaho Power recorded a $44.5 million tax benefit related to the filed deduction for the cumulative method change adjustment and an additional $11.7 million tax benefit for the annual deduction estimate included in its 2010 income tax provision. As of December 31, 2010, Idaho Power had a current uncertain tax position liability of $14.7 million related to this method.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 CAP examination and submitted its report on the 2009 tax year to the U.S. Congress Joint Committee on Taxation (Joint Committee) for review. Idaho Power considers the capitalized repairs method effectively settled and believes that no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

For the year ended December 31, 2011, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $15.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit.

Idaho Power's prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2011, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $6.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. The prescribed regulatory accounting treatment for this method is the same as discussed earlier for the capitalized repairs method.

Cash Impacts of Tax Method Changes

In 2011, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010.

In 2010, IDACORP and Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $33 million and $42 million, respectively. The majority of this cash benefit was realized through reductions to cash payments that would have otherwise been owed to taxing authorities for the 2009 tax year and a federal refund of $24 million received in 2010. Additionally, approximately $6 million of state cash benefits were realized through reduced tax payments for the 2010 year.

The capitalized repairs and uniform capitalization method changes produced an income statement tax benefit of $44.5 million and $65.3 million, respectively, in 2010 prior to the accrual for uncertain tax positions. A portion of this earnings benefit related to previously deferred income tax expense being flowed through the income statement, which does not deliver any cash benefits. In addition, federal tax credits of $17 million previously recognized were restored due to the reduction of 2009 taxable income by the two method changes. The restored credits were a reduction to cash received in 2010, but will be available to deliver cash benefits in future periods.

3. REGULATORY MATTERS

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Total as of December 31, 2011	2010
Regulatory Assets:					
Income taxes		$—	$603,772	$603,772	$429,457
Unfunded postretirement benefits[2]		—	262,503	262,503	182,742
Pension expense deferrals[3]	2012-2015	38,976	19,068	58,044	63,833
Energy efficiency program costs[3]		15,956	—	15,956	19,467
Power supply costs[3]	Varies	8,490	—	8,490	29,753
Fixed cost adjustment[3]	Varies	14,457	—	14,457	12,340
Asset retirement obligations[4]		—	15,557	15,557	15,372
Mark-to-market liabilities[5]		—	4,707	4,707	2,278
Other	2012-2021	993	2,868	3,861	3,573
Total		$78,872	$908,475	$987,347	$758,815
Regulatory Liabilities:					
Income taxes		$—	$49,253	$49,253	$53,440
Removal costs[4]		—	163,173	163,173	157,642
Investment tax credits		—	70,841	70,841	71,972
Deferred revenue-AFUDC [3]		21,034	12,111	33,145	21,211
Power supply costs [3]	Varies	13,121	—	13,121	—
2010 Settlement agreement sharing mechanism[3]	2013	27,099	—	27,099	—
Mark-to-market assets[5]		—	3,754	3,754	573
Other	2012	1,250	159	1,409	1,267
Total		$62,504	$299,291	$361,795	$306,105

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) These items are discussed in more detail below.
(4) Asset retirement obligations and removal costs are discussed in Note 13.
(5) Mark-to-market assets and liabilities are discussed in Note 16.

Idaho Power's regulatory assets and liabilities are amortized over the period in which they are reflected in customer rates. In the event that recovery of Idaho Power's costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power's operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a significant financial impact.

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates.

Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes, and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments are based on (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during each of the years ended December 31, 2011, 2010, and 2009.

Effective Date	$ Change (millions)	Notes
June 1, 2011	$ (40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.
June 1, 2010	$ (146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below in "January 2010 and December 2011 Idaho Settlement Agreements." Concurrent with the PCA rate decrease, the IPUC authorized an $88.7 million increase in base rates, $63.7 million of which was related to power supply costs.
June 1, 2009	$ 84.3	

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE.

Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of the three years ended December 31, 2011, 2010, and 2009 were as follows:

Year and Mechanism	APCU or PCAM Adjustment
2011 PCAM	Actual net power supply costs were below the deadband, resulting in a $1.5 million deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
2010 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2010 APCU	A rate increase of $2.6 million annually took effect June 1, 2010.
2009 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2009 APCU	A rate increase of $3.9 million annually took effect June 1, 2009.

