e-FILING REPORT COVER SHEET

REPORT NAME: Oregon Affiliated Interest Report for 2016

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water)
☐ RO (Other)

Report is required by:
☒ OAR 860-127-0100
☒ Statute ORS 757.005
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☐ No ☐ Yes

If Yes, enter docket number:

Key words:

If known, please select the PUC Section to which the report should be directed:

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

PLEASE NOTE: Do NOT use this form or e-filing with the PUC Filing Center for:

- **Annual Fee Statement form and payment remittance or**
- **OUS or RSPF Surcharge form or surcharge remittance or**
- **Any other Telecommunications Reporting or**
- **Any daily safety or safety incident reports or**
- **Accident reports required by ORS 654.715.**

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

May 17, 2017

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Idaho Power Company's Affiliated Interest Report for 2016

Attention Filing Center:

Pursuant to OAR 860-127-0100 and ORS 757.005, Idaho Power Company herewith transmits for filing its Affiliated Interest Report for 2016.

If you have any questions, please call me at 208-388-5825.

Very truly yours,

Lisa D. Nordstrom

LDN:kkt

Enclosure

Affiliated Interest Report
For the Year Ended December 31, 2016

I. ***An organization chart showing the parent company, all subsidiaries, and the percentage ownership of each. Attach pages showing the information requested below for affiliates with financial transactions with the regulated company.***

See Exhibit I.

A. ***Changes in the list of directors and/or officers common to the regulated utility and to the affiliated interest.***

See Exhibit II.

B. ***Changes in successive ownership between the regulated utility and affiliated interest.***

In 2016, there were no successive ownership changes between Idaho Power Company (Idaho Power) and affiliated interests. See Exhibit I.

C. ***A narrative description of each affiliated interest with which the regulated utility does business. State the factor(s) giving rise to the affiliation.***

See Exhibit III.

D. ***A balance sheet and income statement for each affiliated interest for the 12-month reporting period.***

See Exhibit IV. A copy of the 2016 Annual Report on Form 10-K for IDACORP and Idaho Power has been included with this report.
See Exhibits V and VI. Also included are the side-by-side balance sheets and income statements for the affiliated interest companies. Idaho Power requests confidential treatment of balance sheets and income statements of affiliated interests doing business with the regulated company consistent with the Public Records Law (ORS 192.501 and ORS 192.502).

II. ***Report services transactions as follows (repeat format for each affiliate):***

SERVICE PAYMENT BY THE UTILITY TO THE AFFILIATE

Payments to IDACORP	Total Company	Total Oregon[1]
Cost of Service	$0	$0
Margin of Charges over Cost	0%	0%
Assets Allocable to Services	NA	NA
Overall Rate of Return	0%	0%

Payments to IERCO - Idaho Energy Resources Co. (IERCO) is a regulated subsidiary of Idaho Power in all jurisdictions including Oregon. Separate records and accounts for IERCO are subject to regulatory review and scrutiny together with those of Idaho Power during its general rate cases. Unlike other utility affiliates, for ratemaking purposes IERCO's operations are merged with Idaho Power.

Payments to Other Affiliated Interests – None.

SERVICE PAYMENT BY THE AFFILIATE TO THE UTILITY

Receipts from IDACORP	Total Company	Total Oregon[1]
417.xxx Work Orders	439,832	23,959
920.000 Direct Fixed Cost	15,250	831
922.000 Work Order Overheads	33,446	1,822
Total Receipts[2]	$488,528	$26,612
Cost of Service	$488,528	$26,612
Margin of Charges over Cost	0%	0%
Assets Allocable to Services	NA	NA
Overall Rate of Return	0%	0%

Receipts from IERCO – Idaho Energy Resource Co. (IERCO) is a regulated subsidiary of Idaho Power in all jurisdictions including Oregon. Separate records and accounts for IERCO are subject to regulatory review and scrutiny together with those of Idaho Power during its general rate cases. Unlike other utility affiliates, for ratemaking purposes IERCO's operations are merged with those of Idaho Power.

Receipts from Other Affiliated Interests – None.

1 Based on A&G Allocation factor of 5.45% from 2016 FERC Form 1 Report.

2 See the 2016 Cost Allocation Manual (Exhibit VII)

III. ***For intercompany loans to the utility from affiliates or loans from affiliates to the utility, provide:***

Idaho Power has one short-term intercompany notes receivable to its wholly-owned subsidiary IERCO.

A. ***The month-end amounts outstanding separately for short-term and long-term loans.***

	Note Receivable	Note Payable
January		$ 757,191
February		$ 4,057,149
March		$ 1,537,226
April		$ 589,616
May	$ 3,411,765	
June	$ 5,961,941	
July		$ 1,236,388
August		$ 7,437,890
September		$ 12,818,635
October		$ 14,324,360
November		$ 19,782,762
December		$ 244,435

B. ***The highest amount during the year separately for short-term and long-term loans.***

Note Receivable	Note Payable
$8,061,941	$20,282,762

C. ***A description of the terms and conditions for loans including the basis for interest rates.***

Cash transactions with IERCO's one-third interest in Bridger Coal Company (BCC) are accounted for by means of a short-term intercompany note between IERCO and Idaho Power. BCC requests operating funds weekly, and transfers cash proceeds received from operations monthly. Interest is based on Idaho Power's daily short-term borrowing and investment rates. Interest is accrued monthly.

D. ***The total amount of interest charged or credited and the weighted average rate of interest separately for short-term and long-term loans.***

Total Interest expense	$21,503
Weighted Average interest rate	1.102888%

E. ***Specify the Commission Order(s) approving the transactions where such approval is required by law.***

Commission Order 06-016, UI 244

IV. ***If the utility guarantees any debt of affiliates, identify the entities involved, the nature of the debt, the original amount of the debt, the maximum amount during the year, the balance as of the end of the year, and the Commission Order(s) approving the transactions where such approval is required by law.***

The OPUC granted approval for Idaho Power to guarantee IERCO's one-third share of BCC's self-bond for the reclamation obligation at the Bridger Mine with OPUC Order No. 13-269. In 2016, the self-bond with IERCO's one-third share is set at $70,730,000. The next scheduled renewal date for the self-bond has been set for December 2017.

V. ***Report other transactions (utility leasing of affiliate property, affiliate leasing of utility property, utility purchase of affiliate property, material or supplies, and affiliate purchase of utility property, material or supplies) as follows (repeat format for each affiliate):***

OTHER PAYMENTS BY THE UTILITY TO THE AFFILIATE

	Total Company	Total Oregon[1]
Payments to Bridger Coal		
151.311 Fuel Stock[2]	$86,425,097	$4,029,693
Payments to Ida-West		
555.070 Purchased Power[3]	$7,788,995	$363,173

Payments to Other Affiliated Interests – None.

[1] Fuel Stock is based on Energy Allocation factor of 4.67% and Purchased Power is based on a combination of Demand and Energy Allocation Factors of 4.66% from 2016 FERC Form 1 Report.

[2] Based on contractual agreement among Idaho Power, PacifiCorp and Bridger Coal.

[3] Rates based on PURPA contract terms approved by OPUC Order Number 95-1240.

OTHER PAYMENTS BY THE AFFILIATE TO THE UTILITY

There were no other payments by the affiliate to the utility.
Receipts from Other Affiliated Interests – None.

VI. ***By affiliate and job title, provide the total number of executive, management, and professional/technical employees transferred to and from the utility. By affiliate, provide the total number of other employees transferred to and from the utility.***

There were no transfers of employees to or from the utility.

VII. ***A description of each intracompany cost allocation procedure, and a schedule of cost amounts by account transferred between regulated and non-regulated segments of the company. If this information is provided to the OPUC in another report(s), it need not be presented here. Specify the title and date of the other report(s).***

Not applicable.

VIII. ***Provide copies of annual principal and interest journal record entries for loans to Grid West.***

Grid West was formally dissolved in April, 2006. OPUC Order No. 06-483 dated August 22, 2006 authorized Idaho Power to defer, with interest, the unrecovered amounts. Rate making treatment to amortize these costs was reserved for a ratemaking proceeding. The Company subsequently included the unamortized balance and amortization in its revenue requirement in Case No. UE 213, Order No. 10-064.

EXHIBIT I

EXHIBIT I

IDACORP and Subsidiaries Organization Chart
December 31, 2016

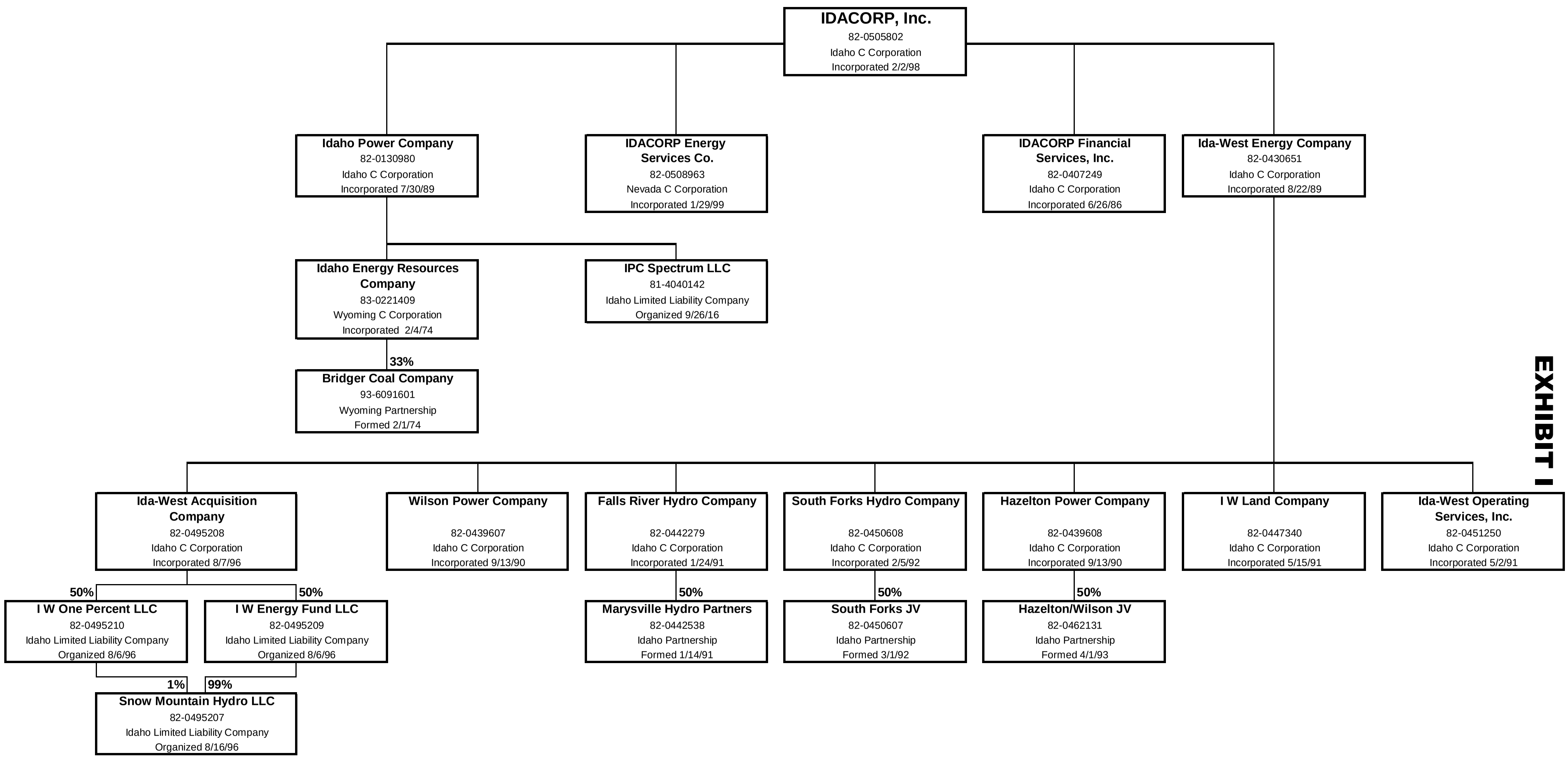

EXHIBIT II

EXHIBIT II
OFFICERS AND DIRECTORS
IDACORP, INC.

DIRECTORS

Darrel T. Anderson	Thomas E. Carlile
Richard J. Dahl	Annette G. Elg
Ronald W. Jibson	Judith A. Johansen
Dennis L. Johnson	J. LaMont Keen
Christine King	Richard J. Navarro
Robert A. Tinstman*	

*** Chairman of the Board**

OFFICERS	TITLE
Darrel T. Anderson	President and Chief Executive Officer
Brian Buckham	Sr. Vice President and General Counsel
Patrick A. Harrington	Corporate Secretary
Steven R. Keen	Sr. Vice President, Chief Financial Officer and Treasurer
Jeffrey L. Malmen	Sr. Vice President of Public Affairs
Ken W. Petersen	Vice President, Controller and Chief Accounting Officer

Revised March 1, 2017

Title change for Brian Buckham

Revised December 31, 2016

Retirement of Rex Blackburn

Revised December 19, 2016

- **Retirement of Dan Minor and Lori D. Smith, title change for Rex Blackburn and appointment of Brian Buckham**

EXHIBIT II
SUBSIDIARIES OF IDACORP, Inc.
OFFICERS AND DIRECTORS

IDAHO POWER COMPANY

DIRECTORS

Darrel T. Anderson
Thomas E. Carlile
Richard J. Dahl
Annette G. Elg
Ronald W. Jibson
Judith A. Johansen
Dennis L. Johnson
J. LaMont Keen
Christine King
Richard J. Navarro
Robert A. Tinstman*

*** Chairman of the Board**

OFFICERS	TITLE
Darrel T. Anderson	President and Chief Executive Officer
Brian Buckham	Sr. Vice President and General Counsel
Jeff S. Glenn	Vice President of Information Technology and Chief Information Officer
Lisa A. Grow	Sr. Vice President and Chief Operating Officer
Patrick A. Harrington	Corporate Secretary
Steven R. Keen	Sr. Vice President, Chief Financial Officer and Treasurer
Lonnie G. Krawl	Sr. Vice President of Administrative Services and Chief Human Resources Officer
Jeffrey L. Malmen	Sr. Vice President of Public Affairs
Tess R. Park	Vice President of Power Supply
Ken W. Petersen	Vice President, Controller and Chief Accounting Officer
N. Vern Porter	Vice President of T&D Engineering and Construction and Chief Safety Officer
Adam J. Richins	Vice President of Customer Operations and Business Development
Tim E. Tatum	Vice President of Regulatory Affairs

Revised March 1, 2017

Appointment of Adam Richins. Title changes for Lisa Grow and Vern Porter.

Revised December 31, 2016

Retirement of Rex Blackburn

Revised December 19, 2016

- **Retirement of Gregory Said, Lori Smith, and Daniel Minor. Title changes for Jeffrey Malmen, Lonnie Krawl and Rex Blackburn; appointments of Brian Buckham, Jeff Glenn, Tess Park, and Tim Tatum.**

EXHIBIT II

SUBSIDIARIES OF IDACORP, Inc.
OFFICERS AND DIRECTORS

IDA-WEST ENERGY COMPANY

DIRECTORS	OFFICERS	
Steven R. Keen	Tom Wicher	President
Lonnie G. Krawl	Pat Harrington	Secretary
Lisa A. Grow		

NOTE: Shareholders Annual Meeting to be held in September. Board of Directors Annual Meeting immediately following Shareholders.

IDACORP FINANCIAL SERVICES, INC.

DIRECTORS	OFFICERS	
Steve R. Keen	Naomi Crafton-Shankel	President
Lonnie G. Krawl	Pat Harrington	Secretary & Treasurer

NOTE: Shareholders Annual Meeting to be held 3rd Wednesday in May. Board of Directors Annual Meeting - Anytime.

IDACORP ENERGY SERVICES CO.

DIRECTORS	OFFICERS	
Bruce MacMahon	Bruce MacMahon	President & Treasurer
	Pat Harrington	Secretary

NOTE: Shareholders Annual Meeting to be held the 1st Tuesday in December. Board of Directors Annual Meeting - immediately following Shareholders.

Revised December 19, 2016

- **Retirement of Lori Smith from IDA-West Energy and IDACORP Financial Services and the appointment of Lonnie Krawl to both.**

*****IDACORP Energy L.P. was dissolved December 31, 2012**

EXHIBIT II
SUBSIDIARIES OF IDAHO POWER COMPANY
DIRECTORS AND OFFICERS

IDAHO ENERGY RESOURCES COMPANY

DIRECTORS	OFFICERS	
Lisa A. Grow	Darrel T. Anderson	President
Darrel T. Anderson	Lisa A. Grow	Vice President
Steven R. Keen	Steven R. Keen	Vice President & Treasurer
	Pat Harrington	Secretary

NOTE: Shareholders Annual Meeting to be held 3rd Tuesday in April. Board of Directors Annual Meeting immediately following Shareholders.

April 19, 2016

- **Resignation of D. Minor as director**
- **Appointment of S. Keen as director, Vice President & Treasurer**
- **Appointment of L. Grow as Vice President**

EXHIBIT III

EXHIBIT III

IDACORP, Inc.
Affiliated Entities

IDACORP, Inc. – IDACORP is a non-regulated holding company formed in 1998. It is the parent of Idaho Power Company (IPC), and other non-regulated subsidiaries. This entity shares officers and directors with IPC, and therefore qualifies as an affiliated interest under Oregon statute.

Idaho Energy Resources Co. (IERCO) – IPC through its wholly owned subsidiary IERCO, owns a one-third interest in Bridger Coal Company (BCC), which supplies coal to the Jim Bridger generating plant owned in part by IPC. As a wholly owned subsidiary, IERCO qualifies as an affiliated interest under Oregon statute.

Ida-West Energy Co. – Ida-West was formed in 1989 and is an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA). Ida-West has a 50 percent interest in nine operating hydroelectric plants with a total generating capacity of 45 MW. This entity shares directors with IPC, and therefore qualifies as an affiliated interest under Oregon statute.

IDACORP Financial Services, Inc. (IFS) – Organized in 1996, IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and tax depreciation benefits. Prior to its transfer to IDACORP effective January 1, 2000, IFS was a wholly owned subsidiary of IPC. This entity shares directors with IPC, and therefore qualifies as an affiliated interest under Oregon statute.

IDACORP Energy Services Co. (IE) – IE was formed in 1999 and served as a limited partner to IDACORP Energy, LP ("IELP"). IELP was formed in 1997 to participate in the electricity and natural gas trading markets. On June 21, 2002, IDACORP announced that IELP would wind down its power marketing operations. In August 2003, IELP sold its forward book of electricity trading contracts to an external third party and wound down business operations. IELP was dissolved on December 31, 2012 and IE remains as the surviving corporation. IE shares directors and officers with IPC, and therefore qualifies as an affiliated interest under Oregon statute.

EXHIBIT IV

EXHIBIT IV

IDAHO POWER CO

FORM 10-K
(Annual Report)

Filed 02/18/16 for the Period Ending 12/31/15

Address	1221 W IDAHO ST
	PO BOX 70
	BOISE, ID 83702
Telephone	2083882200
CIK	0000049648
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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EXHIBIT IV

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, 2015

OR

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

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

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

State of incorporation: Idaho

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)

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, 2015):

IDACORP, Inc.:	$	2,798,093,674	Idaho Power Company:	None

Number of shares of common stock outstanding as of February 12, 2016:

IDACORP, Inc.:	50,297,581
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 2016 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.

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* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2016 annual meeting of shareholders.

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COMMONLY USED TERMS

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

ADITC	-	Accumulated Deferred Investment Tax Credits	IRP	-	Integrated Resource Plan
AFUDC	-	Allowance for Funds Used During Construction	IRS	-	U.S. Internal Revenue Service
APCU	-	Annual Power Cost Update	kW	-	Kilowatt
BCC	-	Bridger Coal Company, a joint venture of IERCo	MATS	-	Mercury and Air Toxics Standards
BLM	-	U.S. Bureau of Land Management	MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
BPA	-	Bonneville Power Administration	MW	-	Megawatt
CAA	-	Clean Air Act	MWh	-	Megawatt-hour
CO_2	-	Carbon Dioxide	NAAQS	-	National Ambient Air Quality Standards
CWA	-	Clean Water Act	NMFS	-	National Marine Fisheries Service
EGUs	-	Electric Utility Generating Units	NOx	-	Nitrogen Oxide
EIS	-	Environmental Impact Statement	NSPS	-	New Source Performance Standards
EPA	-	U.S. Environmental Protection Agency	NSR/PSD	-	New Source Review / Prevention of Significant Deterioration
EPS	-	Earnings Per Share	O&M	-	Operations and Maintenance
ESA	-	Endangered Species Act	OATT	-	Open Access Transmission Tariff
FCA	-	Fixed Cost Adjustment	OPUC	-	Public Utility Commission of Oregon
FERC	-	Federal Energy Regulatory Commission	PCA	-	Power Cost Adjustment
FPA	-	Federal Power Act	PCAM	-	Oregon Power Cost Adjustment Mechanism
GAAP	-	Generally Accepted Accounting Principles	PURPA	-	Public Utility Regulatory Policies Act of 1978
GHG	-	Greenhouse Gas	REC	-	Renewable Energy Certificate
HCC	-	Hells Canyon Complex	RPS	-	Renewable Portfolio Standard
Ida-West	-	Ida-West Energy Company, a subsidiary of IDACORP, Inc.	SEC	-	U.S. Securities and Exchange Commission
Idaho ROE	-	Idaho-jurisdiction return on year-end equity	SMSP	-	Security Plan for Senior Management Employees
IERCo	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company	SO_2	-	Sulfur Dioxide
IESCo	-	IDACORP Energy Services Co., a subsidiary of IDACORP, Inc.	USFWS	-	U.S. Fish and Wildlife Service
IFS	-	IDACORP Financial Services, Inc., a subsidiary of IDACORP, Inc.	VIEs	-	Variable Interest Entities
IPUC	-	Idaho Public Utilities Commission			

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CAUTIONARY NOTE REGARDING 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, such as statements regarding projected or future financial performance, cash flows, capital expenditures, dividends, capital structure or ratios, strategic goals, challenges, objectives, and plans for future operations. Such statements 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," "potential," "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 Part I, Item 1A - “Risk Factors” and Part II, Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations" of this report, as well as in subsequent reports filed by IDACORP and Idaho Power with the Securities and Exchange Commission, and the following important factors:

- the effect of decisions by the Idaho and Oregon public utilities commissions, the Federal Energy Regulatory Commission, and other regulators that impact Idaho Power's ability to recover costs and earn a return;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area and the loss or change in the business of significant customers, and their associated impacts on loads and load growth, and the availability of regulatory mechanisms that allow for timely cost recovery in the event of those changes;
- the impacts of economic conditions, including the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and the collection of receivables;
- unseasonable or severe weather conditions, wildfires, drought, and other natural phenomena and natural disasters, which affect customer demand, hydroelectric generation levels, repair costs, and the availability and cost of fuel for generation plants or purchased power to serve customers;
- advancement of technologies that reduce loads or reduce the need for Idaho Power's generation or sale of electric power;
- adoption of, changes in, and costs of compliance with laws, regulations, and policies relating to the environment, natural resources, and threatened and endangered species, and the ability to recover increased costs through rates;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River Basin, which may impact the amount of power generated by Idaho Power's hydroelectric facilities;
- the ability to purchase fuel, power, and transmission capacity under reasonable terms, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires (either at or caused by Idaho Power facilities), explosions, and mechanical breakdowns that may occur while operating and maintaining an electric system, which can cause unplanned outages, reduce generating output, damage the companies’ assets, operations, or reputation, subject the companies to third-party claims for property damage, personal injury, or loss of life, or result in the imposition of civil, criminal, and regulatory fines and penalties;
- the increased costs and operational challenges associated with purchasing and integrating intermittent renewable energy sources into Idaho Power's resource portfolio;
- administration of reliability, security, and other requirements for system infrastructure required by the Federal Energy Regulatory Commission and other regulatory authorities, which could result in penalties and increase costs;
- disruptions or outages of Idaho Power's generation or transmission systems or of any interconnected transmission system;
- the ability to obtain debt and equity financing or refinance existing debt when necessary and on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets, interest rate fluctuations, decisions by the Idaho or Oregon public utility commissions, and the companies' past or projected financial performance;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to credit and contractual arrangements;
- the ability to enter into financial and physical commodity hedges with creditworthy counterparties to manage price and commodity risk, and the failure of any such risk management and hedging strategies to work as intended;

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- changes in actuarial assumptions, changes in interest rates, and the return on plan assets for pension and other post-retirement plans, which can affect future pension and other postretirement plan funding obligations, costs, and liabilities;
- the ability to continue to pay dividends based on financial performance, and in light of contractual covenants and restrictions and regulatory limitations;
- changes in tax laws or related regulations or new interpretations of applicable laws by federal, state, or local taxing jurisdictions, the availability of tax credits, and the tax rates payable by IDACORP shareholders on common stock dividends;
- employee workforce factors, including the operational and financial costs of unionization or the attempt to unionize all or part of the companies' workforce, the impact of an aging workforce and retirements, the cost and ability to retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, which may result in penalties and fines and increase the cost of compliance, the nature and extent of investigations and audits, and the cost of remediation;
- the inability to obtain or cost of obtaining and complying with required governmental permits and approvals, licenses, rights-of-way, and siting for transmission and generation projects and hydroelectric facilities;
- the cost and outcome of litigation, dispute resolution, and regulatory proceedings, and the ability to recover those costs or the costs of operational changes through insurance or rates, or from third parties;
- the failure of information systems or the failure to secure data, failure to comply with privacy laws, security breaches, or the direct or indirect effect on the companies' business or operations resulting from cyber attacks, terrorist incidents or the threat of terrorist incidents, and acts of war;
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement new technology solutions; and
- adoption of or changes in accounting policies and principles, changes in accounting estimates, and new 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.

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PART I
ITEM 1. BUSINESS

OVERVIEW

Background

IDACORP, Inc. (IDACORP) is a holding company incorporated in 1998 under the laws of the state of Idaho. 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 the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions with access to books and records and imposes record retention and reporting requirements on IDACORP.

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as the successor to a Maine corporation that was organized in 1915 and began operations in 1916. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and capacity and is regulated by the state regulatory commissions of Idaho and Oregon and by the FERC. 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. Idaho Power's utility operations constitute nearly all of IDACORP's current business operations and are IDACORP's only reportable business segment. Segment financial information is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2015, IDACORP had 2,002 full-time employees, 1,993 of whom were employed by Idaho Power, and 21 part-time employees, 19 of whom were employed 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 Services Co. (IESCo), the successor to IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003.

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.

Available Information

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 Idaho Power's website is *www.idahopower.com* . The contents of these websites 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.

UTILITY OPERATIONS

Background

Idaho Power provided electric utility service to approximately 525,000 general business customers in southern Idaho and eastern Oregon as of December 31, 2015 . Over 436,000 of these customers are residential. Idaho Power's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, health care, and winter recreation. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 71 cities in Idaho and 9 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 3 counties in Oregon. Idaho Power's service area is shaded in the illustration on the following page and covers approximately 24,000 square miles with an estimated population of one million.

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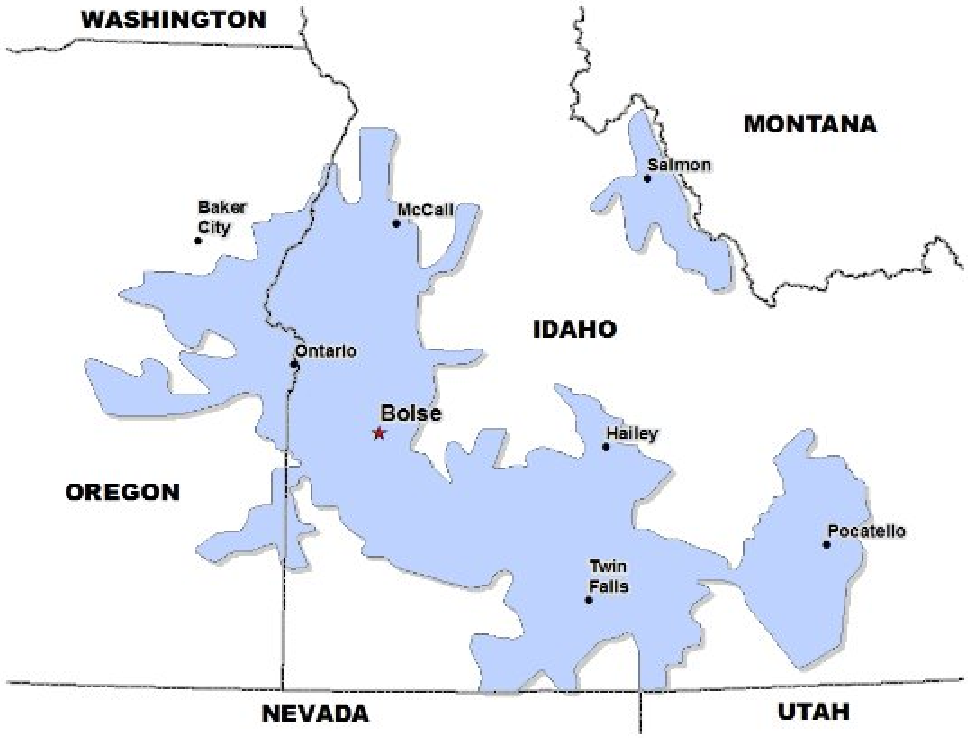

Idaho Power is under the jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC), the Public Utility Commission of Oregon (OPUC), and the FERC. The IPUC and OPUC determine the rates that Idaho Power is authorized to charge to its general business customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. As a public utility under the Federal Power Act, 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). Additionally, the FERC has jurisdiction over Idaho Power's sales of transmission capacity and wholesale electricity, hydroelectric project relicensing, and system reliability, among other items.

Regulatory Accounting

Idaho Power is subject to accounting principles generally accepted in the United States of America, with the impacts of rate regulation reflected in its financial statements. These principles sometimes result in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would record such expenses and revenues. In these instances, the amounts are deferred or accrued 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 that are expected to be refunded. Idaho Power records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

Business Strategy

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business, as Idaho Power's utility operations are the primary driver of IDACORP's operating results. Idaho Power's three-part strategy can be summarized as follows:

- ***Responsible Planning*** : Idaho Power’s planning process is intended to ensure adequate generation, transmission, and distribution 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 upon which Idaho Power and the communities it serves depend. 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 legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions, as well as operating Idaho Power's system in a manner that extracts additional value through changes in fuel mix and generation.

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. Idaho Power has further refined its three-part business strategy to include three core focuses for 2016—improving its core business, growing revenues, and enhancing the brand and positioning the company for the future. IDACORP continues to focus on its core business and its goal of generating returns for its shareholders and long-term shareholder value.

Rates and Revenues

Idaho Power generates revenue primarily through the sale of electricity to retail and wholesale customers and the provision of transmission service. The prices that the IPUC, the OPUC, and the FERC authorize Idaho Power to charge for the electric power and services Idaho Power sells are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. In addition to the discussion below, for more information on Idaho Power's regulatory framework and rate regulation, 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.

Retail Rates **:** Idaho Power periodically evaluates the need to request changes to its retail electricity price structure to cover its operating costs and to seek to earn a return on its investments. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA) mechanism, balancing accounts and tariff riders, and subject-specific filings to recover its costs of providing service and to earn a return on investment. Retail prices are generally determined through formal ratemaking proceedings that are conducted under established procedures and schedules before the issuance of a final order. Participants in these proceedings include Idaho Power, the staffs of the IPUC or OPUC, and other interested parties. The IPUC and OPUC are charged with ensuring that the prices and terms of service are fair, are non-discriminatory, and provide Idaho Power an opportunity to recover its prudently incurred or allowable costs and expenditures and earn a reasonable return on investment. The ability to request rate changes does not, however, ensure that Idaho Power will recover all of its costs or earn a specified rate of return, or that its costs will be recovered in advance of or at the same time as the costs are incurred.

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 amounts recorded under specific authorization from the IPUC or OPUC but deferred for recovery or refund. Deferred amounts are generally collected from or refunded to retail customers through the use of base rates or supplemental tariffs. Outside of base rates, three of the most significant mechanisms for recovery of costs are the PCA mechanisms, FCA mechanism, and energy efficiency rider. The Idaho and Oregon PCA mechanisms are intended to address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers by allowing partial recovery of the difference between net power supply costs included in base rates and actual net power supply costs incurred by Idaho Power. The FCA mechanism is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge for certain Idaho customer classes and linking it instead to a set amount per customer. Separately, Idaho Power collects most of its energy efficiency program costs through an energy efficiency rider on customer bills.

Wholesale Markets **:** As a public utility subject to the provisions of 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 OATT. Idaho Power's OATT transmission rate is revised each year based primarily 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 were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of transmission and reliability standards.

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Idaho Power participates in the wholesale energy markets by purchasing 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. These operating plans are impacted by factors such as customer demand for power, market prices, generating costs, transmission constraints, and availability of generating resources. Some of Idaho Power's 17 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. Idaho Power at times operates these and its other generation facilities to take advantage of market opportunities. 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 capture wholesale marketplace economic benefits, maximize generation unit efficiency and meet peak loads. Compliance factors such as allowable river stage elevation changes and flood control requirements also influence these generation dispatch decisions. Idaho Power's off-system sales revenues depend largely on the availability of generation resources above the amount necessary to serve customer loads as well as adequate market power prices at the time when those resources are available. When either factor is low, off-system sales revenue is reduced.

Energy Sales: Weather, seasonal customer demand, and economic conditions all impact the amount of electricity that Idaho Power sells as well as the costs it incurs to provide that electricity. Idaho Power's utility revenues are not earned, and associated expenses are not incurred, evenly during the year. Idaho Power's retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter. 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. The table that follows presents Idaho Power's revenues and sales volumes for the last three years, classified by customer type. Approximately 95 percent of Idaho Power's general business revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power's operations, including information on energy sales, are discussed further in Part II, Item 7 - MD&A - "Results of Operations - Utility Operations."

	Year Ended December 31,		
	2015	2014	2013
General business revenues (thousands of dollars)			
Residential	$ 512,068	$ 500,195	$ 513,914
Commercial	306,178	299,462	281,009
Industrial	182,254	182,675	165,941
Irrigation	164,403	158,654	159,242
Provision for rate refund for sharing mechanism	(3,159)	(7,999)	(7,602)
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,706)	(10,706)	(10,776)
Total general business revenues	1,151,038	1,122,281	1,101,728
Off-system sales	30,887	77,165	54,473
Other	85,580	79,205	86,897
Total revenues	$ 1,267,505	$ 1,278,651	$ 1,243,098
Energy sales (thousands of MWh)			
Residential	4,977	4,965	5,365
Commercial	4,045	3,944	3,975
Industrial	3,196	3,217	3,182
Irrigation	2,047	1,966	2,097
Total general business	14,265	14,092	14,619
Off-system sales	1,254	2,220	1,683
Total	15,519	16,312	16,302

Competition: Idaho Power's electric utility business has historically been recognized as a natural monopoly. Idaho Power's rates for retail electric services are generally determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses including depreciation on capital investments, an opportunity for Idaho Power to earn a reasonable return on investment as authorized by regulators. However, alternative methods of generation, including customer-owned solar and other forms of distributed generation, compete with Idaho Power for sales to existing customers. Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that could alter demand for Idaho Power's electric energy. Idaho Power also competes with fuel distribution companies in serving the energy needs of customers for space heating, water heating, and appliances.

Idaho Power also participates in the wholesale energy markets and in the electric transmission markets. Generally, these wholesale markets are regulated by the FERC, which requires electric utilities to transmit power to or for wholesale purchasers and sellers and make available, on a non-discriminatory basis, transmission capacity for the purpose of providing these services.

In return for agreeing to provide service to all customers within a defined service area, electric utilities are typically provided with an exclusive right to provide service in that service area. However, certain prescribed areas within Idaho Power's service area, such as municipalities or Native American Tribal reservations, may elect not to take service from Idaho Power and instead operate as a municipal electric utility or otherwise as a separate entity. In such cases, the entity would be required to purchase or otherwise obtain rights (such as by contract) to Idaho Power's distribution infrastructure within the municipal or other designated area. Idaho Power would have no responsibility for providing electric service to the municipal or separate entity, absent Idaho Power's voluntary execution of an agreement to provide that service. Separately, the Shoshone-Bannock Tribes, located in southeastern Idaho, have recently taken steps toward the adoption of a separate utility code applicable to electric utilities operating within the Shoshone-Bannock Tribal Reservation (Reservation). The proposed tribal utility code, if adopted, could ultimately lead to Idaho Power's cessation of its historical provision of service to the Reservation and could result in either no or a limited electric service relationship with the Reservation, or could result solely in Idaho Power's sale of power to the Reservation pursuant to a power purchase agreement. Idaho Power estimates that the average load for the Reservation over the prior five years is approximately 14 MW.

Power Supply

Overview: Idaho Power primarily relies on company-owned hydroelectric, coal-fired, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Market purchases and sales are used to supplement Idaho Power's generation and 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, supply constraints, economic conditions, and availability of generation resources impact power supply costs. Idaho Power’s annual hydroelectric generation varies depending on water conditions in the Snake River Basin. 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 wholesale market purchased power. Economic conditions and governmental regulations can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power. Idaho Power's PCA mechanisms mitigate in large part the potentially adverse financial statement impacts of volatile fuel and power costs.

Idaho Power’s system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand was 3,407 Megawatts (MW), set on July 2, 2013, at which time Idaho Power had deployed 30 MW of demand response programs to mitigate the load demand. The all-time winter peak demand was 2,527 MW, set on December 10, 2009. Idaho Power's peak demand during 2015 was 3,402 MW, the magnitude of which was diminished by the deployment of 60 MW of demand response programs during the peak load period. During these and other similarly heavy load periods Idaho Power’s system is fully committed to serve load and meet required operating reserves. The table that follows shows Idaho Power’s total power supply for the last three years.

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	MWh			Percent of Total Generation		
	2015	2014	2013	2015	2014	2013
	(thousands of MWh)					
Hydroelectric plants	5,910	6,170	5,656	47%	47%	42%
Coal-fired plants	4,676	5,851	6,327	37%	44%	47%
Natural gas fired plants	2,076	1,175	1,576	16%	9%	11%
Total system generation	12,662	13,196	13,559	100%	100%	100%
Purchased power - cogeneration and small power production	2,008	2,286	2,127			
Purchased power - other	1,784	1,867	1,775			
Total purchased power	3,792	4,153	3,902			
Total power supply	16,454	17,349	17,461			

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 of approximately 8.5 million Megawatt-hours (MWh) under median water conditions. The amount of water available for hydroelectric power generation depends on several factors—the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, upstream reservoir storage, springtime precipitation and temperatures, main river and tributary base flows, the condition of the Eastern Snake Plain Aquifer and its spring flow impact, summer time irrigation withdrawals and returns, and upstream reservoir regulation. Idaho Power actively participates in collaborative work groups focused on water management issues in the Snake River Basin, with the goal of preserving the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River.

During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. The result is a greater reliance on other generation resources and power purchases. In 2014, significantly low upstream carryover water storage hindered the impact of the runoff of near-normal snow accumulation, resulting in generation of 6.2 million MWh. In 2015, below-normal snow accumulation resulted in a lower than median hydro production of 5.9 million MWh. The Northwest River Forecast Center of the National Oceanic Atmospheric Administration reported that the 2015 April through July inflow volume into Brownlee Reservoir (the uppermost reservoir of Idaho Power's Hells Canyon Complex) was only 46 percent of normal. By comparison, April through July Brownlee Reservoir inflow was 63 percent of normal in 2014. For 2016, Idaho Power estimates annual generation from its hydroelectric facilities of between 6.0 million MWh and 8.0 million MWh.

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 agencies. 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 project, its largest hydroelectric generation source. 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."

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee" by virtue of its hydroelectric operations. 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, among other items, provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, and possible takeover of a project after expiration of its license upon payment of net investment and severance damages.

Coal-Fired Generation **:** Idaho Power co-owns the following coal-fired power plants:

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

Bridger Coal Company (BCC) supplies coal to the Jim Bridger power plant. Idaho Power owns a one-third interest in BCC and PacifiCorp owns a two-third interest in BCC and is the operator of the Bridger Coal Mine. The mine operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface and underground sources. Idaho Power believes that BCC has sufficient reserves to provide coal deliveries for at least the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2017 from the Black Butte Coal Company's Black Butte mine located near the Jim Bridger plant. This contract supplements the BCC 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, while limited, provides the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

NV Energy is the operator of the North Valmy power plant. NV Energy and Idaho Power have contracts with a coal supplier through 2016. Idaho Power's share of these contracts, together with the existing coal inventory at the North Valmy plant, are expected to meet Idaho Power's projected coal requirements at the plant through 2017. Idaho Power expects to be able to obtain future coal requirements through similar contracts.

Portland General Electric Company is the operator of the Boardman power plant. Idaho Power believes that it has sufficient inventory and coal contracts to supply the Boardman plant with fuel through 2016 and has 25 percent of projected fuel needs for 2017. The Boardman plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Idaho Power expects to meet future coal needs through similar contracts. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

Natural Gas-fired Generation **:** Idaho Power owns and operates the Langley Gulch natural gas-fired combined cycle power plant and the Danskin and Bennett Mountain natural gas-fired simple cycle combustion turbine power plants. All three plants are located in Idaho.

Idaho Power operates the Langley Gulch plant as a baseload unit and the Danskin and Bennett Mountain plants to meet peak supply needs. The plants are also used to take advantage of wholesale market opportunities. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is transported through the Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. These transportation agreements vary in contract length but generally contain the right for Idaho Power to extend the term. 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. This firm storage contract expires in 2043. Idaho Power purchases and stores natural gas with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

As of December 31, 2015, approximately 9.8 million MMBtu's of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through January 2017. Idaho Power plans to manage the procurement of additional natural gas for the peaking units on the daily spot market or from storage inventory as necessary to meet system requirements and fueling strategies.

Purchased Power **:** As described below, Idaho Power purchases power in the wholesale market as well as power pursuant to long-term power purchase contracts and exchange agreements.

Wholesale Market Transactions : To supplement its self-generated power and long-term purchase arrangements, Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk management policy limitations, and unit availability. Depending on availability of excess power or generation capacity, pricing, and opportunities in the markets, Idaho Power also sells power in the wholesale markets. During 2015 and 2014 , Idaho Power purchased 1.8 million MWh and 1.9 million MWh of power through wholesale market purchases at an average cost of $49.57 per MWh and $49.31 per MWh, respectively. During 2015 and 2014 , Idaho Power sold 1.3 million MWh and 2.2 million MWh of power in wholesale market sales, with an average price of $24.63 per MWh and $34.76 per MWh, respectively.

Long-term Power Purchase and Exchange Arrangements : In addition to its wholesale market purchases, Idaho Power has the following notable firm long-term power purchase contracts and energy exchange agreements:

- 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 Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is through 2037.
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock hydroelectric project in southern Idaho in exchange for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement was through December 31, 2015, but the term of the agreement has been extended through December 31, 2020. Idaho Power has the right to renew the agreement for one additional five-year term.
- 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 2033.

PURPA Power Purchase Contracts : Idaho Power purchases power from PURPA projects as mandated by federal law. As of February 5, 2016, Idaho Power had contracts with on-line PURPA-related projects with a total of 784 MW of nameplate generation capacity, with an additional 423 MW nameplate capacity of projects projected to be on-line by June 1, 2017 . The power purchase contracts for these projects have original contract terms ranging from one to 35 years. The expense and volume of PURPA project power purchases during the last three years is included in the following table:

	Year Ended December 31,		
	2015	**2014**	**2013**
PURPA contract expense (in thousands)	$ 131,340	$ 144,617	$ 131,338
MWh purchased under PURPA contracts (in thousands)	2,008	2,286	2,127
Average cost per MWh from PURPA contracts	$ 65.41	$ 63.26	$ 61.75

Pursuant to the requirements of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from "qualifying facilities" that meet the requirements of PURPA. 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 IPUC and OPUC have established specific rules and regulations to calculate the avoided cost that Idaho Power is required to include in PURPA contracts. For PURPA power purchase agreements:

- Idaho Power is required to purchase all of the output from the facilities located inside its service area, 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 area if it has the ability to receive power at the facility's requested point of delivery on Idaho Power's system.
- The IPUC jurisdictional portion of the costs associated with PURPA contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and an Oregon PCA mechanism. Thus, the primary impact of high power purchase costs under PURPA contracts is on customer rates.
- The IPUC issued an order in August 2015 that revised the standard PURPA power purchase contract term for new contracts to 2 years from the previously required 20 year term.
- OPUC jurisdictional regulations have generally provided for PURPA standard contract terms of up to 20 years. Various ongoing cases are being processed at the OPUC in which the contract term and other PURPA regulations are being reviewed.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 kilowatts (kW) and all other types of projects that are smaller than 10 average MWs. For PURPA qualifying facilities that exceed these size limitations, Idaho Power is required to negotiate an applicable price (premised on avoided costs) based upon IPUC regulations.
- The OPUC requires that Idaho Power pay the published avoided costs for all PURPA qualifying facilities with a nameplate rating of 10 MW or less and that Idaho Power negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations. As part of the ongoing cases at the OPUC, the OPUC has temporarily reduced this nameplate rating for solar and wind projects to 3 MW.

Idaho Power, as well as other affected electric utilities, have engaged in proceedings at the IPUC and OPUC relating to PURPA contracts. Final rulings were issued in the IPUC proceedings in 2015, and the OPUC proceedings are ongoing. These proceedings have related to, among other things, appropriate contract term lengths and the prices paid for energy purchased from PURPA projects. Refer to Part II - Item 7 - MD&A - "Regulatory Matters - *Renewable Energy Contracts and PURPA* " for a summary of those proceedings.