In May 2009, the OPUC adopted a stipulation allowing Idaho Power to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for the period May 1 through December 31, 2007. Idaho Power recorded the $6.4 million deferral in 2009 as a reduction to PCA expense. The amount to be recovered was reduced by $0.9 million of previously deferred SO_2 emission allowance sales (including interest) during the same period. Effective January 2011, these costs are being collected through rates and amortized.

Idaho Regulatory Matters

2011 Idaho General Rate Case and Settlement: On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. The filing was based on a 2011 test year and requested approximately $82.6 million in additional Idaho jurisdiction annual revenues in base rates, a 9.9 percent overall average rate increase for Idaho customers.

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. On December 30, 2011, the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 30, 2011 order provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho jurisdictional base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

The settlement stipulation approved by the order also addressed Idaho Power's calculation of the LCAR to be applied in Idaho Power's PCA mechanism. The LCAR adjusts power supply cost recovery within the Idaho PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provides for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

In its general rate case application, Idaho Power had requested approval of the current fixed cost adjustment (FCA) mechanism pilot program, described below, as a permanent rate mechanism for residential and small commercial class customers. Neither the December 30, 2011 order nor the settlement stipulation resolves whether the fixed cost adjustment pilot program should be made permanent.

Neither the order nor the settlement stipulation imposes a moratorium on Idaho Power's filing a general revenue requirement case at a future date.

January 2010 and December 2011 Idaho Settlement Agreements: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change. This provision anticipated a significant reduction in PCA rates for the 2010-2011 PCA year;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one

year.

On April 15, 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. On May 28, 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million. The net effect of these two rate adjustments was an overall decrease in customer rates of $58.2 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Because Idaho Power’s actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdictional earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power and filed with the IPUC on December 12, 2011. The settlement stipulation provides that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more that $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.0 percent, but less than a 10.5 percent, Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers and 25 percent to Idaho Power.

The settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the settlement stipulation provided that Idaho Power would also allocate to customers 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded in 2011 a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers.

2008 Idaho General Rate Case: On January 30, 2009, the IPUC issued an order approving an increase in Idaho base rates, effective February 1, 2009, of approximately $20.9 million annually, a return on equity of 10.5 percent, and an overall rate of return of 8.18 percent. On February 19, 2009, Idaho Power filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased Idaho Power’s Idaho base rates by an additional $6.1 million to approximately $27 million for this rate case. The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed Idaho Power to include in Idaho-jurisdictional rates approximately $6.5 million ($10.7 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefiting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase improves cash flows but does not have a current impact on Idaho Power’s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Idaho Fixed Cost Adjustment : The FCA began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2009. The FCA is designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. On April 29, 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent for residential and small general service customer classes effective January 1, 2012; a determination from the IPUC is pending.

The following table summarizes FCA rate adjustments since inception:

FCA Year	Period rates in effect	Annual Amount (in millions)	
2010	June 1, 2011-May 31, 2012	9.3	
2009	June 1, 2010-May 31, 2011	6.3	
2008	June 1, 2009-May 31, 2010	2.7	
2007	June 1, 2008-May 31, 2009	(2.4	)

As of December 31, 2011, the deferral balance for the FCA was $14.5 million.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2011, Idaho Power's deferral balance was $58.0 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions.

In May 2010, the IPUC approved Idaho Power’s request to increase rates to allow recovery of Idaho Power’s 2009 cash contribution to its defined benefit pension plan, which contribution was made in September 2010. Idaho Power’s application sought approval of $5.4 million in pension cost recovery over a one-year period to allow recovery contemporaneous with Idaho Power’s expected cash contributions to the plan.

In September 2010, Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount, to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On October 1, 2010, Idaho Power filed an application with the IPUC requesting an order accepting Idaho Power's 2011 retirement benefits package, but not requesting recovery through rates of additional pension plan contributions. On April 28, 2011, the IPUC issued an order accepting Idaho Power's 2011 retirement benefits package.

On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan.

Transmission Revenue Shortfall Filing: On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund to transmission customers transmission revenues that Idaho Power had received starting in 2006. This refund ultimately resulted in under-recovery of transmission costs by Idaho Power, and in October 2009 the IPUC authorized Idaho Power to record an Idaho-jurisdiction regulatory asset for the transmission revenue shortfall, for future recovery in customer rates. At December 31, 2011, the transmission revenue shortfall was $2.1 million. The IPUC ordered that Idaho Power advise the IPUC when the FERC has issued its order on rehearing, following which Idaho Power may request a commencement date for the amortization period for the regulatory asset. On December 7, 2011, the FERC issued an order denying rehearing. Accordingly, on February 15, 2012, Idaho Power submitted an application to the IPUC seeking to include the $2.1 million transmission revenue shortfall in customer rates, recoverable over a three-year period beginning June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs.

On August 18, 2011, the IPUC issued an order approving Idaho Power's March 2011 application requesting that the IPUC designate Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. Idaho Power’s 2010 expenditures for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions totaled $44.2 million. On March 16, 2010, Idaho Power filed an application with the IPUC requesting an order designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred expenses. On November 16, 2010, the IPUC issued an order designating all $50.7 million of energy efficiency expenditures as prudently incurred and approved for ratemaking purposes.

On October 22, 2010, Idaho Power filed an application with the IPUC requesting acceptance of the company's demand-side resources (DSR) business model, which included a request for authorization to (a) move demand response incentive payments out of the energy efficiency rider and into the Idaho PCA on a prospective basis beginning on June 1, 2011, and thus subject to a true-up under the PCA mechanism; (b) establish a regulatory asset for the direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers, beginning January 1, 2011, so that Idaho Power may capitalize the direct incentive payments associated with the program, include the costs associated with the program incentive payments in its rate base, and thus earn a rate of return on a portion of its DSR activities; and (c) change the carrying charge on the existing energy efficiency rider balancing account (from the then-current interest rate of 1.0 percent to Idaho Power's authorized rate of return). On April 1, 2011, the IPUC issued an order stating that certain issues raised in the application are more properly considered in a general rate case proceeding. However, the IPUC noted in its order that Idaho Power's energy efficiency rider balance includes approximately $10 million in expenditures that have been previously approved by the IPUC for recovery, and thus authorized recovery of $10 million of the rider balance in Idaho Power's Idaho PCA rates, beginning June 1, 2011. In that order, the IPUC did not approve a change to the energy efficiency rider balance carrying charge.

On May 17, 2011, the IPUC issued an order stating that it will allow Idaho Power to account for specified direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers as a regulatory asset beginning January 1, 2011, but with an amortization period to be determined later by the IPUC.

In its June 1, 2011 general rate case filing, Idaho Power requested authorization to treat demand response incentive payments as power supply costs and establish a base or "normal" level of cost recovery of approximately $11.3 million for those demand response incentive payments in rates. The Idaho general rate case settlement stipulation approved by the IPUC in December 2011 provides that the $11.3 million of base level demand response incentive payments would be tracked as part of the Idaho PCA mechanism. The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Langley Gulch Power Plant Ratemaking Treatment: On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power’s rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues which, if approved, would result in a 14.7 percent overall average rate increase for customers in the Oregon jurisdiction. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2009 Oregon General Rate Case: On February 24, 2010, the OPUC approved a $5 million, or 15.4 percent, increase in base rates in the Oregon jurisdiction. The new rates were effective March 1, 2010, and were based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. Idaho Power's previously authorized rate of return in Oregon was 7.83 percent.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. On February 12, 2009, the IPUC approved Idaho Power's application requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC subsequently clarified that Idaho Power can expect to include in rate base the Idaho portion of prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million, plus certain costs that the company could not quantify with precision at the time of the application. The IPUC also clarified, as requested by Idaho Power, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout Idaho Power's service territory will eliminate or wholly offset the increase in Idaho Power's revenue requirement caused by the authorized depreciation period.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI through the then-current date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded in 2011, 2010, and 2009 was $10.6 million, $10.6 million, and $6.2 million, respectively. On May 28, 2010, the IPUC approved Idaho Power's March 15, 2010 application requesting authorization to implement a $2.4 million base rate increase for identified customer classes to recover costs relating to the AMI project, with the rate increase effective June 1, 2010.