Consideration of Participation in Energy Imbalance Market : Utilities in the western United States outside the California Independent System Operator (California ISO) have traditionally relied upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply. These utilities have limited capability to transact within the hour outside their own borders. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The California ISO and PacifiCorp implemented a new energy imbalance market in 2014 (Western EIM) under which the parties enabled their systems to interact for dispatch purposes. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Participation in the Western EIM is voluntary and available to all balancing authorities in the western United States. Since 2015, Idaho Power has been evaluating the potential power supply cost savings and other advantages, system upgrade requirements, capital and ongoing operating costs, and other aspects of Idaho Power's potential participation in the Western EIM.

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 hundreds of miles away from customers. Idaho Power’s generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum capability and reliability. Idaho Power’s transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy. These interconnections, coupled with transmission line capacity made available under agreements with some of those entities, permit the interchange, purchase, and sale of power among entities in the Western Interconnection. Idaho Power provides wholesale transmission service for eligible transmission customers on a non-discriminatory basis. Idaho Power is a member of the WECC, the NWPP, 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 Interconnection.

Transmission to serve Idaho Power's retail customers is subject to the jurisdiction of the IPUC and OPUC for retail rate making purposes. Idaho Power provides cost-based wholesale and retail access transmission services under the terms of a FERC approved OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers, including Idaho Power, have an equal opportunity to access the transmission system. As required by FERC standards of conduct, Idaho Power's transmission function is operated independently from Idaho Power's energy marketing function.

Idaho Power is jointly working on the permitting of two significant transmission projects. The Boardman-to-Hemingway line is a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho. The Gateway West line is a proposed 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. Both projects are intended to meet future anticipated resource needs and are discussed in Part II, Item 7 – MD&A - "Liquidity and Capital Resources - Capital Requirements" in this report.

Resource Planning

Integrated Resource Planning: The IPUC and OPUC require that Idaho Power prepare biennially an Integrated Resource Plan (IRP). Idaho Power filed its most recent IRP in June 2015. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. 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.

During the time between IRP filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect economic conditions, anticipated resource development, changes in technology, and regulatory requirements.

The load forecast Idaho Power used for purposes of the 2015 IRP predicts an average annual growth rate of 1.2 percent for average loads and 1.5 percent for summer peak loads over the 20-year planning horizon from 2015 to 2034. The rate of load growth can impact the timing and extent of development of resources, such as new generation plants or transmission infrastructure, to serve those loads. The load forecast Idaho Power used in the 2013 IRP predicted an average annual growth rate of 1.1 percent for average loads and 1.4 percent for summer peak loads over the 20-year planning horizon from 2013 to 2032.

The 2015 IRP identified a preferred resource portfolio, which includes the completion of the Boardman-to-Hemingway 500-kV transmission line and the potential early retirement of the North Valmy power plant, both in 2025, with no other new resource needs prior to 2025. However, as noted in the 2015 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third party development of renewable resources, implementation of the EPA's rules under Section 111(d) of the Clean Air Act, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These and other uncertainties could result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions.

The 2015 IRP includes as near-term action items the continued permitting and planning for the Boardman-to-Hemingway transmission line and further investigation of the early retirement of the North Valmy power plant in collaboration with the plant's co-owner. The near-term action plan also includes a decrease in the size of the planned Shoshone Falls expansion from 50 MW to a range of 1.7 MW to 4 MW with a scheduled on-line date in 2019, as well as commencement of an economic evaluation of environmental control retrofits for units 1 and 2 at the Jim Bridger power plant.

Energy Efficiency and Demand Response Programs: Idaho Power’s energy efficiency and demand response portfolio is comprised of 22 programs. These energy efficiency and demand response programs target energy savings across the entire year and system demand reduction in the summer. The 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 generation or transmission 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 heating, ventilation and cooling 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;
- demand response programs to reduce peak summer demand through the voluntary cycling of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through actions taken by business owners and operators; and
- membership in the Northwest Energy Efficiency Alliance, which supports market transformation efforts across the region.

In 2015, Idaho Power’s energy efficiency programs reduced energy usage by approximately 140,000 MWh. For 2015, Idaho Power had a demand response available capacity of approximately 385 MW. In 2015 and 2014, Idaho Power expended approximately $39 million and $37 million, respectively, on both energy efficiency and demand response programs. Funding for these programs is provided through a combination of the Idaho and Oregon energy efficiency tariff riders, base rates, and the Idaho PCA mechanism.

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 impacts Idaho Power’s operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, the modification of system operations to accommodate environmental regulations, and the cost of acquiring and complying with permits and licenses. In addition to generally applicable regulations, Idaho Power's three coal-fired power plants, three natural gas combustion turbine power plants, and 17 hydroelectric generating plants are subject to a broad range of environmental requirements, including those related to air and water quality, waste materials, and endangered species. For a more detailed discussion of these and other environmental issues, refer to Item 7 - MD&A - "Environmental Matters" in this report.

Environmental Expenditures: Idaho Power’s environmental compliance expenditures will remain significant for the foreseeable future, especially given the additional regulations proposed and issued at the federal level. 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):

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	2016		2017 - 2018	
Capital expenditures:				
License compliance and relicensing efforts at hydroelectric facilities	$	16	$	27
Investments in equipment and facilities at thermal plants		29		11
Total capital expenditures	$	45	$	38
Operating expenses:				
Operating costs for environmental facilities - hydroelectric	$	22	$	44
Operating costs for environmental facilities - thermal		14		27
Total operations and maintenance	$	36	$	71

Idaho Power anticipates that finalization and implementation of a number of federal and state rulemakings and other proceedings addressing, among other things, greenhouse gases and endangered species, could result in substantially increased operating and compliance costs in addition to the amounts set forth above, but Idaho Power is unable to estimate those costs given the uncertainty associated with potential future regulations. Idaho Power would seek to recover those increased costs through the ratemaking process.

Idaho Power monitors environmental requirements and assesses whether environmental control measures are or remain economically appropriate. Continued review of the economic appropriateness of further investments in coal-fired plants was included in a February 2014 order of the IPUC, in which the IPUC requested that Idaho Power continue monitoring environmental requirements at a national level and account for their impact in resource planning and promptly apprise the IPUC of developments that could impact the company's continued reliance on the North Valmy plant as a coal-fired resource. Idaho Power has been working with the plant's co-owner to monitor environmental requirements and costs associated with the plant, and to develop alignment on potential retirement dates for the plant. In its 2015 IRP, Idaho Power included retirement scenarios ranging from 2019 to 2025 for the North Valmy plant, with a later date within that range being more likely.

Voluntary CO_2 Intensity Reduction Goal: Idaho Power is engaged in voluntary greenhouse gas emissions intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce Idaho Power's resource portfolio's average carbon dioxide (CO_2) emissions intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emissions intensity of 1,194 lbs CO_2/MWh. The combination of effective utilization of hydroelectric projects, above average stream flows in some years, reduced usage of coal-fired facilities, the purchase of renewable energy, and the addition of the Langley Gulch natural gas-fired power plant positioned Idaho Power to extend its CO_2 emissions intensity reduction goal period for an additional two years, targeting an average reduction of 10 to 15 percent below its 2005 levels for the entire 2010 through 2015 time period. Idaho Power achieved its initial reduction goal, as well as its extended goal through 2015. Idaho Power estimates that its average CO_2 emission intensity from company-owned resources for the 2010 through 2015 period was 21 percent below the 2005 CO_2 emission intensity level.

In 2015, Idaho Power further extended and expanded the goal, seeking to reduce the company-owned resource portfolio average CO_2 emission intensity to 15-20 percent below 2005 levels for the 2010-2017 period.

Carbon Disclosure Project Reporting: Idaho Power's estimated historic CO_2 emissions intensity from its generation facilities, as submitted to the Carbon Disclosure Project, was as follows:

	2010	2011	2012	2013	2014
Emission Intensity (lbs CO_2/MWh)	1,060	677	871	1,129	1,019

IDACORP FINANCIAL SERVICES, INC.

IFS invests 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 has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk with most of IFS's investments having been made through syndicated funds. IFS is no longer actively pursuing further investment opportunities, but will continue to maintain and manage its current portfolio of investments. At December 31, 2015 , the gross amount of IFS's portfolio equaled $182 million in tax credit investments. IFS generated tax credits of $3.3 million , $5.2 million , and $5.5 million in 2015 , 2014 , and 2013 , respectively.

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IDA-WEST ENERGY COMPANY

Ida-West operates and has a 50 percent ownership interest in nine hydroelectric projects that have 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 approximately $8 million in 2015 and $9 million in both 2014 and 2013 .

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below (in alphabetical order), along with their business experience during at least the past five years. Mr. J. LaMont Keen, a member of IDACORP's and Idaho Power's boards of directors and former President and Chief Executive Officer of IDACORP and Idaho Power, 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 appointed.

DARREL T. ANDERSON, 57
- President and Chief Executive Officer of IDACORP, Inc., May 2014 - present
- President and Chief Executive Officer of Idaho Power Company, January 2014 - present
- President and Chief Financial Officer of Idaho Power Company, January 2012 - December 2013
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 2009 - April 2014
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 2009 - December 2011
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company since September 2013

REX BLACKBURN, 60
- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 2009 - present

LISA A. GROW, 50
- Senior Vice President of Operations of Idaho Power Company, January 2016 - present
- Senior Vice President - Power Supply of Idaho Power Company, October 2009 - December 2015

STEVEN R. KEEN, 55
- Senior Vice President - Chief Financial Officer, and Treasurer of IDACORP, Inc., May 2014 - present
- Senior Vice President - Chief Financial Officer, and Treasurer of Idaho Power Company, January 2014 - present
- Vice President - Finance and Treasurer of IDACORP, Inc., June 2010 - April 2014
- Senior Vice President - Finance and Treasurer of Idaho Power Company, January 2012 - December 2013
- Vice President - Finance and Treasurer of Idaho Power Company, June 2010 - December 2011
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 2006 - May 2010

LONNIE KRAWL, 52
- Senior Vice President of Administrative Services and Chief Information Officer of Idaho Power Company, January 2016 - present
- Vice President and Chief Information Officer of Idaho Power Company, October 2013 - December 2015
- Director of Human Resources of Idaho Power Company, July 2009 - September 2013

DANIEL B. MINOR, 58
- Executive Vice President of Idaho Power Company, January 2016 - present
- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 2012 - December 2015
- Executive Vice President of IDACORP, Inc., May 2010 - present
- Executive Vice President - Operations of Idaho Power Company, October 2009 - December 2011

TESSIA PARK, 54

- Vice President of Power Supply of Idaho Power Company, January 2016 - present
- Director of Load Serving Operations of Idaho Power Company, September 2012 - December 2015
- Operating Projects Manager of Idaho Power Company, January 2011 - September 2012
- Manager of Power Supply Operations of Idaho Power Company, August 2009 - January 2011

KEN W. PETERSEN, 52

- Vice President, Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, January 2014 - present
- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 2010 - December 2013
- Corporate Controller of IDACORP, Inc. and Idaho Power Company, December 2007 - May 2010

N. VERN PORTER, 56

- Vice President of Customer Operations of Idaho Power Company, January 2016 - present
- Senior Vice President of Customer Operations of Idaho Power Company, April 2015 - December 2015
- Vice President of Idaho Power Company, January 2014 - April 2015
- Vice President of Delivery Engineering and Construction of Idaho Power Company, May 2012 - December 2013
- Vice President of Delivery Engineering and Operations of Idaho Power Company, October 2009 - May 2012

ITEM 1A. RISK FACTORS

IDACORP and Idaho Power operate in a highly regulated industry and business environment that involves significant risks, many of which are beyond the companies' control. The circumstances and factors set forth below may have a material 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. These risk factors, as well as other information in this report and in other reports the companies file with the SEC, should be considered carefully when making any investment decisions relating to IDACORP or Idaho Power.

If state public utility commissions or the Federal Energy Regulatory Commission authorize customer rates that under-collect or untimely collect through rates the amount Idaho Power needs to cover costs and earn a reasonable rate of return, IDACORP's and Idaho Power's financial condition and results of operations may be adversely affected . The prices that the Idaho Public Utilities Commission (IPUC) and Public Utility Commission of Oregon (OPUC) authorize Idaho Power to charge customers for its retail services, and the tariff rate that the Federal Energy Regulatory Commission (FERC) permits Idaho Power to charge for its transmission services, are generally the most significant factors influencing IDACORP’s and Idaho Power’s business, results of operations, and financial condition. Idaho Power's ability to recover its costs and earn a reasonable rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers’ rates, and differences between the costs embedded in rates and the amount of actual costs incurred. Idaho Power is often required to incur costs before the IPUC, OPUC, or FERC approves the recovery of those costs, and the IPUC, OPUC, and FERC may not allow Idaho Power to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. While rate regulation is premised on the assumption that rates will be established that are fair, just, and reasonable, regulators have considerable discretion in applying this standard. The ratemaking process typically involves multiple intervening parties, including governmental bodies, consumer advocacy groups, and customers, generally with the common objective of limiting rate increases or even reducing rates. Denial or probable denial of recovery by regulators may cause Idaho Power to record an impairment of its assets. In a number of proceedings in recent years, Idaho Power has been denied recovery, or required to defer recovery pending the next general rate case, including denials or deferrals related to compensation expenses.

For additional information relating to Idaho Power's regulatory framework and regulatory matters, see Part I - Item 1 - "Business - Utility Operations," Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, and Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Matters" in this report.

Idaho Power's cost recovery mechanisms may not function as intended and are subject to change, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power has power cost adjustment mechanisms in its Idaho and Oregon jurisdictions and a fixed cost adjustment mechanism in Idaho that provide for periodic adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms track Idaho Power’s actual net power supply costs (primarily fuel and purchased power less off-system sales) and compare these amounts to net power supply costs being recovered in retail rates. A majority of the difference between these two amounts is deferred for future recovery from, or refund to, customers through rates. In recent years, the volatility in power supply costs has been significant, in large part due to changes in hydroelectric generation conditions and the cost of purchase of renewable energy under long-term contracts. While the power cost adjustment mechanisms function to mitigate the potentially adverse impact on net income of power supply cost volatility, the mechanisms do not eliminate the cash flow impact of that volatility. When power costs rise above the level recovered in current retail rates, Idaho Power incurs the costs but recovery of those costs is deferred to a subsequent collection period, which can adversely affect Idaho Power's operating cash flow and liquidity until those costs are recovered from customers. The fixed cost adjustment mechanism is a decoupling mechanism designed to remove Idaho Power's disincentive to invest in energy efficiency activities by allowing Idaho Power to charge residential and small commercial customers when it recovers less than the base level of fixed costs per customer that the IPUC authorized for recovery in the most recent general rate case. Both the power cost and fixed cost adjustment mechanisms were approved through the regulatory process, and thus they are subject to change at the discretion of applicable state regulators, who could decide to modify or eliminate either mechanism in a manner that adversely impacts IDACORP's and Idaho Power's financial condition, cash flows, and results of operations.

IDACORP's and Idaho Power's business, financial condition, and results of operations may be negatively affected by changes in customer growth or customer usage . Growth in the number of customers and customers' usage of electricity are affected by a number of factors, such as population growth or decline in Idaho Power's service area, adoption rates of energy efficiency measures, customer-generated power such as from rooftop solar panels, demand side management requirements, and economic conditions. Many electric utilities have experienced a decline in usage per customer, in part attributable to energy efficiency activities. While Idaho Power has recently experienced a net growth in usage due to an increase in the number of customers, when adjusted for the impacts of weather the average monthly usage on a per customer basis for Idaho residential customers has declined from 1,059 kWh in 2009 to 1,012 kWh in 2014. Rate mechanisms, such as the Idaho fixed cost adjustment, are designed to address the financial disincentive associated with promoting energy efficiency activities, but there is no assurance that the mechanism will result in full or timely collection of Idaho Power's fixed costs, which are currently collected in large part through the company's kWh energy rates that are based on historical sales volume. Any undercollection of fixed costs would adversely impact revenues, earnings, and cash flows. Weak economic conditions may also reduce the amount of energy Idaho Power's customers consume, result in a loss of customers (including large-load industrial and commercial customers) or further decrease the customer growth rate, and increase the likelihood and prevalence of late payments and uncollectible accounts. The formation of municipal utilities or similar entities for distribution systems within Idaho Power's service area could also result in a load decrease. The loss of loads resulting from some of these events may result in IDACORP and Idaho Power modifying or eliminating large generation or transmission projects. This could in turn result in write-downs or write-offs if regulators determine that the costs of the projects were incurred imprudently, which could have a material adverse impact on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

Conversely, if Idaho Power were to experience an unanticipated increase in the demand for energy through, for example, the rapid addition of new industrial and commercial customers, Idaho Power may be required to rely on higher-cost purchased power to meet peak system demand and may need to accelerate investment in additional generation or transmission resources. If the incremental costs associated with the unanticipated changes in loads exceed the incremental revenue received from the sales to the new customers, and Idaho Power is unable to secure timely and full rate relief to recover those increased costs, the resulting imbalance could have an adverse effect on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

IDACORP's and Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather conditions and severe weather. Idaho Power's electric power sales are seasonal, with demand in Idaho Power's service area peaking during the hot summer months, with a secondary peak during the cold winter months. Electric power demands by irrigation customers in Idaho Power's service area, which are impacted by temperatures and the timing and amount of precipitation, among other factors, can also create significant seasonal changes in usage. Seasonality of revenues may be further impacted by Idaho Power's tiered rate structure, under which rates charged to customers are often higher during higher-load periods. Market prices for power also often increase significantly during these peak periods, at times when Idaho Power is required to purchase power in the wholesale markets to meet customer demand. By contrast, when temperatures are relatively mild or where precipitation supplants irrigation systems, loads are often lower as customers are not using electricity for heating and air conditioning or irrigation purposes. Thus, weather conditions and the timing and extent of precipitation can cause IDACORP's and Idaho Power's results of operations and financial condition to fluctuate seasonally, quarterly, and from year to year.

Extreme weather events and their associated impacts (such as fires, high winds, and snow loading) can damage generation facilities and disrupt transmission and distribution systems, causing service interruptions and extended outages through downed transmission and distribution lines, increasing supply chain costs and limiting Idaho Power's ability to meet customer energy demand. Sustained drought conditions are likely to decrease power generation from hydroelectric plants. The effect of the failure of Idaho Power's facilities to operate as planned under extreme weather conditions is particularly burdensome during peak demand periods, such as hot summer days. Damage and disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses. Costs incurred as a result of such events might not be recovered through customer rates if the costs incurred are greater than those allowed for recovery by regulators, and the costs of repair and replacing infrastructure or liability for personal injury or property damage may not be covered in full by insurance.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could decrease revenues . The increasing cost of energy in the electric utility industry has encouraged the development of new technologies for power generation, power storage, and energy efficiency. In particular, in recent years the cost of solar generation has decreased significantly, and there are federal tax incentives in place to help further reduce the cost of solar generation. There is potential that customer-owned power generation systems, particularly if coupled with power storage devices, could become sufficiently cost-effective and efficient that an increasing number of Idaho Power's customers choose to install such systems on their homes or businesses. Additionally, considerable emphasis has been placed on energy efficiency, such as LED lighting and high-efficiency appliances. Energy efficiency programs, including programs sponsored by Idaho Power under a directive from state regulatory commissions, are designed to reduce energy demand. If Idaho Power is unable to adjust its rate design or maintain adequate regulatory mechanisms allowing for timely cost recovery, declining usage from customer-owned generation sources and energy efficiency would result in under-recovery of Idaho Power's costs and reduce revenues, which would impact IDACORP's and Idaho Power's financial condition and results of operations.

Capital expenditures for infrastructure, risks associated with construction of that infrastructure, and the timing and availability of cost recovery for the expenditures, can significantly affect IDACORP's and Idaho Power's financial condition and results of operations . Idaho Power’s business is capital intensive and requires significant investments in energy generation, transmission, and distribution infrastructure. A significant portion of Idaho Power’s facilities were constructed many years ago, and thus require periodic upgrades and frequent maintenance. Also, long-term anticipated increases in both the number of customers and the demand for energy require expansion and reinforcement of that infrastructure. For instance, Idaho Power is in the permitting process for two 500-kV transmission line projects, which are intended to help meet future customer energy demands. Construction projects are subject to usual permitting and construction risks that can adversely affect project costs and the completion time. These risks include, as examples:

- the ability to timely obtain labor or materials at reasonable costs, and defaults by contractors;
- equipment, engineering, and design failures;
- the effects of adverse weather conditions;
- availability of financing;
- the ability to obtain and comply with permits and land use rights, and environmental constraints;
- delays and costs associated with disputes and litigation with third parties; and
- changes in applicable laws or regulations.

If Idaho Power is unable to complete the construction of a project, or incurs costs that regulators do not deem prudent, it may be unable to recover its costs in full through rates or on a timely basis. Further, if Idaho Power is unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, seek to develop additional generation facilities within areas where Idaho Power has available transmission capacity or pursue other more costly options to serve loads. To limit the timing-related risks of these projects, Idaho Power may enter into purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals or permits. If any of the projects are canceled for any reason, including Idaho Power's failure to receive necessary regulatory approvals or permits or because the project is no longer economical, Idaho Power could incur significant cancellation penalties under purchase orders or construction contracts. Additionally, termination of a project carries with it the potential for impairment of the associated asset if regulators deny full recovery of project costs. Thus, termination of a project could negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP's and Idaho Power’s businesses are subject to an extensive set of environmental laws, rules, and regulations, which could impact their operations and increase costs of operations, potentially rendering some generating units uneconomical to maintain or operate, and could increase the costs and alter the timing of major projects. A number of federal, state, and local environmental statutes, rules, and regulations relating to air and water quality, natural resources, renewable energy certificates, and health and safety are applicable to IDACORP's and Idaho Power's operations. Many of these laws and regulations are described in Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Matters" in this report. These laws and regulations generally require IDACORP and Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, and other approvals, including through substantial investment in pollution controls, and may be enforced by both public officials and private individuals. Some of these regulations are pending, changing, or subject to interpretation, and failure to comply may result in penalties, mandatory operational changes, and other adverse consequences, including costs associated with defending against claims by governmental authorities or private parties and complying with new operating requirements. Idaho Power devotes significant resources to environmental monitoring, pollution control equipment, and mitigation projects to comply with existing and anticipated environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations.

Environmental regulations have created the need for Idaho Power to install new pollution control equipment at, and may cause Idaho Power to perform environmental remediation on, its owned and co-owned power generation facilities, often at a substantial cost. For instance, Idaho Power is installing environmental control apparatus in two units of its co-owned Jim Bridger power plant at an estimated cost of $105 million, and may install a second set of control apparatus at two other units at that plant in or around 2021 and 2022. IDACORP and Idaho Power will incur other costs associated with existing environmental regulations, and the companies expect to incur additional costs associated with pending and future environmental regulations, and those costs are likely to be substantial. In some cases, the costs to obtain permits and ensure facilities are in compliance may be prohibitively expensive. If the costs of compliance with those new regulations renders the generating facilities uneconomical to maintain or operate, Idaho Power would need to identify alternative resources for power, potentially in the form of new generation and transmission facilities, market power purchases, demand-side management programs, or a combination of these and other methods. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its existing infrastructure or construction of new infrastructure.

Idaho Power is not guaranteed timely or full recovery through customer rates of costs associated with environmental regulations, environmental compliance, and clean-up of contamination, and regulators may not grant prior approval of cost recovery. For example, in 2013 the IPUC declined to approve Idaho Power's application requesting a binding commitment to provide rate base treatment for Idaho Power's estimated share of the capital investment in environmental control upgrades at the Jim Bridger power plant, instead reserving the prudence determination (and thus ratemaking treatment) for subsequent proceedings. 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 generation or transmission facilities could be delayed, halted, or subjected to additional costs.

Factors contributing to lower hydroelectric generation can increase costs and negatively impact IDACORP's and Idaho Power's financial condition and results of operations . Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. During 2015, 47 percent of Idaho Power's electric power generation was from hydroelectric facilities. Because of Idaho Power's heavy reliance on hydroelectric generation, factors such as precipitation and snow pack, the timing of run-off, and the availability of water in the Snake River basin can significantly affect its operations. The combination of a long-term trend 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 approach to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights reduce Snake River flows available for hydroelectric generation. When hydroelectric generation is reduced, Idaho Power must increase its use of more expensive thermal generating resources and market power purchases; therefore, costs increase and opportunities for off-system sales are reduced, reducing revenues and potentially earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most (but not all) of the increase in net power supply costs caused by lower hydroelectric generation. The timing of recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, adversely affecting cash flows and liquidity.

Obligations imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and negatively affect IDACORP's or Idaho Power's results of operations and financial condition . For the last several years, Idaho Power has been engaged in an effort to renew its federal license for 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 existence of endangered and threatened species in the watershed may result in major operational changes to the region's hydroelectric projects, which may be reflected in hydroelectric licenses, including for the Hells Canyon Complex. 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 generation requirements. One particularly significant issue identified in connection with the Hells Canyon Complex relicensing effort involves water temperature gradients in the Snake River below the Hells Canyon dam. Certain parties in the relicensing proceedings have advocated for the installation of a water temperature management apparatus which, if required to be installed, would involve substantial costs to construct, operate, and maintain. Idaho Power may be unable to recover in full or in a timely manner the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, whether a new multi-year license will ultimately be issued, and whether the IPUC or OPUC will allow recovery through rates of the substantial costs incurred in connection with the licensing process and subsequent compliance. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs (including power purchase costs), and reduce hydroelectric generation, which could negatively affect results of operations and financial condition.

Idaho Power's use of coal and natural gas to fuel power generation facilities exposes it to commodity availability and price risk, which can adversely affect IDACORP's and Idaho Power's results of operations and financial condition . As part of its normal business operations, Idaho Power purchases coal and natural gas in the open market or under short-term or long-term contracts, often with variable pricing terms. Market prices for coal and natural gas are influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Natural gas transportation to Idaho Power's three natural gas plants is limited to one primary pipeline, presenting a heightened possibility of supply constraint and disruptions separate from the risk of counterparty default. Most of Idaho Power's coal supply arrangements are under long-term contracts for coal originating in Wyoming, and thus Idaho Power is exposed to risk of disruption of coal production in, or transportation from, that region. Idaho Power may from time to time enter into new, or renegotiate, these long-term contracts but can provide no assurance that such contracts will be negotiated or renegotiated on satisfactory terms, or at all. There also can be no assurance that counterparties to the natural gas or coal supply agreements will fulfill their obligations to supply natural gas or coal, and they may experience financial or technical problems that inhibit their ability to deliver natural gas or coal. Defaults by coal and natural gas suppliers may cause Idaho Power to seek alternative, and potentially more costly, sources of fuel or rely on other generation sources or wholesale market power purchases. Idaho Power may not be able to fully or timely recover these increased costs through rates, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry . Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, accidents and workforce safety matters, release of hazardous or toxic substances into the air, water, or ground, acts of terrorism or sabotage, the loss of cost-effective disposal options for solid waste such as coal ash, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of those facilities could result in reduced customer satisfaction, reputational harm, 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 for alternative fuels or wholesale market power purchases. Accidents, electrical contacts, fires, explosions, catastrophic failures, general system damage or dysfunction, and other unplanned events related to Idaho Power's infrastructure would increase repair costs and may expose Idaho Power to claims for personal injury and property damage. Further, the transmission system in Idaho Power's service territory is constrained, limiting the ability to transmit electric energy within the service territory and access electric energy from outside the service territory during high-load periods. Idaho Power's transmission facilities are also interconnected with those of third parties, and thus operation of Idaho Power's and third parties' facilities could be adversely affected by unexpected or uncontrollable events. These transmission constraints and events could result in failure to provide reliable service to customers and the inability to deliver energy from generating facilities to the power grid, or not being able to access lower cost sources of electric energy, which could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

Volatility in the financial markets, failure of IDACORP or Idaho Power to satisfy conditions necessary for obtaining loans or issuing debt securities, and 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 . IDACORP and Idaho Power use credit facilities, commercial paper markets, and long-term debt as significant sources of liquidity and funding for operating and capital requirements and debt maturities not satisfied by operating cash flow. The credit facilities represent commitments by the participating banks to make loans and issue letters of credit. However, the obligation of the participating banks to make those loans and issue letters of credit is subject to specified conditions. Idaho Power's ability to issue long-term debt is also subject to a number of conditions included in an indenture, and Idaho Power's ability to issue long-term debt and commercial paper is subject to the availability of purchasers willing to purchase the securities under reasonable terms or at all. Because of these limitations, IDACORP and Idaho Power may be unable to issue commercial paper or short-term or long-term debt at reasonable interest rates and terms or at all. Also, while the credit facilities represent a contractual obligation to make loans, one or more of the participating banks may default on their obligations to make loans under, or may withdraw from, the credit facilities.

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, capital expenditures, and debt maturities. Without additional state regulatory approval, as of the date of this report the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. Also, IDACORP's and Idaho Power's credit facilities include financial covenants that limit the amount of debt that can be outstanding as a percentage of total capital, and Idaho Power's long-term debt has also been issued under an indenture that contains a number of financial covenants. Failure to maintain these covenants could preclude IDACORP and Idaho Power from issuing commercial paper, borrowing under their credit facilities, or issuing long-term debt, and could trigger a default and repayment obligation under debt instruments, which could adversely impact IDACORP's and Idaho Power's financial condition, results of operations, and liquidity.

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. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power. These ratings are premised on financial ratios and performance, the regulatory environment and rate mechanisms, the effectiveness of management, resource risks and power supply costs, and other factors. 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 short- and long-term capital under reasonable terms or at all, 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.

Idaho Power's risk management policy and programs relating to economically hedging commodity exposures and credit risk may not always perform as intended, and as a result IDACORP and Idaho Power may suffer economic losses . Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities, and enters into financial hedge transactions to mitigate in part exposure to variable commodity prices. IDACORP and Idaho Power could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. The derivative instruments used for hedging might not offset the underlying exposure being mitigated as intended, due to pricing inefficiencies or other terms of the derivative instruments, and any such failure to mitigate exposure could result in financial losses. Certain of Idaho Power's hedging and derivative agreements may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in Idaho Power's credit ratings may lead to additional collateral posting requirements. Further, forecasts of future fuel needs and 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. To the extent that commodity markets are illiquid, Idaho Power may not be able to execute its risk management strategies, which could result in undesired over-exposure to unhedged positions. As a result, risk management actions, or the failure or inability to manage commodity price and counterparty risk, may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power could be subject to penalties and operational changes if it violates mandatory reliability and security requirements, which could adversely impact IDACORP's and Idaho Power's results of operations and financial condition. 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 FERC. 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. Idaho Power has received in recent years notices of violations from, and regularly self-reports reliability standard compliance issues to, the FERC, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council. Potential monetary and non-monetary penalties for a violation of FERC 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 for its actual or alleged failure to comply with reliability and security requirements could have a negative effect on its and IDACORP's results of operations and financial condition.

Federally mandated purchases of power from renewable energy projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect Idaho Power's and IDACORP's results of operations and financial condition. An abundance of intermittent, non-dispatchable generation from renewable energy projects interconnected with Idaho Power's system has had an impact on the operation of Idaho Power's generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Idaho Power is generally obligated under federal law to purchase power from certain renewable energy projects, regardless of the then-current load demand, availability of lower cost generation resources, or wholesale energy market prices. This 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, which in turn increases power purchase costs and customer rates. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its operational costs will continue to increase as a result of its efforts to integrate intermittent, non-dispatchable generation from a large number of renewable energy projects. If Idaho Power is unable to timely recover those costs through its power cost adjustment mechanisms or otherwise, those increased costs may negatively affect IDACORP's and Idaho Power's results of operations, financial condition, and cash flows.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs and funding obligations could adversely affect IDACORP's and Idaho Power's financial condition and results of operations - primarily 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 plan costs and 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 inherently uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including timing of retirements or changes in life expectancy assumptions, may also increase Idaho Power's plan costs and funding requirements. Future pension funding requirements and the timing of funding payments are also subject to the impacts of changes in legislation. Depending on the timing of contributions to the plans and Idaho Power's ability to recover costs through rates, cash contributions to the plans could reduce the cash available for the companies' businesses and payment of dividends. 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.

As a holding company, IDACORP does not have its own operating income and must rely on the 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. 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 means. The ability of IDACORP's subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiary's 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 may reduce or cease payment of dividends at any time. See Note 6 - "Common Stock" to the consolidated financial statements included in this report for a further description of restrictions on IDACORP's and Idaho Power's payment of dividends.

IDACORP's and Idaho Power's activities are concentrated in one industry and in one region, which exposes it to risks from lack of diversification, regional economic conditions, and regional legislation and regulation. IDACORP and Idaho Power do not have diversified operations or sources of revenue. Idaho Power comprises the bulk of IDACORP's operations, and Idaho Power's business is concentrated solely in the electricity industry. Furthermore, Idaho Power's provision of electric service to retail customers is conducted exclusively in its southern Idaho and eastern Oregon service area. As a result, IDACORP's and Idaho Power's future performance will be affected by economic conditions, regulatory and legislative activity, and other events in its service area and in the electric power industry.

The impacts of a retiring workforce with specialized utility-specific functions could increase costs and adversely affect IDACORP's and Idaho Power's financial condition and results of operations . Idaho Power's operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, and generation plant operators, require extensive, specialized training. Idaho Power has experienced in recent years an above-average number of employee retirements and expects the increased level of retirement of its skilled workforce and persons in key positions will continue in 2016 and in the near-term. This will require Idaho Power to attract, train, and retain new employees to help prevent a loss of institutional knowledge and avoid a skills gap. The loss of skills and institutional knowledge of experienced employees and the costs associated with attracting, training, and retaining appropriately qualified employees to replace an aging and skilled workforce could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims . From time to time in the normal course of business IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other adverse consequences. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. Two notable existing legal proceedings are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have a negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their operational practices and procedures, which could also have a negative effect on their financial positions and results of operations.

Acts or threats of terrorism, cyber attacks, data or physical security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations or the electric power grid could negatively impact IDACORP's and Idaho Power's financial condition and results of operations . Idaho Power operates in an industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. Idaho Power's generation and transmission facilities and its grid operations 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, and public health and safety. 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. These events, and governmental actions in response, could result in a material decrease in revenues and increase costs to protect, repair, and insure Idaho Power's assets and operate its business.

Federal regulators have stated that a number of organizations continue to seek opportunities to exploit potential vulnerabilities in the U.S. energy infrastructure and that those attacks have become increasingly sophisticated. Attacks on Idaho Power's infrastructure could result from acts of those organizations or other third parties as well as Idaho Power employees or contractors. At the same time, Idaho Power's energy infrastructure is becoming more reliant on network-based infrastructure. Idaho Power's operations require the continuous availability of information technology systems and network infrastructure, and in the normal course of business Idaho Power collects sensitive and confidential customer and employee information and proprietary information of Idaho Power. Although Idaho Power actively monitors developments in cyber security, no security measures can completely shield Idaho Power's systems, infrastructure, and data from vulnerabilities to cyber attacks, intrusions, or other catastrophic events that could result in their failure or reduced functionality, and ultimately the potential loss of sensitive information or the loss of Idaho Power's ability to fulfill critical business functions and provide reliable electric power to customers. The loss of data could result in violations of privacy and other laws, financial loss to Idaho Power or to its customers, customer dissatisfaction, and significant litigation exposure, all of which could materially affect Idaho Power's financial condition and results of operations.

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 and results of operations . IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. In recent years, tax settlements, as well as state regulatory mechanisms with tax-related provisions (such as Idaho Power's October 2014 regulatory settlement stipulation with the IPUC), has significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of ongoing and future income tax proceedings, or the state public utility commissions' treatment of those tax outcomes, could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could negatively affect 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, which could have a negative effect on their financial condition and results of operations.

Changes in accounting standards or rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board and the Securities and Exchange Commission may make changes to accounting standards that impact presentation and disclosures of financial condition and results of operations. Further, new accounting orders issued by the FERC could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles to reflect the impact of regulatory decisions in its financial statements and to defer certain costs as regulatory assets until those costs are collected in rates, and to defer some items as regulatory liabilities. If recovery of these amounts ceases to be probable, 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 could be required to eliminate some or all of those regulatory assets or liabilities. Any of these circumstances could result in write-offs and have a material effect on IDACORP's and Idaho Power’s financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power's properties consist of the physical assets necessary to support its utility operations, which include generation, transmission, and distribution facilities, as well as coal assets that support one of its coal-fired generation plants. In addition to these physical assets, Idaho Power has rights-of-way and water rights that enable it to use its facilities. Idaho Power’s system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, three natural gas-fired plants in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. As of December 31, 2015 , the system also includes approximately 4,860 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 224 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,092 pole-miles of distribution lines.

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Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power's hydroelectric projects is discussed in Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects." Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are included in the table below.

Project	Nameplate Capacity (kW) [1]	License Expiration
Hydroelectric Projects:		
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 (Hells Canyon Complex)	1,166,900	2005 [2]
Swan Falls	27,170	2042
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) [3]	770,501	
North Valmy (coal-fired) [3]	283,500	
Boardman (coal-fired) [3][4]	64,200	
Danskin (gas-fired)	270,900	
Langley Gulch (gas-fired)	318,452	
Bennett Mountain (gas-fired)	172,800	
Salmon (diesel-internal combustion)	5,000	
Total Steam and Other	1,885,353	
Total Generation	3,594,398	

(1) Actual generation capacity from a facility may be greater or less than the rated nameplate generation capacity.
(2) Licensed on an annual basis while the application for a new multi-year license is pending.
(3) 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.
(4) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations by December 31, 2020.

IDACORP's and Idaho Power's headquarters are located in Boise, Idaho. The corporate headquarters campus is comprised of approximately 306,000 square feet of owned office space. Excluding Idaho Power's power generation facilities and substations, Idaho Power owns an additional 907,000 square feet of office, warehouse, and industrial space to support its operations in Idaho and Oregon.

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. Substantially all of Idaho Power's property is subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. Idaho Power's property is subject to minor defects common to properties of such size and character that it believes 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.

Through Idaho Energy Resources Co., Idaho Power 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 hydroelectric plants that have 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 the 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 12, 2016, there were 10,448 holders of record of IDACORP common stock and the closing stock price was $69.59 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.

IDACORP and Idaho Power paid dividends of $ 97 million , $89 million , and $79 million in 2015 , 2014 , and 2013 , respectively.
The amount and timing of dividends paid on IDACORP’s common stock are within the discretion of IDACORP’s board of directors, subject to other restrictions. 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. The IDACORP board of directors has 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. IDACORP's 2015 calendar year payout ratio was 50 percent. Notwithstanding the dividend policy adopted by IDACORP's 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.

IDACORP's and Idaho Power's payment of dividends is subject to a number of restrictions. For information relating to those restrictions, 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 2015 and 2014 as reported by the NYSE:

	2015			2014		
Quarter	High	Low	Dividends paid per share	High	Low	Dividends paid per share
1st	$ 70.48	$ 59.21	$ 0.47	$ 56.65	$ 50.21	$ 0.43
2nd	64.22	55.40	0.47	57.86	52.91	0.43
3rd	64.94	55.96	0.47	58.79	51.70	0.43
4th	70.33	63.38	0.51	70.05	53.39	0.47

IDACORP did not repurchase any shares of its common stock during the fourth quarter of 2015.

Performance Graph

The graph below 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, 2010, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.

EXHIBIT IV

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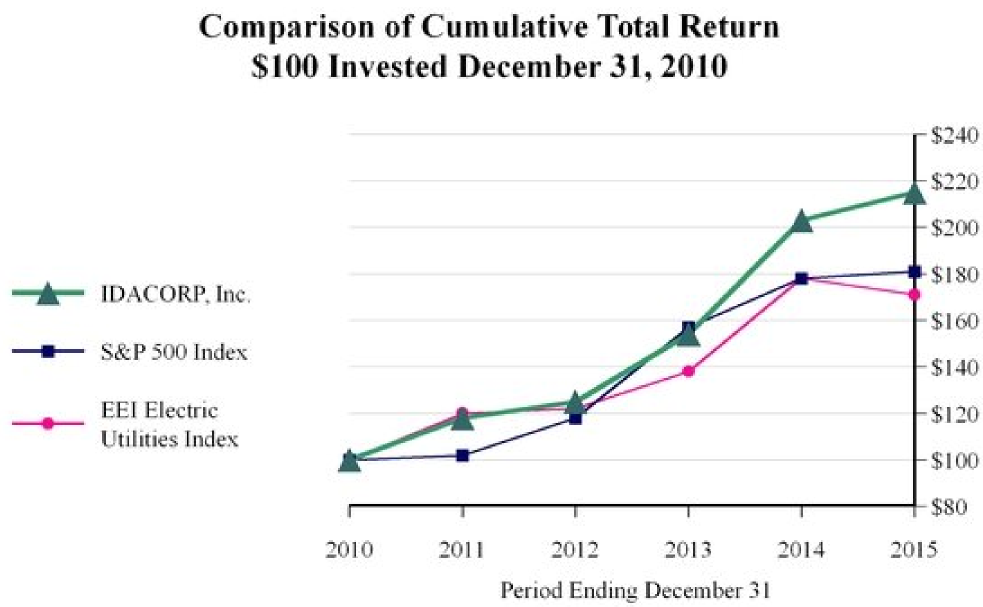

Source: Bloomberg and EEI

	2010	2011	2012	2013	2014	2015
IDACORP	$ 100.00	$ 118.25	$ 124.96	$ 154.34	$ 203.17	$ 215.24
S&P 500	100.00	102.08	118.39	156.70	178.10	180.56
EEI Electric Utilities Index	100.00	119.99	122.49	138.42	178.44	171.48

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 shall 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.

EXHIBIT IV

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ITEM 6. SELECTED FINANCIAL DATA

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

	2015	2014	2013	2012	2011
Operating revenues	$ 1,270,289	$ 1,282,524	$ 1,246,214	$ 1,080,662	$ 1,026,756
Operating income	282,097	253,696	291,742	242,602	155,352
Net income attributable to IDACORP, Inc.	194,679	193,480	182,417	173,014	169,981
Diluted earnings per share	3.87	3.85	3.64	3.46	3.43
Dividends declared per share	1.92	1.76	1.57	1.37	1.20
Financial Condition:					
Total assets [1]	$ 6,023,314	$ 5,701,037	$ 5,347,380	$ 5,274,147	$ 4,908,326
Long-term debt (including current portion) [1]	$ 1,726,474	$ 1,599,686	$ 1,599,139	$ 1,520,553	$ 1,471,621
Financial Statistics:					
Times interest charges earned:					
Before tax [2]	3.61	3.38	3.87	3.41	2.48
After tax [3]	3.12	3.19	3.06	3.02	3.00
Book value per share [4]	$ 40.88	$ 38.85	$ 36.84	$ 34.73	$ 32.76
Market-to-book ratio [5]	166%	170%	141%	125%	129%
Payout ratio [6]	50%	46%	43%	40%	35%
Return on year-end common equity [7]	9.5%	9.9%	9.9%	9.9%	10.4%

(1) Adjusted to reflect the adoption of ASU 2015-03. See Note 1 to the consolidated financial statements included in this report.

The financial statistics listed above are calculated in the following manner:

(2) 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.

(3) 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.

(4) Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

(5) 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 (4) above.

(6) Dividends paid per common share divided by diluted earnings per share.

(7) Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

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

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report, 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. Also refer to "Cautionary Note Regarding Forward-Looking Statements" and Part I - Item 1A - "Risk Factors" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report.

In the MD&A, MWh and dollar amounts in tables, other than earnings per share, are in thousands unless otherwise indicated.

INTRODUCTION

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 whose rates and other matters are regulated by the Idaho Public Utility Commission (IPUC), Public Utility Commission of Oregon (OPUC), and Federal Energy Regulatory Commission (FERC). 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 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. Idaho Power's rates are established through regulatory proceedings that affect its ability to recover its costs and the potential to earn a return on its investment.

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, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co., which is the former limited partner of, and successor by merger to, IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003.

EXECUTIVE OVERVIEW

Management's Outlook

Idaho Power continues to see positive growth in its customer count and associated positive impacts on Idaho Power's revenue. To encourage responsible and sustainable growth, and as part of its planning for the future, Idaho Power actively participates in and supports state and local economic development initiatives. At the same time that Idaho Power pursues customer growth, it must also plan for that growth. Idaho Power's recently completed 2015 Integrated Resource Plan (IRP) assumed growth in customers for the next 20 years and seeks to plan for the infrastructure that will support the anticipated growth and allow Idaho Power to continue to provide reliable, fair-priced electric power to its customers. To that end, Idaho Power's noteworthy capital projects include the replacement of aging assets, upgrades to generation plants, a multi-year plan for replacement of underground conductor, ongoing system upgrades, and continued progress on permitting the Boardman-to-Hemingway and Gateway West 500-kV transmission lines. As of the date of this report, Idaho Power estimates total capital expenditures of nearly $1.5 billion over the next five years.

Idaho Power operates within what it believes to be a constructive regulatory framework, achieved through general rate cases, subject-specific rate filings, tariff riders, and cost recovery mechanisms that share risks and benefits with Idaho Power's customers. To further complement these efforts, Idaho Power has also been focusing on controlling power supply, operating, maintenance, and capital costs through process review and improvement initiatives, and by empowering employees to identify new means to reduce costs, increase efficiencies, and enhance individual and enterprise performance for the benefit of IDACORP's shareholders, Idaho Power's customers, and other stakeholders. As Idaho Power's base rates were most recently reset in a general rate case in 2012, during 2016 Idaho Power plans to evaluate the desirability of filing an application for a general rate change in Idaho or Oregon.

Separately, during 2015 IDACORP continued to make meaningful progress toward its target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, which expanded on the progress made in prior years. From 2012 through

2015, IDACORP's board of directors approved a collective 70 percent increase in the quarterly dividend, from $0.30 to $0.51 per share.