In the Oregon jurisdiction, the OPUC approved accelerated depreciation and recovery of existing meters located in Oregon over an 18-month period beginning January 2009. The approval increased both rates and depreciation expense by $0.8 million in 2009 and $0.4 million in 2010.

Idaho Power has completed the installation of substantially all smart meters associated with the AMI project. On February 15, 2012, Idaho Power filed an application with the IPUC requesting authority to decrease its Idaho-jurisdiction base rates by $10.6 million annually due to the removal of accelerated depreciation expense associated with non-AMI metering equipment. As of the date of this report, a determination and order from the IPUC is pending.

Depreciation Filings

In 2008 and 2009 Idaho Power filed revisions to its depreciation rates with the IPUC, the OPUC, and the FERC. The commissions approved the new rates, which reduce depreciation expense approximately $8.5 million annually. Idaho Power began applying the new depreciation rates in August 2008.

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated net salvage percentages and service life estimates for all plant assets, and adjust Idaho-jurisdictional base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdictional base rates, with new rates effective June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Federal Open Access Transmission Tariff (OATT) Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per KW-year)*
October 1, 2008 to September 30, 2009	$13.81
October 1, 2009 to September 30, 2010	$15.83
October 1, 2010 to September 30, 2011	$19.60
October 1, 2011 to September 30, 2012	$19.79

* In September 2010, Idaho Power made corrections to its OATT rates for the period beginning October 1, 2007 through September 30, 2010, which resulted in the issuance of a $0.5 million refund to transmission customers.

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31 (in thousands of dollars):

	2011	2010
First mortgage bonds:		
6.60% Series due 2011	$—	$ 120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
Total first mortgage bonds	1,295,000	1,415,000
Pollution control revenue bonds:		
5.15% Series due 2024[1]	49,800	49,800
5.25% Series due 2026[1]	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	6,382	7,446
Unamortized premium/discount - net	(3,113)	(3,440)
Total Idaho Power outstanding debt[2]	1,488,614	1,609,351
Debt related to investments in affordable housing	—	1,508
Total IDACORP outstanding debt	1,488,614	1,610,859
Current maturities of long-term debt	(101,064)	(122,572)
Total long-term debt	$ 1,387,550	$ 1,488,287

[1] Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2011 to $1.461 billion.
[2] At December 31, 2011 and 2010, the overall effective cost of Idaho Power's outstanding debt was 5.43 percent and 5.53 percent, respectively.

At December 31, 2011, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were (in thousands of dollars):

2012	2013	2014	2015	2016	Thereafter
$ 101,064	$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,316,407

IDACORP Long-Term Financing

As of December 31, 2011, IDACORP had approximately $539 million remaining on a shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) that can be used for the issuance of debt securities or

IDACORP common stock. Common stock is discussed further in Note 6.

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. As of December 31, 2011, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

On March 2, 2011, Idaho Power repaid at maturity $120 million of first mortgage bonds using proceeds from first mortgage bonds issued in August 2010.

On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement.

Mortgage: As of December 31, 2011, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.3 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

The Mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the Mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of Idaho Power are subject to easements, leases, contracts, covenants, workmen's compensation awards, and similar encumbrances and minor defects and clouds common to properties. The Mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities, or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The Mortgage creates a lien on the interest of Idaho Power in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger, or sale of all or substantially all of the assets of Idaho Power. The Mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

5. NOTES PAYABLE

Credit Facilities

On October 26, 2011, IDACORP and Idaho Power entered into amended and restated credit agreements, which amended and restated their existing $100 million and $300 million credit facilities, respectively. The new credit facilities may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions. The credit facilities mature on October 26, 2016, although IDACORP and Idaho Power have the right to request up to 2 one-year extensions of the credit agreement, in each case subject to certain conditions.

The IDACORP and Idaho Power credit facilities have similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities.