2015 Accomplishments and 2016 Initiatives

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. For the past several years, Idaho Power has been executing its 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 IDACORP's and Idaho Power's achievements and recognitions during 2015 under its three-part business strategy include:

- achieved net income growth for an eighth consecutive year;
- increased IDACORP's quarterly common stock dividend from $0.47 per share to $0.51 per share;
- executed on business optimization initiatives, focusing on improving operations and controlling expenditures;
- made continued progress toward the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects;
- achieved its goal to reduce average CO_2 emissions intensity by 10 to 15 percent below 2005 emissions for the period from 2010 through 2015;
- achieved the highest rolling 12-month customer relationship index score (Idaho Power's internal measure of customer satisfaction) ever recorded by the company; and
- improved Idaho Power's ranking from 17 to 11 in the annual "40 Best Energy Companies" list published by *Public Utilities Fortnightly* .

For 2016, in addition to its specific infrastructure and regulatory projects noted above, IDACORP and Idaho Power have established a number of organizational initiatives, including the following:

- make progress on three core focuses for 2016—improving Idaho Power's core business, growing revenues, and enhancing the brand and positioning the company for the future;
- continue to enhance and promote Idaho Power's safety culture;
- grow financial strength by supporting business development in our service territory while actively managing costs;
- continue progress toward IDACORP's target dividend payout ratio;
- pursue responsible investments that address customer growth while improving reliability, enhancing Idaho Power customers' experience, increasing shareholder value, and managing carbon impacts; and
- integrate new renewable generation resources into Idaho Power's grid and explore intra-hour market opportunities to help achieve greater reliability and improve system dispatch.

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 a number of factors, and the impact of those factors is discussed in more detail later in this MD&A. To provide context for the discussion elsewhere in this report, some of the more notable factors include the following:

- ***Regulation of Rates and Cost Recovery:*** The price that Idaho Power is authorized to charge for its electric and transmission service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Those rates are established by state regulatory commissions and the FERC, and are intended to allow Idaho Power an opportunity to recover its expenses and earn a reasonable return on investment. Because of the significant impact of ratemaking decisions, and in furtherance of its goal of advancing a purposeful regulatory strategy, Idaho Power has focused on timely recovery of its costs through filings with the company's regulators, working to put in place innovative regulatory mechanisms, and on the prudent management of expenses and investments. Idaho Power has a regulatory settlement stipulation in Idaho that remains in effect during 2016. That stipulation includes provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent return on year-end equity in the Idaho jurisdiction (Idaho ROE). Also during 2016, Idaho Power will continue to assess its need to file a general rate case to reset base rates.

- ***Rate Base Growth and Infrastructure Investment:*** As noted above, the rates established by the IPUC and OPUC are determined so as to provide an opportunity for Idaho Power to recover authorized operating expenses and earn a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items.

Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the IPUC and OPUC. In recent years, Idaho Power has been pursuing significant enhancements to its utility infrastructure, including major ongoing transmission projects such as the Boardman-to-Hemingway and Gateway West projects, in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and component replacement, and the company is undertaking a significant relicensing effort for the Hells Canyon Complex (HCC), its largest hydroelectric generation resource. Idaho Power expects to include completed capital projects in its next general rate case or, in circumstances where appropriate, a single-issue rate case for individual projects with a significant capital cost. Depending on the outcome of the regulatory process and items such as the rate of return authorized by the IPUC and OPUC, this growth in rate base has the potential to increase Idaho Power's revenues and earnings.

- ***Economic Conditions:*** Economic conditions impact consumer demand for electricity and revenues, collectability of accounts, the volume of off-system sales, and the need to construct and improve infrastructure, purchase power, and implement programs to meet customer load demands. In recent years, Idaho Power has seen growth in the number of customers in its service area—in 2015 its customer count grew by 1.8 percent, and employment in Idaho Power's service area grew by approximately 4.9 percent in 2015 based on Idaho Department of Labor preliminary December 2015 data. Idaho Power expects that the number of customers will continue to increase in the foreseeable future. To help encourage growth, Idaho Power has in recent years undertaken efforts to promote economic development and attract industrial and commercial customers to its service area.

- ***Weather Conditions:*** Weather and agricultural growing conditions have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy use for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters, irrigation customers use electricity to operate irrigation pumps, and weather conditions can impact the timing and degree of use of those pumps. Idaho Power also has tiered rates and seasonal rates, which contribute to increased revenues during higher-load periods, most notably during the third quarter of each year when overall customer demand is highest. Further, as Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity, precipitation levels impact the mix of Idaho Power's generation resources. When hydroelectric generation is reduced, Idaho Power must rely on more expensive generation sources and purchased power. When favorable hydroelectric generating conditions exist for Idaho Power, they also may exist for other Pacific Northwest hydroelectric facility operators, lowering regional wholesale market prices and impacting the revenue Idaho Power receives from off-system sales of its excess power. Much of the adverse or favorable impact of this volatility is addressed through the Idaho and Oregon power cost adjustment (PCA) mechanisms.

- ***Mitigation of Impact of Fuel and Purchased Power Expense:*** In addition to hydroelectric generation, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities and power purchases in the wholesale markets. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's generation capacity, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. Recently, low natural gas prices have made operation of Idaho Power's natural gas power plants more economical, resulting in increased operation of those plants and lessened operation of coal-fired plants. 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 or solar energy, and wholesale energy market prices. Idaho Power is required by law to purchase power from some 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 at times 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, which results in increased customer rates. The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power, including all of the Idaho-jurisdiction PURPA power purchase costs.

- ***Regulatory and Environmental Compliance Costs:*** Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits by agencies and quasi-governmental agencies, including the FERC and the North American Electric Reliability Corporation. Compliance with these requirements directly influences Idaho Power's operating environment and affects Idaho Power's operating costs. Environmental laws and regulations, in particular, may increase the cost of operating generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power cease operating certain generation plants. For instance, the Boardman coal-fired power plant, in which Idaho

Power owns a 10-percent interest, is scheduled to cease coal-fired operations by the end of 2020, a decision driven in large part by the substantial cost of environmental controls required by existing regulations. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade.

- ***Water Management and Relicensing of the Hells Canyon Hydroelectric Project (HCC):*** Because of Idaho Power's reliance on stream flow 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 its hydroelectric projects. Also, Idaho Power is involved in renewing its long-term federal license for the HCC, its largest hydroelectric generation source. Given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial. Idaho Power cannot currently determine the terms of, and costs associated with, any resulting long-term license.

Summary of 2015 Financial Results

The following is a summary of Idaho Power's net income, net income attributable to IDACORP, and IDACORP's earnings per diluted share for the years ended December 31, 2015 , 2014 , and 2013 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2015	**2014**	**2013**
Idaho Power net income	$ 190,983	$ 189,387	$ 176,741
Net income attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Average outstanding shares – diluted (000's)	50,292	50,199	50,126
IDACORP, Inc. earnings per diluted share	$ 3.87	$ 3.85	$ 3.64

The table below provides a reconciliation of net income attributable to IDACORP, Inc. for year ended December 31, 2015 to the year ended December 31, 2014 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2014		**$ 193.5**
Change in Idaho Power net income:		
Customer growth, net of associated power supply costs	10.3	
Usage per customer, net of associated power supply costs	(6.7)	
Change in FCA revenues due to sales volumes and mechanism change	12.7	
Depreciation expense and property taxes	(6.2)	
Rent from electric property, wheeling and other revenue	3.0	
Other operating and maintenance expenses	(4.2)	
Change in Idaho Power operating income prior to sharing mechanisms	8.9	
Change in operating income as a result of sharing mechanisms	21.5	
Change in Idaho Power operating income	30.4	
Non-operating income and expenses	(0.4)	
Change in income tax benefit related to first mortgage bond redemption costs	7.2	
Change in income tax expense due to cumulative impact of tax method change recorded in 2014	(24.5)	
Other change in income tax expense	(11.1)	
Total increase in Idaho Power net income		1.6
Other changes (net of tax)		(0.4)
Net income attributable to IDACORP, Inc. - December 31, 2015		**$ 194.7**

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IDACORP's 2015 net income was nearly equivalent to its 2014 net income. However, there were several notable differences in the drivers of each year's results. Idaho Power's operating income, excluding the impact of the sharing mechanisms under Idaho regulatory settlement stipulations, increased $8.9 million for 2015 compared with 2014. Increased sales volumes associated with continued growth in the number of Idaho Power customers increased operating income by $10.3 million, though this was partially offset by a $6.7 million decrease from reduced overall usage per customer. Increases in depreciation and property taxes, and other operating and maintenance expenses (which include labor-related expenses), combined to decrease operating income by $10.4 million in 2015 when compared with 2014. Modifications were made to Idaho Power's FCA mechanism for 2015 to track fluctuations in residential and small commercial sales associated with actual weather conditions, as opposed to normalized weather conditions under the 2014 FCA mechanism. The FCA mechanism modification, combined with lower sales per customer, provided a $12.7 million benefit to operating income in 2015 compared with 2014.

Additionally, two income tax matters had a significant impact on the comparative results. Income taxes in 2015 reflect a $7.2 million flow-through impact of a tax deductible make-whole premium Idaho Power paid upon early redemption of long-term debt during 2015. Income tax expense in 2014 included a $24.5 million benefit from the cumulative effect of a tax method change made in that year.

Further, during 2015 Idaho Power recorded a total of $3.2 million as a provision against current revenue related to an October 2014 Idaho regulatory settlement stipulation that requires sharing with Idaho customers of a portion of 2015 earnings when Idaho Power's Idaho ROE exceeds 10.0 percent. By contrast, during 2014 under a prior, yet similar, Idaho regulatory settlement stipulation, Idaho Power recorded $24.7 million for sharing with Idaho customers. Of that amount, $16.7 million was recorded as additional pension expense and $8.0 million was recorded as a provision against current revenues to be refunded to customers through a future rate reduction. From 2011 to 2015, Idaho Power has shared over $120 million with customers through settlement stipulations.

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. In this analysis, the results for 2015 are compared with 2014 and the results for 2014 are compared with 2013 .

Utility Operations

The table below presents Idaho Power’s energy sales and supply (in thousands of MWh) for the last three years.

	Year Ended December 31,		
	2015	**2014**	**2013**
General business sales	14,265	14,092	14,619
Off-system sales	1,254	2,220	1,683
Total energy sales	15,519	16,312	16,302
Hydroelectric generation	5,910	6,170	5,656
Coal generation	4,676	5,851	6,327
Natural gas and other generation	2,076	1,175	1,576
Total system generation	12,662	13,196	13,559
Purchased power	3,792	4,153	3,902
Line losses	(935)	(1,037)	(1,159)
Total energy supply	15,519	16,312	16,302

Sales Volume and Generation : In 2015 , general business sales volume increased by 1 percent compared with the prior year, as the positive sales volume impact of customer growth exceeded reduced usage from moderate weather and energy efficiency measures. Off-system sales volume decreased by 44 percent in 2015 as decreases in output from hydroelectric generation resources reduced the amount of surplus power available for off-system sales. Also, more favorable wholesale market conditions in 2014 provided more opportunities for Idaho Power to operate its non-hydroelectric generation facilities for off-system sales during 2014 than in 2015.

Generation from Idaho Power's hydroelectric plants declined 4 percent in 2015 compared with 2014 due largely to below-average stream flows. The below-average hydroelectric generation during 2013 through 2015 resulted from relatively low snow pack and spring season run-off during the three-year period. At Idaho Power's thermal plants, coal-fired generation

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decreased while natural gas-fired generation increased, as low natural gas prices made natural gas-fired plants more economical to run in 2015 than in 2014.

The financial impacts of fluctuations in off-system sales, purchased power, fuel expense, and other power supply-related expenses are mitigated by the Idaho and Oregon PCA mechanisms, as further discussed later in this report.

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

	Year Ended December 31,		
	2015	2014	2013
Revenue			
Residential	$ 512,068	$ 500,195	$ 513,914
Commercial	306,178	299,462	281,009
Industrial	182,254	182,675	165,941
Irrigation	164,403	158,654	159,242
Total	1,164,903	1,140,986	1,120,106
Provision for sharing	(3,159)	(7,999)	(7,602)
Deferred revenue related to HCC relicensing AFUDC [1]	(10,706)	(10,706)	(10,776)
Total general business revenues	$ 1,151,038	$ 1,122,281	$ 1,101,728
Volume of Sales (MWh)			
Residential	4,977	4,965	5,365
Commercial	4,045	3,944	3,975
Industrial	3,196	3,217	3,182
Irrigation	2,047	1,966	2,097
Total MWh sales	14,265	14,092	14,619
Number of customers at year-end			
Residential	436,102	428,294	422,188
Commercial	68,352	67,522	66,734
Industrial	118	121	115
Irrigation	20,293	19,826	19,398
Total customers	524,865	515,763	508,435

[1] Idaho Power is collecting approximately $10.7 million annually in the Idaho jurisdiction for AFUDC on HCC construction work in progress, but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs are placed in service.

Changes in rates, changes in customer demand, and changes in FCA revenues are typically the primary causes of fluctuations in general business revenue from period to period. See "Regulatory Matters" in this MD&A for a list of rate changes implemented over the last three years. The primary influences on changes in customer demand for electricity are weather, economic conditions, and energy efficiency. Extreme temperatures increase sales to customers who use electricity for cooling and heating, while moderate temperatures decrease sales. Precipitation levels and the timing of precipitation during the agricultural growing season also affect sales to customers who use electricity to operate irrigation pumps. For purposes of illustration and comparison, Boise, Idaho weather-related information for the last three years is presented in the table that follows.

	Year Ended December 31,			
	2015	2014	2013	Normal
Heating degree-days [1]	4,694	4,976	6,032	5,556
Cooling degree-days [1]	1,280	1,129	1,320	942

[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. While Boise, Idaho weather conditions are not necessarily representative of weather conditions throughout Idaho Power's service area, the greater Boise area has the majority of Idaho Power's customers.

Idaho Power's rate structure provides for higher rates during the summer when system loads are at their highest, and includes tiers such that rates increase as a customer's consumption level increases. These seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings.

General Business Revenues - 2015 Compared with 2014 : General business revenue increased $28.8 million in 2015 compared with 2014. The factors affecting general business revenues included the following:

- Rates . Two rate changes impacted general business revenue—an Idaho PCA rate increase effective June 1, 2014, and an Idaho PCA rate decrease effective June 1, 2015, both described in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. Overall, rate changes combined to decrease general business revenue by $2.2 million in 2015.

- Usage . Lower usage per customer in 2015, primarily driven by the impact of more moderate winter weather on residential customer usage, as well as energy efficiency, decreased general business revenue by $0.7 million. Residential usage per customer was 1.4 percent lower in 2015.

- Customers . Customer growth increased general business revenue by $14.1 million. Customer growth from 2014 to 2015 was 1.8 percent.

- Sharing . General business revenue was impacted by Idaho Power's revenue sharing mechanism. This mechanism is associated with Idaho regulatory settlement agreements that provide for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. The impact of this mechanism is partially recorded as a reduction to general business revenue. Reductions of $3.2 million and $8.0 million were recorded in 2015 and 2014, respectively, resulting in a net increase to general business revenue of $4.8 million in 2015.

- FCA Revenue . FCA mechanism revenues increased $12.7 million compared with 2014, including the impacts of weather and of modifications made to the mechanism by the IPUC effective January 1, 2015. The modifications to the FCA mechanism are described in more detail in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

General Business Revenues - 2014 Compared with 2013 : General business revenue increased $20.6 million in 2014 compared with 2013. The factors affecting general business revenues included the following:

- Rates . Rate changes, primarily associated with increased power supply costs, combined to increase general business revenue by $64.8 million. The revenue impact of the rate changes was partially offset by associated changes in operating expenses—Idaho PCA amortization expense increased $42.8 million in 2014 due to the change in the corresponding Idaho PCA true-up rates.

- Usage . Lower usage per customer, primarily driven by the impact of more moderate weather during 2014 on residential customer usage, as well as energy efficiency, decreased general business revenue by $55.7 million. Residential usage per customer was 9.1 percent lower in 2014.

- Customers . Continued customer growth partially offset the decrease in overall MWh sales, increasing revenue by $11.9 million. Customer growth from 2013 to 2014 was 1.4 percent.

- Sharing . The overall increase in general business revenue was impacted by Idaho Power's revenue sharing mechanism. This mechanism, which was in place for 2012 through 2014, is associated with the December 2011 Idaho regulatory settlement agreement that provides for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. The impact of this mechanism is partially recorded as a reduction to general business revenue. Reductions of $8.0 million and $7.6 million were recorded in 2014 and 2013, respectively, resulting in a net decrease to general business revenue of $0.4 million in 2014.

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

	Year Ended December 31,		
	2015	**2014**	**2013**
Revenue	$ 30,887	$ 77,165	$ 54,473
MWh sold	1,254	2,220	1,683
Revenue per MWh	$ 24.63	$ 34.76	$ 32.37

Off-System Sales - 2015 Compared with 2014 : Off-system sales revenue decreased by $46.3 million , or 60 percent , in 2015. Off-system sales volumes decreased 44 percent, as 2014 sales benefited from more favorable market conditions, at times, for selling power off-system. The average price of off-system sales transactions in 2015 was 29 percent lower than 2014, indicative of generally lower market prices in 2015. Decreases in output from hydroelectric resources and an increase in overall load due to customer growth also reduced the amount of surplus power available for sale off-system during 2015.

Off-System Sales - 2014 Compared with 2013 : Off-system sales revenue increased by $22.7 million , or 42 percent , in 2014 as a result of favorable market conditions, at times, for selling power off-system. Off-system sales volumes also benefitted from greater amounts of surplus system energy resulting from slightly lower system loads and increased hydroelectric generation and PURPA power purchases.

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

	Year Ended December 31,		
	2015	**2014**	**2013**
Transmission services and other	$ 55,048	$ 52,051	$ 51,260
Energy efficiency	30,532	27,154	35,637
Total other revenues	$ 85,580	$ 79,205	$ 86,897

Other Revenues - 2015 Compared with 2014 : Other revenues increased $6.4 million , or 8 percent, in 2015. The increases in 2015 were primarily the result of increased electricity transmission (wheeling) volumes and greater customer participation in energy efficiency programs. Most energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings.

Other Revenues - 2014 Compared with 2013 : Other revenues decreased $7.7 million in 2014, resulting primarily from an order issued by the IPUC in the prior year that allowed Idaho Power to recover custom efficiency program incentive payments made between January 1, 2011 and June 1, 2013, through the energy efficiency rider. Based on the order, $14.3 million of other revenue (as well as energy efficiency program expense) was recognized in the second quarter of 2013. Partially offsetting the impact of this order from the IPUC was higher utilization of energy efficiency programs when compared with 2013.

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

	Year Ended December 31,		
	2015	2014	2013
Expense			
PURPA contracts	$ 131,340	$ 144,617	$ 131,338
Other purchased power (including wheeling)	88,430	92,071	85,038
Demand response incentive payments	6,701	7,940	4,203
Total purchased power expense	$ 226,471	$ 244,628	$ 220,579
MWh purchased			
PURPA contracts	2,008	2,286	2,127
Other purchased power	1,784	1,867	1,775
Total MWh purchased	3,792	4,153	3,902
Cost per MWh from PURPA contracts	$ 65.41	$ 63.26	$ 61.75
Cost per MWh from other purchased power	$ 49.57	$ 49.31	$ 47.91
Weighted average - all sources (excluding demand response incentive payments)	$ 57.96	$ 56.99	$ 55.45

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase more power during heavy load periods than during light load periods, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Market energy prices are typically higher during heavy load periods than during 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 transaction prices. Most of the non-PURPA purchased power and substantially all of the PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms.

Purchased Power - 2015 Compared with 2014 : Purchased power expense decreased $18.2 million , or 7 percent , in 2015. The decrease was due primarily to reduced volumes purchased from both PURPA and non-PURPA sources. Volume decreases were partially offset by increases in average prices.

Purchased Power - 2014 Compared with 2013 : Purchased power expense increased $24.0 million, or 11 percent, in 2014, mostly resulting from an increase in generation provided by PURPA wind contracts when compared with 2013. In addition, wholesale gas and electricity market conditions warranted third-party power purchases to serve system load at times rather than dispatching Idaho Power-owned thermal resources. Finally, the increases in demand response program incentive payments primarily relate to the temporary cessation of some of these programs during 2013, which were reinstated for 2014.

Fuel Expense **:** The table below presents Idaho Power's fuel expenses and thermal generation for the last three years.

	Year Ended December 31,		
	2015	2014	2013
Expense			
Coal [(1)]	$ 131,286	$ 156,172	$ 160,277
Natural gas and other thermal	54,945	45,069	54,205
Total fuel expense	$ 186,231	$ 201,241	$ 214,482
MWh generated			
Coal [(1)]	4,676	5,851	6,327
Natural gas and other thermal	2,076	1,175	1,576
Total MWh generated	6,752	7,026	7,903
Cost per MWh - Coal	$ 28.08	$ 26.69	$ 25.33
Cost per MWh - Natural gas and other thermal	26.47	38.36	34.39
Weighted average, all sources	$ 27.58	$ 28.64	$ 27.14

(1) 2015 excludes 147 MWh of generation from the Jim Bridger power plant for which costs were capitalized during feasibility testing of capital projects under contemplation.

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 periods.

Fuel Expense - 2015 Compared with 2014 : In 2015, fuel expense decreased $15.0 million , or 7 percent , compared with 2014 , due principally to decreased output from coal-fired steam plants during 2015 combined with lower regional natural gas prices for fuel used at the natural gas-fired steam plants. Overall generation decreased 4 percent due to lower system loads and lower wholesale energy prices. The expense per MWh for natural gas decreased approximately 30 percent in 2015 compared to 2014. These lower natural gas prices led to a shift of generation from coal-fired steam plants to natural gas-fired steam plants.

Fuel Expense - 2014 Compared with 2013 : In 2014, fuel expense decreased $13.2 million, or 6 percent, compared with 2013, due principally to decreased output from the natural gas-fired steam plants during 2014, resulting from lower system load demands and increased generation provided by facilities under PURPA contracts. The coal-fired steam plants were also operated less in 2014 when compared with 2013, as higher hydroelectric generation enabled lower utilization of the coal-fired steam plants to serve system load requirements. Partially offsetting these decreases were higher commodity costs when compared with 2013.

PCA Mechanisms **:** Idaho Power's power supply costs (primarily purchased power and fuel, less off-system sales) can vary significantly from year to year. Volatility of power supply costs arises from factors such as weather conditions, wholesale market prices and volumes of power purchased and sold in the wholesale markets, Idaho Power's hydroelectric and thermal generation volumes and fuel costs, generation plant availability, and retail loads. To address the volatility of power supply costs, Idaho Power's PCA mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. In the Idaho jurisdiction, the PCA includes a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and the company (5 percent), with the exception of PURPA power purchases and demand-response program incentives, which are allocated 100 percent to customers. Because of the PCA 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 in a future period, resulting in fluctuations in operating cash flows from year to year. The table that follows presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2015	**2014**	**2013**
Idaho power supply cost deferrals	$ (35,802)	$ (48,104)	$ (67,127)
Amortization of prior year authorized balances	52,568	70,339	27,590
Total power cost adjustment expense	$ 16,766	$ 22,235	$ (39,537)

The power supply deferrals represent the portion of the power supply cost fluctuations deferred under the PCA mechanisms. When actual power supply costs are higher than the amount forecasted in PCA rates most of the difference is deferred. The amortization of the prior year's balances represents the offset to the amounts being collected or 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 - 2015 Compared with 2014 : Actual net power supply cost deferrals decreased in 2015 relative to 2014, a change of $12.3 million —from $48.1 million to $35.8 million . Power supply costs collected through base rates increased on June 1, 2014, resulting in less costs needing to be recovered through the PCA mechanism since that time. The $52.6 million of amortization offsets the collection from customers of prior years' deferrals.

PCA Mechanisms - 2014 Compared with 2013 : Actual net power supply cost deferrals decreased in 2014 relative to 2013, a change of $19.0 million—from $67.1 million to $48.1 million. Power supply costs collected through base rates increased on June 1, 2014, resulting in less costs needing to be recovered through the PCA mechanism since that time. The $70.3 million of amortization offsets the collection from customers of prior years' deferrals.

***Other Operations and Maintenance Expenses* :** The changes in operations and maintenance (O&M) expenses for the periods presented are discussed below.

O&M - 2015 Compared with 2014 : Other O&M expense decreased by $12.4 million in 2015 compared with 2014, a decrease of 3.5 percent, due to the following factors:

- $16.7 million was recorded as additional pension expense in 2014 related to a December 2011 Idaho regulatory settlement agreement, which required sharing with Idaho customers of a portion of earnings in excess of a 10 percent Idaho ROE (thereby reducing customers' future pension obligations). There were no additional expenses related to the settlement agreement in 2015;
- Excluding the additional 2014 pension expense, labor-related expenses increased $2.1 million, or 1.1 percent, in 2015 due to normal escalations in labor and benefits costs; and
- Other O&M expenses increased $2.2 million, the most notable increase being hydroelectric generation expenses that were $2.0 million higher, primarily due to increased repair costs and purchased services.

O&M - 2014 Compared with 2013 : Other O&M expense increased by $5.7 million in 2014 compared with 2013, an increase of less than two percent, primarily due to an increase of $4.6 million in labor-related expenses caused by normal escalations in labor and benefits costs.

Gain on Sale of Investments

In 2013, Idaho Power recognized an $11.6 million gain on the sale of marketable securities. These investments relate to the Rabbi trust designated to provide funding for Idaho Power's obligations under its Security Plan for Senior Management Employees. Gross proceeds from the sale were $25.7 million. No such sale occurred in 2015 or 2014.

Income Taxes

IDACORP's and Idaho Power's 2015 income tax expense increased $28.9 million and $28.7 million, respectively, when compared to 2014. The increase was primarily due to greater Idaho Power pre-tax earnings in 2015 and lower flow-through income tax benefits from discrete items. In 2014, Idaho Power recorded a $24.5 million income tax benefit related to the cumulative impact of tax accounting method changes for its capitalized repairs deduction. During 2015, Idaho Power recorded an income tax benefit of $7.2 million for the tax deduction related to the call premium Idaho Power paid on the early redemption of long-term debt.

Income tax expense in 2014 decreased significantly compared with 2013, principally as a result of the Idaho Power capitalized repair deduction method changes. For additional information relating to IDACORP's and Idaho Power's income taxes, including the availability of tax credit carryforwards, see Note 2 - “Income Taxes” to the consolidated financial statements included in this report.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Idaho Power has been pursuing significant enhancements to its utility infrastructure in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and component replacement. Idaho Power's expenditures for property, plant and equipment, excluding AFUDC, were $284 million in 2015 and $265 million in 2014 . Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of nearly $1.5 billion over the period from 2016 through 2020 .

Idaho Power funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. During 2015, Idaho Power has continued its efforts to optimize operations, control costs, and generate operating cash inflows to meet operating expenditures, contribute to capital expenditure requirements, and pay dividends to shareholders. Idaho Power periodically files for rate adjustments for recovery of operating costs and both the return of, and a return on, capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators. During 2016, Idaho Power intends to evaluate the timing of filing of its next general rate case.

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As of February 12, 2016 , IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $100 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) on May 22, 2013, which may be used for the issuance of debt securities and common stock, including up to 3 million shares of IDACORP common stock available for issuance under IDACORP's sales agency agreement executed in July 2013;
- Idaho Power's shelf registration statement, filed with the SEC jointly with IDACORP on May 22, 2013, which may be used for the issuance of first mortgage bonds and debt securities; $250 million is available for issuance under a selling agency agreement executed in July 2013 and pursuant to state regulatory authority; and
- IDACORP's and Idaho Power's issuance of commercial paper, which may be issued up to an amount equal to the available credit capacity under their respective credit facilities.

Based on planned capital expenditures and operating and maintenance expenses for 2016 , the companies believe they will be able to meet capital requirements and fund corporate expenses during 2016 with a combination of existing cash and operating cash flows generated by Idaho Power's utility business. IDACORP and Idaho Power believe they could meet any short-term cash shortfall with existing credit facilities and expect to continue to manage short-term liquidity through commercial paper markets.

IDACORP and Idaho Power monitor capital markets with a view toward opportunistic debt and equity transactions, taking into account current and potential future long-term needs. As a result, IDACORP may issue debt securities or may issue common stock under the existing continuous equity program, and Idaho Power may issue debt securities, if the companies believe terms available in the capital markets are favorable and that issuances would be financially prudent. Idaho Power also periodically analyzes whether partial or full early redemption of one or more existing outstanding series of first mortgage bonds is desirable, and in some cases may refinance indebtedness with new indebtedness issued with more favorable terms, including interest rates lower than the series being redeemed. To that end, on March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, its $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes due July 2018. In accordance with the redemption provisions of the original terms of the notes, the redemption included payment by Idaho Power of a make-whole premium of $17.9 million. Idaho Power used a portion of the net proceeds of the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption. During 2016, Idaho Power may determine to redeem prior to maturity one or more other outstanding series of first mortgage bonds, depending on capital availability and market conditions.

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, 2015 , IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

	IDACORP	Idaho Power
Debt	46%	48%
Equity	54%	52%

IDACORP and Idaho Power generally maintain their cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills, money market funds, and bank deposits.

Operating Cash Flows

IDACORP's and Idaho Power's principal sources of cash flows from operations are Idaho Power's sales of electricity and transmission capacity. Significant uses of cash flows from operations include the purchase of fuel and power, other operating expenses, interest, and pension plan contributions. Operating cash flows can be significantly influenced by factors such as weather conditions, rates and the outcome of regulatory proceedings, and economic conditions. As fuel and purchased power are significant uses of cash, Idaho Power has regulatory mechanisms in place that provide for the deferral and recovery of the majority of the fluctuation in those costs. However, if actual costs rise above the level allowed in retail rates, deferral balances increase (reflected as a regulatory asset), negatively affecting operating cash flows until such time as those costs, with interest, are recovered from customers.

IDACORP’s and Idaho Power’s operating cash inflows in 2015 were $353 million and $346 million , respectively, a decrease of $11 million for IDACORP and a slight increase for Idaho Power when compared with 2014 . Significant items that affected the companies' operating cash flows in 2015 relative to 2014 were as follows:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho rate mechanisms, decreased operating cash inflows by $18 million ;
- Idaho Power made $39 million of cash contributions to its defined benefit pension plan in 2015, compared with $30 million of cash contributions during 2014.
- changes in deferred taxes and in taxes accrued and receivable combined to increase cash flows by $34 million and $50 million at IDACORP and Idaho Power, respectively; and
- comparative changes in working capital balances due primarily to timing—principally related to a smaller decrease in accounts receivable in 2015 compared to the decrease in accounts receivable in 2014. Changes in accounts receivable balances reduced operating cash flows $16 million and $18 million for IDACORP and Idaho Power, respectively.

IDACORP's and Idaho Power's operating cash inflows in 2014 were $364 million and $343 million , respectively, increases of $59 million and $53 million, respectively, compared with 2013 . Significant items that affected the companies' operating cash flows in 2014 relative to 2013 included:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply costs deferred and collected under the Idaho PCA mechanism, increased operating cash inflows by $58 million;
- changes in working capital balances due primarily to timing. Decreases in receivable balances from 2013 to 2014 compared with the increase in receivable balances experienced from 2012 to 2013 resulted in an increase to cash flows for 2014 of approximately $50 million for IDACORP and $52 million for Idaho Power;
- cash outflows related to income taxes increased by approximately $10 million for IDACORP and $16 million for Idaho Power from 2013 to 2014; and
- Idaho Power's joint venture, BCC, made net distributions to Idaho Power of $4 million in 2014, as compared with $15 million in 2013. A build-up in coal inventories at BCC during 2014 reduced BCC's cash available for distribution.

Investing Cash Flows

Investing activities consist primarily of capital expenditures related to new construction and improvements to Idaho Power’s generation, transmission, and distribution facilities. Idaho Power's construction expenditures, including AFUDC, were $294 million , $274 million , and $247 million in 2015 , 2014 , and 2013 , respectively. These capital expenditures were primarily for construction of utility infrastructure needed to address Idaho Power’s aging plant and equipment, customer growth, and environmental and regulatory compliance requirements. As discussed in "Capital Requirements" below, Idaho Power received $11 million in both 2015 and 2013 from Boardman-to-Hemingway project joint permitting participants relating to a portion of these construction expenditures. Additionally, Idaho Power's investments in its Rabbi Trust designated to fund its non-qualified pension plan were $10 million, $8 million, and $7 million in 2015, 2014, and 2013, respectively. In 2015, Idaho Power used $30 million of Rabbi Trust assets to acquire company-owned life insurance.

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, managing commodity price risk, and other financial commitments through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho Power, and non-utility operating expenses through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities. The following are significant items and transactions that affected financing cash flows in 2013 , 2014 , and 2015 :

- on April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds due 2023 and $75 million in principal amount of 4.00% first mortgage bonds due 2043;
- on October 1, 2013 Idaho Power repaid at maturity $70 million of its 4.25% first mortgage bonds;
- on March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, Series J, maturing on March 1, 2045;
- on April 23, 2015, Idaho Power redeemed, prior to maturity, its $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes due July 2018;
- IDACORP and Idaho Power paid dividends of approximately $97 million , $88 million , and $79 million in 2015 , 2014 , and 2013 , respectively; and
- IDACORP's net change in commercial paper borrowings were reductions of $11 million and $23 million and $15 million in 2015 , 2014 , and 2013 respectively .

Financing Programs and Available Liquidity

IDACORP Equity Programs: On July 12, 2013, IDACORP entered into a Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM), under which IDACORP may offer and sell up to 3 million shares of its common stock from time to time through BNYMCM as IDACORP's agent. IDACORP has no obligation to sell any minimum number of shares under the Sales Agency Agreement. As of the date of this report, 3 million shares of IDACORP common stock remain available for sale under the Sales Agency Agreement with BNYMCM. As of the date of this report, IDACORP does not expect to issue any shares of its common stock under the Sales Agency Agreement prior to its expiration in July 2016.

Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases of IDACORP common stock for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. However, IDACORP may determine at any time to resume original issuances of common stock under those plans. As noted above, an important component of that determination will be IDACORP's and Idaho Power's capital structure.

Idaho Power First Mortgage Bonds : Idaho Power's issuance of long-term indebtedness is subject to the approval of the IPUC, OPUC, and Wyoming Public Service Commission (WPSC). In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. However, on April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a maximum interest rate limit of seven percent.

On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million in aggregate principal amount of first mortgage bonds, Series J (Series J Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes. As of the date of this report, $250 million remained on Idaho Power's Selling Agency Agreement for the issuance of first mortgage bonds, including Series J Notes, or debt securities.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture, market conditions, regulatory authorizations, and covenants contained in other financing agreements.

The Indenture limits the 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, 2015 was limited to approximately $279 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. Separately, the Indenture also 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. As of December 31, 2015 , Idaho Power could issue approximately $1.5 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

Refer to Note 4 - “Long-Term Debt” to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

IDACORP and Idaho Power Credit Facilities **:** In November 2015, IDACORP and Idaho Power entered into Credit Agreements for $100 million and $300 million credit facilities, respectively. These facilities replaced IDACORP's and Idaho Power's existing Second Amended and Restated Credit Agreements, dated October 26, 2011, as amended. Each of the credit facilities 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 $100 million at any one time outstanding, including swingline loans not to exceed $10 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 and letters of credit not to exceed $100 million at any time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million . 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, provided that the federal funds rate and LIBOR rate will not be less than zero percent. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating, 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. The credit facilities terminate on November 6, 2020, though IDACORP and Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

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 65 percent 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, 2015 , the leverage ratios for IDACORP and Idaho Power were 46 percent and 48 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. 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 December 31, 2015 , IDACORP and Idaho Power believe they were in compliance with all facility covenants. Further, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2016 .

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 incurring 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 percentage points 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 WPSC, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. Idaho Power has obtained approval of the state public utility commissions of Idaho, Oregon, and Wyoming for the issuance of short-term borrowings through November 2022.

IDACORP and Idaho Power Commercial Paper: IDACORP and Idaho Power have commercial paper programs under which they issue unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time not to exceed the available capacity under their respective credit facilities, described above. IDACORP's and Idaho Power's credit facilities are available to the companies to support borrowings under their commercial paper programs. The commercial paper issuances are used to provide an additional financing source for the companies' short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Individual instruments carry a fixed rate during their respective terms, although the interest rates are reflective of current market conditions, subjecting the companies to fluctuations in interest rates.

Available Short-Term Borrowing Liquidity

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

	December 31, 2015		December 31, 2014	
	IDACORP [2]	Idaho Power	IDACORP [2]	Idaho Power
Revolving credit facility	$ 100,000	$ 300,000	$ 125,000	$ 300,000
Commercial paper outstanding	(20,000)	—	(31,300)	—
Identified for other use [1]	—	(24,245)	—	(24,245)
Net balance available	$ 80,000	$ 275,755	$ 93,700	$ 275,755

[1] Port of Morrow and American Falls bonds that Idaho Power could be required to purchase prior to maturity under the optional or mandatory purchase provisions of the bonds, if the remarketing agent for the bonds were unable to sell the bonds to third parties.

[2] Holding company only.

At February 12, 2016 , IDACORP had no loans outstanding under its credit facility and $17.5 million of commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding. The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2015 and 2014 :

	December 31, 2015		December 31, 2014	
	IDACORP [1]	Idaho Power	IDACORP [1]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$ 20,000	$ —	$ 31,300	$ —
Weighted average interest rate	0.88%	—%	0.43%	—%
Daily average amount outstanding during the year	$ 22,054	$ —	$ 37,786	$ —
Weighted average interest rate during the year	0.53%	—%	0.32%	—%
Maximum month-end balance	$ 43,400	$ —	$ 47,300	$ —

[1] Holding company only.

Impact of Credit Ratings on Liquidity and Collateral Obligations

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, depends in part 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:

	IDACORP	Idaho Power
Moody's Investors Service:		
Rating Outlook	Stable	Stable
Long-Term Issuer Rating	Baa1	A3
First Mortgage Bonds	None	A1
Senior Secured Debt	None	A1
Commercial Paper	P-2	P-2
Tax-Exempt Debt	None	A3/VMIG-2
Standard & Poor's Rating Services:		
Corporate Credit Rating	BBB	BBB
Rating Outlook	Stable	Stable
Short-Term Rating	A-2	A-2

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, 2015 , Idaho Power had posted $0.9 million of performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on its unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral, and 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, 2015 , the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $11.6 million. To minimize capital requirements, Idaho Power actively monitors its portfolio exposure and the potential exposure to additional requests for performance assurance collateral through sensitivity analysis.

Capital Requirements

Idaho Power's construction expenditures, excluding AFUDC, were $284 million during the year ended December 31, 2015 . The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2016 through 2020 (in millions of dollars). However, given the uncertainty associated with the timing of infrastructure projects and associated expenditures, actual expenditures and their timing could deviate substantially from those set forth in the table.

	2016	2017	2018-2020
Ongoing capital expenditures (excluding item listed below in this table)	$ 280-285	$ 275-285	820-870
Jim Bridger plant selective catalytic reduction equipment (discussed below)	20-25	0	40-50
Total (excluding AFUDC)	$ 300-310	275-285	860-920

Major Infrastructure Projects: Idaho Power is engaged in the development of a number of significant projects and has entered into arrangements with third parties for joint development of infrastructure projects. The most notable projects are described below.

Jim Bridger Plant Selective Catalytic Reduction Equipment : Idaho Power and the plant co-owners are installing selective catalytic reduction (SCR) equipment to reduce nitrogen oxide (NO_x) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. The regional haze rules provide for installation of SCR on unit 3 and unit 4. The rules provide for an equivalent technology for NO_x reductions on unit 2 by 2021 and unit 1 by 2022. Idaho Power estimates that the total cost for Idaho Power's share of the upgrades on units 3 and 4 is approximately $105 million, excluding AFUDC. As of December 31, 2015, Idaho Power had expended $83 million, excluding AFUDC, on SCR installation at units 3 and 4. The unit 3 SCR has been installed and was operating as of November 30, 2015. As of the date of this report, the unit 4 project remains on schedule and Idaho Power expects the total project cost to be at or below the originally estimated amount.

Boardman-to-Hemingway Transmission Line : 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, would provide transmission service to meet future resource needs. The Boardman-to-Hemingway line was included in the preferred resource portfolio in Idaho Power’s 2015 IRP. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration (BPA) to pursue permitting of the project. The joint funding agreement provides that Idaho Power's interest in the permitting phase of the project would be approximately 21 percent, and that during future negotiations relating to construction of the transmission line Idaho Power would seek to retain that percentage interest in the completed project. Assuming both other participants fund their full share of the total cost of the permitting phase of the project, Idaho Power's estimated share of the cost of the permitting phase of the project is approximately $40 million, including Idaho Power's AFUDC. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including AFUDC for Idaho Power's share of the project. 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. In December 2015, Idaho Power received an early payment of $11.4 million from a joint permitting participant. Construction costs beyond the permitting phase are not included in the table above.

Idaho Power has expended approximately $73 million on the Boardman-to-Hemingway project through December 31, 2015. Pursuant to the terms of the joint funding arrangements, approximately $35 million of that amount has been received by Idaho Power as reimbursement from the project participants as of December 31, 2015. Approximately $15 million more must be reimbursed to Idaho Power in the future by the project participants for expenses Idaho Power incurred, for a total amount reimbursable by joint permitting participants of $49 million. In addition to the $49 million amount, $5 million is subject to reimbursement at a later date from the joint permitting participants, assuming their continued participation in the project, for expenses Idaho Power incurred prior to execution of the joint funding arrangements. Idaho Power plans to seek recovery of its share of project costs through the regulatory process.

The permitting phase of the Boardman-to-Hemingway project is subject to review and approval by the U.S. Bureau of Land Management (BLM) as the lead federal agency on behalf of other federal agencies, the U.S. Forest Service, and the Oregon Department of Energy. The BLM issued a draft environmental impact statement (EIS) for the project in December 2014, and as of the date of this report Idaho Power expects the BLM to issue a final EIS during 2016 and a record of decision in late 2016 or early 2017. In the separate Oregon state permitting process, Idaho Power submitted a preliminary application for a site certificate in February 2013 and intends to finalize the amended preliminary application in 2016. Idaho Power is unable to determine an in-service date for the line but, given the status of ongoing permitting activities, expects the in-service date would be in 2022 or beyond.

Gateway West Transmission Line : Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. In January 2012, Idaho Power and PacifiCorp entered a joint funding agreement for permitting of the project. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $64 million, including AFUDC. Idaho Power has expended approximately $29 million on the permitting phase of the project through December 31, 2015. 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 $200 million and $400 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 beyond the permitting phase are not included in the table above.

The permitting phase of the project is subject to review and approval of the BLM. The BLM released its record of decision under the National Environmental Policy Act in November 2013. In its record of decision, the BLM identified its final decision on the routing of the project, issued right-of-way grants on public land for some segments, and deferred a decision on two segments (in both of which Idaho Power has an interest) to resolve routing concerns in those areas. Several interested parties have appealed the BLM's record of decision, and Idaho Power has intervened in the proceedings. The BLM has initiated the supplemental EIS process for the two deferred segments. As of the date of this report, the BLM's schedule provides for the issuance of a record of decision on the two deferred segments in 2016.

Hells Canyon Complex Relicensing : The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. Idaho Power has been engaged in the process of obtaining from the FERC a new long-term license for the HCC. As noted in "Regulatory Matters" in this MD&A, the past and anticipated future costs associated with obtaining a new long-term license for the HCC are significant. Idaho Power expects that the annual capital expenditures and operating and maintenance expenses associated with compliance with the terms and conditions of the long-term license could also be substantial, but the company is currently unable to estimate those costs in light of the uncertainty surrounding the ultimate terms and conditions that may be included in the license. Idaho Power intends to seek recovery of those relicensing and compliance costs in rates through the regulatory process.

Shoshone Falls Plant Expansion : The Shoshone Falls plant expansion project was included in Idaho Power's 2013 IRP and, as originally planned, was to consist of constructing a new powerhouse, intake structure, penstock, and substation and installing a new turbine to increase the nameplate generation capacity of the plant from 12.5 MW to 61.5 MW. However, following additional analysis of the costs and potential benefits of the expansion, Idaho Power's 2015 IRP includes in the near-term action plan a modified project that would result in a significantly smaller increase in nameplate generation capacity at the facility, in a range of 1.7 MW to 4 MW, with a potential on-line date as early as 2019. Idaho Power is performing additional engineering and cost studies to determine the most suitable project that will optimize and improve the reliability of the facility. Following consultation with FERC staff, Idaho Power has concluded it can proceed with the modified expansion under the terms and conditions of the current operating license.

Completed Transmission System Transaction : To enhance the abilities of Idaho Power and PacifiCorp to serve their respective customers, in October 2014, Idaho Power and PacifiCorp executed a Joint Ownership and Operating Agreement (Joint Operating Agreement) applicable to certain transmission-related equipment to be exchanged by Idaho Power and PacifiCorp. The asset exchange was finalized on October 30, 2015, under the terms of a Joint Purchase and Sale Agreement dated October 24, 2014, between Idaho Power and PacifiCorp. Under the terms of the Joint Purchase and Sale Agreement each party agreed to transfer to the other transmission-related equipment with an estimated year-end 2014 net book value of approximately $43 million, subject to true-up as of the closing date. Additionally, the Joint Purchase and Sale Agreement terminated or amended a number of legacy long-term agreements related to the ownership and operation of transmission-related equipment and transmission services between Idaho Power and PacifiCorp. In 2014, Idaho Power collected approximately $8 million in transmission revenues under legacy long-term transmission agreements that were terminated in connection with the Joint Purchase and Sale Agreement. As a result of the transaction and termination of those long-term transmission agreements, an increase to Idaho Power's OATT rate will be phased-in over a two-year period, as discussed in "Regulatory Matters" in the MD&A.