At December 31, 2011, no amounts were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2011, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings of commercial paper were as follows at December 31 (in thousands of dollars):

	IDACORP		Idaho Power		Total	
	2011	2010	2011	2010	2011	2010
Commercial paper balances:						
At the end of year	$54,200	$66,900	$—	$—	$54,200	$66,900
Average during the year	$65,574	$19,754	$—	$348	$65,574	$20,102
Weighted-average interest rate						
At the end of the year	0.47 %	0.43 %	— %	— %	0.47 %	0.43 %

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes common stock transactions during the last three years and shares reserved at December 31, 2011:

	Shares issued			Shares reserved
	2011	2010	2009	December 31, 2011
Balance at beginning of year	49,419,452	47,925,882	46,929,203	
Continuous equity program	—	973,585	489,360	3,000,000
Dividend reinvestment and stock purchase plan	119,999	144,655	209,859	2,638,807
Employee savings plan	91,277	105,375	156,814	3,618,903
Long-term incentive and compensation plan	333,444	256,662	112,128	1,703,842
Restricted stock plan	—	13,293	28,518	256,154
Balance at end of year	49,964,172	49,419,452	47,925,882	

IDACORP enters into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. IDACORP's current sales agency agreement is with BNY Mellon Capital Markets, LLC. As of December 31, 2011, there were approximately 3 million shares remaining available to be sold under the current sales agency agreement. No shares were issued under the sales agency agreement in 2011. IDACORP sold 973,585 shares under the program in 2010 at an average price of $35.47 and 489,360 shares in 2009 at an average price of $28.79.

Idaho Power Common Stock

In 2011, 2010, and 2009, IDACORP contributed $16 million, $50 million, and $20 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

Restrictions on Dividends

A covenant under IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants in their respective credit facilities or Idaho Power's Revised Code of Conduct. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $827 million and $723 million, respectively, at December 31, 2011. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to the company from any material subsidiary.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power's articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act, but if conservatively interpreted could limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

Idaho Power must obtain approval of the OPUC before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

7. STOCK-BASED COMPENSATION

IDACORP has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2011, the maximum number of shares available under the LTICP and RSP were 1,503,861 and 15,796, respectively.

Stock Awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the market price of common stock on the grant date and is charged to compensation expense over the vesting period, based on the number of shares expected to vest.

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

The performance awards are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

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

	IDACORP		Idaho Power	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2011	351,953	$ 26.35	329,501	$ 26.35
Shares granted	136,644	30.30	135,016	30.30
Shares forfeited	(11,451)	27.32	(11,451)	27.32
Shares vested	(137,208)	25.28	(115,883)	25.28
Nonvested shares at December 31, 2011	339,938	$ 26.40	337,183	$ 26.40

The total fair value of shares vested during the years ended December 31, 2011, 2010, and 2009 was $4.1 million, $3.3 million, and $3.9 million, respectively. At December 31, 2011, IDACORP had $4 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4 million. These costs are expected to be recognized over a weighted-average period of 1.68 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2011, a total of 11,920 shares were awarded to directors at a grant date fair value of $37.74 per share. Directors elected to defer receipt of 5,960 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2011, all compensation costs have been recognized. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

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

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
IDACORP				
Outstanding at December 31, 2010	385,785	$37.47	1.12	$541
Exercised	(255,746)	36.84		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	27,806	$32.29	1.75	$281
Vested and exercisable at December 31, 2011	27,806	$32.29	1.75	$281
Idaho Power				
Outstanding at December 31, 2010	202,634	$38.05	1.13	$314
Exercised	(90,945)	35.54		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	9,456	$33.67	1.58	$83
Vested and exercisable at December 31, 2011	9,456	$33.67	1.58	$83

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The following table presents information about options vested and exercised (in thousands of dollars):

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
Fair value of options vested	$—	$110	$266	$—	$96	$208
Intrinsic value of options exercised	884	1,491	204	535	1,475	204
Cash received from exercises	9,423	5,475	591	3,838	5,394	591
Tax benefits realized from exercises	345	583	80	209	577	80

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

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
Compensation cost	$4,207	$3,706	$4,199	$4,082	$3,489	$3,986
Income tax benefit	1,645	1,449	1,642	1,596	1,364	1,587

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share (EPS) for the years ended December 31, 2011, 2010, and 2009 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2011	2010	2009
Numerator:			
Net income attributable to IDACORP, Inc.	$166,693	$142,798	$124,350
Denominator:			
Weighted-average common shares outstanding - basic	49,457	48,193	47,124
Effect of dilutive securities:			
Options	16	32	16
Restricted Stock	85	115	42
Weighted-average common shares outstanding - diluted	49,558	48,340	47,182
Basic earnings per share	$3.37	$2.96	$2.64
Diluted earnings per share	$3.36	$2.95	$2.64

The diluted EPS computation excludes 137,880, 332,182, and 594,107 options for the years ended December 31, 2011, 2010 and 2009, respectively, because the options' exercise prices were greater than the average market price of the common stock during that year. In total, 27,806 options were outstanding at December 31, 2011, with expiration dates between 2012 and 2015.

9. COMMITMENTS

Purchase Obligations

At December 31, 2011, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousand of dollars):

	2012	2013	2014	2015	2016	Thereafter
Cogeneration and power production	$165,693	$196,261	$209,295	$214,960	$218,220	$3,687,810
Power and transmission rights	10,772	4,243	3,188	2,210	1,879	4,401
Fuel	79,138	64,852	66,309	22,661	8,909	98,212

As of December 31, 2011, Idaho Power had signed agreements to purchase energy from 119 CSPP facilities with contracts ranging from one to 35 years. Ninety-six of these facilities, with a combined nameplate capacity of 606 MW, were on-line at the end of 2011; the other 23 facilities under contract, with a combined nameplate capacity of 383 MW, are projected to come on-line by year end 2014. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2011, Idaho Power purchased 1,495,108 megawatt-hours (MWh) from these projects at a cost of $90 million, resulting in a blended price of $60.36 per MWh. Idaho Power purchased 910,429 MWh at a cost of $55 million in 2010, and 970,419 MWh at a cost of $59 million in 2009.

In addition, IDACORP has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousand of dollars:

	2012	2013	2014	2015	2016	Thereafter
Operating leases	$2,041	$2,875	$2,768	$2,199	$1,203	$15,711
Equipment, maintenance, and service agreements	38,553	15,271	6,169	4,897	3,700	8,254
FERC and other industry-related fees	12,391	12,031	9,745	9,745	6,596	32,981

IDACORP’s expense for operating leases was approximately $5.3 million in 2011, $3.4 million in 2010, and $3.5 million in 2009.

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2011, the value of the reclamation trust fund totaled $80 million. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

IDACORP and Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2011, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. IDACORP and Idaho Power intend to vigorously protect and defend their interests and pursue their rights. However, the ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. IDACORP and Idaho Power monitor those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, thereof, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, IDACORP and Idaho Power do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, IDACORP's and Idaho Power's accruals for legal proceedings are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. As available information changes, the matters for which IDACORP and Idaho Power are able to estimate the loss may change, and the estimates themselves may change.

For certain of those matters described in this report for which IDACORP or Idaho Power have determined a loss contingency may, in the future, be at least reasonably possible, IDACORP and Idaho Power have stated that they are unable to estimate the possible loss or a range of possible loss that may result from those matters. Depending on a range of factors, such as the complexity of the facts, the unique nature of the legal theories, the pace of discovery, the timing of court decisions, and the adverse party's willingness to negotiate towards a resolution, it may be months or years after the filing of a case before IDACORP or Idaho Power may be in a position to estimate the possible loss or range of possible loss for those matters.