Other Infrastructure Projects: Idaho Power continues to add to its system to accommodate for growth and to reinvest for reliability and general system improvement. These system enhancement projects involve significant capital expenditures. Examples of system enhancements over the period 2016 through 2020, and their estimated costs, include the following:

- $50-$85 million per year for transmission-related projects other than the Boardman-to-Hemingway and Gateway West projects;
- $30-$35 million per year for reconstruction of distribution lines;
- $15-$20 million per year for replacement of underground distribution cables;
- $25-$40 million per year for ongoing thermal plant improvement programs other than SCR equipment;
- $25-$40 million per year for hydroelectric plant improvement programs;
- $5-$10 million per year for reliability-related construction projects, such as wood pole crossarm replacements and feeder system improvement; and
- $30-$45 million per year for general plant improvements, such as information technology, facilities, and fleet vehicles.

Approval of Long-Term Service Agreement for Natural Gas Plants: During 2015, Idaho Power executed a long-term service agreement for maintenance services at three of Idaho Power's natural gas plants, with a total estimated obligation of $82 million over the term of the agreement. In addition to the provision of maintenance services to Idaho Power, the agreement provided for Idaho Power's sale of approximately $22 million of capitalized spare parts to the service provider. Idaho Power expects that the arrangement will decrease the long-term costs of operating Idaho Power's natural gas plants. The agreement became effective in the fourth quarter of 2015, following receipt of an order on reconsideration from the IPUC approving accounting treatment acceptable to Idaho Power.

Environmental Regulation Costs: Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal-fired plants and for its hydroelectric relicensing efforts. The near-term cost estimates for environmental matters are summarized in Part I, Item 1 - "Business" of this report. The capital portion of these amounts is included in the Capital Requirements table above but does 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.

Long-Term Resource Planning: The IPUC and OPUC require that Idaho Power prepare biennially an Integrated Resource Plan (IRP). Idaho Power filed its most recent IRP in June 2015. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The 2015 IRP includes as near-term action items the continued permitting and planning for the Boardman-to-Hemingway transmission line and further investigation of the early retirement of the North Valmy power plant in collaboration with the plant's co-owner. The near-term action plan also includes a decrease in the size of the planned Shoshone Falls expansion described above, as well as commencement of an economic evaluation of environmental control retrofits for units 1 and 2 at the Jim Bridger power plant. Additional information on Idaho Power's IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

Defined Benefit Pension Plan Contributions and Recovery

Idaho Power contributed $39 million , $30 million , and $30 million to its defined benefit pension plan in 2015 , 2014 , and 2013 , respectively. Idaho Power estimates that it has no minimum contribution requirement for 2016 , though it plans to contribute at least $20 million to the pension plan during 2016 . Idaho Power may elect to contribute more than that amount based on long-term projections. Idaho Power's contributions are made in a continued effort to balance the regulatory collection of these expenditures with the amount and timing of contributions to mitigate the cost of being in an underfunded position. In 2016 and beyond, Idaho Power expects continuing significant contribution obligations under the pension plan. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations.

Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2015 , Idaho Power's deferral balance associated with the Idaho jurisdiction was $82.5 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. The IPUC has authorized Idaho Power to recover and amortize $17.1 million of deferred pension costs annually, and has applied $68.1 million against the deferred amount under its Idaho sharing mechanisms. The primary impact of pension contributions is on timing of cash flows, as cost recovery lags behind the timing of contributions.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations as of December 31, 2015, for the respective periods in which they are due:

	Payments Due by Period				
	Total	2016	2017-2018	2019-2020	Thereafter
	(millions of dollars)				
Long-term debt [(1)]	$ 1,747	$ 1	$ 1	$ 330	$ 1,415
Future interest payments [(2)]	1,417	83	165	153	1,016
Operating leases [(3)]	17	—	2	2	13
Purchase obligations:					
Cogeneration and small power production [(4)]	4,736	199	475	469	3,593
Fuel supply agreements	251	60	59	18	114
Other [(5)]	263	62	52	36	113
Pension and postretirement benefit plans [(6)]	264	8	75	138	43
Other long-term liabilities	1	—	1	—	—
Total	$ 8,696	$ 413	$ 830	$ 1,146	$ 6,307

(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, 2015.

(3) The operating leases include right-of-way easements. Approximately $1 million of the obligations included 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.

(4) Subsequent to the end of 2015, as of February 5, 2016, three power purchase contracts with solar projects not yet online with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts.

(5) Approximately $84 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. Other purchase obligations also includes Idaho Power's estimated proportionate funding obligation for goods and services under non-fuel purchase agreements at its jointly owned generation facilities. In some instances, Idaho Power is not a direct party to an underlying purchase agreement, but is obligated under the instruments governing the joint ventures to reimburse the co-owner for payments the co-owner makes pursuant to the purchase agreement. Those estimated amounts have been included in the table above.

(6) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2020 with any level of precision, and amounts through 2020 are estimates only and are subject to change. 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 considerations, 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.

IDACORP has a dividend policy 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 IDACORP's board of directors' dividend decisions. Notwithstanding the dividend policy adopted by IDACORP's board of directors, 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 factors above, among others. In September of 2013 , 2014 , and 2015 , IDACORP's board of directors voted to increase the quarterly dividend to $0.43 per share, $0.47 per share, and $0.51 per share of IDACORP common stock, respectively. IDACORP's 2015 calendar year payout ratio was 50 percent.

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 results of operations and financial condition. Certain legal or administrative proceedings to which IDACORP or Idaho Power are parties or are otherwise involved, and certain actual or potential legal claims pertaining to Idaho Power, are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, in many instances 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.

Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of potential new regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

Off-Balance Sheet Arrangements

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was $73 million at December 31, 2015 , representing IERCo's one-third share of BCC's total reclamation obligation of $218 million . BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2015 , the value of the reclamation trust fund totaled $70 million . During 2015 , the reclamation trust fund distributed approximately $6 million for reclamation activity costs associated with the BCC surface mine. 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

Introduction

Idaho Power's development of rate case plans takes into consideration short-term and long-term needs for rate relief and involves several factors that can affect the timing of rate filings. These factors include, among others, in-service dates of major capital investments, the timing of changes in major revenue and expense items, and customer growth rates. Idaho Power's most recent general rate cases in Idaho and Oregon were filed during 2011, and Idaho Power filed a large single-issue rate case for the Langley Gulch power plant in Idaho and Oregon in 2012. These significant rate cases resulted in the resetting of base rates in both Idaho and Oregon during 2012. Idaho Power also reset its base-rate power supply expenses in the Idaho jurisdiction for purposes of updating the collection of costs through retail rates in 2014, but without a resulting net increase in rates. Between general rate cases, Idaho Power relies upon power cost adjustment mechanisms, tariff riders, and other mechanisms to reduce regulatory lag, which refers to the period of time between making an investment or incurring an expense and recovering that investment or expense and earning a return.

Management's regulatory focus in recent years has been largely on regulatory settlement stipulations and the design of rate mechanisms. During 2016, Idaho Power plans to continue to assess its need to file and timing of a general rate case in its two retail jurisdictions, based on its consideration of the factors described above, among others.

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Notable Retail Rate Changes in Idaho and Oregon

Included in the table that follows are notable regulatory developments during 2013, 2014, and 2015 that affected Idaho Power's results for the periods. Also refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for a description of regulatory mechanism and associated orders of the IPUC and OPUC, which should be read in conjunction with the discussion of regulatory matters in this MD&A.

Description	Effective Date	Estimated Annualized Revenue Impact (millions) (1)
2013 Idaho FCA (2)	6/1/2013	(1)
2013 Idaho PCA (2)(3)	6/1/2013	140
2013 Oregon APCU (2)	6/1/2013	3
2014 Idaho FCA (2)	6/1/2014	6
2014 Idaho PCA (2)(4)	6/1/2014	(88)
Transfer of power supply costs from the Idaho PCA mechanism to Idaho base rates (5)	6/1/2014	99
2015 Idaho FCA (2)	6/1/2015	2
2015 Idaho PCA (2)(6)	6/1/2015	(12)

(1) The annual amount collected in rates is typically not recovered on a linear basis (i.e., 1/12th per month), and is instead recovered in proportion to general business sales volumes.

(2) The rate changes for the Idaho PCA and FCA are applicable only for one-year periods. Similarly, a portion of the rate changes from the Oregon APCU are applicable only for one-year periods.

(3) 2013 PCA rates reflect $7 million of Idaho revenue-sharing related to 2012 financial results pursuant to an IPUC order issued in 2013 under regulatory settlement agreements approved in January 2010 and December 2011. The $140 million increase in PCA rates includes the reduction in the PCA mechanism component of the revenue sharing amount from $27 million for the 2012 PCA to $7 million for the 2013 PCA.

(4) 2014 PCA rates reflect (a) the application of $20 million of surplus Idaho energy efficiency rider funds, (b) $8 million of customer revenue sharing for the year 2013 under a regulatory settlement agreement approved in December 2011, and (c) a $99 million shift in base net power supply expenses from recovery via the PCA mechanism to recovery through base rates.

(5) See footnote (4) above. Approval of the transfer of collection of specified power supply costs from the Idaho PCA mechanism to Idaho base rates resulted in no net change in customer rates.

(6) 2015 PCA rates reflect the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of a December 2011 settlement stipulation, (b) a $1.5 million customer benefit relating to a change to the PCA methodology described below, and (c) $4.0 million of surplus Idaho energy efficiency rider funds.

Idaho and Oregon General Rate Cases and Base Rate Adjustments

Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from the regulatory settlement of a general rate case filing Idaho Power made in 2011. In the general rate case, the IPUC issued an order approving a settlement stipulation that provided for an overall 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a $34.0 million overall increase in Idaho Power's annual Idaho-jurisdictional base rate revenues. Neither the IPUC's order nor the settlement stipulation specified an authorized rate of return on equity.

Effective March 1, 2012, Idaho Power implemented new Oregon base rates resulting from its receipt of an order from the OPUC approving a settlement stipulation in its general rate case proceedings that provided for a $1.8 million base rate revenue increase, a rate of return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction.

Idaho and Oregon base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. In June 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rate revenues, effective July 1, 2012, for inclusion of the investment and associated costs of the plant in rates. The order also provided for a $335.9 million increase in Idaho rate base. On September 20, 2012, the OPUC issued an order approving a $3.0 million increase in annual Oregon jurisdiction base rate revenues, effective October 1, 2012, for inclusion of the investment and associated costs of the plant in Oregon rates.

In March 2014, the IPUC issued an order approving Idaho Power's application requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

Non-Base Rate Idaho Regulatory Settlement Stipulations

Settlement Stipulation for 2012 to 2014 : In December 2011, the IPUC issued an order, separate from the then-pending Idaho general rate case proceeding, approving a settlement stipulation that allowed Idaho Power to, in certain circumstances, amortize additional ADITC if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 was less than 9.5 percent, to help achieve a 9.5 percent Idaho ROE for the applicable year. The more specific terms and conditions of the December 2011 Idaho settlement stipulation are described in Note 3 - "Regulatory Matters - *Notable Idaho Regulatory Matters* " to the consolidated financial statements included in this report. Under the December 2011 settlement stipulation, when Idaho Power's actual Idaho ROE for any of those years exceeded 10.0 percent, Idaho Power was required to share a portion of its Idaho-jurisdiction earnings with Idaho customers. As Idaho Power's 2012, 2013, and 2014 Idaho ROE exceeded 10.0 percent, Idaho Power did not amortize additional ADITC for those years, but instead shared earnings with customers. The amounts Idaho Power recorded for sharing for those years were as follows (in millions of dollars):

	2014	2013	2012
Additional pension expense funded through sharing	$ 16.7	$ 16.5	$ 14.6
Provision against current revenue as a result of sharing	8.0	7.6	7.2
Total	$ 24.7	$ 24.1	$ 21.8

Settlement Stipulation for 2015 to 2019 : In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The more specific terms and conditions of the October 2014 settlement stipulation are described in Note 3 - "Regulatory Matters - *Notable Idaho Regulatory Matters* " to the consolidated financial statements included in this report. IDACORP and Idaho Power believe that the terms allowing amortization of additional ADITC in the October 2014 settlement stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015, as its Idaho ROE for 2015 was above 10.0 percent. Accordingly, the full $45 million of additional ADITC remains available for future use under the terms of the settlement stipulation.

Modifications to Idaho Annual Rate Adjustment Mechanisms

PCA Mechanism: In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties evaluated Idaho Power's application of the true-up component of the PCA mechanism. The July 2014 docket arose from a prior order of the IPUC, which noted that the IPUC Staff believed that Idaho Power's application of the true-up component introduced a line-loss bias that inflated the true-up revenue that Idaho Power collects under the PCA. In May 2015, the IPUC approved a settlement stipulation that modified the calculation of the true-up component of the PCA mechanism. The mechanics of the PCA mechanism and the terms of the PCA settlement stipulation are described in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

FCA Mechanism: Also in July 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA. Concerns cited included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs.

The FCA is designed to remove Idaho Power's financial 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. Stated generally, under the FCA Idaho Power charges residential and small commercial customers when it recovers less "actual fixed costs per customer" than the base level of fixed costs that the IPUC authorized for recovery through rates in the last general rate case, and Idaho Power credits those customers when its "actual fixed costs per customer" recovered exceed that base level of fixed costs. The FCA is adjusted each year to collect, or refund, the difference between the authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year.

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In years when actual sales per customer are higher than weather-normalized sales due to high summer or low winter temperatures, Idaho Power expects that the new FCA methodology will be less favorable to Idaho Power than the prior methodology. Conversely, Idaho Power expects that the new FCA methodology will be more favorable to Idaho Power in years when actual sales per customer are lower than weather normalized sales due to cooler summer or warmer winter temperatures. Implementation of the new methodology was retroactive to January 1, 2015, as contemplated by the settlement stipulation. For 2015, application of the new FCA methodology resulted in Idaho Power recording greater FCA revenues than would have been recorded for the year under the prior mechanism.

Deferred 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 forecasts of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. Idaho Power's PCA mechanisms in its Idaho and Oregon jurisdictions provide for annual adjustments to the rates charged to retail customers. The PCA mechanism and associated financial impacts are described in "Results of Operations" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Factors that have influenced significant PCA rate changes in recent years include year-to-year volatility in hydroelectric generation conditions, market energy prices and the volume of off-system sales, power purchase costs from renewable energy projects, and revenue sharing under Idaho regulatory settlement stipulations. From year to year, the factors that influence power supply costs can vary significantly, which can result in significant accruals and deferrals under the PCA mechanism. The PCA rate changes reflected in the table under the heading "Notable Retail Rate Changes in Idaho and Oregon" are illustrative of the volatility of net power supply costs and the impact on PCA rates.

As noted above under the heading "Idaho and Oregon General Rate Cases and Base Rate Adjustments," in light of the existence of permanent increases in power supply costs, in March 2014 the IPUC issued an order approving Idaho Power's application requesting recovery of a portion of its ongoing power supply costs through base rates rather than through the Idaho PCA mechanism.

The following table summarizes the change in deferred net power supply costs over the prior two years.

	Idaho	Oregon [1]	Total
Balance at December 31, 2013	$ 84,843	$ 6,611	$ 91,454
Current period net power supply costs deferred	48,104	—	48,104
Revenue sharing applied to deferred power supply costs	(7,624)	—	(7,624)
Energy efficiency rider funds applied to deferred power supply costs	(20,000)	—	(20,000)
Prior deferred costs amortized and recovered through rates	(48,489)	(2,210)	(50,699)
SO_2 allowance and renewable energy certificate (REC) sales	(2,895)	(127)	(3,022)
Interest and other	573	403	976
Balance at December 31, 2014	54,512	4,677	59,189
Current period net power supply costs deferred	35,802	—	35,802
Revenue sharing applied to deferred power supply costs	(7,999)	—	(7,999)
Energy efficiency rider funds applied to deferred power supply costs	(4,000)	—	(4,000)
Prior deferred costs amortized and recovered through rates	(32,519)	(2,294)	(34,813)
SO_2 allowance and renewable energy certificate (REC) sales	(1,575)	(70)	(1,645)
Interest and other	335	351	686
Balance at December 31, 2015	$ 44,556	$ 2,664	$ 47,220

[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 $3 million). Deferrals are amortized sequentially.

Open Access Transmission Tariff Rate Proceedings

Idaho Power uses a formula rate for transmission service provided under its OATT. The transmission rates are updated annually based primarily on financial and operational data Idaho Power files with the FERC. In August 2015, Idaho Power filed with the FERC and publicly posted its final informational filing for its 2015 transmission rate, reflecting a transmission rate of $23.43 per kW-year, to be effective for the period from October 1, 2015 to September 30, 2016. Historic OATT rate information is included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Leading up to the final informational filing, in a draft transmission rate posting Idaho Power made in June 2015, Idaho Power included in its draft OATT rate calculations the expected changes in demand associated with the then-pending transmission system transaction with PacifiCorp (described in "Liquidity and Capital Resources" in this MD&A), resulting in a draft rate of $33.23 per kW-year. The transmission system transaction terminated certain legacy transmission agreements and provided for new long-term point-to-point transmission service for PacifiCorp. In response to concerns from transmission customers, Idaho Power subsequently shifted its procedural approach for incorporating the impacts of the transmission system transaction on its OATT rate. Idaho Power's 2015 transmission rate of $23.43 per kW-year for the period from October 1, 2015 to September 30, 2016 does not include the impact of the transmission system transaction. In a July 2015 filing, Idaho Power requested clarification from the FERC as to when Idaho Power may fully incorporate the effects of the pending transmission system transaction in the formula used to determine its OATT rate. On November 19, 2015, the FERC issued an order requiring Idaho Power to reflect historic loads in the load denominator used in the transmission formula rate, resulting in an OATT rate increase that is phased-in over a two-year period rather than on an accelerated basis.

Relicensing of Hydroelectric Projects

Overview: Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses have a term of 30 to 50 years depending on the size, complexity, and cost of the project. The expiration dates for the FERC licenses for each of the facilities are included in Part I - Item 2 - "Properties" in this report. Costs for the relicensing of Idaho Power's hydroelectric projects 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 $221 million for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2015. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.7 million when grossed-up for the effect of income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. As of December 31, 2015, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $88 million. In addition to the discussion below, see "Environmental Matters" in this MD&A for a discussion of environmental compliance under FERC licenses for Idaho Power's hydroelectric generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application with the FERC for a new license in anticipation of the July 2005 expiration of the then-existing license. Since the expiration of that license, Idaho Power has been operating the project under annual licenses issued by the FERC. In December 2004, Idaho Power and eleven other parties, including National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS), involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on Endangered Species Act (ESA) listed species pending the relicensing of the project. 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 ESA, which remain unresolved.

In connection with its relicensing efforts, 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. Section 401 of the CWA requires that a state either approve or deny a Section 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.

In September 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, including the bull trout and fall Chinook salmon and steelhead, 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 has begun the process for construction of new aerated runners at the Brownlee project (part of the HCC) at an estimated cost of $50 million. Other measures that have been proposed or considered have included modification of spillways at Brownlee and Hells Canyon to address total dissolved gas issues, and upstream watershed improvements or the installation of a temperature control structure to address water temperatures during a small portion of the year. If Idaho Power is required to take these or other additional measures to satisfy relicensing requirements, it could add substantially to project costs. Idaho Power continues to work with the Oregon and Idaho Departments of Environmental Quality on the water quality certification issue and the water quality measures that will be required to obtain 401 certification.

As of the date of this report, Idaho Power is unable to predict the timing of issuance by the FERC of any license order or the ultimate capital investment and ongoing operating and maintenance costs Idaho Power will incur in complying with any new license. However, as of the date of this report, Idaho Power estimates that the annual costs it will incur to obtain a new long-term license for the HCC, including AFUDC but excluding costs expected to be incurred for complying with the license after issuance, are likely to range from $20 million to $30 million until issuance of the license.

Renewable Energy Standards and Contracts

Renewable Portfolio Standards: Numerous proponents have introduced legislation in the U.S. Congress that would require electric 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 or State of Idaho RPS is in effect. Idaho Power will be required to comply with a five- or ten-percent RPS in Oregon beginning in 2025 (depending on loads at that time), and Idaho Power expects to meet either RPS requirement with Renewable Energy Certificates (REC) obtained from the purchase of power from the Elkhorn Valley wind project.

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 years ended December 31, 2015 and 2014, Idaho Power's REC sales totaled $1.8 million and $3.2 million, respectively. The comparative decrease in REC sales resulted primarily from the elimination of a REC purchase and sale agreement with a third party.

Were Idaho Power to be subject to additional RPS legislation, it may cease in full or in part the sale of RECs it receives, seek to obtain RECs from additional projects, generate RECs from any REC-generating facilities it owns or may be required to construct in light of an RPS, or purchase RECs in the market. Historically, Idaho Power has generally not received the RECs associated with PURPA projects. However, an order issued by the IPUC in December 2012, described below, provides that Idaho Power will own a portion of the RECs generated by some PURPA projects. The required purchase of additional RECs to meet RPS requirements would increase Idaho Power's costs, which Idaho Power expects would be wholly or largely passed on to customers through rates and the PCA mechanisms.

Renewable Energy Contracts and PURPA: Idaho Power purchases wind power from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project -- the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of February 5, 2016, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW and an additional 50 MW of CSPP wind power projects not on-line and scheduled to come on-line by year-end 2016. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of power from other CSPP and non-CSPP renewable generation sources, such as biomass, solar, small hydroelectric projects, and two geothermal projects. As of February 5, 2016, Idaho Power had contracts to purchase 364 MW of energy from solar projects not yet on-line and 9 MW of energy from hydroelectric projects not yet on-line. All of the solar projects have estimated on-line dates no later than year-end 2016, though with the extension of federal solar tax credit availability, it is likely the on-line date for some of the projects will extend into 2017. The following tables sets forth, as of February 5, 2016, the number and nameplate capacity of Idaho Power's signed CSPP-related agreements. These agreements have original contract terms ranging from one to 35 years.

Status	Number of CSPP Contracts	Nameplate Capacity (MW)
On-line as of February 5, 2016	109	784
Contracted and projected to come on-line by June 1, 2017	28	423

Pursuant to the requirements of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from CSPP facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements can result in Idaho Power acquiring energy that it does not need to serve customer loads at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Integration of these sources of power into Idaho Power's portfolio does not eliminate Idaho Power's need to construct facilities and infrastructure that provide reliable power. For instance, at the time Idaho Power reached its all-time system peak demand of 3,407 MW on July 2, 2013, wind resources on Idaho Power's system, representing roughly 675 MW of nameplate capacity (including non-PURPA wind) were contributing only 57 MW of power due to lack of wind. As the volume of CSPP purchases increases under PURPA, the magnitude of the costs and integration issues also increases. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms, and thus the primary impact of PURPA agreements is on customer rates.

In light of the volume of intermittent generation Idaho Power is required to purchase pursuant to existing PURPA power purchase agreements and the substantial increase in volume of proposed new solar generation facilities seeking power purchase agreements with Idaho Power, in January 2015 Idaho Power filed an application with the IPUC requesting that the IPUC issue an order directing that the maximum required term for prospective PURPA power purchase agreements be reduced from 20 years to two years. In its application, Idaho Power stated that the requested modification to terms of PURPA energy purchases is necessary to prevent harm to Idaho Power's customers that may result from entering into additional long-term, fixed-rate purchase agreements when Idaho Power predicts that there is no need for new generation capacity through 2021. In February 2015, the IPUC issued an order reducing the maximum contract term of certain future PURPA power purchase agreements from 20 years to five years during the pendency of the proceedings. In August 2015, the IPUC issued an order reducing the length of PURPA contracts that involve avoided-cost-based pricing to two years.

For the Oregon jurisdiction, on April 24, 2015, Idaho Power made filings with the OPUC requesting, among other things, a reduction in the term of standard PURPA power purchase agreements from 20 years to two years for projects above 100 kW, and a temporary suspension of Idaho Power's obligation to enter into new fixed-price standard PURPA agreements during the pendency of the proceedings. On June 23, 2015, the OPUC issued an order denying Idaho Power’s request for a temporary suspension but reduced the eligibility cap for standard contracts from 10 MW to 3 MW on a temporary basis during the pendency of the proceedings. The current phases in these proceedings have been fully submitted and are awaiting a ruling by the OPUC.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the environment, including the Clean Air Act (CAA), the CWA, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the Endangered Species Act (ESA), among other laws. These laws are administered by a number of federal, state, and local agencies. In addition to imposing continuing compliance obligations and associated costs, these laws and regulations provide authority to regulators to levy substantial penalties for noncompliance, injunctive relief, and other sanctions. Idaho Power's three co-owned coal-fired power plants and three natural gas-fired combustion turbine power plants are subject to many of these regulations. Idaho Power's 17 hydroelectric projects are also further subject to a number of water discharge standards and other environmental requirements.

Compliance with current and future environmental laws and regulations may:

- increase the operating costs of generating plants;
- increase the construction costs and lead time for new facilities;
- require the modification of existing generating plants, which could result in additional costs;
- require the curtailment or shut-down of existing generating plants; or
- reduce the output from current generating facilities.

Current and future environmental laws and regulations will increase the cost of operating fossil fuel-fired generation plants and constructing new generation and transmission facilities, in large part through the substantial cost of permitting activities and the required installation of additional pollution control devices. In many parts of the United States, some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate. The decision to agree to cease operation of the Boardman coal-fired plant, in which Idaho Power owns a 10 percent interest, by the end of 2020, was based in part on the significant future cost of compliance with environmental laws and regulations.

In addition to increasing costs generally, these environmental laws and regulations could affect IDACORP's and Idaho Power's results of operations and financial condition if the costs associated with these environmental requirements and early plant retirements cannot be fully recovered in rates on a timely basis. Part I, Item 1 - “Business - Utility Operations - *Environmental Regulation and Costs* ” in this report includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2016 to 2018. Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2018, though they could be substantial.

Endangered Species Act Matters

Overview: The listing of a species of fish, wildlife, or plants as threatened or endangered under the ESA may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or relicense or operate its hydroelectric facilities. When a species is added to the federal list of threatened and endangered species, it is protected from “take,” which is defined to include harming the species. The ESA directs that, concurrent with a designation of a threatened or endangered species, and where prudent and determinable, the applicable agencies also designate “any habitat of such species which is then considered to be critical habitat.” The ESA also provides that each federal agency must ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of its critical habitat. If an action is determined to result in adverse modification of critical habitat, the federal agency must adopt changes to the proposed action to avoid the adverse modification. These changes are often quite extensive and can affect the size, scope, and even the feasibility of a project moving forward. In February 2016, the USFWS and the NMFS issued a set of regulatory and policy changes relating to critical habitat and adverse modification determinations under the ESA. While the ultimate impact of implementation of those changes is yet to be determined, taken as a whole, Idaho Power believes that the changes could result in the applicable agencies having greater authority in making designations of critical habitat and could increase the likelihood of adverse modification determinations.

The construction of generation, transmission, or distribution facilities and the relicensing of Idaho Power's hydroelectric projects can be federally authorized actions that fall under the ESA. There are a number of threatened or endangered species within Idaho Power's service area and within or near proposed transmission line routes, including the slickspot peppergrass and the Washington ground squirrel. Further, there are a number of ESA-listed fish and other aquatic species located in waterways in which Idaho Power has hydroelectric facilities, including fall Chinook salmon, bull trout, Bliss Rapids snail, and Snake River physa snail. To date, efforts to protect these and other listed species have not significantly affected generation levels or operating costs at any of Idaho Power's hydroelectric facilities. However, the ongoing relicensing of the HCC presents endangered species and fisheries issues that may require operational adjustments and could adversely impact the amount of output from hydroelectric dams, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

Non-Listing of Greater Sage Grouse: In 2010, the U.S. Fish and Wildlife Service announced that listing of the greater sage grouse as threatened or endangered under the Endangered Species Act was warranted but precluded by higher priority listing actions. Due to the presence of sage grouse in the vicinity of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines, siting of these projects has required more extensive, costly, and time consuming evaluation, permitting, and engineering. Listing of the greater sage grouse as threatened or endangered would have resulted in the need for a Section 7 consultation under the Endangered Species Act, increasing the cost and time requirements for the permitting of these transmission projects. After evaluating scientific and other information regarding the greater sage-grouse, the U.S. Fish and Wildlife Service determined in September 2015 that protection for the greater sage-grouse under the Endangered Species Act is no longer warranted and withdrew the species from the candidate species list. This determination does not reduce the scope or magnitude of the consideration of sage grouse issues, or possible mitigation requirements associated with sage grouse, in Idaho Power's separate permitting processes for the transmission lines. It does, however, eliminate the requirement for a Section 7 consultation with the U.S. Fish and Wildlife Service under the ESA.

ESA Issues Related to Specific Projects:

Hells Canyon Relicensing Project : In 2007, the FERC requested initiation of formal consultation under the ESA with the NMFS and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has yet to be initiated and the NMFS and the USFWS continue to gather and consider information relative to the effects of relicensing on relevant ESA listed species. Idaho Power continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns. In December 2004, Idaho Power and eleven other parties, including NMFS and the USFWS, entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. At the conclusion of formal consultation and with the issuance of biological opinions by the NMFS and the USFWS and an operating license by the FERC, Idaho Power may be required to implement additional measures or further modify or adjust operations to comply with Section 7 of the ESA. The issuance of a final biological opinion during 2016 is unlikely.

Boardman-to-Hemingway and Gateway West Transmission Projects : Slickspot peppergrass was listed as threatened by the USFWS in 2009. In May 2011, the USFWS issued a proposed rule to designate critical habitat for the slickspot peppergrass and proposed to designate approximately 58,000 acres of critical habitat in four southeast Idaho counties. Most of the species is located on federal land. Additionally, the Washington ground squirrel is considered a “candidate species” under the ESA. The existence of slickspot peppergrass and Washington ground squirrel within or near the proposed routes for the Boardman-to-Hemingway and Gateway West projects is impacting, and Idaho Power expects it to continue to impact, the cost and timing of permitting and construction of the projects. The listing of either species would result in the need for a Section 7 consultation under the ESA, which would increase the cost of obtaining permits for the project and could further delay the in-service date of the project.

Climate Change and the Regulation of Greenhouse Gas (GHG) Emissions

Overview: 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 and energy loads;
- 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 those and other 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 plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources; 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.

Federal and state regulations pertaining to GHG emissions under the CAA have raised uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many 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. Stringent emissions standards could result in significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units and create power system reliability issues. Some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate, particularly in light of relatively low natural gas prices that decrease the cost to operate natural gas-fired power plants.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions. These include the specific GHG emissions limits imposed, the timing of implementation of these limits, 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 the timing and amount of cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National GHG Initiatives; Final Rule Under CAA Section 111(d): The EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in the enactment of a series of EPA regulations to address GHG emissions.

In May 2010, the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rules require the use of "best available control technology" 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, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. While the rules are complex, Idaho Power believes that its owned and co-owned fossil fuel-fired generation plants are, as of the date of this report, in compliance with the GHG Tailoring Rule.

In June 2014, the EPA released, under Section 111(d) of the CAA, a proposed rule for addressing greenhouse gas emissions from existing fossil fuel-fired electric generating units (EGUs). According to the EPA, the proposed rule was designed to achieve a 30 percent reduction in CO_2 emissions from the power sector. The EPA's proposal required that states meet their respective goals by 2030. On August 3, 2015, the EPA released the final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan. The final rule contains several changes from the proposed rule. The final rule requires states to adopt plans to collectively reduce 2005 levels of power sector CO_2 emissions by 32% by the year 2030. The final rule provides states until September 2018 to submit implementation plans and until 2022 (rather than 2020 under the proposed rule) to begin achieving emissions reductions.

In the final rule, the EPA used a procedure to determine the "best system of emission reduction" that was different than under the proposed rule, establishing two sets of uniform emissions rates (one for coal-fired EGUs and one for natural gas-fired EGUs) and developing state limits based on the number and type of affected EGUs in each state. For the final rule, the EPA analyzed emissions reductions that affected EGUs could achieve by applying three "building blocks," that the EPA concluded met the statutory standard "best system of emission reduction":

- Building Block 1: Improving heat rate at existing coal-fired steam EGUs;
- Building Block 2: Shifting electricity generation from higher-emitting coal-fired steam EGUs to lower-emitting existing natural gas combined cycle generation; and
- Building Block 3: Shifting generation from affected fossil fuel-fired EGUs to new zero-emitting renewable energy generation.

The EPA also changed its approach to calculating the emissions targets. In the final rule, the EPA specified nationwide “sub-category” CO_2 emission performance standards applicable to affected steam coal-fired EGUs (1,305 lbs/MWh) and stationary natural gas combustion turbines (771 lbs/MWh). There are a number of methods states may use to achieve compliance. States may simply require affected EGUs to meet these emission rate standards. As in the proposed rule, the EPA also calculated statewide target emission rates, though the method used to calculate the state targets was different in the final rule. The EPA also included equivalent mass-based limits (in short tons) for each state, with the intent of making it easier for states to adopt intrastate or interstate allowance-based emissions trading programs. Other modifications to the proposed rule included an allowance for increased use of thermal generation due to hydroelectric plant variability, and adjustments for plants like the Langley Gulch natural gas power plant that commenced commercial operations during 2012.

Idaho Power's owned and co-owned generation facilities are in the states of Idaho, Nevada, Oregon, and Wyoming. Idaho Power is evaluating the impact that the final rule will have on its operations in those states. Idaho Power is working with state representatives, neighboring utilities, and others as it analyzes the rule and prepares for compliance. However, because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, as of the date of this report Idaho Power is unable to determine the financial or operational impacts of the final rule. Further, on February 9, 2016, the U.S. Supreme Court issued an order staying the implementation of the rule pending the completion of certain legal challenges, which has an uncertain impact on the ultimate timeline for implementation of the rule. In its 2015 IRP, Idaho Power included a number of scenarios for the potential outcome of the then-pending 111(d) rulemaking process, and in the future will continue to make operational decisions based on the implementation of the final rule and any compliance deadlines ultimately imposed.

State GHG Initiatives and Idaho Power’s Voluntary GHG Reduction Initiative: In August 2007, the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The Boardman coal-fired power plant located in Oregon, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements but is scheduled to cease coal-fired operations in 2020.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Idaho’s Governor issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but they are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel generating plants (i.e. Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry. Idaho Power is engaged in voluntary GHG emissions intensity reduction efforts, which is discussed in Part I, Item 1 - “Business - Utility Operations - *Environmental Regulation and Costs* ."

Clean Air Act Matters

Overview: In addition to the CAA developments related to GHG emissions described above, several other regulatory programs developed under the CAA apply to Idaho Power. These include the final Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards (NAAQS), NSR/PSD Rules, and the Regional Haze Rule.

MATS Implementation: The final Mercury and Air Toxics Standards (MATS) rule under the CAA, previously referred to as the Utility MACT Rule, was issued in February 2012. The final rule established emission limits for hazardous air pollutants from new and existing coal-fired and oil-fired steam electric generating units. The MATS rule provided that sources must be in compliance with emission limits by April 2015. Idaho Power and the plant co-owners have installed mercury continuous emission monitoring systems on all of the coal-fired units at the Jim Bridger, Boardman, and North Valmy coal-fired generating plants, along with control technology to reduce mercury, acid gases, and particulate matter emissions for purposes of compliance with the MATS rule. Idaho Power believes that as of the date of this report the coal-fired plants are in compliance with the MATS rule. Legal challenges relating to the MATS rule, to which Idaho Power is not a party and pursuant to which the EPA is performing a court-mandated cost analysis for the rule, are pending.

National Ambient Air Quality Standards: The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. These six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans, or SIPs, based on attainment of these ambient air quality standards. Recent developments and pending actions related to certain of those items relevant to Idaho Power include the following:

- $\underline{NO_x}$. In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a 1-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power owns or has an interest in a natural gas or coal-fired power plant as "unclassifiable/attainment" for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants. As the designations have not yet been finalized, as of the date of this report Idaho Power is unable to predict the impact of the NAAQS for NO_x on its operations. However, the costs of installation and implementation of any additional pollution reduction technology could be substantial.

- $\underline{SO_2}$. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Idaho, Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data. In February 2013, the EPA issued letters to the states of Idaho and Oregon, finding that the most recent air quality data for those states showed no violations of the 2010 SO_2 standard. As a result, the EPA is waiting to propose designation actions for those states, and is likely to proceed with designation actions once additional data are gathered. Idaho Power expects that designations for Nevada and Wyoming will also be addressed in a separate future action.

- *Ozone* . In late 2014, the EPA issued a proposed rule that would update the ozone standard under the CAA, from 75 parts per billion over an eight-hour period to 65 to 70 parts per billion over an eight-hour period. On October 1, 2015, the EPA issued a final rule lowering the national ozone standard under the CAA to 70 parts per billion. The EPA stated that the vast majority of U.S. counties will meet the standards by 2025 with federal and state rules and programs now in place or underway. The EPA's plan provides for finalizing non-attainment designations in 2017, and it plans to propose rules and guidance over the next year to help states with potential non-attainment areas implement the revised standards. Non-attainment areas will have until 2020 to late 2037 to meet the new standard, with attainment dates varying based on the ozone level in the area. Due to high levels of background ozone, which can be caused by factors such as elevation, vegetation, wildfire, and international transport, attainment in areas within the Intermountain West may be difficult, and the formulation of state implementation plans to bring an area into compliance with the new standard may be challenging due to the existence of ozone caused by factors outside of local control. If the EPA were to make non-attainment determinations in areas where Idaho Power owns or co-owns power plants, or proposes to construct power plants, the state implementation plan for those areas could result in changes to the nature and frequency of operation of existing generation plants and make more difficult or costly the construction of new power generation plants. However, as the EPA has not yet made attainment and non-attainment designations, Idaho Power is unable to predict the potential impact of the standard on its operations. Idaho Power will seek to work with state regulators on implementation plans for any non-attainment areas, in an effort to reduce the potential adverse impact on Idaho Power's operation of its existing power generation plants and construction of future facilities.

Because the EPA has not yet completed the designation of areas as attaining or not attaining the NAAQS for NO_x, SO_2, and ozone, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations, though it does expect at least some increases in capital and operating costs from the standards if areas in which Idaho Power operate, or adjacent areas, receive non-attainment designations.

Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any "Class I" (wilderness) areas. This includes all four units at the Jim Bridger and the Boardman coal-fired plants. The RH BART rules would have required installation of a suite of emissions controls at the Boardman plant; however, in December 2010 the Oregon Environmental Quality Commission approved a plan to install a less costly suite of environmental controls and cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

In December 2009, the Wyoming Department of Environmental Quality (WDEQ) issued a RH BART permit to PacifiCorp as the operator of the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install SCR equipment for NO_x control at Jim Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by December 31, 2017 to install add-on NO_x controls at Jim Bridger unit 2 by 2021 and unit 1 by 2022. In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp agreed to the timing and nature of the controls. The settlement agreement was conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze SIP that are consistent with the terms of the settlement agreement. On January 10, 2014, the EPA approved Wyoming's Regional Haze SIP as to the Jim Bridger plant, with the NO_x control compliance dates set forth in the settlement agreement. Several interested parties have appealed the EPA's decisions on Wyoming's RH SIP on various grounds. Idaho Power has not appealed the EPA's decisions but has intervened in the proceedings to participate if and to the extent the Jim Bridger plant could be affected.

New Source Review / Prevention of Significant Deterioration: NSR/PSD is a pre-construction permitting program that requires a stationary source of air pollution to obtain a permit before beginning construction. The purpose of the program is to ensure that air quality is not significantly degraded by the addition of new and modified facilities, industrial boilers, and power plants. Under current NSR provisions of the CAA, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory equivalent before beginning the construction of a stationary source that will emit regulated pollutants, or before modifying an existing stationary source that will increase its emission levels. 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 under 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. As part of an industry-wide assessment of compliance with NSR and NSPS, EPA has sought information from a number of utilities regarding their coal-fired generating facilities. In 2003, the EPA sent information requests pursuant to the CAA to the Jim Bridger plant, seeking information relevant to NSR and NSPS compliance. Additional requests were received by the Boardman plant in 2008, with a follow up request for information in 2009 and by the Valmy plant in 2009. In September 2010, the EPA issued a Notice of Violation to Portland General Electric Company, the operator of the Boardman plant, alleging that Portland General Electric Company violated the NSPS under Section 111 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. To date, the EPA has not taken action on the Notice of Violation, and a related private lawsuit under the CAA was settled in 2011.

Regulation of Coal Combustion Residuals

The Resource Conservation and Recovery Act (RCRA) is a federal statute regulating the generation, treatment, storage, and disposal of solid and hazardous wastes. In December 2014, the EPA signed a final rule for the disposal of coal combustion residuals (CCRs), which are regulated under the RCRA. The rule established structural integrity design criteria and requires that owners and operators of coal-fired power plants periodically conduct a number of structural integrity related assessments and install monitoring apparatus. The final rule also imposes location restrictions on impoundments, requires the closure of impoundments that cannot meet the location restrictions, imposes liner design criteria and operating requirements, and imposes certain record keeping and notification requirements. Additionally, the EPA's rule imposed obligations associated with the closure of CCR impoundments. Idaho Power and its co-owners of coal-fired units performed engineering and cost studies to determine the impacts of the rule, and during 2015 Idaho Power recorded an increase of approximately $5 million in its asset retirement obligation for the Jim Bridger coal-fired plant. The amounts recorded for asset retirement obligations for Idaho Power's other jointly-owned coal-fired plants were not impacted by the EPA's new rule.

Clean Water Act Matters

Definition of "Waters of the United States" Under the CWA : On August 28, 2015, the EPA's and U.S. Army Corps of Engineers' final rule defining the phrase "waters of the United States" under the CWA became effective. Idaho Power believes that the final rule potentially expands federal jurisdiction under the CWA beyond traditional navigable waters, interstate waters, territorial seas, tributaries, and adjacent wetlands, to a number of other waters, including waters with a "significant nexus" to those traditional waters. As a result of the potential expansion, the final rule may result in additional permitting and regulatory requirements under multiple provisions of the CWA. Idaho Power has analyzed the final rule and expects that while it may incur additional permitting and other costs associated with the rule, the aggregate amount of increased costs is unlikely to have a material adverse effect on Idaho Power's operations or financial condition, in part due to the relatively arid climate of Idaho Power's service area and the existing application of the CWA to most of Idaho Power's facilities, including its hydroelectric plants.

On October 9, 2015, the United States Court of Appeals for the Sixth Circuit issued a nationwide stay of the final waters of the United States rule from becoming effective. In response to the Sixth Circuit's decision, the EPA resumed nationwide use of the agency's prior regulations defining the term "waters of the United States." The EPA stated that those regulations will be implemented as they were prior to August 27, 2015, by applying relevant case law, applicable policy, and the best science and technical data on a case-by-case basis in determining which waters are protected by the Clean Water Act.

Regulation of Cooling Water Intake Structures: The CWA generally prohibits the discharge of any "pollutant" from a point source into waters of the United States without a permit. Pollutants are broadly defined to include changes in temperature. Section 316(b) of the CWA requires that National Pollutant Discharge Elimination System permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures employ the best technology available (BTA) to minimize harmful impacts on the environment, such as the removal of fish, fish larvae, marine mammals, and other aquatic organisms from waters of the U.S. In May 2014, the EPA issued final rules that establish requirements under Section 316(b) of the CWA for existing power generation facilities that withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. Given the nature of its co-owned coal-fired plants, Idaho Power expects that its cost to comply with the new rules will be nominal at the Jim Bridger power plant and that it will incur no costs related to the rule at the North Valmy and Boardman plants.

Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See "Relicensing of Hydroelectric Projects" in this MD&A for additional information on the impact of the CWA on that relicensing effort.

Effluent Limitation Guidelines and Standards: In June 2013, the EPA issued proposed rulemaking to revise the technology-based effluent limitation guidelines and standards under the CWA for water discharged from steam electric power plants, which includes coal-fired plants. On September 30, 2015, the EPA issued the final rule, which established limits on the levels of specified metals in wastewater that can be discharged from steam electric power plants. The EPA stated that it estimates that approximately 12 percent of steam electric power plants will incur some costs associated with the final rule. Idaho Power has analyzed the final rule and, given the nature of its co-owned coal-fired plants, as of the date of this report does not anticipate that the rule will materially affect Idaho Power's operations or financial condition.

November 2015 Presidential Memorandum

On November 3, 2015, President Obama issued a Presidential Memorandum directing the Departments of Defense, Interior and Agriculture, the Environmental Protection Agency, and all bureaus or agencies within them to avoid and then minimize harmful effects to land, water, wildlife, and other ecological resources caused by land- or water-disturbing activities, and to ensure that any remaining harmful effects are effectively addressed, consistent with existing mission and legal authorities. The Presidential Memorandum requires agencies to adopt clear and consistent approaches for avoiding, minimizing, or compensating for impacts of agency activities and activities agencies approve under their jurisdiction. The agencies also are required to develop institutionalized steps for implementing the Presidential Memorandum's policy objectives.

For mitigation, agencies are advised to adopt a "net benefit goal" for natural resource use, along with at least a "no net loss" policy of natural resources affected by federal actions, including permitting. The PM prescribes the application of a mitigation hierarchy consisting of first avoiding, then minimizing, and finally compensating for impacts of applicable activities with a federal nexus. Idaho Power expects that the relevant agencies will issue policies and guidelines during the next two years. The policies and guidelines may result in additional costs associated with construction and maintenance activities on federal lands, including transmission projects. To the extent Idaho Power operations affect any natural resources on federal lands, whether fish, wildlife, or plants, the company could face strict standards of "no net loss," which could significantly increase costs depending on the type of resource impacted, such as listed species under the Endangered Species Act.

Review of Federal Coal Leases

On January 15, 2016, the U.S. Department of the Interior announced that it would launch a comprehensive review to identify and evaluate potential reforms to the federal coal lease program. The review is intended to address questions such as how, when, and where to lease coal resources, how to account for the environmental and public health impacts of federal coal production, and how to ensure taxpayers are earning a fair return for the use of the coal resources. The U.S. Department of the Interior stated that it will not issue new coal leases during the pendency of the review, except under limited circumstances, but mining under existing leases will not be suspended during the review. The Bridger Coal Mine, which mines and supplies coal to the Jim Bridger coal-fired power plant, currently leases its coal under a federal coal lease. Any sizable expansion of the Bridger Coal Mine beyond its current leases is unlikely to occur during the U.S. Department of the Interior's coal lease review. Idaho Power believes that BCC has adequate reserves under existing leases to satisfy its coal delivery obligations to the Jim Bridger plant during the term of the existing coal supply contract through 2024, and that the Jim Bridger plant will otherwise have access to sufficient coal supplies for its operation for the foreseeable future. However, depending on the outcome of the Department of the Interior's review, the availability of coal resources could decline and the cost of leases for coal resources could increase, which could increase the fuel cost for each of Idaho Power's co-owned coal-fired plants.

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 accounting policies and estimates discussed below 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 had recorded $1.4 billion of regulatory assets and $418 million of regulatory liabilities at December 31, 2015 . 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 could be required to eliminate those regulatory assets or liabilities. Either circumstance could have a material effect on Idaho Power's financial condition or results of operations.

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 provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes for other items are provided for the temporary differences between the income tax and financial accounting treatment of such items. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax temporary differences where the prescribed regulatory accounting methods, or flow-through, direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

Refer to Note 1 - “Summary of Significant Accounting Policies” and Note 2 - “Income Taxes” to the consolidated financial statements included in this report for additional information relating to income taxes.

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 Security Plan for Senior Management Employees (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, 2015 , with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2016 pension expense will be increased to 4.60 percent from the 4.25 percent used in 2015 .

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 yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index, and Idaho Power believes 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 2016 pension expense will be 7.5 percent, the same assumption as was used for 2015 . The long-term rate of return used in 2014 was 7.75 percent

Gross net periodic pension and other postretirement benefit cost for these plans totaled $51 million , $32 million , and $55 million for the years ended December 31, 2015 , 2014 , and 2013 , respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2016 , gross pension and other postretirement benefit costs are expected to total approximately $54 million , which takes into account the change in the discount rate noted above.

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	
	2016	2015	2016	2015
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (6.9)	$ (7.2)	$ (2.9)	$ (2.9)
Effect of 0.5% rate decrease on net periodic benefit cost	7.6	8.0	2.9	3.0

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $69 million decrease in the combined benefit obligations of the plans as of December 31, 2015 . A 0.5 percent decrease in the plans' discount rates would have resulted in an $78 million increase in the combined benefit obligations of the plans as of December 31, 2015 .

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, 2015 , a total of $86 million of expense was deferred as a regulatory asset. Approximately $24 million is expected to be deferred in 2016 . Idaho Power recorded pension expense in 2015 , 2014 , and 2013 of $19 million , $35 million , and $36 million , respectively.

Refer to Note 11 – “Benefit Plans” to 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, if material, 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

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)* . ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted one year earlier. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendment focus on limited partnerships and similar legal entities, and is effective for interim and annual reporting periods beginning after December 31, 2015. IDACORP and Idaho Power do not believe the impact of ASU 2015-02 on their financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods therein. IDACORP and Idaho Power are currently evaluating the impact of ASU 2016-01 on their financial statements.

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, 2015 . IDACORP has not entered into any of these market-risk-sensitive instruments for trading purposes.

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, 2015 , IDACORP and Idaho Power had $33.2 million and $14.2 million, respectively, in net floating rate debt. The fair market value of this debt was a respective $33.2 million and $14.2 million. Assuming no change in financial structure, if variable interest rates were to average one percentage point higher than the average rate on December 31, 2015 , annual interest expense would increase and pre-tax earnings would decrease by approximately $0.3 million for IDACORP and $0.1 million for Idaho Power.

***Fixed Rate Debt* :** As of December 31, 2015 , IDACORP and Idaho Power had $1.7 billion in fixed rate debt, with a fair market value equal to $1.8 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 $246 million if market interest rates were to decline by one percentage point from their December 31, 2015 levels.

Commodity Price Risk

IDACORP's exposure to changes in commodity prices is related to Idaho Power's ongoing utility operations that produce electricity to meet the demand of its retail electric customers. These effects of changes in commodity prices on Idaho Power are mitigated in large part by Idaho Power's Idaho and Oregon PCA mechanisms. 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. 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 power generation. 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.

The primary objectives of Idaho Power’s energy purchase and sale activity are to meet the demand of retail electric customers, to maintain appropriate physical reserves to ensure reliability, and to 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 only engages in a nominal amount of trading activity 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

IDACORP is subject to credit risk based on Idaho Power's 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, 2015 , Idaho Power had posted $0.9 million 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 additional 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 energy and fuel portfolio and market conditions as of December 31, 2015 , the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $11.6 million. To minimize capital requirements, Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls through sensitivity analysis.

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 continuously monitors levels of nonpayment from customers and makes any necessary adjustments to its provision for uncollectible accounts accordingly.

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 is exposed to price fluctuations in equity markets, primarily through Idaho Power's defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity security investments at Idaho Power. The equity securities held by the pension plan and in such accounts are diversified to achieve broad market participation and reduce the impact of any single investment, sector, or geographic region. Idaho Power has established asset allocation targets for the pension plan holdings, which are described in Note 11 - "Benefit Plans" to the consolidated financial statements included in this report. Idaho Power has invested a significant portion of its $24.5 million of financial instruments classified as available-for-sale securities in exchange traded short-term bond funds. A hypothetical 5 percent increase in interest rates would result in an approximate $2.4 million decrease in the fair value of available-for-sale securities as of December 31, 2015 .

EXHIBIT IV

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

All other schedules have been omitted because they are not required, not applicable, or the required information is otherwise included.

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 1,151,038	$ 1,122,281	$ 1,101,728
Off-system sales	30,887	77,165	54,473
Other revenues	85,580	79,205	86,897
Total electric utility revenues	1,267,505	1,278,651	1,243,098
Other	2,784	3,873	3,116
Total operating revenues	1,270,289	1,282,524	1,246,214
Operating Expenses:			
Electric utility:			
Purchased power	226,470	244,628	220,579
Fuel expense	186,231	201,241	214,482
Power cost adjustment	16,766	22,235	(39,537)
Other operations and maintenance	342,146	354,567	348,867
Energy efficiency programs	30,532	27,154	35,636
Depreciation	138,110	132,987	129,735
Taxes other than income taxes	32,808	31,748	30,561
Total electric utility expenses	973,063	1,014,560	940,323
Other	15,129	14,268	14,149
Total operating expenses	988,192	1,028,828	954,472
Operating Income	282,097	253,696	291,742
Allowance for Equity Funds Used During Construction	21,785	17,931	14,858
Earnings of Unconsolidated Equity-Method Investments	11,128	12,372	11,939
Other Income, Net	7,159	6,328	17,013
Interest Expense:			
Interest on long-term debt	83,056	80,562	81,492
Other interest	8,922	7,703	7,203
Allowance for borrowed funds used during construction	(10,044)	(8,464)	(7,663)
Total interest expense, net	81,934	79,801	81,032
Income Before Income Taxes	240,235	210,526	254,520
Income Tax Expense	45,760	16,772	72,226
Net Income	194,475	193,754	182,294
Adjustment for loss (income) attributable to noncontrolling interests	204	(274)	123
Net Income Attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Weighted Average Common Shares Outstanding - Basic (000's)	50,220	50,131	50,052
Weighted Average Common Shares Outstanding - Diluted (000's)	50,292	50,199	50,126
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.88	$ 3.86	$ 3.64
Earnings Attributable to IDACORP, Inc. - Diluted	$ 3.87	$ 3.85	$ 3.64

The accompanying notes are an integral part of these statements.

EXHIBIT IV

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2015	**2014**	**2013**
	(thousands of dollars)		
Net Income	$ 194,475	$ 193,754	$ 182,294
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $0 and $1,894	—	—	2,951
Reclassification adjustment for gains included in net income, net of tax of $0, $0 and $4,550	—	—	(7,087)
Net unrealized losses	—	—	(4,136)
Unfunded pension liability adjustment, net of tax of $1,851 $(4,881), and $3,016	2,882	(7,605)	4,699
Total Comprehensive Income	197,357	186,149	182,857
Comprehensive loss (income) attributable to noncontrolling interests	204	(274)	123
Comprehensive Income Attributable to IDACORP, Inc.	$ 197,561	$ 185,875	$ 182,980

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 114,802	$ 56,808
Receivables:		
Customer (net of allowance of $1,196 and $1,960, respectively)	73,505	79,083
Other (net of allowance of $159 and $144, respectively)	8,642	16,018
Income taxes receivable	13,058	11,867
Accrued unbilled revenues	65,805	56,270
Materials and supplies (at average cost)	56,924	55,404
Fuel stock (at average cost)	61,818	55,171
Prepayments	17,979	18,476
Deferred income taxes	—	42,359
Current regulatory assets	49,215	50,042
Other	288	603
Total current assets	462,036	442,101
Investments	140,743	165,424
Property, Plant and Equipment:		
Utility plant in service	5,485,464	5,248,212
Accumulated provision for depreciation	(1,913,927)	(1,841,011)
Utility plant in service - net	3,571,537	3,407,201
Construction work in progress	396,931	401,930
Utility plant held for future use	7,090	7,090
Other property, net of accumulated depreciation	16,855	17,256
Property, plant and equipment - net	3,992,413	3,833,477
Other Assets:		
American Falls and Milner water rights	11,592	13,698
Company-owned life insurance	48,566	23,893
Regulatory assets	1,305,210	1,192,345
Long-term receivables (net of allowance of $552 and $552, respectively)	22,538	6,317
Other	40,216	23,782
Total other assets	1,428,122	1,260,035
Total	$ 6,023,314	$ 5,701,037

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 1,064	$ 1,064
Notes payable	20,000	31,300
Accounts payable	95,526	89,324
Taxes accrued	10,762	10,367
Interest accrued	22,292	22,630
Accrued compensation	42,961	43,774
Current regulatory liabilities	2,217	11,400
Advances from customers	31,214	17,204
Other	16,270	14,718
Total current liabilities	242,306	241,781
Other Liabilities:		
Deferred income taxes	1,137,375	1,065,290
Regulatory liabilities	416,282	390,207
Pension and other postretirement benefits	394,030	403,334
Other	45,867	44,238
Total other liabilities	1,993,554	1,903,069
Long-Term Debt	1,725,410	1,598,622
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 50,352,051 and 50,308,702 shares issued, respectively)	849,112	845,402
Retained earnings	1,230,105	1,132,237
Accumulated other comprehensive loss	(21,276)	(24,158)
Treasury stock (11,221 and 38,764 shares at cost, respectively)	(57)	(280)
Total IDACORP, Inc. shareholders' equity	2,057,884	1,953,201
Noncontrolling interests	4,160	4,364
Total equity	2,062,044	1,957,565
Total	$ 6,023,314	$ 5,701,037

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Activities:			
Net income	$ 194,475	$ 193,754	$ 182,294
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	142,581	137,088	133,776
Deferred income taxes and investment tax credits	38,645	19,163	65,568
Changes in regulatory assets and liabilities	13,699	32,135	(25,581)
Pension and postretirement benefit plan expense	30,207	44,627	45,907
Contributions to pension and postretirement benefit plans	(42,843)	(33,720)	(33,393)
Earnings of unconsolidated equity-method investments	(11,128)	(12,372)	(11,939)
Distributions from unconsolidated equity-method investments	12,458	5,261	17,526
Allowance for equity funds used during construction	(21,785)	(17,931)	(14,858)
Gain on sale of investments and assets	(97)	(193)	(11,678)
Other non-cash adjustments to net income, net	2,788	5,085	3,297
Change in:			
Accounts receivable	4,740	20,433	(29,557)
Accounts payable and other accrued liabilities	2,440	6,359	(517)
Taxes accrued/receivable	818	(13,631)	4,747
Other current assets	(14,861)	(13,124)	(12,165)
Other current liabilities	403	1,771	1,819
Other assets	3,021	(3,655)	(830)
Other liabilities	(2,367)	(6,707)	(8,867)
Net cash provided by operating activities	353,194	364,343	305,549
Investing Activities:			
Additions to property, plant and equipment	(294,021)	(274,094)	(246,674)
Payments received from transmission project joint funding partners	11,377	—	11,364
Purchase of available-for-sale securities	(14,106)	(8,000)	(32,661)
Proceeds from sale of available-for-sale securities	34,243	—	25,661
Purchase of life insurance investment	(30,000)	—	—
Other	801	9,674	5,717
Net cash used in investing activities	(291,706)	(272,420)	(236,593)
Financing Activities:			
Issuance of long-term debt	250,000	—	150,000
Retirement of long-term debt	(121,064)	(1,064)	(71,064)
Dividends on common stock	(96,810)	(88,489)	(78,832)
Net change in short-term borrowings	(11,300)	(23,450)	(14,950)
Issuance of common stock	—	195	255
Acquisition of treasury stock	(3,277)	(2,737)	(2,124)
Make-whole premium on retirement of long-term debt	(17,872)	—	—
Other	(3,171)	2,268	(606)
Net cash used in financing activities	(3,494)	(113,277)	(17,321)
Net increase (decrease) in cash and cash equivalents	57,994	(21,354)	51,635
Cash and cash equivalents at beginning of the year	56,808	78,162	26,527
Cash and cash equivalents at end of the year	$ 114,802	$ 56,808	$ 78,162
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 8,857	$ 11,364	$ 1,437
Interest (net of amount capitalized)	$ 79,442	$ 77,295	$ 77,968
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 23,840	$ 28,438	$ 24,246

EXHIBIT IV

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Statements of Equity

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 845,402	$ 839,750	$ 834,922
Issued	—	195	255
Other	3,710	5,457	4,573
Balance at end of year	849,112	845,402	839,750
Retained Earnings:			
Balance at beginning of year	1,132,237	1,027,461	923,981
Net income attributable to IDACORP, Inc.	194,679	193,480	182,417
Common stock dividends ($1.92, $1.76, and $1.57 per share, respectively)	(96,811)	(88,704)	(78,937)
Balance at end of year	1,230,105	1,132,237	1,027,461
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(24,158)	(16,553)	(17,116)
Net unrealized holding loss on securities (net of tax)	—	—	(4,136)
Unfunded pension liability adjustment (net of tax)	2,882	(7,605)	4,699
Balance at end of year	(21,276)	(24,158)	(16,553)
Treasury Stock:			
Balance at beginning of year	(280)	(8)	(21)
Issued	3,500	2,465	2,137
Acquired	(3,277)	(2,737)	(2,124)
Balance at end of year	(57)	(280)	(8)
Total IDACORP, Inc. shareholders’ equity at end of year	2,057,884	1,953,201	1,850,650
Noncontrolling Interests:			
Balance at beginning of year	4,364	4,090	4,213
Net (loss) income attributable to noncontrolling interests	(204)	274	(123)
Balance at end of year	4,160	4,364	4,090
Total equity at end of year	$ 2,062,044	$ 1,957,565	$ 1,854,740

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Revenues:			
General business	$ 1,151,038	$ 1,122,281	$ 1,101,728
Off-system sales	30,887	77,165	54,473
Other revenues	85,580	79,205	86,897
Total operating revenues	1,267,505	1,278,651	1,243,098
Operating Expenses:			
Operation:			
Purchased power	226,470	244,628	220,579
Fuel expense	186,231	201,241	214,482
Power cost adjustment	16,766	22,235	(39,537)
Other operations and maintenance	342,146	354,567	348,867
Energy efficiency programs	30,532	27,154	35,636
Depreciation	138,110	132,987	129,735
Taxes other than income taxes	32,808	31,748	30,561
Total operating expenses	973,063	1,014,560	940,323
Income from Operations	294,442	264,091	302,775
Other Income (Expense):			
Allowance for equity funds used during construction	21,785	17,931	14,858
Earnings of unconsolidated equity-method investments	9,773	10,814	10,242
Other (expense) income, net	(5,071)	(4,363)	5,772
Total other income	26,487	24,382	30,872
Interest Charges:			
Interest on long-term debt	83,056	80,562	81,492
Other interest	8,706	7,472	6,817
Allowance for borrowed funds used during construction	(10,044)	(8,464)	(7,663)
Total interest charges	81,718	79,570	80,646
Income Before Income Taxes	239,211	208,903	253,001
Income Tax Expense	48,228	19,516	76,260
Net Income	$ 190,983	$ 189,387	$ 176,741

The accompanying notes are an integral part of these statements.

EXHIBIT IV

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Net Income	$ 190,983	$ 189,387	$ 176,741
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $0 and $1,894	—	—	2,951
Reclassification adjustment for gains included in net income, net of tax of $0, $0 and $4,550	—	—	(7,087)
Net unrealized losses	—	—	(4,136)
Unfunded pension liability adjustment, net of tax of $1,851 $(4,881), and $3,016	2,882	(7,605)	4,699
Total Comprehensive Income	$ 193,865	$ 181,782	$ 177,304

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$ 5,485,464	$ 5,248,212
Accumulated provision for depreciation	(1,913,927)	(1,841,011)
In service - net	3,571,537	3,407,201
Construction work in progress	396,931	401,930
Held for future use	7,090	7,090
Electric plant - net	3,975,558	3,816,221
Investments and Other Property	121,267	142,825
Current Assets:		
Cash and cash equivalents	110,756	46,695
Receivables:		
Customer (net of allowance of $1,196 and $1,960, respectively)	73,505	79,083
Other (net of allowance of $159 and $144, respectively)	8,520	15,890
Income taxes receivable	5,432	20,428
Accrued unbilled revenues	65,805	56,270
Materials and supplies (at average cost)	56,924	55,404
Fuel stock (at average cost)	61,818	55,171
Prepayments	17,846	18,356
Current regulatory assets	49,215	50,042
Other	288	603
Total current assets	450,109	397,942
Deferred Debits:		
American Falls and Milner water rights	11,592	13,698
Company-owned life insurance	48,566	23,893
Regulatory assets	1,305,210	1,192,345
Other	56,533	23,937
Total deferred debits	1,421,901	1,253,873
Total	$ 5,968,835	$ 5,610,861

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(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	712,258	712,258
Capital stock expense	(2,097)	(2,097)
Retained earnings	1,127,426	1,033,350
Accumulated other comprehensive loss	(21,276)	(24,158)
Total common stock equity	1,914,188	1,817,230
Long-term debt	1,725,410	1,598,622
Total capitalization	3,639,598	3,415,852
Current Liabilities:		
Current maturities of long-term debt	1,064	1,064
Accounts payable	94,970	88,552
Accounts payable to related parties	1,059	2,027
Taxes accrued	10,745	10,329
Interest accrued	22,292	22,630
Accrued compensation	42,835	43,410
Current regulatory liabilities	2,217	11,400
Advances from customers	31,214	17,204
Other	15,506	20,219
Total current liabilities	221,902	216,835
Deferred Credits:		
Deferred income taxes	1,252,371	1,141,755
Regulatory liabilities	416,282	390,207
Pension and other postretirement benefits	394,030	403,334
Other	44,652	42,878
Total deferred credits	2,107,335	1,978,174
Commitments and Contingencies		
Total	$ 5,968,835	$ 5,610,861

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Activities:			
Net income	$ 190,983	$ 189,387	$ 176,741
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	141,972	136,496	133,135
Deferred income taxes and investment tax credits	25,702	15,454	59,355
Changes in regulatory assets and liabilities	13,699	32,135	(25,581)
Pension and postretirement benefit plan expense	30,185	44,579	45,861
Contributions to pension and postretirement benefit plans	(42,821)	(33,672)	(33,347)
Earnings of unconsolidated equity-method investments	(9,773)	(10,814)	(10,242)
Distributions from unconsolidated equity-method investments	10,833	3,586	14,901
Allowance for equity funds used during construction	(21,785)	(17,931)	(14,858)
Gain on sale of investments and assets	(97)	(186)	(11,678)
Other non-cash adjustments to net income, net	(687)	2,087	629
Change in:			
Accounts receivable	1,998	20,072	(31,472)
Accounts payable	2,646	6,183	(397)
Taxes accrued/receivable	17,179	(22,911)	6,740
Other current assets	(14,849)	(13,137)	(12,166)
Other current liabilities	443	1,776	1,721
Other assets	3,021	(3,655)	(831)
Other liabilities	(2,222)	(6,238)	(8,603)
Net cash provided by operating activities	346,427	343,211	289,908
Investing Activities:			
Additions to utility plant	(293,968)	(273,911)	(246,670)
Payments received from transmission project joint funding partners	11,377	—	11,364
Purchase of available-for-sale securities	(14,106)	(8,000)	(32,661)
Proceeds from the sale of available-for-sale securities	34,243	—	25,661
Purchase of life insurance investment	(30,000)	—	—
Other	706	8,508	3,971
Net cash used in investing activities	(291,748)	(273,403)	(238,335)
Financing Activities:			
Issuance of long-term debt	250,000	—	150,000
Retirement of long-term debt	(121,064)	(1,064)	(71,064)
Dividends on common stock	(96,907)	(88,584)	(78,926)
Make-whole premium on retirement of long-term debt	(17,872)	—	—
Other	(4,775)	—	(2,299)
Net cash provided by (used in) financing activities	9,382	(89,648)	(2,289)
Net increase (decrease) in cash and cash equivalents	64,061	(19,840)	49,284
Cash and cash equivalents at beginning of the year	46,695	66,535	17,251
Cash and cash equivalents at end of the year	$ 110,756	$ 46,695	$ 66,535
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 7,487	$ 26,116	$ 9,667
Interest (net of amount capitalized)	$ 79,226	$ 77,063	$ 77,583
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 23,840	$ 28,438	$ 24,246

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,		
	2015	2014	2013
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 1,033,350	$ 932,547	$ 834,732
Net Income	190,983	189,387	176,741
Dividends on Common Stock	(96,907)	(88,584)	(78,926)
Retained Earnings, End of Year	$ 1,127,426	$ 1,033,350	$ 932,547

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, these 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 area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily 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 wholly-owned 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 Services Co. (IESCo), which is the former limited partner of, and current successor by merger to, IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the assets, liabilities, revenues and expenses of each company and its wholly-owned subsidiaries listed above, as well as any variable interest entities (VIEs) for which the respective company is the primary beneficiary. 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.

IDACORP also consolidates one variable interest entity (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, 2015 , Marysville had approximately $19 million of assets, primarily a hydroelectric plant, and approximately $12 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 from Marysville and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is identified as the primary beneficiary because the combination of its ownership interest in the joint venture with the intercompany note and the EEC note result in Ida-West's ability to control the activities of the joint ventures. 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.

The BCC joint venture is also a VIE, but because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner, Idaho Power is not the primary beneficiary. The carrying value of BCC was $95 million at December 31, 2015 , and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $73 million guarantee for mine reclamation costs, which is discussed further in Note 9.

IFS's affordable housing limited partnership and other real estate investments are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 5 to 99 percent and were acquired between 1996 and 2010. As a limited partner, IFS does not control these entities and they are not consolidated. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $10 million at December 31, 2015 .

Ida-West's other investments in PURPA facilities, BCC and IFS's investments are accounted for under the equity method of accounting (see Note 14).

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Except for amounts related to sales of electricity by Ida-West's PURPA projects to Idaho Power, all intercompany transactions and balances have been eliminated in consolidation.

The accompanying consolidated financial statements include Idaho Power's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 12).

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

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition.

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 record such expenses and revenues. In these instances, the amounts are deferred or accrued 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 that are expected to be refunded. 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.

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, 2015 and 2014 . Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

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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 unless they are designated as normal purchases and normal sales. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities and a nominal number of power transactions, Idaho Power's physical forward contracts are designated as normal purchases and normal sales. 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. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho;
- franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement; and
- collection in base rates of a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex (HCC) relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead deferred 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 2.68 percent in 2015 , 2.68 percent in 2014 , and 2.69 percent in 2013 .

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as construction work in progress on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. Idaho Power may seek recovery of such costs in customer rates, although there can be no guarantee such recovery would be granted.

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 is recognized in the financial statements. There were no material impairments of long-lived assets in 2015 , 2014 , or 2013 .

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the HCC relicensing project, 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 total interest expense. Idaho Power's weighted-average monthly AFUDC rate was 7.6 percent for 2015 , and 7.7 percent for both 2014 and 2013 .

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 (commonly referred to as normalized accounting), 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. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities from the beginning to the end of the period. 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 unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not provide deferred income taxes for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are provided for other temporary differences unless accounted for using flow-through.

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.

Other Accounting Policies

Debt discount, expense, and premium are deferred and amortized over the terms of the respective debt issues. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

Supplemental Cash Flows Information

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million . Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged.

Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

Reclassifications

Certain prior year amounts on IDACORP's and Idaho Power's consolidated balance sheets and consolidated statements of cash flows have been reclassified to conform to the current year presentation. Advances from customers are now classified in a separate line in current liabilities on the balance sheet. Previously, such amounts were presented in accounts payable or other in current liabilities. Also, payments received from transmission funding joint project partners are now presented in a separate line in investing cash flows on the cash flows statement. Previously, these amounts were netted against additions to property, plant and equipment.

Recently Issued Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-03, *Interest - Imputation of Interest (Subtopic 835-30) Simplifying the Presentation of Debt Issuance Costs,* which changed the required balance sheet presentation of debt issuance costs. The ASU requires that debt issuance costs be reported as reductions of long-term debt rather than as long-term assets. As allowed, IDACORP and Idaho Power elected to early-adopt the provisions of this ASU for its December 31, 2015 financial statements; retrospective application is required. Debt issuance costs of $16.5 million and $15.8 million at December 31, 2015 and 2014, respectively, are now reported as reductions of long-term debt. These costs were previously presented as other assets and other deferred debits on IDACORP's and Idaho Power's respective balance sheets. See Note 4 for a discussion of long-term debt.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740) - Balance Sheet Classification of Deferred Taxes,* which requires that all deferred taxes be presented as non-current. As allowed, IDACORP and Idaho Power elected to early-adopt the provisions of this ASU for its December 31, 2015 balance sheets. Also as allowed, prior periods were not retrospectively adjusted.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* . ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted one year earlier. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendments focus on limited partnerships and similar legal entities, and is effective for interim and annual reporting periods beginning after December 31, 2015. IDACORP and Idaho Power do not believe the impact of ASU 2015-02 on their financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. IDACORP and Idaho Power are currently evaluating the impact of ASU 2016-01 on their financial statements.

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2. INCOME TAXES

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

	IDACORP			Idaho Power		
	2015	2014	2013	2015	2014	2013
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$ 84,154	$ 73,588	$ 89,125	$ 83,724	$ 73,116	$ 88,550
Change in taxes resulting from:						
AFUDC	(11,140)	(9,238)	(7,882)	(11,140)	(9,238)	(7,882)
Capitalized interest	2,693	2,278	1,832	2,693	2,278	1,832
Investment tax credits	(2,963)	(3,002)	(3,119)	(2,963)	(3,002)	(3,119)
Removal costs	(4,807)	(3,656)	(3,527)	(4,807)	(3,656)	(3,527)
Capitalized overhead costs	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)
Capitalized repair costs	(28,700)	(26,250)	(19,250)	(28,700)	(26,250)	(19,250)
Bond redemption costs	(6,459)	—	—	(6,459)	—	—
Tax method change – capitalized repairs	—	(24,516)	4,583	—	(24,516)	4,583
State income taxes, net of federal benefit	7,343	4,680	6,730	7,503	5,334	6,970
Depreciation	17,149	16,040	14,820	17,149	16,040	14,820
Affordable housing tax credits	(3,258)	(5,189)	(5,503)	—	—	—
Affordable housing investment amortization	1,519	2,757	1,684	—	—	—
Other, net	(1,021)	(1,970)	1,483	(22)	(1,840)	2,033
Total income tax expense	$ 45,760	$ 16,772	$ 72,226	$ 48,228	$ 19,516	$ 76,260
Effective tax rate	19.0%	8.0%	28.4%	20.2%	9.3%	30.1%

The items comprising income tax expense are as follows:

	IDACORP			Idaho Power		
	2015	2014	2013	2015	2014	2013
	(thousands of dollars)					
Income taxes current:						
Federal	$ 4,831	$ (4,926)	$ 3,416	$ 16,470	$ (2,805)	$ 10,988
State	2,704	3,516	3,241	6,056	6,867	5,917
Total	7,535	(1,410)	6,657	22,526	4,062	16,905
Income taxes deferred:						
Federal	34,770	17,159	61,947	27,696	21,833	60,934
State	626	(3,260)	1,806	(2,486)	(6,421)	(804)
Total	35,396	13,899	63,753	25,210	15,412	60,130
Investment tax credits:						
Deferred	3,455	3,044	2,344	3,455	3,044	2,344
Restored	(2,963)	(3,002)	(3,119)	(2,963)	(3,002)	(3,119)
Total	492	42	(775)	492	42	(775)
Affordable housing investment amortization	2,337	4,241	2,591	—	—	—
Total income tax expense	$ 45,760	$ 16,772	$ 72,226	$ 48,228	$ 19,516	$ 76,260

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

	IDACORP		Idaho Power	
	2015	2014	2015	2014
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 51,131	$ 55,490	$ 51,131	$ 55,490
Deferred compensation	27,573	25,355	27,489	25,240
Deferred revenue	34,282	28,529	34,282	28,529
Tax credits	147,299	154,044	30,307	26,843
Partnership investments	7,220	8,190	—	—
Retirement benefits	126,885	132,571	126,885	132,571
Other	11,245	15,222	10,745	14,553
Total	405,635	419,401	280,839	283,226
Deferred tax liabilities:				
Property, plant and equipment	474,879	451,118	474,879	451,118
Regulatory assets	875,028	802,188	875,028	802,188
Power cost adjustments	18,489	23,192	18,489	23,192
Partnership investments	16,925	17,492	9,829	10,227
Retirement benefits	126,090	122,360	126,090	122,360
Other	31,600	25,982	28,895	22,252
Total	1,543,011	1,442,332	1,533,210	1,431,337
Net deferred tax liabilities	$ 1,137,376	$ 1,022,931	$ 1,252,371	$ 1,148,111

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. See Note 1 for further discussion of accounting policies related to income taxes.

Tax Credit Carryforwards

As of December 31, 2015, IDACORP had $108.7 million of general business credit and $0.7 million of alternative minimum tax credit carryforwards for federal income tax purposes and $37.9 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2035 , and the Idaho investment tax credit expires from 2021 to 2029 .

Uncertain Tax Positions

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2015 and prior tax years. Both companies recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

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 for examination are 2015 for federal and 2012-2015 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. In 2015, t he IRS completed its examination of IDACORP's 2014 tax year with no unresolved income tax issues.

Tax Accounting Method Changes for Repair-Related Expenditures

In the fourth quarter of 2014, Idaho Power finalized an income tax accounting method change for its 2014 tax year associated with the electric generation property portion of its capitalized repairs tax method it adopted in fiscal year 2010. As a result of the change, Idaho Power recorded an $8.8 million tax benefit related to the cumulative method change adjustment for years prior to 2014 and reversed a related $4.6 million tax expense estimate it had recorded in 2013 (discussed below).

The method change was pursuant to Revenue Procedure 2013-24 and brought Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric generation property. The change also incorporated provisions of the final tangible property regulations issued by the U.S. Treasury Department and IRS in 2013 that addressed the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP’s 2014 consolidated federal income tax return in September 2015. The IRS approved the method change prior to the filing of the return as part of IDACORP’s 2014 CAP examination.

In the third quarter of 2014 Idaho Power, in coordination with the IRS through IDACORP’s CAP examination process, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in the third quarter of 2014. Idaho Power finalized these changes with the filing of IDACORP’s 2013 consolidated federal income tax return in September 2014. The IRS approved the repairs method modifications prior to the filing of the return as part of IDACORP’s 2013 CAP examination.

In connection with the issuance of the tangible property regulations and following the provisions of Revenue Procedure 2013-24 (discussed above), in 2013 Idaho Power assessed and estimated the impact of a method change associated with the electric generation property portion of its capitalized repairs method. Based upon this assessment, in 2013 Idaho Power recorded $4.6 million of income tax expense related to the estimated cumulative method change adjustment for years prior to 2013.

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3. REGULATORY MATTERS

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters.

Regulatory Assets and Liabilities

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 record such expenses and revenues. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense. The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	As of December 31, 2015 Earning a Return [1]	As of December 31, 2015 Not Earning a Return	Total as of December 31, 2015	Total as of December 31, 2014
Regulatory Assets:					
Income taxes		$ —	$ 875,027	$ 875,027	$ 802,188
Unfunded postretirement benefits [2]		—	251,762	251,762	264,548
Pension expense deferrals		62,642	23,148	85,790	63,644
Energy efficiency program costs [3]		4,482	—	4,482	4,690
Power supply costs [4]	Varies	47,220	—	47,220	59,189
Fixed cost adjustment [4]	2016-2017	36,820	—	36,820	23,737
Asset retirement obligations [5]		—	14,410	14,410	17,309
Mark-to-market liabilities [6]		—	4,973	4,973	3,961
Long-term service agreement [7]	2043	18,592	11,633	30,225	—
Other	2016-2021	1,096	2,620	3,716	3,121
Total		$ 170,852	$ 1,183,573	$ 1,354,425	$ 1,242,387
Regulatory Liabilities:					
Income taxes		$ —	$ 51,131	$ 51,131	$ 55,490
Removal costs [5]		—	183,505	183,505	180,063
Investment tax credits		—	79,655	79,655	79,163
Deferred revenue-AFUDC [8]		58,835	28,855	87,690	72,975
Energy efficiency program costs [3]		6,554	—	6,554	—
Power supply costs [4]		—	—	—	1
Settlement agreement sharing mechanism [4]	2016-2017	3,159	—	3,159	7,999
Mark-to-market assets [6]		—	405	405	1,880
Other		5,219	1,180	6,399	4,036
Total		$ 73,767	$ 344,731	$ 418,498	$ 401,607

(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) The 2015 energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance. Both jurisdiction's balances were assets at December 31, 2014.
(4) These items are discussed in more detail in this Note 3.
(5) Asset retirement obligations and removal costs are discussed in Note 13.
(6) Mark-to-market assets and liabilities are discussed in Note 16.
(7) A portion not earning a return as of December 31, 2015 will be eligible to earn a return as of January 1, 2018.
(8) Idaho Power is collecting revenue in the Idaho jurisdiction for AFUDC on HCC relicensing costs but is deferring revenue recognition of the amounts collected until the license is issued and the asset is placed in service under the new license.

Idaho Power's regulatory assets and liabilities are typically 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 materially adverse 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 net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs being recovered. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs are recorded as a deferred charge or credit on the balance sheets for future recovery or refund. The power supply costs deferred primarily result from changes in contracted power purchase prices and volumes, changes in wholesale market prices and transaction volumes, fuel prices, and the levels of Idaho Power's own generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustment consists of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared with net power supply costs included 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 exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three most recent Idaho PCA rate adjustments, all of which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	$ Change (millions)	Notes
June 1, 2015	$ (11.6)	The net decrease in Idaho PCA rates included the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of the December 2011 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds.
June 1, 2014	$ (88.2)	2014 PCA rates are net of (a) $20.0 million of surplus Idaho energy efficiency rider funds, and (b) $7.6 million of customer revenue sharing under a regulatory settlement stipulation. In addition, on June 1, 2014, there was an increase in base net power supply costs that shifted $99.3 million in power supply expenses from recovery via the PCA mechanism to recovery via base rates. The shifting of base net power supply costs is discussed in more detail below.
June 1, 2013	$ 140.4	The 2013 PCA rate increase was net of $7.2 million of customer revenue sharing under regulatory settlement stipulations.

In March 2014, the IPUC issued an order approving Idaho Power's application requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties further evaluated Idaho Power's application of the true-up component of the PCA mechanism and whether a deferral balance adjustment was appropriate. While the IPUC's docket was closed in August 2014 with no adjustment to the PCA true-up revenue amount, Idaho Power subsequently met with the IPUC Staff to explore approaches to increasing the accuracy of the actual cost recovery under the PCA mechanism. In May 2015, the IPUC approved a settlement stipulation that resulted in the replacement of the existing load-based adjustment used for determining the power cost deferrals under the PCA mechanism with a similar sales-based adjustment. The sales-based adjustment functions in the same manner as the previous load-based adjustment but measures deviations between Idaho-specific test year sales and actual Idaho sales rather than deviations between test year loads and actual loads. The approved settlement stipulation implemented the new methodology as of January 1, 2015.

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 Oregon-jurisdictional 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 2015, 2014, and 2013 are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2015 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2015 APCU	A rate decrease of $0.7 million annually took effect June 1, 2015.
2014 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.
2013 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2013 APCU	A rate increase of $2.9 million annually took effect June 1, 2013.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014. Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from IPUC approval of a settlement stipulation that provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion . The settlement stipulation resulted in a 4.07 percent , or $34.0 million , overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. Idaho base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. In June 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Neither the settlement stipulation nor the IPUC orders adjusting base rates specified an authorized rate of return on equity or imposed a moratorium on Idaho Power filing a general rate case at a future date.

As noted above in this Note 3, the IPUC also issued a March 2014 order approving Idaho Power's request for an increase in the normalized or "base level" net power supply expense to be used to update base rates and in the determination of the Idaho PCA rate that became effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: In December 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that provided as follows:

- If Idaho Power's actual Idaho-jurisdiction return on year-end equity (Idaho ROE) for 2012, 2013, or 2014 was less than 9.5 percent , then Idaho Power may amortize up to a total of $45 million of additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum 9.5 percent Idaho ROE in the applicable year.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeded 10.0 percent , the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA mechanism adjustment.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeded 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 as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

As Idaho Power's Idaho ROE exceeded 10.5 percent for each of 2012, 2013, and 2014, Idaho Power did not amortize additional ADITC for those years, but instead shared a portion of its Idaho-jurisdiction earnings with Idaho customers. The amounts

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Idaho Power recorded in each of 2012, 2013, and 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation were as follows (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense
2014	$8.0	$16.7
2013	$7.6	$16.5
2012	$7.2	$14.6

October 2014 Idaho Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation are as follows:

- If Idaho Power's annual Idaho ROE in any year is less than 9.5 percent , then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.5 percent Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.0 percent , the amount of earnings exceeding a 10.0 percent Idaho ROE and up to and including a 10.5 percent Idaho ROE will be allocated 75 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment and 25 percent to Idaho Power.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.5 percent , the amount of earnings exceeding a 10.5 percent Idaho ROE will be allocated 50 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension expense deferral regulatory asset (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to Idaho Power's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5 percent , 10.0 percent , and 10.5 percent) will be adjusted prospectively.

Neither the settlement stipulation nor the associated IPUC order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the term of the settlement stipulation.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015 under the October 2014 Idaho settlement stipulation, as its Idaho ROE for 2015 was above 10.0 percent .

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism is designed to remove Idaho Power’s financial 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 mechanism is adjusted each year to collect, or refund, the difference between the authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in the FCA recovery is capped at no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The following table summarizes FCA amounts approved for collection in the prior three FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2014	June 1, 2015-May 31, 2016	$16.9
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

In July 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA mechanism (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA charges effective June 1, 2016.

Notable Oregon Regulatory Matters

Oregon Base Rate Changes: Oregon base rates were most recently established in a general rate case in 2012. In February 2012, the OPUC issued an order approving a settlement stipulation that provided for a $1.8 million base rate increase, a return on equity of 9.9 percent , and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. Subsequently, in September 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

Idaho Power uses a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based primarily 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, 2015 to September 30, 2016	$ 23.43
October 1, 2014 to September 30, 2015	$ 22.48
October 1, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.29

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $121.3 million , which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

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4. LONG-TERM DEBT

The following table summarizes IDACORP's and Idaho Power's long-term debt at December 31 (in thousands of dollars):

	2015	2014
First mortgage bonds:		
6.025% Series due 2018	$ —	$ 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
2.95% Series due 2022	75,000	75,000
2.50% Series due 2023	75,000	75,000
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
4.30% Series due 2042	75,000	75,000
4.00% Series due 2043	75,000	75,000
3.65% Series Due 2045	250,000	—
Total first mortgage bonds	1,555,000	1,425,000
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	2,127	3,191
Unamortized issuance costs and discounts	(20,998)	(18,850)
Total IDACORP and Idaho Power outstanding debt (2)	1,726,474	1,599,686
Current maturities of long-term debt	(1,064)	(1,064)
Total long-term debt	$ 1,725,410	$ 1,598,622

(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, 2015 to $1.721 billion .
(2) At December 31, 2015 and 2014 , the overall effective cost of Idaho Power's outstanding debt was 4.96 percent and 5.19 percent , respectively.

At December 31, 2015 , the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2016	2017	2018	2019	2020	Thereafter
$ 1,064	$ 1,064	$ —	$ 100,000	$ 230,000	$ 1,415,344

Long-Term Debt Issuances, Maturities, and Availability

On March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes, Series H due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million . Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April 2013, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. On April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a maximum interest rate limit of seven percent .

On May 22, 2013, IDACORP and Idaho Power filed a joint shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of, in the case of Idaho Power, an unspecified principal amount of its first mortgage bonds and debt securities. On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight 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, secured medium term notes, Series J (Series J Notes), under Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes pursuant to the Indenture. As of December 31, 2015 , $250 million in principal amount of Series J Notes remained available for issuance under the Indenture.

Mortgage **:** As of December 31, 2015 , Idaho Power could issue under its Indenture approximately $1.5 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 Indenture.

The mortgage of the Indenture 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 of the Indenture. The lien 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 of the Indenture 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 of the Indenture 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 Indenture 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 Indenture for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 billion . The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. Idaho Power may amend the Indenture and increase this amount without consent of the holders of the first mortgage bonds. The Indenture 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 November 6, 2015, IDACORP and Idaho Power entered into Credit Agreements replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide credit facilities that 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 $100 million , including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 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 , and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 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 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, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent . 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 credit 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. The credit facilities mature on November 6, 2020, though IDACORP and Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

At December 31, 2015 , no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2015 , Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of IDACORP’s and Idaho Power's short-term borrowings were as follows at December 31, 2015 and December 31, 2014 :

	IDACORP		Idaho Power		Total	
	2015	2014	2015	2014	2015	2014
Commercial paper balances:						
At the end of year	$ 20,000	$ 31,300	$ —	$ —	$ 20,000	$ 31,300
Average during the year	$ 22,054	$ 37,786	$ —	$ —	$ 22,054	$ 37,786
Weighted-average interest rate						
At the end of the year	0.88%	0.43%	—%	—%	0.88%	0.43%

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes IDACORP common stock transactions during the last three years and shares reserved at December 31, 2015 :

	Shares issued			Shares reserved
	2015	2014	2013	December 31, 2015
Balance at beginning of year	50,308,702	50,233,463	50,158,486	
Continuous equity program	—	—	—	3,000,000
Dividend reinvestment and stock purchase plan	—	—	—	2,576,723
Employee savings plan	—	—	—	3,567,954
Long-term incentive and compensation plan	43,349	75,239	74,977	1,424,695
Restricted stock plan	—	—	—	256,154
Balance at end of year	50,352,051	50,308,702	50,233,463	

IDACORP has historically entered into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. On July 12, 2013, IDACORP entered into its current Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM). Under the agreement, IDACORP may offer and sell up to 3 million shares of its common stock from time to time in at-the-market offerings through BNYMCM as IDACORP's agent. IDACORP has no obligation to issue any minimum number of shares under the Sales Agency Agreement. As of the date of this report, no shares of IDACORP common stock have been issued under the current Sales Agency Agreement.

Restrictions on Dividends

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. 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. At December 31, 2015 , the leverage ratios for IDACORP and Idaho Power were 46 percent and 48 percent , respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $1.1 billion and $980 million , respectively, at December 31, 2015 . There are additional facility covenants, subject to exceptions, that prohibit or restrict the sale or disposition of property without consent and any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2015 , IDACORP and Idaho Power were in compliance with those covenants.

Idaho Power's Revised Policy and Code of Conduct relating to transactions between and among Idaho Power, IDACORP, and other affiliates, which was approved by the IPUC in April 2008, provides 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. At December 31, 2015 , Idaho Power's common equity capital was 52 percent of its total adjusted capital. Further, Idaho Power must obtain approval from 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. As of the date of this report, 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 account" is undefined in the Federal Power Act or its regulations, but Idaho Power does not believe the restriction would limit Idaho Power's ability to pay dividends out of current year earnings or retained earnings.

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 stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP (for officers and key employees) permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2015 , the maximum number of shares available under the LTICP and RSP were 1,043,542 and 15,796 , respectively, excluding (i) issued but unvested performance-based restricted shares and (ii) issued but unvested time-based restricted shares.

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 closing 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 the attainment of specific performance conditions over the three-year vesting period. The performance conditions are two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. Depending on the level of attainment of the performance conditions and the year issued, the final number of shares awarded can range from zero to 150 percent of the target award for awards granted prior to 2015 and from zero to 200 percent of the target award for awards granted in 2015. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The grant-date fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The grant-date fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

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, 2015	255,073	$ 43.90	250,396	$ 43.91
Shares granted	116,781	54.01	115,863	54.05
Shares forfeited	(10,904)	55.32	(10,413)	55.63
Shares vested	(130,130)	36.91	(127,056)	36.84
Nonvested shares at December 31, 2015	230,820	$ 52.41	228,790	$ 52.44

The total fair value of shares vested during the years ended December 31, 2015 , 2014 , and 2013 was $8.3 million , $6.6 million , and $5.0 million , respectively. At December 31, 2015 , IDACORP had $4.7 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 $4.7 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 2015 , a total of 15,324 shares were awarded to directors at a grant date fair value of $62.62 per share. Directors elected to defer receipt of 3,831 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

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		
	2015	2014	2013	2015	2014	2013
Compensation cost	$ 5,299	$ 5,609	$ 4,888	$ 5,221	$ 5,458	$ 4,783
Income tax benefit	2,072	2,193	1,911	2,042	2,134	1,870

No equity compensation costs have been capitalized.