Given the substantial or indeterminate amounts sought in certain of the matters described below, and the inherent unpredictability of such matters, an adverse outcome in certain of these matters could have a material adverse effect on IDACORP's and Idaho Power's financial condition, results of operations, or cash flows in particular quarterly or annual periods. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery of incurred costs through the ratemaking process.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). Except as to the matters described below under “Pacific Northwest Refund,” Idaho Power and IE believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and predict that these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. During that period, Idaho Power or IE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in Port of Seattle, Washington v. FERC, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales originating in the Pacific Northwest to the California Department of Water Resources (CDWR) in the scope of the proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On October 3, 2011, the FERC issued its order on remand. The FERC ordered that the record be re-opened to permit parties seeking refunds to submit seller-specific evidence in support of their claims for sales made during the period confined to December 25, 2000 through June 20, 2001. The seller-specific claims must show that a seller engaged in unlawful market activity with a causal connection to have directly affected the negotiation of the specific contract or contracts to which the seller was a party. Neither claims of general dysfunction in the California markets nor in the Pacific Northwest market will be sufficient to support claims. While directing a trial-type hearing, the FERC also directed that the hearings be held in abeyance so that the matter may be presented to a settlement judge. On November 2, 2011, each of the City of Seattle, Washington, the City of Tacoma, Washington, the Port of Seattle, and the California Parties (consisting of the California Attorney General and the California Public Utilities Commission) filed requests for rehearing, seeking to expand the scope of the October 3, 2011 order. The designated settlement judge has met with the parties and convened a settlement conference to establish settlement procedures. The FERC's Chief Administrative Law Judge memorialized certain settlement procedures to which the parties agreed in an order issued on November 23, 2011.

IE and Idaho Power intend to continue to defend their positions in the Pacific Northwest refund proceedings vigorously. As of the date of this report, it is difficult to predict the outcome of this matter. Idaho Power does not believe that claims conforming to the requirements of the FERC's October 3, 2011 order have been submitted, and the FERC's order remains subject to rehearing and reconsideration. Idaho Power and IE are unable to predict when and how the FERC will act on the rehearing requests, which contracts would be subject to refunds, whether the FERC will order refunds, or how the refunds would be calculated. As a result of these factors, as of the date of this report Idaho Power and IE are unable to estimate the reasonably possible loss or range of losses that Idaho Power or IE could incur as a result of this matter. However, based on the status of settlement discussions with one party to the proceedings, for that portion of the matter Idaho Power reserved for a contingent liability an amount immaterial to IDACORP's or Idaho Power's financial statements in the fourth quarter of 2011.

EPA Notice of Violation - Boardman

In September 2010, the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation to Portland General Electric Company (PGE), alleging that PGE had violated the New Source Performance Standards (NSPS) and operating permit requirements under the Clean Air Act (CAA) as a result of modifications made to the Boardman coal-fired plant in 1998 and 2004. PGE is the operator of the Boardman plant, and Idaho Power has a 10 percent ownership interest in the plant. The Notice of Violation states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but it does not impose any penalties or specify the amount of any proposed penalties with respect to the alleged violations. It is difficult to meaningfully predict the eventual outcome of this matter given the complexity of the environmental statutes and claims cited in the Notice of Violation and the matters at issue, the unspecified nature of the penalty or other remedy sought, and the absence of factual information given the early stage of the proceedings. As of the date of this report, based on available information and the status of this matter, Idaho Power is unable to estimate the reasonably possible loss or range of losses that Idaho Power could incur as a result of this matter. However, PGE, the plant operator, has stated that based on its understanding of the penalties authorized under the CAA, the maximum penalty that could be imposed for the alleged violations is approximately $60 million, with Idaho Power's share of any such penalty being limited to 10 percent of the amount ultimately assessed, if any.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses.

Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970's and early 1980's these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation on March 25, 1988.

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State

Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power also continues its active participation in the SRBA in seeking to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Legal Proceedings

IDACORP and Idaho Power are parties to legal claims, actions, and proceedings in addition to those discussed above. However, as of the date of this report the companies believe that resolution of these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

11. BENEFIT PLANS

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee’s final average earnings. Idaho Power’s policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of

1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2011 and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. Idaho Power was not required to contribute to the plan in 2009. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2011 and 2010, approximately $41.2 million and $46.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		SMSP	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation at January 1	$569,934	$506,744	$59,126	$52,719
Service cost	20,478	17,671	1,950	1,541
Interest cost	30,322	29,119	3,094	3,004
Actuarial loss	55,535	35,909	4,251	5,186
Benefits paid	(20,830)	(19,509)	(3,378)	(3,324)
Benefit obligation at December 31	655,439	569,934	65,043	59,126
Change in plan assets:				
Fair value at January 1	397,003	313,474	—	—
Actual return on plan assets				