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8. EARNINGS PER SHARE

The following table presents the computation of IDACORP’s basic and diluted earnings per share for the years ended December 31, 2015 , 2014 , and 2013 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2015	2014	2013
Numerator:			
Net income attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Denominator:			
Weighted-average common shares outstanding - basic	50,220	50,131	50,052
Effect of dilutive securities	72	68	74
Weighted-average common shares outstanding - diluted	50,292	50,199	50,126
Basic earnings per share	$ 3.88	$ 3.86	$ 3.64
Diluted earnings per share	$ 3.87	$ 3.85	$ 3.64

9. COMMITMENTS

Purchase Obligations

At December 31, 2015 , Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2016	2017	2018	2019	2020	Thereafter
Cogeneration and power production	$ 199,156	$ 233,197	$ 241,356	$ 234,772	$ 234,316	$ 3,592,891
Fuel	60,122	43,276	16,206	9,169	8,833	114,417

As of December 31, 2015 , Idaho Power had 784 MW nameplate capacity of PURPA-related projects on-line, with an additional 448 MW nameplate capacity of projects projected to be on-line by June 1, 2017 . Of the 448 MW nameplate capacity of projected PURPA-related projects at the end of 2015, as of February 5, 2016, three contracts with solar projects with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. Idaho Power's expenses associated with PURPA-related projects were approximately $131 million in 2015 , $145 million in 2014 , and $131 million in 2013 .

Idaho Power also has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousands of dollars):

	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 233	$ 971	$ 985	$ 1,062	$ 897	$ 12,625
Equipment, maintenance, and service agreements	48,707	11,703	14,869	9,214	12,095	83,721
FERC and other industry-related fees	12,894	12,746	12,746	8,632	5,942	29,708

IDACORP’s expense for operating leases was approximately $4.4 million in 2015 , $5.9 million in 2014 , and $5.3 million in 2013 .

Guarantees

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was $73 million at December 31, 2015 , representing IERCo's one-third share of BCC's total reclamation obligation. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2015 , the value of the reclamation trust fund was $70 million . During 2015 , the reclamation trust fund distributed approximately $6 million for reclamation activity costs associated with the BCC surface mine. 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, all of which are made to the Jim Bridger plant. 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, 2015 , 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. 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, 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 loss contingencies 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. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in the western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings to consider requiring refunds and other forms of disgorgement from energy sellers. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit, and thus there remains some uncertainty about the ultimate outcome of the proceedings. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that the current state of the FERC's orders, if maintained, and the settlement releases they have obtained, will restrict potential claims that might result from the pending proceedings. As a result, IDACORP and Idaho Power predict that these matters will not have a material adverse effect on their respective results of operations or financial condition. However, if unanticipated orders are issued by the FERC or by the Ninth Circuit Court of Appeals or other courts, exposure to indirect claims in the proceedings could exist. These indirect claims would consist of so-called "ripple claims," which involve potential claims for refunds in the Pacific Northwest markets from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. Given the speculative nature of ripple claims and in light of Idaho Power's and IESCo participating in the market as both a buyer and seller of energy, Idaho Power and IESCo are unable to estimate the possible loss or range of loss that could result from the proceedings and have no amount accrued relating to the proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Hoku Corporation Bankruptcy Claims

On June 26, 2015, the trustee in the Hoku Corporation chapter 7 bankruptcy case (*In Re: Hoku Corporation* , United States Bankruptcy Court, District of Idaho, Case No. 13-40838 JDP) filed a complaint against Idaho Power, alleging that specified payments made by Hoku Corporation to Idaho Power in the six years prior to Hoku Corporation's bankruptcy filing in July 2013 should be recoverable by the trustee as constructive fraudulent transfers. Hoku Corporation was the parent entity of Hoku Materials, Inc., with which Idaho Power had an electric service agreement approved by the IPUC in March 2009. Under the electric service agreement, Idaho Power agreed to provide electric service to a polysilicon production facility under construction by Hoku Materials in the state of Idaho. Idaho Power also had agreements with Hoku Materials pertaining to the design and construction of apparatus for the provision of electric service to the polysilicon plant. The trustee's complaint against Idaho Power includes alternative causes of action for constructive fraudulent transfer under the federal bankruptcy code, Idaho law, and federal law, with requests for recovery from Idaho Power in amounts up to approximately $36 million . The complaint alleges that the payments made by Hoku Corporation to Idaho Power are subject to recovery by the trustee on the basis that Hoku Corporation was insolvent at the time of the payments and did not have any legal or equitable title in the polysilicon plant or liability for Hoku Materials' debts, and thus did not receive reasonably equivalent value for the payments it made for or on behalf of Hoku Materials.

As of the date of this report, the proceedings are in preliminary stages and it is not possible to determine Idaho Power's potential liability, if any, or to reasonably estimate a possible loss or range of possible loss, if any, within the trustee's alternative prayers for relief. Idaho Power intends to vigorously defend against the claims.

Other Proceedings

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, record an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the companies believe that resolution of those matters will not have a material adverse effect on their respective consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to estimate the financial impact of these regulations. However, Idaho Power does believe that future capital investment for infrastructure and modifications to its electric generating facilities could be significant to comply with these regulations.

11. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. Idaho Power also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power has two pension plans–a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit pension plan for certain senior management employees called the Security Plan for Senior Management Employees (SMSP). Idaho Power also has a nonqualified defined benefit pension plan for directors that was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power’s funding policy for the pension plan is to contribute 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 2015 , 2014 , and 2013 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

	Pension Plan		SMSP	
	2015	2014	2015	2014
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 844,812	$ 695,093	$ 94,410	$ 77,773
Service cost	33,164	25,292	1,689	1,645
Interest cost	35,171	35,415	3,868	3,856
Actuarial (gain) loss	(47,952)	114,496	(352)	15,324
Benefits paid	(29,672)	(25,484)	(4,226)	(4,188)
Projected benefit obligation at December 31	835,523	844,812	95,389	94,410
Change in plan assets:				
Fair value at January 1	559,719	545,092	—	—
Actual return on plan assets	(9,431)	10,111	—	—
Employer contributions	39,000	30,000	—	—
Benefits paid	(29,672)	(25,484)	—	—
Fair value at December 31	559,616	559,719	—	—
Funded status at end of year	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,423)	$ (4,193)
Noncurrent liabilities	(275,907)	(285,093)	(90,966)	(90,217)
Net amount recognized	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 253,212	$ 263,350	$ 34,260	$ 38,808
Prior service cost	74	295	673	857
Subtotal	253,286	263,645	34,933	39,665
Less amount recorded as regulatory asset	(253,286)	(263,645)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,933	$ 39,665
Accumulated benefit obligation	$ 714,994	$ 719,617	$ 86,838	$ 84,684

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. The recorded value of these investments was approximately $69.3 million and $65.0 million at December 31, 2015 and 2014 , respectively, and is reflected in Investments and in Company-owned life insurance on the consolidated balance sheets.

The following table shows the components of net periodic benefit cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan			SMSP		
	2015	2014	2013	2015	2014	2013
Service cost	$ 33,164	$ 25,292	$ 31,357	$ 1,689	$ 1,645	$ 2,178
Interest cost	35,171	35,415	31,830	3,868	3,856	3,258
Expected return on assets	(42,310)	(42,289)	(35,755)	—	—	—
Amortization of net loss	13,927	3,911	17,118	4,195	2,618	2,840
Amortization of prior service cost	221	347	347	185	220	212
Net periodic pension cost	40,173	22,676	44,897	9,937	8,339	8,488
Adjustments due to the effects of regulation [1]	(21,173)	12,124	(9,013)	—	—	—
Net periodic benefit cost recognized for financial reporting	$ 19,000	$ 34,800	$ 35,884	$ 9,937	$ 8,339	$ 8,488

[1] Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates.

The following table shows the components of other comprehensive income for the plans (in thousands of dollars):

	Pension Plan			SMSP		
	2015	2014	2013	2015	2014	2013
Actuarial (loss) gain during the year	$ (3,790)	$ (146,674)	$ 154,261	$ 353	$ (15,324)	$ 4,664
Reclassification adjustments for:						
Amortization of net loss	13,927	3,911	17,118	4,195	2,618	2,840
Amortization of prior service cost	221	347	347	185	220	212
Adjustment for deferred tax effects	(4,050)	55,678	(67,136)	(1,851)	4,881	(3,017)
Adjustment due to the effects of regulation	(6,308)	86,738	(104,590)	—	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ —	$ 2,882	$ (7,605)	$ 4,699

In 2016 , IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $17.3 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2015 , relating to the pension plan and SMSP. This amount consists of $13.5 million of amortization of net loss and $0.1 million of amortization of prior service cost for the pension plan, and $3.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2016	2017	2018	2019	2020	2021-2025
Pension Plan	$ 30,086	$ 32,529	$ 35,156	$ 37,795	$ 40,527	$ 241,079
SMSP	4,516	4,582	4,371	4,547	4,964	25,659

As of December 31, 2015 , IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2016 , though Idaho Power plans to contribute at least $20 million to the pension plan during 2016 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active-employee group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power’s future obligations under this plan.

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

	2015	2014
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 65,999	$ 57,341
Service cost	1,235	1,011
Interest cost	2,678	2,841
Actuarial (gain) loss	(5,008)	7,026
Benefits paid [(1)]	(2,511)	(2,220)
Benefit obligation at December 31	62,393	65,999
Change in plan assets:		
Fair value of plan assets at January 1	38,375	37,111
Actual return on plan assets	85	3,888
Employer contributions [(1)]	(383)	(404)
Benefits paid [(1)]	(2,511)	(2,220)
Fair value of plan assets at December 31	35,566	38,375
Funded status at end of year (included in noncurrent liabilities)	$ (26,827)	$ (27,624)

[(1)] Contributions and benefits paid are each net of $3,518 thousand and $3,379 thousand of plan participant contributions, and $330 thousand and $344 thousand of Medicare Part D subsidy receipts for 2015 and 2014 , respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2015	2014
Net (gain) loss	$ (1,654)	$ 759
Prior service cost	130	145
Subtotal	(1,524)	904
Less amount recognized in regulatory assets	1,524	(904)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2015	2014	2013
Service cost	$ 1,235	$ 1,011	$ 1,315
Interest cost	2,678	2,841	2,633
Expected return on plan assets	(2,680)	(2,595)	(2,328)
Amortization of net loss	—	—	98
Amortization of prior service cost	15	183	(229)
Net periodic postretirement benefit cost	$ 1,248	$ 1,440	$ 1,489

The following table shows the components of other comprehensive income for the plan (in thousands of dollars):

	2015	2014	2013
Actuarial gain (loss) during the year	$ 2,413	$ (5,733)	$ 20,673
Reclassification adjustments for:			
Amortization of net loss	—	—	98
Amortization of prior service cost	15	183	(229)
Adjustment for deferred tax effects	(949)	2,170	(8,031)
Adjustment due to the effects of regulation	(1,479)	3,380	(12,511)
Other comprehensive income related to postretirement benefit plans	$ —	$ —	$ —

In 2016 , IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $26 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2015 , relating to the postretirement benefit plan. The entire amount represents $26 thousand of amortization of prior service cost.

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

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

	2016	2017	2018	2019	2020	2021-2025
Expected benefit payments	$ 4,010	$ 4,050	$ 4,100	$ 4,150	$ 4,190	$ 21,030
Expected Medicare Part D subsidy receipts	380	430	470	510	560	3,480

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2015	2014	2015	2014	2015	2014
Discount rate	4.60%	4.25%	4.60%	4.20%	4.60%	4.20%
Rate of compensation increase [(1)]	4.11%	4.30%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014

[(1)] The 2015 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.61% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

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

	Pension Plan			SMSP			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Discount rate	4.25%	5.20%	4.20%	4.20%	5.10%	4.15%	4.20%	5.15%	4.20%
Expected long-term rate of return on assets	7.50%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.11%	4.30%	4.38%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	9.7%	6.4%	6.8%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

In October 2014, the Society of Actuaries released a new set of mortality tables referred to as RP-2014. Mortality tables are used by defined benefit plans to estimate the life expectancy of plan participants and the expected length of benefit payments in retirement. Idaho Power's measurement of its plan benefit obligations as of December 31, 2015 and 2014, and its net periodic benefit cost for 2015, reflect the adoption of the new tables, which was not material.

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The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 9.7 percent in 2015 and is assumed to decrease to 8.3 percent in 2016, 6.8 percent in 2017, 5.4 percent in 2018 and to gradually decrease to 4.8 percent by 2099 . The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent , or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2015 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 407	$ (297)
Effect on accumulated postretirement benefit obligation	3,719	(2,838)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2015 for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2015
Debt securities	24%	25%
Equity securities	54%	55%
Real estate	6%	7%
Other plan assets	16%	13%
Total	100%	100%

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

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

The three major goals in Idaho Power's asset allocation process are to:

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

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

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

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

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 16. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the
categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2015				
Pension plan assets:				
Cash and cash equivalents	$ 10,519	$ —	$ —	$ 10,519
Short-term bonds	11,023	—	—	11,023
Intermediate bonds	11,499	92,742	—	104,241
Long-term bonds	—	21,747	—	21,747
Equity Securities: Large-Cap	73,489	—	—	73,489
Equity Securities: Mid-Cap	64,397	—	—	64,397
Equity Securities: Small-Cap	47,777	—	—	47,777
Equity Securities: Micro-Cap	22,186	—	—	22,186
Equity Securities: International	7,698	59,787	—	67,485
Equity Securities: Emerging Markets	9,679	23,167	—	32,846
Real estate	—	—	39,035	39,035
Private market investments	—	—	37,316	37,316
Commodities funds	—	27,555	—	27,555
Total pension assets	$ 258,267	$ 224,998	$ 76,351	$ 559,616
Postretirement plan assets [(1)]	$ 16	$ 35,550	$ —	$ 35,566
Assets at December 31, 2014				
Pension plan assets:				
Cash and cash equivalents	$ 19,190	$ —	$ —	$ 19,190
Short-term bonds	—	10,991	—	10,991
Intermediate bonds	—	101,867	—	101,867
Long-term bonds	—	21,615	—	21,615
Equity Securities: Large-Cap	66,151	—	—	66,151
Equity Securities: Mid-Cap	68,974	—	—	68,974
Equity Securities: Small-Cap	50,972	—	—	50,972
Equity Securities: Micro-Cap	22,962	—	—	22,962
Equity Securities: International	6,555	57,705	—	64,260
Equity Securities: Emerging Markets	8,629	22,915	—	31,544
Real estate	—	—	33,996	33,996
Private market investments	—	—	37,118	37,118
Commodities funds	—	30,079	—	30,079
Total pension assets	$ 243,433	$ 245,172	$ 71,114	$ 559,719
Postretirement plan assets [(1)]	$ 11	$ 38,364	$ —	$ 38,375

[(1)] The postretirement benefits assets are primarily life insurance contracts.

For the year ended December 31, 2015 , there were no significant transfers into or out of Levels 1, 2, or 3. For the year ended December 31, 2014 , there were $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1.

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The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3) (in thousands of dollars):

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2014	$ 33,709	$ 28,019	$ 61,728
Realized gains	1,430	866	2,296
Unrealized (losses) gains	(545)	1,305	760
Purchases	2,434	3,806	6,240
Settlements	90	—	90
Ending balance - December 31, 2014	37,118	33,996	71,114
Realized gains	1,897	923	2,820
Unrealized (losses) gains	(3,152)	3,193	41
Purchases	2,255	923	3,178
Sales	(802)	—	(802)
Ending balance - December 31, 2015	$ 37,316	$ 39,035	$ 76,351

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs:

Level 2 Bonds, Equity Securities, and Level 2 Commodities : These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 2 Postretirement Assets: These assets represent an investment in a life insurance contract and are recorded at fair value, which is the cash surrender value, less any unpaid expenses. The cash surrender value of this insurance contract is contractually equal to the insurance contract's proportionate share of the market value of an associated investment account held by the insurer. The investments held by the insurer's investment account are all instruments traded on exchanges with readily determinable market prices.

Level 3 Real Estate : Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments : Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

The fair value of the Level 3 assets is determined based on pricing provided or reviewed by third-party vendors to our investment managers. While the input amounts used by the pricing vendors in determining fair value are not provided, and therefore unavailable for Idaho Power's review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar assets classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately $7 million each year from 2013 to 2015 .

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and Idaho Power's consolidated balance sheets at both December 31, 2015 and 2014 were $2.0 million .

12. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2015 and 2014 (in thousands of dollars):

	2015		2014	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 2,422,175	2.46%	$ 2,316,941	2.48%
Transmission	1,077,065	2.01%	1,016,207	2.03%
Distribution	1,578,445	2.72%	1,516,933	2.72%
General and Other	407,779	5.62%	398,131	5.49%
Total in service	5,485,464	2.68%	5,248,212	2.68%
Accumulated provision for depreciation	(1,913,927)		(1,841,011)	
In service - net	$ 3,571,537		$ 3,407,201	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses for each facility is included in the Consolidated Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2015 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW [(1)]
Jim Bridger Units 1-4	Rock Springs, WY	$ 641,382	$ 46,094	$ 296,671	33	771
Boardman	Boardman, OR	81,252	113	63,715	10	64
Valmy Units 1 and 2	Winnemucca, NV	402,276	1,135	184,604	50	284

(1) Idaho Power's share of nameplate capacity.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $93 million in 2015 and $79 million in each of 2014 and 2013 .

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $8 million in 2015 and $9 million in each of 2014 and 2013.

IDACORP's consolidated VIE, Marysville, owns a hydroelectric plant with a net book value of approximately $19 million at December 31, 2015 and 2014.

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13. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant, and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its estimated settlement value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, Idaho Power records regulatory assets or liabilities instead of accretion, depreciation, and gains or losses, as approved by the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyl-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2015 , changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $5.0 million in the recorded AROs. The increase in the AROs in 2015 is primarily related to the impact of new coal combustion residual regulations on the Bridger generating facility.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, natural gas-fired generation facilities, and jointly owned coal-fired generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the removal costs recorded as regulatory liabilities on IDACORP's and Idaho Power's consolidated balance sheets as of December 31, 2015 and 2014 .

The following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	2015	2014
Balance at beginning of year	$ 21,930	$ 25,765
Accretion expense	993	1,061
Revisions in estimated cash flows	5,043	(4,140)
Liability settled	(1,813)	(756)
Balance at end of year	$ 26,153	$ 21,930

14. INVESTMENTS

The table below summarizes IDACORP's and Idaho Power's investments as of December 31 (in thousands of dollars):

	2015	2014
Idaho Power investments:		
Bridger Coal Company (equity method investment)	$ 95,159	$ 96,219
Exchange traded short-term bond funds and cash equivalents	24,459	44,942
Executive deferred compensation plan investments	102	141
Other investments	—	1
Total Idaho Power investments	119,720	141,303
Investments in affordable housing (IDACORP Financial Services)	9,909	12,762
Ida-West joint ventures (equity method investments)	11,123	11,393
Total IDACORP investments	$ 140,752	$ 165,458

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Equity Method Investments

Idaho Power, through its subsidiary IERCo, is a 33 percent owner of BCC. Ida-West, through separate subsidiaries, owns 50 percent of three electric generation projects that are accounted for using the equity method: South Forks Joint Venture, Hazelton/Wilson Joint Venture, and Snow Mountain Hydro LLC. All projects are reviewed periodically for impairment. The table below presents IDACORP's and Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

	2015	2014	2013
Bridger Coal Company (Idaho Power)	$ 9,773	$ 10,814	$ 10,242
Ida-West joint ventures	1,355	1,614	1,707
Other	—	(56)	(10)
Total	$ 11,128	$ 12,372	$ 11,939

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value. Any unrealized gains or losses on available-for-sale securities are included in income, as the fair value option has been elected for these instruments. Unrealized gains and losses on available-for-sale securities were immaterial at December 31, 2015 and December 31, 2014 . The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2015	2014	2013
Proceeds from sales	$ 34,243	$ —	$ 25,661
Gross realized gains from sales	—	—	11,637
Gross realized losses from sales	—	—	—

At the end of each reporting period, IDACORP and Idaho Power analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2015 and December 31, 2014 , there were no indicators of other-than-temporary impairment related to IDACORP's and Idaho Power's investments.

Investments in Affordable Housing

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 has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk, with most of IFS's investments having been made through syndicated funds.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. 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.

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges. Idaho Power offsets fair value amounts recognized on its balance sheet and applies collateral related to derivative instruments executed with the same counterparty under the same master netting agreement. Idaho Power does not offset a counterparty's current derivative contracts with the counterparty's long-term derivative contracts, although Idaho Power's master netting arrangements would allow current and long-term positions to be offset in the event of default. Also, in the event of default, Idaho Power's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting presented in the derivative fair value and offsetting table below.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31, 2015 , 2014 and 2013 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income [1] 2015	2014	2013
Financial swaps	Off-system sales	$ 2,882	$ (4,119)	$ (2,637)
Financial swaps	Purchased power	748	(1,416)	947
Financial swaps	Fuel expense	(6,045)	3,862	731
Financial swaps	Other operations and maintenance	(50)	(158)	35
Forward contracts	Off-system sales	—	277	185
Forward contracts	Purchased power	(6)	(279)	(196)
Forward contracts	Fuel expense	54	94	217

[1] Excludes unrealized gains or losses on derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 16 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Derivative Instrument Summary

The table below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets and reconciles the gross amounts of derivatives recognized as assets and as liabilities to the net amounts presented in the balance sheets at December 31, 2015 and 2014 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
December 31, 2015							
Current:							
Financial swaps	Other current assets	$ 999	$ (785) [1]	$ 214	$ 785	$ (785)	$ —
Financial swaps	Other current liabilities	177	(177)	—	5,146	(177)	4,969
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	3	—	3
Long-term:							
Financial swaps	Other assets	148	(22)	126	22	(22)	—
Total		$ 1,388	$ (984)	$ 404	$ 5,956	$ (984)	$ 4,972
December 31, 2014							
Current:							
Financial swaps	Other current assets	$ 2,509	$ (2,002)	$ 507	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	379	(379)	—	4,335	(379) [1]	3,956
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	5	—	5
Long-term:							
Forward contracts	Other assets	63	—	63	—	—	—
Total		$ 3,015	$ (2,381)	$ 634	$ 5,096	$ (1,135)	$ 3,961

[1] Current asset and current liability derivative amounts offset include $0.9 million of collateral receivable and $1.2 million of collateral payable and for the periods ending December 31, 2015 and 2014, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2015 and 2014 (in thousands of units):

		December 31,	
Commodity	Units	2015	2014
Electricity purchases	MWh	357	115
Electricity sales	MWh	120	238
Natural gas purchases	MMBtu	11,597	6,913
Natural gas sales	MMBtu	78	409
Diesel purchases	Gallons	1,068	243

Credit Risk

At December 31, 2015 , Idaho Power did not have material credit risk exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are commonly under Western Systems Power Pool agreements, physical gas contracts are usually under North American Energy Standards Board contracts, and financial transactions are usually under International Swaps and Derivatives Association, Inc. contracts. These contracts contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2015 , was $5.7 million . Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2015 , Idaho Power would have been required to post an additional $9.0 million of cash collateral to its counterparties.

16. FAIR VALUE MEASUREMENTS

IDACORP and Idaho Power have categorized their financial instruments into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument.

Financial assets and liabilities recorded on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

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

- Level 2: Financial assets and liabilities whose values are based on the following:
  a) quoted prices for similar assets or liabilities in active markets;
  b) quoted prices for identical or similar assets or liabilities in non-active markets;
  c) pricing models whose inputs are observable for substantially the full term of the asset or liability; and
  d) pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

  IDACORP and Idaho Power Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data.

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

IDACORP’s and Idaho Power’s assessment of a particular input's significance to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. An item recorded at fair value is reclassified among levels when changes in the nature of valuation inputs cause the item to no longer meet the criteria for the level in which it was previously categorized. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2015 and 2014 .

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The following table presents information about IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014 (in thousands of dollars):

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds:								
IDACORP - Parent	$ 1,000	$ —	$ —	$ 1,000	$ —	$ —	$ —	$ —
Idaho Power	10,000	—	—	10,000	100	—	—	100
Derivatives	340	64	—	404	506	128	—	634
Trading securities: Equity securities	102	—	—	102	141	—	—	141
Available-for-sale securities: ETFs	24,459	—	—	24,459	44,942	—	—	44,942
Liabilities:								
Derivatives	$ 286	$ 4,686	$ —	$ 4,972	$ 17	$ 3,944	$ —	$ 3,961

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

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2015 and 2014 , using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		(thousands of dollars)		
IDACORP				
Assets:				
Notes receivable [1]	$ 3,804	$ 3,804	$ 3,804	$ 3,804
Liabilities:				
Long-term debt [1]	1,726,474	1,813,243	1,615,502	1,788,197
Idaho Power				
Liabilities:				
Long-term debt [1]	$ 1,726,474	$ 1,813,243	$ 1,615,502	$ 1,788,197

[1] Notes receivable and long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16.

Notes receivable are related to Ida-West and are valued based on unobservable inputs, including discounted cash flows, which are partially based on forecasted hydroelectric conditions. Long-term debt is not traded on an exchange and is valued using quoted rates for similar debt in active markets. Carrying values for cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued approximate fair value.

17. SEGMENT INFORMATION

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of Idaho Power. Idaho Power's regulated operations include the generation, transmission, distribution, purchase, and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of Idaho Power that is also subject to regulation and is a 33 percent owner of BCC, an unconsolidated joint venture.

IDACORP's other operating segments are below the quantitative and qualitative thresholds for reportable segments and are included in the "All Other" category in the table below. This category is comprised of IFS's investments in affordable housing developments and historic rehabilitation projects, Ida-West's joint venture investments in small hydroelectric generation

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projects, the remaining activities of IESCo, the successor to which wound down its energy marketing operations in 2003, and IDACORP's holding company expenses.

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

	Utility Operations	All Other	Eliminations	Consolidated Total
2015				
Revenues	$ 1,267,505	$ 2,784	$ —	$ 1,270,289
Operating income	282,252	(155)	—	282,097
Other income	25,868	37	—	25,905
Interest income	3,037	64	(62)	3,039
Equity-method income	9,773	1,355	—	11,128
Interest expense	81,718	278	(62)	81,934
Income before income taxes	239,211	1,024	—	240,235
Income tax expense (benefit)	48,228	(2,468)	—	45,760
Income attributable to IDACORP, Inc.	190,983	3,696	—	194,679
Total assets	5,968,835	71,704	(17,225)	6,023,314
Expenditures for long-lived assets	278,905	52	—	278,957
2014				
Revenues	$ 1,278,651	$ 3,873	$ —	$ 1,282,524
Operating income	253,437	259	—	253,696
Other income	21,517	37	—	21,554
Interest income	2,705	34	(34)	2,705
Equity-method income	10,814	1,558	—	12,372
Interest expense	79,570	265	(34)	79,801
Income before income taxes	208,903	1,623	—	210,526
Income tax expense (benefit)	19,516	(2,744)	—	16,772
Income attributable to IDACORP, Inc.	189,387	4,093	—	193,480
Total assets	5,604,506	109,044	(12,513)	5,701,037
Expenditures for long-lived assets	273,911	183	—	274,094
2013				
Revenues	$ 1,243,098	$ 3,116	$ —	$ 1,246,214
Operating income	291,691	51	—	291,742
Other income	29,288	152	—	29,440
Interest income	2,426	44	(39)	2,431
Equity-method income	10,242	1,697	—	11,939
Interest expense	80,646	425	(39)	81,032
Income before income taxes	253,001	1,519	—	254,520
Income tax expense (benefit)	76,260	(4,034)	—	72,226
Income attributable to IDACORP, Inc.	176,741	5,676	—	182,417
Total assets	5,249,228	109,541	(11,389)	5,347,380
Expenditures for long-lived assets	235,306	4	—	235,310

18. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's Other income, net and Idaho Power's Other (expense) income, net (in thousands of dollars):

IDACORP - Other income, net	**2015**	**2014**	**2013**
Investment income, net	$ 2,890	$ 2,655	$ 2,373
Carrying charges on regulatory assets	1,774	1,949	2,204
Gain on sale of investments	—	—	11,637
Other income	777	588	852
Life insurance proceeds, net of premiums	1,739	1,164	18
Other expenses	(21)	(28)	(71)
Total	$ 7,159	$ 6,328	$ 17,013
Idaho Power - Other (expense) income, net			
Investment income, net	$ 2,889	$ 2,655	$ 2,369
Carrying charges on regulatory assets	1,774	1,949	2,204
Gain on sale of investments	—	—	11,637
Other income	739	551	700
SMSP expense	(9,937)	(8,339)	(8,488)
Life insurance proceeds, net of premiums	1,739	1,164	18
Other expense	(2,275)	(2,343)	(2,668)
Total	$ (5,071)	$ (4,363)	$ 5,772

19. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to the SMSP. The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2015 , 2014 , and 2013 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Unrealized Gains and Losses on Available-for-Sale Securities	**Defined Benefit Pension Items**	**Total**
December 31, 2013			
Balance at beginning of period	$ 4,136	$ (21,252)	$ (17,116)
Other comprehensive income before reclassifications	2,951	2,840	5,791
Amounts reclassified out of AOCI	(7,087)	1,859	(5,228)
Net current-period other comprehensive income	(4,136)	4,699	563
Balance at end of period	$ —	$ (16,553)	$ (16,553)
December 31, 2014			
Balance at beginning of period	$ —	$ (16,553)	$ (16,553)
Other comprehensive income before reclassifications	—	(9,333)	(9,333)
Amounts reclassified out of AOCI	—	1,728	1,728
Net current-period other comprehensive income	—	(7,605)	(7,605)
Balance at end of period	$ —	$ (24,158)	$ (24,158)
December 31, 2015			
Balance at beginning of period	$ —	$ (24,158)	$ (24,158)
Other comprehensive income before reclassifications	—	214	214
Amounts reclassified out of AOCI	—	2,668	2,668
Net current-period other comprehensive income	—	2,882	2,882
Balance at end of period	$ —	$ (21,276)	$ (21,276)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2015 , 2014 , and 2013 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI		
	Year Ended December 31,		
	2015	2014	2013
Unrealized gains on available-for-sale securities			
Realized gain on sale of securities, before tax [(1)]	$ —	$ —	$ (11,637)
Tax benefit [(2)]	—	—	4,550
Net of tax	—	—	(7,087)
Amortization of defined benefit pension items [(3)]			
Prior service cost	185	220	212
Net loss	4,195	2,618	2,839
Total before tax	4,380	2,838	3,051
Tax benefit [(2)]	(1,712)	(1,110)	(1,192)
Net of tax	2,668	1,728	1,859
Total reclassification for the period	$ 2,668	$ 1,728	$ (5,228)

(1) The realized gain is included in IDACORP's consolidated income statement in other income, net and in Idaho Power's consolidated income statements in other income (expense), net.
(2) The tax benefit is included in income tax expense (benefit) in the consolidated income statements of both IDACORP and Idaho Power.
(3) Amortization of these items is included in IDACORP's consolidated income statements in other operating expenses and in Idaho Power's consolidated income statements in other expense, net.

20. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.9 million in 2015 , $1.4 million in 2014 , and $1.0 million in 2013 .

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid Ida-West $8 million in 2015 and $9 million in each of 2014 and 2013.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014 , and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015 . Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2015 and 2014 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of presentation for deferred income taxes in 2015 due to the adoption of Accounting Standards Update (ASU) 2015-17 *Income Taxes (Topic 740)-Balance Sheet Classification of Deferred Taxes.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the "Company") as of December 31, 2015 and 2014 , and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2015 . Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2015 and 2014 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of presentation for deferred income taxes in 2015 due to the adoption of Accounting Standards Update (ASU) 2015-17 *Income Taxes (Topic 740)-Balance Sheet Classification of Deferred Taxes.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

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SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2015 and 2014 (in thousands of dollars, except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
IDACORP, Inc.				
2015				
Revenues	$ 279,395	$ 336,328	$ 369,165	$ 285,401
Operating income	42,904	85,976	104,664	48,552
Net income	23,344	66,190	73,267	31,673
Net income attributable to IDACORP, Inc.	23,430	66,080	73,336	31,832
Basic earnings per share	$ 0.47	$ 1.32	$ 1.46	$ 0.63
Diluted earnings per share	$ 0.47	$ 1.31	$ 1.46	$ 0.63
2014				
Revenues	$ 292,719	$ 317,783	$ 382,201	$ 289,821
Operating income	48,578	71,809	105,722	27,586
Net income	27,185	44,697	87,234	34,638
Net income attributable to IDACORP, Inc.	27,404	44,540	86,889	34,648
Basic earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
Diluted earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
Idaho Power Company				
2015				
Revenues	$ 278,774	$ 335,321	$ 368,517	$ 284,893
Income from operations	46,159	88,836	107,614	51,833
Net income	23,462	64,340	71,727	31,455
2014				
Revenues	$ 292,320	$ 316,655	$ 380,711	$ 288,964
Income from operations	51,949	74,369	107,644	30,129
Net income	27,900	42,653	84,600	34,233

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures - IDACORP, Inc.

The Chief Executive Officer and Chief Financial Officer of IDACORP, Inc., based on their evaluation of IDACORP, Inc.'s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2015 , have concluded that IDACORP, Inc.'s disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - IDACORP, Inc.

Management's Annual Report on Internal Control Over Financial Reporting

The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2015 . In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)* .

Based on its assessment, management concluded that, as of December 31, 2015 , IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2015 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2015 .

February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2015 , based on criteria established in *Internal Control* - *Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting* . Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control* - *Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2015 of the Company and our report dated February 18, 2016 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's change in the method of presentation for deferred income taxes.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

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Disclosure Controls and Procedures - Idaho Power Company

The Chief Executive Officer and Chief Financial Officer of Idaho Power Company, based on their evaluation of Idaho Power Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2015 , have concluded that Idaho Power Company's disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - Idaho Power Company

Management's Annual Report on Internal Control Over Financial Reporting

The management of Idaho Power Company (Idaho Power) is responsible for establishing and maintaining adequate internal control over financial reporting of Idaho Power. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Idaho Power's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2015 . In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)* .

Based on its assessment, management concluded that, as of December 31, 2015 , Idaho Power's internal control over financial reporting is effective based on those criteria.

Idaho Power's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2015 and issued a report which appears on the next page and expresses an unqualified opinion on the effectiveness of Idaho Power's internal control over financial reporting as of December 31, 2015 .

February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2015 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting* . Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015 of the Company and our report dated February 18, 2016 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's change in the method of presentation for deferred income taxes.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

Changes in Internal Control Over Financial Reporting - IDACORP, Inc. and Idaho Power Company

There have been no changes in IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "Board of Directors - Committees of the Board of Directors - Audit Committee," "Corporate Governance at IDACORP - Codes of Business Conduct," and "Corporate Governance at IDACORP - Certain Relationships and Related Transactions" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders are hereby incorporated by reference.

Information regarding IDACORP's executive officers required by this item appears in Item 1 of this report under "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers, and Five-Percent Shareholders" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2015 , with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP) and the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP).

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders (1)	—	$ —	1,059,338 (2)
Equity compensation plans not approved by shareholders	—	$ —	—
Total	—	$ —	1,059,338

(1) Consists of the RSP and the LTICP.

(2) 1,043,542 shares under the LTICP may be issued in connection with stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares, or other equity-based awards as of December 31, 2015. 15,796 shares remain available for future issuance under the RSP and may be issued as restricted stock or performance-based restricted stock. The number of shares listed in this column excludes (i) issued but unvested performance-based restricted shares, and (ii) issued but unvested time-based restricted shares, in both cases issued pursuant to the LTICP and unvested as of December 31, 2015.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Certain Relationships and Related Transactions" and "Corporate Governance at IDACORP – Director Independence and Executive Sessions" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders are hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP: The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees our principal independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill to Idaho Power for the fiscal years ended December 31, 2015 and 2014 :

	2015	2014
Audit fees	$ 1,280,500	$ 1,239,913
Audit-related fees [(1)]	6,732	32,300
Tax fees [(2)]	37,655	1,640
All other fees [(3)]	2,000	2,000
Total	$ 1,326,887	$ 1,275,853

(1) Audits of Idaho Power's benefit plans and compliance audit for the U.S. Department of Energy Smart Grid Investment Grant Program.

(2) Includes fees for benefit plan tax returns and consultation related to tax planning.

(3) Accounting research tool subscription.

Policy on Audit Committee Pre-Approval:

Idaho Power and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, the Audit Committee has established and periodically reviews a pre-approval policy for audit and non-audit services. For 2014 and 2015 , all audit and non-audit services and all fees paid in connection with those services were pre-approved by the Audit Committee.

In addition to the audits of Idaho Power's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax, and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include: audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed services; however, the Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to Idaho Power's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee, and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel, and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

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In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations, and whether the nature of the engagement and the related fees are consistent with the following principles:

- the independent public accounting firm cannot function in the role of management of Idaho Power; and
- the independent public accounting firm cannot audit its own work.

The pre-approval policy and separate supplements to the pre-approval policy describe the specific audit, audit related, tax, and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of consolidated financial statements and financial statement schedules.

(3) Exhibits . ***Note Regarding Reliance on Statements in Agreements*** : The agreements filed as exhibits to this Annual Report on Form 10-K are filed to provide information regarding their terms and are not intended to provide any other factual or disclosure information about IDACORP, Inc., Idaho Power Company, or the other parties to the agreements. Some of the agreements contain statements, representations, and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (a) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate; (b) have been qualified by disclosures that were made to the other party, which disclosures are not necessarily reflected in the agreement; (c) may apply standards of materiality in a way that is different from what may be viewed as material to investors; and (d) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, readers should not rely upon the statements, representations, or warranties made in the agreements.

		Incorporated by Reference				
Exhibit No.	**Exhibit Description**	**Form**	**File No.**	**Exhibit No.**	**Date**	**Included Herewith**
2	Agreement and Plan of Exchange between IDACORP, Inc. and Idaho Power Company, dated as of February 2, 1998	S-4	333-48031	A	3/16/1998	
3.1	Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on June 30, 1989	S-3 Post-Effective Amend. No. 2	33-00440	4(a)(xiii)	6/30/1989	
3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on November 5, 1991	S-3	33-65720	4(a)(ii)	7/7/1993	
3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on June 30, 1993	S-3	33-65720	4(a)(iii)	7/7/1993	
3.4	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998	S-8 Post-Effective Amend. No. 1	33-56071-99	3(d)	10/1/1998	
3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000	10-Q	1-3198	3(a)(iii)	8/4/2000	
3.6	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005	8-K	1-3198	3.3	1/26/2005	
3.7	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007	8-K	1-3198	3.3	11/19/2007	

EXHIBIT IV

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		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
3.8	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-3198	3.14	5/21/2012	
3.9	Amended Bylaws of Idaho Power Company, amended on November 15, 2007 and presently in effect	8-K	1-3198	3.2	11/19/2007	
3.10	Articles of Incorporation of IDACORP, Inc.	S-3	333-64737	3.1	11/4/1998	
3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998	S-3 Amend. No. 1	333-64737	3.2	11/4/1998	
3.12	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998	S-3 Post-Effective Amend. No. 1	333-00139-99	3(b)	9/22/1998	
3.13	Articles of Amendment to Articles of Incorporation of IDACORP, Inc., as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-14465	3.13	5/21/2012	
3.14	Amended and Restated Bylaws of IDACORP, Inc., amended on October 29, 2014 and presently in effect	10-Q	1-14465	3.15	10/30/2014	
4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees		2-3413	B-2		
4.2	Idaho Power Company Supplemental Indentures to Mortgage and Deed of Trust:					
	File number 1-MD, as Exhibit B-2-a, First, July 1, 1939					
	File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943					
	File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947					
	File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948					
	File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949					
	File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951					
	File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957					
	File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957					
	File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957					
	File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958					
	File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958					
	File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959					
	File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960					
	File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961					
	File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964					
	File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966					
	File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966					
	File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972					
	File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974					
	File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974					
	File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974					
	File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976					
	File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978					
	File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979					
	File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981					
	File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982					
	File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986					
	File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989					
	File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990					
	File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991					
	File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991					

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		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992					
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993					
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993					
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000					
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001					
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003					
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003					
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iv), Thirty-ninth, October 1, 2003					
	File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005					
	File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006					
	File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007					
	File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007					
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008					
	File number 1-3198, Form 10-K filed on 2/23/10, as Exhibit 4.10, Forty-fifth, February 1, 2010					
	File number 1-3198, Form 8-K filed on 6/18/10, as Exhibit 4, Forty-sixth, June 1, 2010					
	File number 1-3198, Form 8-K filed on 7/12/2013, as Exhibit 4.1, Forty-seventh, July 1, 2013					
4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.23)	10-Q	1-3198	4(b)	8/4/2000	
4.4	Agreement of Idaho Power Company to furnish certain debt instruments	S-3	33-65720	4(f)	7/7/1993	
4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments	10-Q	1-14465	4(c)(ii)	11/6/2003	
4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine corporation, and Idaho Power Migrating Corporation	S-3 Post-Effective Amend. No. 2	33-00440	2(a)(iii)	6/30/1989	
4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.1	2/28/2001	
4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.2	2/28/2001	
4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	S-3	333-67748	4.13	8/16/2001	
4.10	Idaho Power Company Instrument of Further Assurance relating to Mortgage and Deed of Trust, dated as of August 3, 2010	10-Q	1-3198	4.12	8/5/2010	
10.1	Agreement, dated as of October 11, 1973, between Idaho Power Company and Pacific Power & Light Company		2-49584	5(c)		
10.2	Amended and Restated Agreement for the Operation of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp	10-K	1-14465, 1-3198	10.4	2/19/2015	
10.3	Amended and Restated Agreement for the Ownership of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp	10-K	1-14465, 1-3198	10.5	2/19/2015	
10.4	Joint Ownership and Operating Agreement, dated October 24, 2014, between Idaho Power Company and PacifiCorp	8-K	1-14465, 1-3198	10.1	10/24/2014	
10.5	Letter Agreement, dated January 23, 1976, between Idaho Power Company and Portland General Electric Company		2-56513	5(i)		

EXHIBIT IV

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.6	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and Idaho Power Company	S-7	2-62034	5(s)	6/30/1978	
10.7	Amendment, dated September 30, 1977, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(t)	6/30/1978	
10.8	Amendment, dated October 31, 1977, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(u)	6/30/1978	
10.9	Amendment, dated January 23, 1978, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(v)	6/30/1978	
10.10	Amendment, dated February 15, 1978, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(w)	6/30/1978	
10.11	Amendment, dated September 1, 1979, relating to the agreement filed as Exhibit 10.5	S-7	2-68574	5(x)	7/23/1980	
10.12	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir	S-7	2-68574	5(z)	7/23/1980	
10.13	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and Idaho Power Company	S-7	2-64910	5(y)	6/29/1979	
10.14	Framework Agreement, dated October 1, 1984, between the State of Idaho and Idaho Power Company relating to Idaho Power Company's Swan Falls and Snake River water rights	S-3	33-65720	10(h)	7/7/1993	
10.15	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.14	S-3	33-65720	10(h)(i)	7/7/1993	
10.16	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.14	S-3	33-65720	10(h)(ii)	7/7/1993	
10.17	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.14	10-Q	1-14465	10.58	5/7/2009	
10.18	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between Idaho Power Company and the Twin Falls Canal Company and the Northside Canal Company Limited	S-3	33-65720	10(m)	7/7/1993	
10.19	Credit Agreement, dated November 6, 2015, among IDACORP, Inc., Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein	8-K	1-14465, 1-3198	10.1	11/9/2015	
10.20	Credit Agreement, dated November 6, 2015, among Idaho Power Company, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein	8-K	1-14465, 1-3198	10.2	11/9/2015	
10.21	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.22	Guaranty Agreement, dated February 10, 1992, between Idaho Power Company and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc.	S-3	33-65720	10(m)(i)	7/7/1993	

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Exhibit No.	Exhibit Description	Incorporated by Reference: Form	File No.	Exhibit No.	Date	Included Herewith
10.23	Guaranty Agreement, dated April 11, 2000, between Idaho Power Company and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho	10-Q	1-3198	10(c)	8/4/2000	
10.24	Guaranty Agreement, dated as of August 30, 1974, between Idaho Power Company and Pacific Power & Light Company	S-7	2-62034	5(r)	6/30/1978	
10.25 [1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008	10-K	1-14465, 1-3198	10.15	2/26/2009	
10.26 [1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees I	10-Q	1-14465, 1-3198	10.62	11/1/2012	
10.27 [1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 30, 2011	10-K	1-14465, 1-3198	10.21	2/22/2012	
10.28 [1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees II	10-Q	1-14465, 1-3198	10.63	11/1/2012	
10.29 [1]	Amendment, dated January 16, 2014, to the Idaho Power Company Security Plan for Senior Management Employees II	10-K	1-14465, 1-3198	10.26	2/20/2014	
10.30 [1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007	10-Q	1-14465, 1-3198	10(h)(iii)	10/31/2007	
10.31 [1]	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (Time-Vesting)	10-Q	1-14465, 1-3198	10(h)(vi)	11/2/2006	
10.32 [1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (Performance Vesting)	10-Q	1-14465, 1-3198	10(h)(vii)	11/2/2006	
10.33 [1]	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006	10-Q	1-14465, 1-3198	10(h)(viii)	11/2/2006	
10.34 [1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 19, 2015					X
10.35 [1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h)(xix)	11/2/2006	
10.36 [1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h)(xx)	11/2/2006	
10.37 [1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (senior vice president and higher), approved November 20, 2008	10-K	1-14465, 1-3198	10.24	2/26/2009	
10.38 [1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (below senior vice president), approved November 20, 2008	10-K	1-14465, 1-3198	10.25	2/26/2009	
10.39 [1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, approved March 17, 2010	8-K	1-14465, 1-3198	10.1	3/24/2010	
10.40 [1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 12, 2016					X
10.41 [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 18, 2010	10-K	1-14465, 1-3198	10.33	2/23/2011	
10.42 [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting)	10-K	1-14465, 1-3198	10.43	2/19/2015	
10.43 [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals)	10-K	1-14465, 1-3198	10.44	2/19/2015	
10.44 [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting) (For 2014 and Prior Outstanding Awards)	10-Q	1-14465, 1-3198	10(h)(xvii)	11/2/2006	

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		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
10.45 [1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals) (For 2014 and Prior Outstanding Awards)	10-Q	1-14465, 1-3198	10.69	5/5/2011	
10.46 [1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated January 16, 2014 (superseded by Exhibit 10.47 effective February 10, 2016)	10-K	1-14465, 1-3198	10.42	2/20/2014	
10.47 [1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated February 11, 2016					X
10.48 [1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008	10-K	1-14465, 1-3198	10.32	2/26/2009	
10.49 [1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2015 (superseded by Exhibit 10.50 effective January 1, 2016)	10-K	1-14465, 1-3198	10.49	2/19/2015	
10.50 [1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2016					X
10.51 [1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.46	2/26/2009	
10.52 [1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.47	2/26/2009	
10.53 [1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.48	2/26/2009	
10.54 [1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.49	2/26/2009	
10.55 [1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.50	2/26/2009	
10.56 [1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.51	2/26/2009	
10.57 [1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.52	2/26/2009	
10.58 [1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.53	2/26/2009	
10.59 [1]	Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016					X
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
21.1	Subsidiaries of IDACORP, Inc.	10-K	1-14465, 1-3198	21.1	2/21/2013	
23.1	Consent of Registered Independent Accounting Firm					X
23.2	Consent of Registered Independent Accounting Firm					X
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification					X
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification					X
31.3	Idaho Power Rule 13a-14(a) CEO certification					X
31.4	Idaho Power Rule 13a-14(a) CFO certification					X
32.1	IDACORP, Inc. Section 1350 CEO certification					X
32.2	IDACORP, Inc. Section 1350 CFO certification					X
32.3	Idaho Power Section 1350 CEO certification					X
32.4	Idaho Power Section 1350 CFO certification					X
95.1	Mine Safety Disclosures					X

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		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X

[1] Management contract or compensatory plan or arrangement

EXHIBIT IV

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IDACORP, INC.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 194,426	$ 193,707	$ 182,463
Investment income	1	—	3
Total income	194,427	193,707	182,466
Expenses:			
Operating expenses	831	1,376	940
Interest expense	276	261	416
Other expenses	45	45	71
Total expenses	1,152	1,682	1,427
Income from Before Income Taxes	193,275	192,025	181,039
Income Tax Benefit	(1,404)	(1,455)	(1,378)
Net Income Attributable to IDACORP, Inc.	194,679	193,480	182,417
Other comprehensive (income) loss	2,882	(7,605)	563
Comprehensive Income Attributable to IDACORP, Inc.	$ 197,561	$ 185,875	$ 182,980

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 100,465	$ 109,289	$ 96,391
Investing Activities:			
Distributions from (contributions to) subsidiaries	—	—	2,282
Net cash provided by (used in) investing activities	—	—	2,282
Financing Activities:			
Issuance of common stock	—	195	255
Dividends on common stock	(96,810)	(88,489)	(78,832)
(Decrease) increase in short-term borrowings	(11,300)	(23,450)	(14,950)
Change in intercompany notes payable	5,572	(198)	647
Other	(1,675)	(469)	(431)
Net cash used in financing activities	(104,213)	(112,411)	(93,311)
Net (decrease) increase in cash and cash equivalents	(3,748)	(3,122)	5,362
Cash and cash equivalents at beginning of year	5,776	8,898	3,536
Cash and cash equivalents at end of year	$ 2,028	$ 5,776	$ 8,898

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,	
	2015	2014
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 2,028	$ 5,776
Receivables	946	1,702
Income taxes receivable	7,241	—
Deferred income taxes	—	42,766
Other	119	106
Total current assets	10,334	50,350
Investment in subsidiaries	2,007,984	1,910,084
Other Assets:		
Deferred income taxes	76,410	44,546
Other	402	287
Total other assets	76,812	44,833
Total assets	$ 2,095,130	$ 2,005,267
Liabilities and Shareholders' Equity		
Current Liabilities:		
Notes payable	$ 20,000	$ 31,300
Accounts payable	13	8
Taxes accrued	—	8,950
Other	765	854
Total current liabilities	20,778	41,112
Other Liabilities:		
Intercompany notes payable	15,292	9,658
Other	1,175	1,296
Total other liabilities	16,467	10,954
IDACORP, Inc. Shareholders' Equity	2,057,885	1,953,201
Total Liabilities and Shareholders' Equity	$ 2,095,130	$ 2,005,267

The accompanying note is an integral part of these statements.

NOTE TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2015 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries: IDACORP has accounted for the earnings of its subsidiaries under the equity method of accounting in these unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends that IDACORP subsidiaries paid to IDACORP of $99 million in 2015 and $91 million in 2014 and 2013 .

EXHIBIT IV

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2015 , 2014 , and 2013

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions [1]	Balance at End of Year
			(thousands of dollars)		
2015:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,104	$ 3,327	$ 819	$ 4,895	$ 1,355
Reserve for uncollectible notes	552	—	—	—	552
Other Reserves:					
Injuries and damages	1,995	890	—	1,011	1,874
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Reserve for uncollectible notes	885	(333)	—	—	552
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Reserve for uncollectible notes	1,260	(375)	—	—	885
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, and notes reserves, includes reversals of amounts previously written off.

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IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2015 , 2014 , and 2013

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions [1]	Balance at End of Year
		(thousands of dollars)			
2015:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,104	$ 3,327	$ 819	$ 4,895	$ 1,355
Other Reserves:					
Injuries and damages	1,995	890	—	1,011	1,874
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, includes reversals of amounts previously written off.

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SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 18, 2016	IDACORP, INC.
Date	
By:	*/s/ Darrel T. Anderson*
	Darrel T. Anderson
	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	**Title**	**Date**
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 18, 2016
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 18, 2016
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 18, 2016
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 18, 2016
/s/ Thomas Carlile Thomas Carlile	Director	February 18, 2016
/s/ Richard J. Dahl Richard J. Dahl	Director	February 18, 2016
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 18, 2016
/s/ Judith A. Johansen Judith A. Johansen	Director	February 18, 2016
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 18, 2016
/s/ J. LaMont Keen J. LaMont Keen	Director	February 18, 2016
/s/ Christine King Christine King	Director	February 18, 2016
/s/ Richard J. Navarro Richard J. Navarro	Director	February 18, 2016

EXHIBIT IV

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SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 18, 2016 — Idaho Power Company

Date

By: */s/ Darrel T. Anderson*

Darrel T. Anderson

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 18, 2016
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 18, 2016
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 18, 2016
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 18, 2016
/s/ Thomas Carlile Thomas Carlile	Director	February 18, 2016
/s/ Richard J. Dahl Richard J. Dahl	Director	February 18, 2016
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 18, 2016
/s/ Judith A. Johansen Judith A. Johansen	Director	February 18, 2016
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 18, 2016
/s/ J. LaMont Keen J. LaMont Keen	Director	February 18, 2016
/s/ Christine King Christine King	Director	February 18, 2016
/s/ Richard J. Navarro Richard J. Navarro	Director	February 18, 2016

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[1] Management contract or compensatory plan or arrangement.

EXHIBIT IV

Exhibit 10.34

IDACORP, INC.
NON-EMPLOYEE DIRECTORS STOCK COMPENSATION PLAN
(As Amended November 19, 2015)

I. Purpose

The purpose of the IDACORP, Inc. Non-Employee Directors Stock Compensation Plan is to provide ownership of the Company's stock to non-employee members of the Board of Directors and to strengthen the commonality of interest between directors and shareholders.

II. Definitions

When used herein, the following terms shall have the respective meanings set forth below:

"Annual Retainer" means the annual retainer payable by the Company to Non-Employee Directors and shall include, for purposes of this Plan, meeting fees, cash retainers and any other cash compensation payable to Non-Employee Directors by the Company for services as a director.

"Annual Meeting of Shareholders" means the annual meeting of shareholders of the Company at which directors of the Company are elected.

"Board" or "Board of Directors" means the Board of Directors of the Company.

"Change in Control" means the earliest of the following to occur: (a) any person (which shall not include the Company, any Subsidiary or any employee benefit plan of the Company or of any Subsidiary) ("Person") or group (as that term is defined in Treasury Regulation Section 1.409A-3(i)(5)(v)(B)) acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such Person or Persons) ownership of stock of the Company possessing 30% or more of the total voting power of the stock of the Company; (b) any Person or group (as that term is defined in Treasury Regulation Section 1.409A-3(i)(5)(v)(B)) acquires ownership of the stock of the Company that, together with stock held by such Person or group, constitutes more than 50% of the total fair market value or total voting power of the stock of the Company (this part (b) applies only when there is a transfer of stock of the Company and the Company's stock remains outstanding after the transaction); (c) a majority of the members of the Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board; or (d) any Person or group (as that term is defined in Treasury Regulation Section 1.409A-3(i)(5)(v)(B)) acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such Person or Persons) assets from the Company that have a gross fair market value equal to or more than 40% of the total gross fair market value of all of the assets of the Company immediately before such acquisition or acquisitions.

EXHIBIT IV

Notwithstanding anything contained herein to the contrary, no transaction or event shall constitute a Change in Control for purposes of the Plan unless the transaction or event constitutes a change in the ownership of a corporation (as defined in Treasury Regulation Section 1.409A-3(i)(5)(v)), a change in effective control of a corporation (as defined in Treasury Regulation Section 1.409A-3(i)(5)(vi)) or a change in the ownership of a substantial portion of the assets of a corporation (as defined in Treasury Regulation Section 1.409A-3(i)(5)(vii)) and the term Change in Control shall be interpreted in a manner consistent with the proper interpretation of the similar provisions in the Section 409A Treasury Regulations.

"Code" means the Internal Revenue Code of 1986, as amended.

"Committee" means the Compensation Committee of the Board of Directors.

"Common Stock" means the common stock, without par value, of the Company.

"Company" means IDACORP, Inc., an Idaho corporation, and any successor corporation.

"Deferral Account" means an account maintained by the Company in the name of a Participant that is used to track the Deferred Stock Units of a Participant who elects to defer receipt of his or her Stock Payments pursuant to Section VI hereof.

"Deferral Election" means a Participant's deferral election, as defined in Section VI(A) hereof.

"Deferred Stock Unit" means a notional entry in a Participant's Deferral Account representing one share of Common Stock.

"Effective Date" means May 17, 1999.

"Employee" means any officer or other common law employee of the Company or of any Subsidiary.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Non-Employee Director" or "Participant" means any person who is elected or appointed to the Board of Directors of the Company and who is not an Employee.

"Plan" means the Company's Non-Employee Directors Stock Compensation Plan, adopted by the Board on May 5, 1999, as it may be amended from time to time.

"Separation from Service" means a Participant's separation from service (as that term is used in Section 409A(a)(2)(A)(i) of the Code) with the Company.

"Stock Payment" means that portion of the Annual Retainer to be paid to Non-Employee Directors in shares of Common Stock rather than cash for services rendered as a director of the Company, as provided in Section V hereof.

"Subsidiary" means any corporation (other than the Company) in an unbroken chain of corporations beginning with the Company if each of the corporations other than the last corporation in the unbroken chain owns stock possessing 50 percent or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

III. Shares of Common Stock Subject to the Plan

Subject to Section VII below, the maximum aggregate number of shares of Common Stock that may be delivered under the Plan is 100,000 shares. The Common Stock to be delivered under the Plan will be made available from treasury stock or shares of Common Stock purchased on the open market.

IV. Administration

The Plan shall be administered by the Compensation Committee of the Board of Directors. The Company shall pay all costs of administration of the Plan. Subject to and not inconsistent with the express provisions of the Plan, the Committee has and may exercise such powers and authority of the Board as may be necessary or appropriate for the Committee to carry out its functions under the Plan. Without limiting the generality of the foregoing, the Committee shall have full power and authority (i) to determine all questions of fact that may arise under the Plan, (ii) to interpret the Plan and to make all other determinations necessary or advisable for the administration of the Plan and (iii) to prescribe, amend and rescind rules and regulations relating to the Plan, including, without limitation, any rules which the Committee determines are necessary or appropriate to ensure that the Company and the Plan will be able to comply with all applicable provisions of any federal, state or local law. All interpretations, determinations and actions by the Committee will be final and binding upon all persons, including the Company, the Participants and their estates and beneficiaries.

V. Determination of Annual Retainer and Stock Payments

A. Annual Retainer

The Board shall determine the Annual Retainer payable to all Non-Employee Directors of the Company.

B. Stock Payments

Subject to the provisions of Section V(C) below, each director who is a Non-Employee Director on March 1 of each year shall receive, on March 1 or the first business day thereafter, as a portion of the Annual Retainer, a Stock Payment of $100,000 in value of Common Stock. Non-Employee Directors may elect to defer receipt of the

Stock Payment in accordance with the provisions of Section VI hereof. The number of shares granted (or credited as Deferred Stock Units pursuant to a Deferral Election in accordance with Section VI hereof) shall be determined based on (i) for shares granted from treasury stock and Deferred Stock Units, the closing price of the Common Stock on the consolidated transaction reporting system on the business day immediately preceding the date paid to the Non-Employee Director or credited to his or her Deferral Account, as the case may be, and (ii) for open market purchases, the actual price paid to purchase the shares.

Non-Employee Directors who are initially elected to the Board after March 1 in any year shall receive a prorated Stock Payment on the first business day of the month following the effective date of their election to the Board, but in no event later than March 15 of the year following the year in which they are initially elected to the Board. The Stock Payment will be prorated by multiplying $100,000 by a fraction, the numerator of which equals the number of months (with a partial month counted as a full month) remaining in the calendar year and the denominator of which is twelve.

At the time of payment (or, if applicable, at the time of distribution of any shares of Common Stock pursuant to Section VI hereof), a certificate evidencing the shares of Common Stock shall be registered in the name of the Participant and issued to the Participant.

C. Non-Employee Directors on April 1, 2007 and Thereafter

A Non-Employee Director initially elected to the Board effective on or after April 1, 2007 shall receive, on March 1 or the first business day thereafter, a prorated Stock Payment if the Board is aware on March 1 that the Non-Employee Director will not continue to serve on the Board for the entire year. The number of shares granted (or credited as Deferred Stock Units pursuant to a Deferral Election) shall be calculated by multiplying $100,000 by a fraction, the numerator of which is the number of actual or expected months (with a partial month counted as a full month) of service on the Board during the year and the denominator of which is twelve. If the Board is not aware on March 1 that a Non-Employee Director initially elected to the Board effective on or after April 1, 2007 will not serve on the Board for the entire year, such Non-Employee Director shall receive a full Stock Payment and shall not be required to forfeit or otherwise return any shares of Common Stock granted as a Stock Payment or credited as Deferred Stock Units pursuant to the Plan notwithstanding any change in status of such Non-Employee Director which renders him or her ineligible to continue as a Participant in the Plan.

D. Non-Employee Directors Prior to April 1, 2007

A Non-Employee Director initially elected to the Board effective prior to April 1, 2007 will not receive a prorated Stock Payment as set forth in the immediately preceding Section V(C), but rather will receive a full Stock Payment on March 1 or the first business day thereafter, notwithstanding the fact that the Board may be aware that the Non-Employee Director will not continue to serve on the Board for the entire year. The number of shares granted (or credited as Deferred Stock Units pursuant to a Deferral Election) shall be calculated in the manner set forth in Section V(B) hereof. No Non-Employee Director who was a member of the Board effective prior to April 1, 2007 shall be required to forfeit or otherwise return any shares of Common Stock granted as a Stock Payment or credited as Deferred Stock Units pursuant to the Plan notwithstanding any change in status of such Non-Employee Director which renders him or her ineligible to continue as a Participant in the Plan.

E. No Further Stock Payments

Notwithstanding the foregoing, Non-Employee Directors will not receive a Stock Payment under the Plan on or after February 26, 2010.

VI. Deferral of Stock Payment

A. Deferral Elections

A Participant may elect to defer receipt of his or her Stock Payment by timely filing a deferral election (a "Deferral Election") in accordance with such procedures as may from time to time be prescribed by the Committee. A Deferral Election shall be valid only if it is delivered prior to the first day of the calendar year in which the services giving rise to the Stock Payment being deferred are to be performed.

A Participant's Deferral Election shall become irrevocable as of the last date the Deferral Election could be delivered or such earlier date as may be established by the Committee. A Participant may revoke or change a Deferral Election at any time prior to the date the election becomes irrevocable, subject to such restrictions as the Committee may establish from time to time. Any such revocation or change shall be in a form and manner determined by the Committee. A Participant's Deferral Election shall remain in effect and will apply to Stock Payments in future years (beyond the first year to which it relates) unless and until the Participant revokes the Deferral Election. The deadline for revocation of a Deferral Election for this purpose shall be the same as the deadline for delivering a Deferral Election with respect to the year or such earlier date as may be established by the Committee. Revocation shall be effected by the Participant's delivery of a Termination of Deferral Election Agreement or such other document as the Committee may prescribe for such purpose.

If a valid Deferral Election is timely filed by a Participant, a Deferral Account shall be established for the Participant and credited with a number of Deferred Stock Units equal to the number of shares of Common Stock that would have been received by the Participant pursuant to Section V hereof absent the Deferral Election.

B. Dividends

If dividends are paid on shares of Common Stock, a Participant's Deferral Account shall be credited on the dividend payment date with a number of additional Deferred Stock Units (and/or fraction thereof) determined by dividing (i) the dividends that would have been paid on the Deferred Stock Units held in the Participant's Deferral Account as of the dividend record date as if they were actual shares of Common Stock by (ii) the closing price of the Common Stock on the consolidated transaction reporting system on the dividend payment date.

C. Deferred Stock Units

Amounts in a Participant's Deferral Account shall remain denominated in the form of Deferred Stock Units until distributed.

D. Time of Distribution

Deferral Accounts shall be distributed (or, in the case of installments, distributions shall commence) upon Separation from Service. Participants shall elect in their Deferral Elections whether distributions shall be in a lump sum or in installments, subject to such terms and conditions as the Committee may from time to time prescribe. In the case of a Participant's death, whether before or after distributions have commenced, the Participant's Deferral Account balance shall be distributed in a lump sum as soon as practicable (but in all events within 90 days) thereafter to the Participant's estate or, if applicable, designated beneficiary.

Upon a Change in Control, the Participant's Deferral Account balance shall be distributed in a lump sum as soon as practicable (but in all events within 90 days) thereafter to the Participant.

E. Beneficiaries

A Participant may designate a beneficiary or beneficiaries (which may be an entity other than a natural person) to receive any payments to be made under Section VI hereof upon the Participant's death. At any time, and from time to time, any such designation may be changed or canceled by the Participant without the consent of any beneficiary. Any such designation, change or cancellation must be by written notice filed with the Secretary of the Company and shall not be effective until received by the Secretary of the Company. If a Participant designates more than one beneficiary, any payments under Section VI hereof to such beneficiaries shall be made in equal amounts unless the Participant has designated otherwise, in which case the payments shall be made in the amounts designated by the Participant. If no beneficiary has been designated by the Participant, or the designated beneficiaries have predeceased the Participant, payment shall be made to the Participant's estate. If any dispute shall arise as to the entitlement of any person to any portion of the Participant’s Deferral Account balance, the Company's obligations under this Plan will be satisfied if it makes payment to the Participant's estate.

F. Distribution of Deferral Accounts

Distribution shall be in shares of Common Stock, with each Deferred Stock Unit equal to one share of Common Stock and any fractional shares paid in cash.

G. Section 409A

To the extent applicable, it is intended that this Plan will comply with Section 409A of the Code and any regulations and guidance issued thereunder, and the Plan shall be interpreted accordingly.

VII. Adjustments in Authorized Shares and Deferred Stock Units

In the event of any equity restructuring (within the meaning of Financial Accounting Standards No. 123(R)), such as a stock dividend, stock split, spinoff, rights offering or recapitalization through a large, nonrecurring cash dividend, the Committee shall cause an equitable adjustment to be made in (i) the number and kind of shares of Common Stock that may be delivered under the Plan and (ii) the number and kind of Deferred Stock Units in Participants' Deferral Accounts, in either case to prevent dilution or enlargement of rights. In the event of any other change in corporate capitalization, such as a merger, consolidation or liquidation, the Committee may, in its sole discretion, cause an equitable adjustment as described in the foregoing sentence to be made, to prevent dilution or enlargement of rights. The maximum number of shares issuable under the Plan and the number of Deferred Stock Units allocated to a Participant's Deferral Account as a result of any such adjustment shall be rounded down to the nearest whole share or unit. Adjustments made by the Committee pursuant to this Section VII shall be final, binding and conclusive.

VIII. Amendment and Termination of Plan

The Board will have the power, in its discretion, to amend, suspend or terminate the Plan at any time, subject to the satisfaction of all obligations under the Plan to Participants (and Participants' estates and beneficiaries). However, no such termination, suspension or amendment or other action with respect to the Plan shall adversely affect the Participants' Deferral Account balances which have accrued prior to such action.

IX. Effective Date and Duration of the Plan

The Plan will become effective upon the Effective Date and shall remain in effect, subject to the right of the Board of Directors to terminate the Plan at any time pursuant to Section VIII, until all shares subject to the Plan have been granted or distributed according to the Plan's provisions.

X. Miscellaneous Provisions

A. Continuation of Directors in Same Status

Nothing in the Plan or any action taken pursuant to the Plan shall be construed as creating or constituting evidence of any agreement or understanding, express or implied, that the Company will retain a Non-Employee Director as a director or in any other capacity for any period of time or at a particular retainer or other rate of compensation, as conferring upon any Participant any legal or other right to continue as a director or in any other capacity, or as limiting, interfering with or otherwise affecting the right of the Company to terminate a Participant in his or her capacity as a director or otherwise at any time for any reason, with or without cause, and without regard to the effect that such termination might have upon him or her as a Participant under the Plan.

B. Compliance with Government Regulations

Neither the Plan nor the Company shall be obligated to issue any shares of Common Stock pursuant to the Plan at any time unless and until all applicable requirements imposed by any federal and state securities and other laws, rules and regulations, by any regulatory agencies or by any stock exchanges upon which the Common Stock may be listed have been fully met. As a condition precedent to any issuance of shares of Common Stock pursuant to the Plan, the Board or the Committee may require a Participant to take any such action and to make any such covenants, agreements and representations as the Board or the Committee, as the case may be, in its discretion deems necessary or advisable to ensure compliance with such requirements. The Company shall in no event be obligated to register the shares of Common Stock deliverable under the Plan pursuant to the Securities Act of 1933, as amended, or to qualify or register such shares under any securities laws of any state upon their issuance under the Plan or at any time thereafter, or to take any other action in order to cause the issuance and delivery of such shares under the Plan or any subsequent offer, sale or other transfer of such shares to comply with any such law, regulation or requirement. Participants are responsible for complying with all applicable federal and state securities and other laws, rules and regulations in connection with any offer, sale or other transfer of the shares of Common Stock issued under the Plan or any interest therein including, without limitation, compliance with the registration requirements of the Securities Act of 1933, as amended (unless an exemption therefrom is available), or with the provisions of Rule 144 promulgated thereunder, if applicable, or any successor provisions. Certificates for shares of Common Stock may be legended as the Committee shall deem appropriate.

C. Nontransferability of Rights

No Participant shall have the right to assign the right to receive any Stock Payment or any other right or interest under the Plan, contingent or otherwise, or to cause or permit any encumbrance, pledge or charge of any nature to be imposed on any such Stock Payment or any such right or interest (prior to the issuance of stock certificates evidencing such Stock Payment).

D. Successor Entities

All obligations of the Company or any Subsidiary under the Plan shall be binding on any successor to the Company or any Subsidiary, respectively, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, reorganization or other transaction involving all or substantially all of the business and/or assets of the Company or any Subsidiary. References to the Company or Subsidiary in the Plan shall be deemed to refer to the successors thereto, as applicable.

E. Severability

In the event that any provision of the Plan is held invalid, void or unenforceable, the same shall not affect, in any respect whatsoever, the validity of any other provision of the Plan.

F. Governing Law

To the extent not preempted by Federal law, the Plan and all rights and obligations hereunder shall be governed by and interpreted in accordance with the laws of the State of Idaho, without regard to conflicts of law provisions.

G. No Right to Company Assets

Nothing in this Plan shall be construed as giving the Participant, Participant's beneficiaries or any other person any equity or interest of any kind in the assets of the Company or creating a trust of any kind or a fiduciary relationship of any kind between the Company and any such person. As to any claim for payments due under the provisions of this Plan, the Participant, Participant's beneficiaries and any other persons having a claim for payments shall be unsecured creditors of the Company.

Amended as of September 20, 2007 to add proration

Amended as of November 15, 2007 to increase stock payment from $40,000 to $45,000 effective January 1, 2008

Amended as of November 20, 2008 to permit deferrals

Amended as of February 26, 2010 to permit no further Stock Payments

Amended as of January 19, 2012 to increase stock payment from $45,000 to $60,000 effective January 1, 2012

Amended as of January 16, 2014 to increase stock payment from $60,000 to $75,000 effective January 1, 2014

Amended as of November 20, 2014 to increase stock payment from $75,000 to $80,000 effective January 1, 2015

Amended as of November 19, 2015 to increase stock payment from $80,000 to $100,000 effective January 1, 2016

EXHIBIT IV

Exhibit 10.40

IDACORP, Inc. and/or Idaho Power Company Executive Officers
with Amended and Restated Change in Control Agreements
(as of February 12, 2016)

Name	Title	Date of Agreement
Darrel T. Anderson	President and Chief Executive Officer of IDACORP, Inc. and Idaho Power Company	12/23/2008
Rex Blackburn	Sr. Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company	4/1/2009
Lisa A. Grow	Sr. Vice President of Operations of Idaho Power Company	12/12/2008
Patrick A. Harrington	Corporate Secretary of IDACORP, Inc. and Idaho Power Company	12/9/2008
Steve R. Keen	Senior Vice President, Chief Financial Officer, and Treasurer of IDACORP, Inc. and Idaho Power Company	12/30/2008
Lonnie Krawl*	Senior Vice President of Administrative Services and Chief Information Officer of Idaho Power Company	9/30/2013
Daniel B. Minor	Executive Vice President of IDACORP, Inc. and Idaho Power Company	12/30/2008
Kenneth W. Petersen*	Vice President, Controller, and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company	5/20/2010
N. Vern Porter*	Vice President of Idaho Power Company	3/18/2010

*Change in control agreement does not include 13 th -month trigger or tax gross-up provisions.

EXHIBIT IV

Exhibit 10.47

IDACORP, Inc.
EXECUTIVE INCENTIVE PLAN
(As Amended and Restated February 11, 2016)

1. PURPOSE and TERM

The purpose of this IDACORP, Inc. Executive Incentive Plan (the "Plan") is to reinforce goals for profitable growth and continuation of a sound overall financial condition of IDACORP, Inc. by providing incentive compensation opportunities to selected key employees. The Plan is designed to:

- attract, retain and motivate key employees;
- relate compensation to performance and financial results; and
- provide a portion of compensation in a variable rather than a fixed form.

The Plan became effective on January 1, 2007. The Plan was amended by the Board on March 18, 2010 and approved by the shareholders of IDACORP, Inc. on May 20, 2010, effective for the Plan Year beginning January 1, 2011. The Plan shall remain in effect until terminated by the Board.

It is intended that compensation payable under the Plan will qualify as "performance-based compensation," within the meaning of Section 162(m) of the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder, if the Company desires such qualification.

2. DEFINITIONS

Whenever used in the Plan, the following terms shall have the meanings set forth below and, when such meaning is intended, the initial letter of the word is capitalized.

Award means, for a Plan Year, as to each Participant, an opportunity granted under the Plan with respect to such Plan Year for the Participant to earn an incentive payment under the Plan.

Base Salary means, for any Participant for a Plan Year, the aggregate actual dollar amount of fixed base compensation paid to such Participant during the Plan Year (or portion thereof, as applicable) for eligible service to the Company and its Subsidiaries, as determined in the Company's discretion. For purposes of this Plan and for clarity, Base Salary shall exclude (a) all equity awards, performance-based compensation, bonuses, special awards, and benefits, (b) any amount paid to an Employee in connection with leave for military service or short-term disability, and (c) such other items as the Committee or CEO (as to non-Officers) shall determine in their discretion do not constitute Base Salary, but shall be calculated prior to any reductions for salary deferred pursuant to any deferred compensation plan or for contributions to a plan qualifying under Section 401(k) of the Code or contributions to a cafeteria plan under Section 125 of the Code.

Board means the Board of Directors of the Company.

Cause means:

(a) if the Participant is party to an employment or change in control agreement that includes a definition of "Cause," the term "Cause" as defined in such agreement or

(b) if the Participant is not a party to an employment or change in control agreement that includes a definition of "Cause," a Participant's (i) willful and repeated refusal or failure to perform duties; (ii) willful or intentional act that has injured (or could reasonably be expected to injure) the reputation or business of the Company or a Subsidiary in any material respects; (iii) continued or repeated absence, unless due to serious injury or illness; (iv) conviction of (or pleading nolo contendere to) a felony; (v) commission of an act of fraud, embezzlement, theft or gross misconduct against the Company or a Subsidiary, (vi) violation of a material policy of the Company or a Subsidiary or (vii) other action or inaction that the Company deems to constitute "Cause" for purposes of the Plan.

<u>CEO</u> means the Chief Executive Officer of the Company.

<u>Change in Control</u> means the earliest of the following to occur:

a) any Person, excluding (i) the Company or any Subsidiary, (ii) a corporation or other entity owned, directly or indirectly, by the stockholders of the Company immediately prior to the transaction in substantially the same proportions as their ownership of stock of the Company, (iii) an employee benefit plan (or related trust) sponsored or maintained by the Company or any Subsidiary or (iv) an underwriter temporarily holding securities pursuant to an offering of such securities ("Change in Control Person") is the beneficial owner (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of 20% or more of the combined voting power of the then outstanding voting securities eligible to vote generally in the election of directors of the Company; provided, however, that no Change in Control will be deemed to have occurred as a result of a change in ownership percentage resulting solely from an acquisition of securities by the Company;

b) consummation of a merger, consolidation, reorganization or share exchange, or sale of all or substantially all of the assets, of the Company or Idaho Power Company (a "Qualifying Transaction"), unless, immediately following such Qualifying Transaction, all of the following have occurred: (i) all or substantially all of the beneficial owners of the Company immediately prior to such Qualifying Transaction beneficially own in substantially the same proportions, directly or indirectly, more than 50% of the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors of the corporation or other entity resulting from such Qualifying Transaction (including, without limitation, a corporation or other entity which, as a result of such transaction, owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) (as the case may be, the "Successor Entity"), (ii) no Change in Control Person is the beneficial owner (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of 20% or more of the combined voting power of the then outstanding voting securities eligible to vote generally in the election of directors of the Successor Entity and (iii) at least a majority of the members of the board of directors of the Successor Entity are Incumbent Directors;

c) a complete liquidation or dissolution of the Company or Idaho Power Company or

d) within a 24-month period, individuals who were directors of the Board immediately before such period ("Incumbent Directors") cease to constitute at least a majority of the directors of the Board; provided, however, that any director who was not a director of the Board at the beginning of such period shall be deemed to be an Incumbent Director if the election or nomination for election of such director was approved by the vote of at least two-thirds of the directors of the Board then still in office (i) who were in office at the beginning of the 24-month period or (ii) whose election or nomination for election was so approved, in each case, unless such individual was elected or nominated as a result of an actual or threatened election contest or as a result of an actual or threatened solicitation of proxies or consents by or on behalf of any Change in Control Person other than the Board.

For avoidance of doubt, transactions for the purpose of dividing Idaho Power Company's assets into separate distribution, transmission or generation entities or such other entities as the Company or Idaho Power Company may determine shall not constitute a Change in Control unless so determined by the Board.

Code means the Internal Revenue Code of 1986, as amended.

Committee means the Compensation Committee of the Board, whose members shall be outside directors as defined in Section 162(m) of the Code.

Company means IDACORP, Inc. and any successor thereto.

Coverage Period means the period commencing on the date of a Change in Control and ending on the last day of the calendar year in which the Change in Control occurs.

Covered Employee means at any date (i) any individual who, with respect to the previous tax year of the Company, was a "covered employee" of the Company for purposes of Section 162(m) of the Code; provided, however, that the term “Covered Employee” shall not include any such individual who is designated by the Committee, in its discretion, at the time of any Award or at any subsequent time, as reasonably expected not to be such a “covered employee” with respect to the current tax year of the Company and (ii) any individual who is designated by the Committee, in its discretion, at the time of any Award or at any subsequent time, as reasonably expected to be such a “covered employee” with respect to the current tax year of the Company or with respect to the tax year of the Company in which any applicable Award will be paid.

Disability means termination of a Participant's employment with the Company and/or its Subsidiaries, as applicable, if the Participant is eligible to receive benefits under the Long-Term Disability Program maintained by the Company or its Subsidiaries.

Employee means an individual who is on the payroll of the Company or a Subsidiary, who is not covered by any collective bargaining agreement to which the Company or any of its Subsidiaries is a party and is classified in the payroll system as a regular, full-time, part-time or temporary employee.

Exchange Act means the Securities Exchange Act of 1934, as amended.

Officer shall have the meaning set forth in Rule 16a-1(f) under the Exchange Act, and shall also include such other vice presidents and other persons as shall be determined from time to time by the Committee or the Board to constitute officers of the Company or any Subsidiary for purposes of this Plan.

Participant means an Employee selected for participation in the Plan.

Performance Goals means for any Plan Year one or more objective performance goals selected and established by the Committee in accordance with the requirements of Section 6 of the Plan.

Person shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act.

Plan Year means the calendar year.

Pre-Change in Control Board means the Board, as composed prior to a Change in Control.

Retirement means a Participant's termination from employment with the Company and its Subsidiaries, as applicable, if the date of termination occurs on or after attainment of any of the following: (a) age 55 with 10 years of service or (b) 30 years of service; *provided, however* , that notwithstanding an employee's satisfaction of the age and/or years of service requirements set forth in subsections (a) or (b) of this paragraph, termination for Cause shall not be deemed a Retirement, and the Company and its Subsidiaries, as applicable, shall have the sole discretion to determine whether any termination from employment did or did not, under the circumstances, constitute a Retirement under this Plan.

Subsidiary means

(a) any corporation more than fifty (50%) percent of the outstanding securities having ordinary voting power of which shall at the time be owned or controlled, directly or indirectly, by the Company or one or more of its Subsidiaries or by the Company and one or more of its Subsidiaries or

(b) any partnership, limited liability company, association, joint venture or similar business organization more than fifty (50%) percent of the ownership interests having ordinary voting power of which shall at the time be so owned or controlled.

Target Award Amount means the amount payable if target performance levels are achieved pursuant to the Plan.

3. ADMINISTRATION

The Plan will be administered by the Committee, which is authorized to interpret the Plan, establish rules and regulations necessary to administer the Plan and take all other actions, not inconsistent with the terms of the Plan, that it determines are necessary or appropriate for the proper administration of the Plan; provided, however, that (a) the Committee will report on its actions to the Board and (b) all Awards made to Officers of the Company or any Subsidiary and all payments pursuant to Awards to such Officers shall be subject to Board approval to the extent provided in Section 7. For avoidance of doubt, as provided in Sections 6 and 7, the Committee shall establish Performance Goals and certify achievement of Performance Goals.

For all Awards and payments under the Plan made to Officers of the Company or any Subsidiary, the Committee shall make recommendations to the Board regarding the terms, conditions and amounts of Awards and any payments it determines should be made with respect to Awards.

For all Awards and payments under the Plan made to non-Officers, the CEO shall approve such Awards and payments pursuant to the Plan, and is authorized to take all actions necessary for the administration of such Awards and payments, including, but not limited to, determining the non-Officer Persons who are eligible to participate in the Plan.

All actions, determinations, interpretations and decisions made by the CEO, Committee and/or the Board regarding the Plan or its administration will be final, conclusive and binding upon all parties concerned; provided, that as between the CEO and the Board and Committee, the actions, determinations, interpretations, and decisions of the Board and Committee shall control over the actions, determinations, interpretations, and decisions of the CEO when in conflict. Neither the CEO nor any member of the Committee or the Board shall incur any liability by reason of any action or determination made with respect to the Plan.

4. ELIGIBILITY AND PARTICIPATION

Each year, the Committee shall select the Officers of the Company and Subsidiaries, if any, who are eligible for participation in the Plan, and the CEO shall select the non-Officer Employees, if any, who are eligible for participation in the Plan.

An Employee who holds an eligible position on the first day of a Plan Year, or who is hired, transferred or promoted into an eligible position during the first two (2) months of a Plan Year, may participate in the Plan for that Plan Year only if selected for participation during the first ninety (90) days of the Plan Year. An Employee who is hired, transferred or promoted into an eligible position after the first two (2) months of the Plan Year may participate in the Plan for the Plan Year only if selected to participate within thirty (30) days after assuming an eligible position; provided, however, that in no event shall a person who is a Covered Employee be added to the Plan for any Plan Year after the close of the eighth month of the Plan Year. An Employee who is hired, transferred or promoted into an eligible position during a Plan Year and selected to participate in the Plan for that Plan Year shall receive a prorated target Award opportunity based on such Employee’s partial year of participation, unless the Board of CEO, as applicable, specifies a different methodology. No such proration shall be made with respect to a Covered Employee if it would not otherwise meet the requirements of Section 162(m) of the Code.

The Committee may grant Awards to Covered Employees not intended to qualify as "performance-based compensation," within the meaning of Section 162(m) of the Code, and to the extent it does so, the provisions of the Plan relating to Covered Employees shall not apply to such Award.

Participation in the Plan during a particular Plan Year shall not entitle a Participant to participation in the Plan in future years.

5. AWARD OPPORTUNITIES

For each Plan Year, the Committee shall establish a target Award opportunity for each Officer Participant, and the CEO shall establish a target Award opportunity for each non-Officer Participant. The target Award opportunity shall be a percentage of each Participant’s Base Salary or a specified dollar amount that may be earned upon achievement of prescribed Performance Goals.

In addition to the target Award opportunity, the Committee (as to Officer Participants) and the CEO (as to non-Officer Participants) may establish Award opportunity levels for achievement above or below the target levels.

Award opportunities need not be uniform among Participants.

In no event shall the maximum Award opportunity, or the actual Award paid, to any Covered Employee for any Plan Year exceed $2,000,000.

6. ESTABLISHMENT OF PERFORMANCE GOALS

The Committee shall establish specific Performance Goals for such Plan Year, including target levels and, if the Committee so determines, one or more threshold, above target or other enhanced or reduced achievement levels associated with each Performance Goal, and the specific Performance Goals for a Covered Employee's Award, including any threshold, above target or other enhanced or reduced achievement levels associated with a Performance Goal, shall be established by the Committee not later than a date that is within the first ninety (90) days of each Plan Year. The Committee shall also determine an objective formula or standard for computing the amount of compensation payable to the Participant if the Performance Goals are met. If the Committee adds a Participant who is a Covered Employee to the Plan for a Plan Year after initially establishing the Award opportunities and the Performance Goals for the Plan Year, the Committee shall establish the Performance Goals (if different from the Performance Goals established for other similarly situated Participants) applicable to the new Participant within thirty (30) days after adding the Participant to the Plan. The outcome must be substantially uncertain at the time the Committee establishes the Performance Goals for an Award granted to a Covered Employee.

The Performance Goals for a Plan Year shall be based upon one or more of the following measures: (a) earnings per share, (b) earnings per share growth, (c) adjusted earnings per share, (d) adjusted earnings, (e) adjusted earnings before interest and taxes, (f) earnings before interest, taxes, depreciation and amortization, (g) operating income, (h) gross income, (i) net income, (j) operating cash flow, (k) stock price, (l) O&M expense, (m) other O&M expense, (n) capital expenditures, (o) total shareholder return, (p) return on equity, (q) return on capital, (r) operating ratios, (s) profit returns and margins, (t) financial return ratios, (u) performance against budget, (v) cost recovery, (w) health and safety, as measured by, among other things, one or more of recordable case rate, severity rate and internal safety assessments, (x) customer satisfaction, as measured by, among other things, one or more of service cost, service levels, responsiveness, and survey results with respect to, among other things, power service, billing, customer service/relations, communications, rates and fees, transmission lines and corporate issues, (y) network reliability, as measured by, among other things, one or more of outage frequency, outage duration, frequency of service interruptions, average frequency of customer interruptions and average number of interruptions per customer, (z) environmental, including, among other things, one or more of improvement in, or attainment of, emissions levels, project completion milestones and prevention of environmental violations, (aa) strategic business objectives, consisting of one or more objectives based upon meeting specified cost targets, business expansion goals, accomplishment of mergers, acquisitions, dispositions or similar extraordinary business transactions or goals relating to capital raising and capital management and (bb) any combination of the foregoing. Performance Goals may be expressed on an absolute and/or on a relative basis, on a before- or after-tax basis, on a consolidated or subsidiary or business unit basis, may be based on or otherwise employ comparisons based on internal targets, the past performance of the Company and/or the past or current performance of other companies and may include or exclude any or all extraordinary, non-core, non-operating or non-recurring items, or such other items as the Committee may determine.

The Committee shall assign a percentage weight to each Performance Goal established by the Committee for each Plan Year, which shall aggregate to 100 percent. The Committee may assign different weights to Performance Goals for each Participant or for classes of Participants.

Under normal business conditions, the Committee shall not revise the Performance Goals or weightings after it has established them for a Plan Year. However, in the event of unusual conditions, the Committee may revise the Performance Goals to maintain as closely as possible the previously expected level of overall performance as is practicable. No adjustments to Award opportunities or Performance Goals shall be made with respect to a Covered Employee for a Plan Year if such adjustment would cause an Award that is intended to qualify as “performance-based compensation” within the meaning of Section 162(m) of the Code and the regulations promulgated thereunder to fail to so qualify.

7. DETERMINATION OF AWARDS AND PAYMENT

As soon as practicable after the end of each Plan Year, but in any event prior to payment, the Committee shall, except as otherwise provided in Section 9, certify in writing the performance achievement relative to the Performance Goals.

With respect to Participants who are Officers of the Company or a Subsidiary, the Committee shall approve and recommend Award payments for approval by the Board and the Board shall approve the Award payments; provided, however, for the avoidance of doubt, in no event shall the Committee or the Board approve an Award payment above the amount of compensation otherwise payable to a Covered Employee if the Performance Goals are met for the Plan Year. The Committee and the Board may, in their sole and absolute discretion, approve a reduction, including a reduction to zero, of an Award payment for any or all Officer Participants. An Award to an Officer shall be deemed earned only at such time as the Board has approved payment of the Award to the Participant.

With respect to Participants who are not Officers of the Company or a Subsidiary, the CEO shall approve Award payments to such non-Officers. The CEO may, in his or her sole and absolute discretion, approve a reduction, including a reduction to zero, of an Award payment for any or all non-Officer Participants. An Award shall be deemed earned only at such time as the CEO has approved payment of the Award to the Participant.

Unless the Committee shall determine otherwise at the time it establishes the Performance Goals for the Plan Year, no Awards shall be paid under the Plan if awards are not paid to employees under the IDACORP, Inc. Employee Incentive Plan for the same Plan Year or if net income is less than the cash dividend paid on IDACORP common stock for the same Plan Year.

Except as otherwise provided in Section 9 or Section 12, Awards shall be paid as promptly as practicable after the Board has approved the Award payments for Officers of the Company and any Subsidiary and the CEO has approved the Award payments for non-Officers; provided, however, that the payment date shall in all events be between January 1 and March 15 of the calendar year immediately following the Plan Year to which the Award relates. All Award payments shall be made in cash in a lump sum.

The Company or Subsidiary, as the case may be, shall deduct from all payments made under the Plan an amount necessary to satisfy federal, state and/or local tax withholding requirements.

In lieu of receiving a cash payment for an Award, Participants may elect to defer up to 50 percent of the amount of their Awards pursuant to the terms of the Idaho Power Company Executive Deferred Compensation Plan.

8. EFFECT OF TERMINATION OF EMPLOYMENT

(a) If a Participant's employment is terminated for any reason other than Retirement, death or Disability, except as provided in Section 9 herein and unless otherwise determined by the Committee, (i) with respect to the Participant's Award relating to the Plan Year in which the employment termination occurs, such Award will be cancelled and the Participant will not be eligible to receive a payment under the Plan with respect to that Plan Year and (ii) with respect to the Participant's Award relating to the prior Plan Year (if such Award was either not yet approved or approved but not yet paid as of the date of employment termination), such Award will remain in effect, the amount payable to the Participant (if any) shall be determined in accordance with Section 7 hereof based on actual performance through the end of the prior Plan Year and any amount payable to the Participant shall be paid pursuant to Section 7 hereof at the same time such amount would have been paid had the Participant remained employed through the payment date.

(b) Except as otherwise provided in Section 9 herein, if a Participant's employment is terminated due to Retirement, death or Disability, (i) with respect to the Participant's Award relating to the Plan Year in which the employment termination occurs, (A) such

Award shall remain in effect, (B) the amount payable to the Participant (if any) shall be determined by multiplying (I) the amount that would have been paid if the Participant had remained employed through the payment date, determined in accordance with Section 7 hereof based on actual performance through the end of the Plan Year, by (II) a fraction, the numerator of which equals the number of days the employee worked in the Plan Year in which the termination of employment occurs and the denominator of which is 365 and (C) any amount payable to the Participant shall be paid pursuant to Section 7 hereof at the same time such amount(s) would have been paid had the Participant remained employed through the payment date and (ii) with respect to the Participant's Award relating to the prior Plan Year (if such Award was either not yet approved or approved but not yet paid as of the date of employment termination), (A) such Award shall remain in effect, (B) the amount payable to the Participant (if any) shall be determined in accordance with Section 7 hereof based on actual performance through the end of the Plan Year to which the Award relates and (C) any amount payable to the Participant shall be paid pursuant to Section 7 hereof at the same time such amount would have been paid had the Participant remained employed through the payment date.

(c) No Award shall be paid to a Participant whose employment is terminated for Cause.

(d) For purposes of the Plan, (i) transfer of employment of a Participant between the Company and any one of its Subsidiaries (or between Subsidiaries) and transfer of employment to a Successor Entity or other successor of the Company or a Subsidiary shall not be deemed a termination of employment unless so determined by the Committee and (ii) if a Participant is employed by the Company and a Subsidiary or more than one Subsidiary, a Participant shall not be deemed to have terminated employment unless the Participant's employment with each such entity terminates.

9. CHANGE IN CONTROL

(a) If a Change in Control involving a Successor Entity occurs, the Pre-Change in Control Board may require that the Successor Entity (i) assume or otherwise continue all or any part of the Awards that are outstanding at the time of the Change in Control or (ii) substitute outstanding Awards with awards that are no less favorable to Participants (as determined in the sole discretion of the Pre-Change in Control Board).

(b) If a Successor Entity refuses to assume or continue such Awards or to provide substitute awards that are deemed acceptable by the Pre-Change in Control Board or if a Change in Control not involving a Successor Entity occurs and the Pre-Change in Control Board determines that the Change in Control would adversely affect outstanding Awards, the Pre-Change in Control Board, in its sole discretion, may (i) with respect to outstanding Awards that relate to the Plan Year in which the Change in Control occurs, deem all or a portion of the outstanding Awards vested (at target or another level determined by the Pre-Change in Control Board), (ii) with respect to outstanding Awards that relate to the prior Plan Year and that were either not yet approved or approved but not yet paid as of the date of the Change in Control, provide for the accelerated vesting of the outstanding Awards (at target or another level determined by the Pre-Change in Control Board) or (iii) take such other action with respect to outstanding Awards, which action need not be consistent among Participants, as it deems appropriate (including taking no action).

(c) The Pre-Change in Control Board may make or cause to be made such changes to Performance Goals and other terms of Awards as it may deem appropriate to reflect or adjust for changes resulting from a Change in Control.

(d) If a Participant's employment is terminated for any reason other than Cause during the Coverage Period, (i) with respect to outstanding Awards that relate to the Plan Year in which the Change in Control occurs, the Participant shall be vested in either (A) a prorated Award determined by multiplying the Participant's Target Award Amount (or another amount determined by the Pre-Change in Control Board) by a fraction, the numerator of which equals the number of days the Participant worked in the Plan Year in which the termination of employment occurs and the denominator of which is 365 or (B) if so determined by the Pre-Change in Control Board, a full Award in an amount determined by the Pre-Change in Control Board and (ii) with respect to outstanding Awards that relate to the prior Plan Year and that were either not yet approved or approved but not yet paid as of the date of the Change in Control, the Pre-Change in Control Board, in its sole discretion, may provide for the accelerated vesting of outstanding Awards (at target or another level determined by the Pre-Change in Control Board).

(e) Any Award vested pursuant to this Section 9 shall be paid on the date selected by the Pre-Change in Control Board, provided that such date shall in no event be later than the earlier of (i) the date such payment would have been made in the ordinary course and (ii) 2½ months following the event triggering the payment (*i.e.* , the Change in Control or termination of employment).

(f) Notwithstanding anything to the contrary contained in the Plan, no payment or distribution under the Plan or pursuant to an Award that (i) is determined by the Company to be deferred compensation subject to Section 409A of the Code and (ii) would be distributed because of a Change in Control shall be so distributed because of the Change in Control pursuant to this Section 9 unless the distribution qualifies under Section 409A(a)(2)(A)(v) of the Code as a distribution upon a change in ownership or effective control or a change in the ownership of a substantial portion of assets or otherwise qualifies as a permissible distribution under Section 409A of the Code. To the extent an amount would have been distributed because of a Change in Control pursuant to this Section 9, but the distribution is prohibited by the prior sentence, the Award shall nevertheless vest pursuant to subsection (b) of this Section 9 as of the date of the Change in Control (except to the extent it would violate Section 409A of the Code), but distribution of such vested amounts shall not occur until the event or date distribution would have occurred absent the Change in Control.

10. PLAN IS NOT A CONTRACT

No provision of the Plan nor any document describing the Plan or establishing rules or regulations regarding the Plan's administration shall be deemed to confer on any Participant the right to continue in the Company's or Subsidiary's employ nor shall any such provision or document affect the right of the Company or any Subsidiary to terminate any Participant's employment.

11. AMENDMENT AND TERMINATION OF THE PLAN AND AWARDS

The Board reserves the right to amend, suspend or terminate the Plan and any Award under the Plan at any time in whole or in part, for any reason, and without the consent of any Participant or other person;

provided, however, that, except as provided in Section 9, the Plan and any Award under the Plan may not be amended, suspended or terminated during the Coverage Period without the written consent of each Participant whose Award would be affected by the amendment.

12. SECTION 409A

To the extent applicable to an Award that provides for the payment of deferred compensation subject to Section 409A of the Code, it is intended that the Plan will comply with Section 409A of the Code and any regulations and guidance issued thereunder, and the Plan shall be interpreted accordingly. To the extent an Award is subject to Section 409A of the Code and payment of deferred compensation pursuant to the Award is to be made because of the Participant's termination of employment, notwithstanding anything to the contrary contained in the Plan, no payment shall be made due to Participant's termination of employment unless and until Participant has experienced a separation from service, as that term is used in Section 409A(a)(2)(A)(i) of the Code (a "Separation from Service") with the Company. Notwithstanding anything contained herein to the contrary, if it is determined that any payments to be made upon a Separation from Service constitute deferred compensation for purposes of Section 409A of the Code and the Participant is a "specified employee," as determined under the Company's policy for determining specified employees, on the date on which the Separation from Service occurs, no such payments shall be made before the date that is six months following the Participant's Separation from Service unless the Participant dies during such six-month period, in which case payment may be made as soon as practicable (but not more than 60 days) after the Participant's death.

13. PLAN BINDING ON SUCCESSOR ENTITIES

All obligations of the Company or any Subsidiary under the Plan shall be binding on any successor to the Company or any Subsidiary, respectively, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, reorganization or other transaction involving all or substantially all of the business and/or assets of the Company or any Subsidiary. References to the Company or Subsidiary in the Plan shall be deemed to refer to the successors thereto, as applicable.

14. MISCELLANEOUS

(a) Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine, the plural shall include the singular and the singular shall include the plural.

(b) Severability. In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

(c) Governing Law. To the extent not preempted by Federal law, the Plan shall be construed in accordance with, and governed by, the laws of the State of Idaho without regard to any conflicts of law or choice of law rule or principle that might otherwise reference construction or interpretation of the Plan to the substantive law of another jurisdiction.

(d) Headings. The headings of sections are included solely for convenience of reference. If there is any conflict between such headings and the text of the Plan, the text shall control.

EXHIBIT IV

Exhibit 10.50

IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors (Effective January 1, 2016)

All directors of IDACORP also serve as directors of Idaho Power. The fees and other compensation discussed below are for service on both boards. Employee directors receive no compensation for service on the boards.

Form of Fee	Amount
Base Board Annual Retainer	$ 65,000
Base Committee Annual Retainers (1)	
Audit Committee	12,000
Compensation Committee	6,000
Corporate Governance and Nominating Committee	6,000
Executive Committee	3,000
Additional Chair Annual Retainers	
Chairperson of the Board of Directors	100,000
Chair of the Audit Committee	12,500
Chair of the Compensation Committee	10,000
Chair of the Corporate Governance and Nominating Committee	7,500
Annual Stock Awards	100,000
Subsidiary Board Fees:	
IDACORP Financial Services:	
Monthly retainer	750
Meeting fees	600
Ida-West Energy:	
Monthly retainer	750
Meeting fees	600

(1) The Chairperson of the Board of Directors does not receive base committee retainers.

Deferral Arrangements

Directors may defer all or a portion of their annual IDACORP, Idaho Power, IDACORP Financial Services, Inc., and Ida-West Energy retainers and meeting fees and receive a lump-sum payment of all amounts deferred with interest or a series of up to 10 equal annual payments after they separate from service with IDACORP and Idaho Power. Any cash fees that were deferred before 2009 for service as a member of the board of directors are credited with the preceding month's average Moody's Long-Term Corporate Bond Yield for utilities, or the Moody's Rate, plus 3%, until January 1, 2019 when the interest rate will change to the Moody's Rate. All cash fees that are deferred for service as a member of the board of directors after January 1, 2009 are credited with interest at the Moody's Rate. Interest is calculated on a pro rata basis each month using a 360-day year and the average Moody's Rate for the preceding month.

Directors may also defer their annual stock awards, which are then held as deferred stock units with dividend equivalents reinvested in additional deferred stock units. Upon separation from service with IDACORP and Idaho Power, directors will receive either a lump-sum distribution or a series of up to 10 equal annual installments. Upon a change in control the directors' deferral accounts will be distributed to each participating director in a lump sum. The distributions will be in shares of IDACORP common stock, with each deferred stock unit equal to one share of IDACORP common stock and any fractional shares paid in cash.

EXHIBIT IV

Exhibit 10.59

IDAHO POWER COMPANY

EMPLOYEE SAVINGS PLAN

Amended and Restated as of January 1, 2016 (revised)

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EXHIBIT IV

IDAHO POWER COMPANY

EMPLOYEE SAVINGS PLAN

Amended and Restated as of January 1, 2016

<u>Introduction</u>

The Company originally adopted the Idaho Power Company Employee Savings Plan (the "Plan") on July 1, 1974, and the Plan has been amended and restated from time to time thereafter. Effective October 9, 1994, the Idaho Power Company Employee Stock Ownership Plan was merged with and into the Plan. This is an amendment and restatement of the Plan as previously amended and restated generally effective January 1, 2010, as amended by the First, Second, Third, Fourth and Fifth Amendments. This restatement generally will be effective January 1, 2016, except to the extent that certain provisions either are not required by law to be effective until a later date, or are required by law to be effective at an earlier date, and except as otherwise specifically indicated.

In connection with this amendment and restatement, the Company intends to preserve all Code section 411(d)(6) protected benefits within the meaning of Treasury Regulation § 1.411(d)-4 and this document should be interpreted accordingly. The Plan is intended to qualify under Code Sections 401(a) and 401(k), and the Trust Agreement established pursuant to the Plan is an employees' trust intended to constitute a tax exempt organization under Code section 501(a).

Prior to January 1, 1998, the Plan was designed to qualify as a profit sharing plan for purposes of Sections 401(a), 402, 412 and 417 of the Code. Effective January 1, 1998, the Plan was converted to a stock bonus plan under Code section 401(a) and an employee stock ownership plan within the meaning of Code section 4975(e)(7) ("ESOP") that is designed to invest primarily in Company Stock. Effective January 1, 2001, only the Company Stock Fund portion of the Plan constitutes an ESOP, and the remainder of the Plan is a non-ESOP stock bonus plan. See Article 5 for more information regarding the Non-ESOP Company Stock Fund and the ESOP Company Stock Fund. It is intended that the Plan will at all times meet the stock distribution requirement of Code section 409(h)(1)(A) by permitting Participants to direct the investment of their Accounts into Company Stock prior to distribution. It is further intended that the Plan will at all times meet the ESOP diversification requirements of Code section 401(a)(28)(B) by permitting Participants to direct the investment of their entire Account into investments other than Company Stock, thereby providing complete diversification at all times.

EXHIBIT IV

1. DEFINITIONS

1.1 Administrator

"Administrator" means the Company, or the Committee, if one is appointed pursuant to Section 9.1.

1.2 Account

"Account" means the records, including subaccounts, maintained by the Administrator in the manner provided in Article 4 to determine the interest of each Participant in the assets of the Plan and may refer to any or all of the Participant's Deferral Contribution Account, After-Tax-Account, Roth Deferral Account, Matching Contribution Account, and Rollover Account, as applicable.

1.3 After-Tax Contribution

"After-Tax Contribution" means a contribution described in Section 3.3.

1.4 Alternate Payee

"Alternate Payee" means any spouse, former spouse, child or other dependent of a Participant who is recognized by a qualified domestic relations order as having a right to receive all or a portion of the Account of a Participant under the Plan.

1.5 Beneficiary

"Beneficiary" means any person or persons designated in writing by the Participant (which designation may be changed from time to time) to receive benefits under the Plan payable upon the death of a Participant. If the Participant is married, designation of a Beneficiary who is not the Participant's Spouse shall require spousal consent which is notarized. If no such designation is in effect at the time of death of the Participant, or if no person so designated shall survive the Participant, the Beneficiary shall be his or her Spouse, or if the deceased Participant has no surviving Spouse, the Participant's estate.

1.6 Board of Directors

"Board of Directors" or "Board" means the Board of Directors of the Company.

1.7 Code

"Code" means the Internal Revenue Code of 1986, as amended from time to time and, as appropriate, any predecessor provisions.

EXHIBIT IV

1.8 Company

" Company " means Idaho Power Company, an Idaho corporation, and any successor thereto.

1.9 Company Stock

" Company Stock " means shares of common stock, par value $2.50 per share, of IDACORP, Inc., which stock is publicly traded.

1.10 Compensation

" Compensation " with respect to any Participant means the Base Pay of a Participant, plus amounts under any Company approved annual incentive plan of the Employer, paid during the Plan Year for services rendered to his or her Employer. A Participant's Compensation shall include Deferral Contributions under this Plan and any deductions under Code section 125 or 129 and shall include amounts that are not includable in an Employee's gross income by reason of Code section 132(f).

" Base Pay " means, for regular full-time employees, the salary established by the wage schedule for each position plus any partial disability payments, less any reductions for time not worked. For other employees, Base Pay means hours worked times hourly rate. Payment for compensated time off is included in Base Pay. Overtime, including restoration overtime, is excluded from Base Pay, provided that with respect to Shift Workers, beginning with the first pay period starting after July 1, 2014, up to 80 hours in each two week pay period shall be included as Base Pay, regardless of whether such hours are considered overtime with respect to the particular workweek in which the hours were worked.

For purposes of this definition, " Shift Worker " means an employee who works in a business unit where shifts are continuously staffed 24-7, who is regularly scheduled to work those shifts, and who regularly works on weekends and traditional holidays.

Compensation will exclude amounts (including but not limited to severance or separation pay or annual incentive compensation) paid after the Participant terminates employment with the Controlled Group, or otherwise ceases to be eligible to participate in the Plan; provided, however, that payments made in the first month after termination relating to pre-termination wages or payoff of unused vacation and/or sick leave will constitute Compensation.

1.10.1 Limitation on Compensation

For purposes of determining benefits under the Plan (other than Employee Contributions), Compensation is limited to $245,000, as indexed for the cost of living pursuant to Code Sections 401(a)(17) and 415(d), per Plan Year.

1.10.2 Section 415 Compensation

(a) Post-Termination. To determine Compensation for purposes of Code section 415 (and not for the purpose of determining Employee Contributions), Compensation shall not include any amounts paid after an Employee's "severance from employment" with the Employer, except as provided below.

(i) Compensation shall include payments made after severance from employment by the later of two and one-half months after severance from employment or the end of the Plan Year that includes the date of severance from employment provided such payment would have been paid to the Employee if employment had continued and the payment is regular compensation for services performed during the Employee's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar payments.

(ii) Compensation shall include payments made after severance from employment by the later of two and one-half months after severance from employment or the end of the Plan Year that includes the date of severance from employment provided such payment is for unused accrued bona fide sick, vacation, or other leave, but only if the Employee would have been able to use the leave if employment had continued and if such amounts would have been included in compensation if they were paid prior to the Employee's severance from employment with the Employer.

(iii) Compensation shall not include payments made after severance from employment by the later of two and one-half months after severance from employment or the end of the Plan Year that includes the date of severance from employment provided such payment is received by an Employee pursuant to a nonqualified unfunded deferred compensation plan, but only if the payment would have been paid to the Employee at the same time if the Employee had continued in employment with the Employer and only to the extent that the payment is includable in the Employee's gross income and such amounts would have been included in compensation if they were paid prior to the Employee's severance from employment with the Employer.

(iv) Compensation shall include amounts paid after an Employee's severance from employment with the Employer if the Employee is not currently performing services for the Employer by reason of qualified military service (as defined by Code Section 414(u)(1)) to the extent the payments do not exceed the amounts the Employee would have received if the Employee had continued to perform services for the Employer rather than entering qualified military service.

(v) Compensation shall not include amounts paid after an Employee's severance from employment with the Employer notwithstanding that the Employee is permanently and totally disabled (as defined by Code Section 22(e)(3)).

(b) Highly Compensated Employee. Code Section 415 Compensation shall be used to determine whether an Employee is a highly compensated employee.

1.11 Controlled Group

" Controlled Group " means the Company and any and all other corporations, trades and businesses, the employees of which, together with employees of the Company, are required by Code section 414 (b), (c), (m) or (o) to be treated as if they were employed by a single employer.

1.12 Controlled Group Member

" Controlled Group Member " means each corporation or unincorporated trade or business that is or was a member of the Controlled Group, but only during the period when it is or was such a member.

1.13 Deferral Contribution

" Deferral Contribution " means a contribution described in Section 3.1.

1.14 Direct Rollover

" Direct Rollover " means a payment by the Plan to the Eligible Retirement Plan specified by a Distributee.

1.15 Disability

" Disability " (or " Disabled ") means a physical or mental condition of a Participant that constitutes total and permanent disability for purposes of the Company's Long Term Disability Plan.

EXHIBIT IV

1.16 Distributee

" Distributee " means an Employee; a former Employee; an Employee's or former Employee's surviving Spouse; a non-spouse designated beneficiary; or an Employee's or former Employee's Spouse or former spouse who is an Alternate Payee under a QDRO.

1.17 Eligible Retirement Plan

" Eligible Retirement Plan " means an individual retirement account described in Code sections 408(a) or 408(b), a Roth IRA described in Code section 408A(b) (effective January 1, 2008), an annuity plan described in Code sections 403(a) or 403(b), a qualified trust described in Code section 401(a) and an eligible plan under Code section 457(b) which is maintained by a state, political subdivision of a state or any agency or instrumentality of a state or political subdivision of a state and which agrees to separately account for amounts transferred into such a plan from this Plan. This definition of Eligible Retirement Plan shall also apply in the case of a distribution to a surviving spouse, or to a spouse or former spouse who is the alternate payee under a QDRO, or, effective January 1, 2010, to a non spouse beneficiary.

1.18 Eligible Rollover Distribution

" Eligible Rollover Distribution " means any distribution of all or any portion of the Account balance to the credit of the Distributee other than the following: (i) any distribution that is one of a series of substantially equal periodic payments (made not less frequently than annually) for the life (or life expectancy) of the Distributee and the Distributee's Beneficiary, or for a specified period of 10 years or more; (ii) any distribution to the extent such distribution is required under Code section 401(a)(9); and (iii) the portion of any distribution that is not includable in gross income (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

Notwithstanding the foregoing, effective January 1, 2007, a portion of a distribution shall not fail to be an Eligible Rollover Distribution merely because the portion consists of After-Tax Contributions or Roth Deferrals which are not includable in gross income. However, such portion may be transferred only to an individual retirement account or annuity described in Code sections 408(a) or (b), or to a qualified defined contribution plan described in Code sections 401(a) or 403(a) that agrees to separately account for amounts so transferred, including separately accounting for the portion of such distribution which is includable in gross income and the portion of such distribution which is not so includable.

1.19 Employee

" Employee " means any person who is (i) employed by any Controlled Group Member if their relationship is, for federal income tax purposes, that of employer and employee.

1.20 Employee Contributions

" Employee Contributions " means Deferral Contributions, After-Tax Contributions, and Roth Deferrals.

1.21 Employer

" Employer " or " Participating Employer " means the Company and any Controlled Group Member or organizational unit thereof which meets the requirements of Section 14.1 of the Plan. The Company will maintain a list of currently participating Employers, along with the effective dates of their participation. The Company may choose to satisfy the obligation of any Employer hereunder.

1.22 ERISA

" ERISA " means the Employee Retirement Income Security Act of 1974, as amended from time to time.

1.23 Investment Funds

" Investment Funds " means the Funds described in Article 5.

1.24 Long Term Disability Participant

" Long Term Disability Participant " means a Participant who qualifies for, and receives benefits from, the Employer's Long Term Disability Plan.

1.25 Matching Contribution

" Matching Contribution " means a contribution described in Section 3.4.

1.26 Named Fiduciary

" Named Fiduciary " means the Fiduciary Committee, which is appointed by the Chairman of the Board of Directors and Chief Executive Officer.

1.27 Participant

" Participant " means an Employee or former Employee who has met the applicable eligibility requirements of Article 2 and who has not yet received a distribution of the entire amount of his or her interest in the Plan.

1.28 Plan

" Plan " means the IDAHO POWER COMPANY EMPLOYEE SAVINGS PLAN, the terms of which are set forth herein, as amended from time to time.

1.29 Plan Year

" Plan Year " means the period with respect to which the records of the Plan are maintained, which shall be the 12-month period beginning on January 1 and ending on December 31.

1.30 QDRO

" QDRO " means a qualified domestic relations order within the meaning of Code section 414(p).

1.31 Qualified Matching Contribution

" Qualified Matching Contribution " means a contribution by an Employer to the Plan pursuant to Section 10.7 which is used to satisfy the Contribution Percentage test set forth in that Section.

1.32 Qualified Non-Elective Contribution

" Qualified Non-Elective Contribution " means a contribution by an Employer to the Plan that is made pursuant to Section 10.6. Such contributions shall be considered Deferral Contributions for all purposes of the Plan and shall be used to satisfy the "Actual Deferral Percentage" test as set forth in Section 10.6.

1.33 Qualified Plan

" Qualified Plan " means an employee benefit plan that is qualified under Code sections 401(a) or 403(a).

1.34 Rollover Contribution

" Rollover Contribution " means a contribution described in Section 3.5.

1.35 Roth Deferral

"Roth Deferral " means a Deferral Contribution, as defined in Section 1.13, that a Participant must include as income at the time of deferral and which the Participant designates irrevocably in a salary reduction agreement at the time of the deferral election, as a Roth Deferral.

1.36 Self-Directed Brokerage Fund

" Self-Directed Brokerage Fund " means an Investment Fund that consists solely of all or part of the assets of a single Participant's Account, which assets the Participant controls by investment directives to the Trustee and which may not be commingled with assets of any other Participant's Accounts.

1.37 Spouse

"Spouse" means the person to whom a Participant is legally married at a specified time; "surviving Spouse" means the person to whom a Participant is legally married at the time of his or her death. For the period from June 26, 2013 through September 15, 2013, marriage shall be determined based on the law of the jurisdiction where the Participant is domiciled. Beginning September 16, 2013, marriage shall be determined based on the law of the jurisdiction where the marriage was performed.

1.38 Trust Agreement

" Trust Agreement " means the agreement or agreements between the Company and the Trustee establishing a trust fund to provide for the investment, reinvestment, administration and distribution of contributions made under the Plan and the earnings thereon, as amended from time to time, including any successor trust that may be established with a successor trustee.

1.39 Trust Fund

" Trust Fund " or " Trust " means the assets of the Plan held by the Trustee pursuant to the Trust Agreement.

1.40 Trustee

" Trustee " means the one or more individuals or organizations who have entered into the Trust Agreement as Trustee(s), and any duly appointed successor.

1.41 Valuation Date

" Valuation Date " means the date with respect to which the Trustee determines the fair market value of the assets comprising the Trust Fund or any portion thereof. The regular Valuation Date shall mean every business day of the Trustee, if a financial institution; otherwise, every business day on which the New York Stock Exchange is open.

EXHIBIT IV

2. PARTICIPATION

2.1 Eligibility to Participate

2.1.1 General

Each Employee, other than an ineligible Employee under Section 2.3, will be eligible to become a Participant once he or she has attained age 18, if then employed by an Employer.

2.1.2 Matching Contributions

Matching Contributions will be due for all Employee Contributions as provided in Section 3.4.

2.2 Commencement of Participation

An Employee eligible to participate in the Plan may enroll as a Participant on his or her hire date or as of any subsequent pay period.

2.3 Exclusions from Participation

2.3.1 Ineligible Employees

An Employee who is otherwise eligible to participate in the Plan will not become or continue as an active Participant if such Employee:

(i) is covered by a collective bargaining agreement that does not expressly provide for participation in the Plan;

(ii) is a leased employee required to be treated as an Employee under Code section 414(n);

(iii) is employed by a Controlled Group Member or an organizational unit thereof that is not an Employer; or

(iv) is a person performing services for the Employer who is not contemporaneously treated as a common law employee on the Employer's payroll records and personnel records, including, but not limited to, any person (A) whom the Employer treats as an independent contractor, (B) who is paid through a third party business entity's payroll, or (C) who is hired through an agreement with an employee staffing agency, regardless of whether the relationship between the Employer and the person subsequently is determined to be an employer/common law employee relationship because of (1) reclassification by a governmental agency (whether retroactively or prospectively), (2) decision by a court, mediation, arbitration, or similar proceeding, or (3) mutual agreement between the Employer and the person.

2.3.2 Participation after Exclusion

An Employee or Participant who is or becomes ineligible to participate in the Plan will be eligible to participate in the Plan on the first day he or she is no longer described in subsection 2.3.1 and is credited with one or more hours of service by an Employer, provided that he or she has otherwise met the requirements of Section 2.1. Such an Employee or Participant may commence or resume participation in the Plan as soon as administratively feasible, after completing the enrollment procedure established by the Administrator.

EXHIBIT IV

3. CONTRIBUTIONS

3.1 Deferral Contributions

3.1.1 Amount of Deferral Contributions

(a) Elections. Upon enrollment, a Participant may direct that his or her Employer make Deferral Contributions to the Trust Fund of from 1 percent to 100 percent of his or her Compensation (in 1 percent increments) for each pay period. Any Deferral Contribution election shall be effective only with respect to Compensation paid after his or her election is completed and, except for occasional bona fide administrative considerations, after the Participant's performance of services with respect to which such election is made.

(b) Default Elective Contributions. Each eligible Employee who does not make an affirmative election pursuant to subsection (a) in effect (including an affirmative election to not contribute to the Plan) upon becoming eligible to participate in the Plan shall be deemed to have elected to make a Deferral Contribution of 6 percent of his or her Compensation, commencing as soon as administratively feasible following his or her hire date, subject to the Employee's right to alter or revoke such deemed election at any time thereafter.

(c) Special One-Time Default Enrollment. Each eligible Employee who does not have an affirmative election pursuant to subsection (a) in effect as of January 1, 2012, shall be deemed to have elected to make a Deferral Contribution of 6 percent of his or her Compensation, commencing on or about February 1, 2012, subject to the Employee's right to alter or revoke such deemed election prior to its commencement date or at any time thereafter. An affirmative election not to contribute is considered an affirmative election, excluding the Employee from the auto-enrollment process.

(d) Notices. At least 30 days but not more than 90 days before the beginning of each Plan Year, the Employer will provide each Employee a comprehensive notice of the Employee's rights and obligations under the automatic contribution arrangement, written in a manner calculated to be understood by the average Employee. If an Employee becomes eligible within 90 days prior to the beginning of the

Plan Year and does not receive the notice for that reason, the notice will be provided no more than 90 days before the Employee becomes eligible but not later than the date the Employee becomes eligible. In addition, notices will be provided to Employees as soon as practical after hire (or as soon as practical after he or she satisfies the Plan participation requirements, if later). The notice will accurately describe: (i) the amount of Deferral Contributions that will be made on the Employee’s behalf absent an affirmative election; (ii) the Employee’s right to have no Deferral Contributions made on his or her behalf or to have a different amount of Deferral Contributions made; and (iii) how Deferral Contributions will be invested in the absence of the Employee’s investment instructions. An Employee will have a reasonable opportunity after receipt of the notice described in this subsection to make an affirmative election regarding Deferral Contributions (either to have no Deferral Contributions made or to have a different amount of Deferral Contributions made) before Default Deferral Contributions are made on the Employee’s behalf. Default Deferral Contributions being made on behalf of an Employee will cease as soon as administratively feasible after the Employee makes an affirmative election.

(e) Limitations. If a Participant’s Deferral Contributions must be reduced to comply with the requirements of Section 10.6 or the requirements of applicable law, the Deferral Contributions as so reduced will be the maximum percentage of his or her Compensation permitted by such Section or law notwithstanding the 1 percent increments requirement. A Participant’s Deferral Contributions, After-Tax Contributions and Roth Deferrals are limited to 100 percent of a Participant’s Compensation for a Plan Year.

3.1.2 Payments to Trustee

Deferral Contributions made for a Participant during a pay period pursuant to a salary reduction agreement will be transmitted to the Trustee as soon as practicable, but in no event later than the period prescribed by law.

3.1.3 Changes in/Suspension of Contributions

The percentage or percentages designated by a Participant or deemed designated by a Participant pursuant to Section 3.1.1 shall continue in effect, notwithstanding any changes in the Participant’s Compensation. A Participant may, however, in accordance with the percentages permitted by subsection 3.1.1, change the percentage of his or her Deferral

Contributions, effective as of any pay period (with respect to all pay periods ending on or after such period), by filing a notice with the Administrator prior to such pay period in accordance with procedures established by the Administrator from time to time. A Participant may suspend Deferral Contributions at any time, to be effective as soon as administratively feasible thereafter.

3.1.4 Resumption of Contributions

A Participant who suspends Deferral Contributions may, upon prior notice to the Administrator, resume making such Deferral Contributions as of any pay period.

3.1.5 Establishment of Procedures by Administrator

The Administrator may establish procedures for electing and changing deferrals which may, without limitation, provide for different notice periods, different methods (including telephonic or electronic, as permitted by applicable law) of making deferral elections and changes and more or less frequent times at which deferral elections or changes may become effective.

3.2 Excess Deferrals

3.2.1 Limit on Deferral Contributions

(a) A Participant’s Deferral Contributions for any taxable year of such Participant shall not exceed the dollar limitation contained in Code section 402(g) in effect for such taxable year except to the extent permitted under Section 3.2.1(b) and Code section 414(v). For purposes of this Section and except as otherwise provided in this Section, a Participant's Deferral Contributions shall mean the sum of (i) any Deferral Contributions made to this Plan, (ii) any elective contribution under any other qualified cash or deferred arrangement as defined in Code section 401(k) to the extent not includable in gross income for the taxable year under Code section 402(e)(3) (determined without regard to Code section 402(g)), (iii) any elective employer contribution to a SIMPLE arrangement as described in Code section 408(p)(2) (determined without regard to Code section 402(g)), (iv) any employer contribution to a simplified employee pension as defined in Code section 408(k) to the extent not includable in gross income for the taxable year under Code section 402(h)(1)(B) (determined without regard to Code section 402(g)), (v) any employer contribution to an annuity contract under Code section 403(b) under a salary reduction agreement within the meaning of Code section 3121(a)(5)(D) to the extent not includable in gross income for the taxable year under Code section 403(b) (determined without regard to Code section 402(g)), (vi) any employee contribution designated as deductible under a trust described in Code section 501(c)(18) to the extent deductible from the individual's income for the taxable year on account of section 501(c)(18) (without regard to Code section 402(g)), and (vii) Roth Deferrals.

(b) A Participant who is eligible to make Deferral Contributions under the Plan and who will attain age 50 before the close of the Plan Year shall be eligible to make catch-up contributions in accordance with, and subject to the limitations of, Code section 414(v). Such catch-up contributions shall not be taken into account for purposes of the provisions of the Plan implementing the required limitations of Code sections 402(g) or 415. The Plan shall not be treated as failing to satisfy the provision of the Plan implementing the requirements of Code sections 401(k)(3), 410(b) or 416 by reason of making such catch-up contributions.

3.2.2 Distribution of Excess Deferrals

If a Participant’s Deferral Contributions exceed the amount described in subsection 3.2.1 (hereinafter called the “excess deferrals”) during a taxable year of the Participant, such excess deferrals (adjusted for Trust Fund earnings and losses in the manner described in subsection 4.4.3) shall be distributed to the Participant by April 15 following the close of the taxable year in which such excess deferrals occurred if, by March 1 following the close of such taxable year, the Participant notifies the Administrator of any excess deferral amount allocated to the Participant’s Deferral Contribution under this Plan.

3.2.3 Preventing Excess Deferrals

To ensure that excess deferrals will not be made to the Plan for any taxable year for any Participant, the Administrator will monitor (or cause to be monitored) the amount of Deferral Contributions being made to the Plan for each Participant during each taxable year and may take action to prevent Deferral Contributions made for any Participant under the Plan for any taxable year from exceeding the maximum amount under this Section. This action is in addition to, and not in lieu of, any other actions that may be taken hereunder or that may be permitted by applicable law or regulation in order to ensure that the limitations described in this Section are met.

3.2.4 Matching Contributions Attributable to Excess Deferrals

If a Participant receives a distribution of excess deferrals pursuant to subsection 3.2.2, Matching Contributions, if any, made with respect to such distributed Deferral Contributions (adjusted for Trust Fund earnings and losses as set forth in subsection 4.4.3) shall be forfeited and credited against the Employer's obligation to make Matching Contributions under Section 3.4.

3.3 After-Tax and Roth Contributions

Upon enrollment, a Participant will be entitled to contribute to the Trust Fund an amount between 1 percent and 100 percent of his or her Compensation (in 1 percent increments) for each pay period as an After-Tax or Roth Contribution which is non-deductible. Deferral Contributions, After-Tax and Roth Contributions are limited to 100 percent of a Participant's Compensation.

The percentage of Compensation designated by the Participant as his or her After-Tax or Roth Contribution rate will continue in effect (unless restricted hereunder) until he or she elects to change such percentage. A Participant may elect to begin After-Tax or Roth Contributions or change After-Tax or Roth Contribution rate effective as of any payroll period. Such change shall be effected in accordance with procedures established by the Administrator. A Participant may suspend his or her After-Tax or Roth Contributions to the Plan at any time. The suspension will be effective as soon as administratively feasible. A Participant who suspends After-Tax or Roth Contributions can once again make After-Tax or Roth Contributions as of any payroll period.

3.4 Matching Contributions

3.4.1 Amount of Matching Contributions

Each Employer will contribute to the Trust on account of each Plan Year a Matching Contribution equal to 100 percent of each Participant's Employee Contributions for a pay period, in an amount up to the first 2 percent of the Participant's Compensation with respect to such pay period. For the Employee Contributions equal to the next 4 percent of the Participant's Compensation for a pay period (i.e., above 2 percent to 6 percent), the Employer will make a Matching Contribution of 50 percent.

3.4.2 Time of Matching Contributions

Each Employer will make its Matching Contributions to the Trust in one or more installments not later than the due date (including extensions) for the filing of the Employer's income tax return for the year for which the contributions are made.

3.5 Rollover Contributions

Rollover Contributions shall be permitted, subject to the provisions of this Section. The Administrator may direct the Trustee to accept, in accordance with procedures approved by the Administrator, all or part of an Eligible Rollover Distribution for the benefit of a Participant from (i) the Participant, (ii) another Qualified Plan, including, in a trustee-to-trustee transfer, After-Tax Contributions or Roth Deferrals to that plan, (iii) an annuity contract described in Code section 403(b), (iv) an individual retirement account (except a Roth IRA) or annuity as defined in Code sections 408(a) or 408(b) that is eligible to be rolled over and otherwise would be includible in gross income, or (v) an eligible plan under Code section 457(b) which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state. The approved procedures shall require that the Administrator or Trustee reasonably conclude that any accepted Eligible Rollover Distribution is a valid rollover contribution in accordance with Treasury regulations and guidance.

3.6 Actual Deferral Percentage Limitation on Deferral Contributions

Deferral Contributions will be subject to the average percentage test set forth in Section 10.6.

3.7 Actual Contribution Percentage Limitation on Matching, After-Tax and Roth Deferral Contributions

After-Tax Contributions, Roth Deferrals and Matching Contributions will be subject to the average contribution percentage test set forth in Section 10.7.

3.8 Military Service

Notwithstanding any provision of this Plan to the contrary, contributions, benefits and service credit with respect to qualified military service will be provided in accordance with Code section 414(u).

EXHIBIT IV

4. ALLOCATIONS TO PARTICIPANTS' ACCOUNTS

4.1 Establishment of Accounts

The Administrator will establish a Deferral Contribution Account, After-Tax Contribution Account, Roth Deferral Account, Matching Contribution Account, and, if applicable, a Rollover Account, for each Participant and may establish one or more subaccounts of a Participant's Accounts, if the Administrator determines that subaccounts are necessary or desirable in administering the Plan.

4.2 Allocation of Contributions

4.2.1 Deferral Contributions

Deferral Contributions made by an Employer on behalf of a Participant will be allocated to the Participant's Deferral Contribution Account.

4.2.2 After-Tax Contributions

After-Tax Contributions made by a Participant will be allocated to the Participant's After-Tax Contribution Account.

4.2.3 Roth Deferral Contributions

Roth Deferral Contributions made by a Participant will be allocated to the Participant's Roth Deferral Contribution Account.

4.2.4 Matching Contributions

Matching Contributions made by an Employer on behalf of a Participant will be allocated to the Participant's Matching Contribution Account.

4.2.5 Rollover Contributions

Each Rollover Contribution made by a Participant shall be allocated to his or her Rollover Account.

4.2.6 Qualified Non-Elective Contributions and Qualified Matching Contributions

Qualified Non-Elective Contributions and Qualified Matching Contributions will be allocated to the Deferral Contribution Accounts of the Participants designated as the group of Participants to whom the contribution is to be allocated based on the ratio that each designated Participant's Compensation for the Plan Year bears to the Compensation of all designated Participants for the Plan Year; provided, however, that subaccounts will be maintained for the purpose of excluding Qualified Matching Contributions from the "Actual Deferral Percentage" test pursuant to Section 10.6 below and for the purpose of excluding Qualified Matching Contributions and Qualified Non-Elective Contributions from the amount available for hardship withdrawals under Section 7.8 below.

4.2.7 Targeted Contribution Limit (QNEC)

Qualified Non-Elective Contributions cannot be taken into account in determining the ADP (pursuant to Section 10.4) or ACP (pursuant to Section 10.5) of a nonhighly compensated employee to the extent that such contributions exceed the product of that nonhighly compensated employee's Code section 414(s) compensation and the greater of five percent (5%) or two (2) times the Plan's "representative contribution rate." Any Qualified Non-Elective Contribution taken into account under the ACP Test under Treas. Reg. section 1.401(m)-2(a)(6) (including the determination of the representative contribution rate for purposes of Treas. Reg. section 1.401(m)-2(a)(6)(v)(B)), is not permitted to be taken into account for purposes of the ADP Test (including the determination of the “representative contribution rate” under this Section), and in the same manner, any such contribution taken into account in the ADP Test under Treas. Reg. section 1.401(k)-2(a)(6) will not be taken into account under the ACP Test. For purposes of this section:

(a) The Plan's "representative contribution rate" is the lowest "applicable contribution rate" of any eligible nonhighly compensated employee among a group of eligible nonhighly compensated employees that consists of half of all eligible nonhighly compensated employees for the Plan Year (or, if greater, the lowest "applicable contribution rate" of any eligible nonhighly compensated employee who is in the group of all eligible nonhighly compensated employees for the Plan Year and who is employed by the Employer on the last day of the Plan Year).

(b) The "applicable contribution rate" for an eligible nonhighly compensated employee in determining the ADP of a nonhighly compensated employee is the sum of the Qualified Matching Contributions (as defined in Treas. Reg. section 1.401(k)-6) taken into account in determining the ADP for the eligible nonhighly compensated employee for the Plan Year and the Qualified Non-Elective Contributions made for the eligible nonhighly compensated employee for the Plan Year, divided by the eligible nonhighly compensated employee's Code section 414(s) compensation for the same period.

(c) The "applicable contribution rate" for an eligible nonhighly compensated employee in determining the ACP of an nonhighly compensated employee is the sum of the Matching Contributions (as defined in Treas. Reg. section 1.401(m)-1(a)(2)) taken into account in determining the ACP for the eligible nonhighly compensated employee for the Plan Year and the Qualified Non-Elective Contributions made for the eligible nonhighly compensated employee for the Plan Year, divided by the eligible nonhighly compensated employee's Code section 414(s) compensation for the same period.

Notwithstanding the above, Qualified Non-Elective Contributions that are made in connection with an Employer's obligation to pay prevailing wages under the Davis Bacon Act (46 Stat. 1494), Public Law 71-798, Service Contract Act of 1965 (79 Stat. 1965), Public Law 89-286, or similar legislation can be taken into account for a Plan Year for a non-highly compensated employee to the extent such contributions do not exceed 10 percent of that non-highly compensated employee's Code section 414(s) compensation.

Qualified Matching Contributions may only be used to calculate an ADP to the extent that such Qualified Matching Contributions are Matching Contributions that are not precluded from being taken into account under the ACP test for the Plan Year under Section 4.2.8 below.

4.2.8 Targeted Matching Contribution Limit (QMAC)

Matching Contributions with respect to Deferral Contributions for a Plan Year are not taken into account under the ACP Test (pursuant to Section 10.5) for a nonhighly compensated employee to the extent they exceed the greatest of: (i) five percent (5%) of the nonhighly compensated employee's Code section 414(s) compensation for the Plan Year; (ii) the nonhighly compensated employee's Deferral Contributions for the Plan Year; and (iii) the product of two (2) times the Plan's "representative matching rate" and the nonhighly compensated employee's Deferral Contributions for the Plan Year.

For purposes of this section, the Plan's "representative matching rate" is the lowest "matching rate" for any eligible nonhighly compensated employee among a group of nonhighly compensated employees that consists of half of all eligible nonhighly compensated employees in the Plan for the Plan Year who make Deferral Contributions for the Plan

Year (or, if greater, the lowest "matching rate" for all eligible nonhighly compensated employees in the Plan who are employed by the Employer on the last day of the Plan Year and who make Deferral Contributions for the Plan Year). For purposes of this subsection, the "matching rate" for an Employee generally is the Matching Contributions made for such Employee divided by the Employee's Deferral Contributions for the Plan Year. If the matching rate is not the same for all levels of Deferral Contributions for an Employee, then the Employee's "matching rate" is determined assuming that an Employee's Deferral Contributions are equal to six percent (6%) of Code section 414(s) compensation. If the Plan provides a match with respect to the sum of the Employee's After-Tax Contributions and Deferral Contributions, then for purposes of this subsection, that sum is substituted for the amount of the Employee's Deferral Contributions in (i) through (iii) above in this section and in determining the "matching rate," and Employees who make either After-Tax Contributions or Deferral Contributions are taken into account in determining the Plan's "representative matching rate."

Similarly, if the Plan provides a match with respect to the Employee's After-Tax Contributions, but not Deferral Contributions, then for purposes of this subsection, the Employee's AfterTax Contributions are substituted for the amount of the Employee's Deferral Contributions in (i) through (iii) above in this subsection and in determining the "matching rate," and Employees who make After-Tax Contributions are taken into account in determining the Plan's "representative matching rate."

4.2.9 Limitation on QNECs and QMACs

Qualified Non-Elective Contributions and Qualified Matching Contributions cannot be taken into account to determine an ADP to the extent such contributions are taken into account for purposes of satisfying any other ADP Test, any ACP Test, or the requirements of Treas. Reg. sections 1.401(k)-3, 1.401(m)-3, or 1.401(k)-4. Thus, for example, Matching Contributions that are made pursuant to Treas. Reg. section 1.401(k)-3(c) cannot be taken into account under the ADP Test. Similarly, if the Plan switches from the current year testing method to the prior year testing method pursuant to Treas. Reg. section 1.401(k)-2(c), Qualified Non-Elective Contributions that are taken into account under the current year testing method for a year may not be taken into account under the prior year testing method for the next year.

4.2.10 Additional Provisions

(a) Excess contributions and excess aggregate contributions are annual additions notwithstanding their correction. Excess deferrals are annual additions unless they are distributed in accordance with the Plan. Deferral Contributions which are excess annual additions that are returned in accordance with the Plan are disregarded in calculating the Employee's Elective Deferrals and the numerators of the ADP and ACP.

(b) Any contributions and any adjustments which are made to any contributions and the determination and treatment of the ADP and ACP shall satisfy such other requirements which may be prescribed by the Secretary of the Treasury. In conformance with the Code, the Employer may separately apply the ADP and ACP Tests to Employees who are and are not otherwise excludable employees, and also may disaggregate and separately test within the Plan, within the meaning of Code sections 410(b) and 401(k) and the Treasury regulations thereunder. The provisions of Code section 401(k)(3)(F) may be used to exclude from consideration all nonhighly compensated employees who have not satisfied the minimum age and service requirements of Code section 410(a)(1)(A). The ADP and ACP tests shall be performed separately for each commonly controlled entity.

(c) The Employer shall maintain records sufficient to demonstrate satisfaction of the ADP Test, the ACP Test and the amount of contributions used in such tests.

4.3 Limitation on Allocations

Article 10 sets forth certain rules under Code Sections 401(k), 401(m) and 415 that limit the amount of Employee Contributions and Employer contributions that may be allocated to a Participant’s Accounts for a Plan Year.

4.4 Allocation of Trust Fund Income and Loss

4.4.1 Accounting Records

The Administrator, through its accounting records, will segregate each Account and subaccount and will maintain a separate and distinct record of all income and losses of the Trust Fund attributable to each Account or subaccount. Income or loss of the Trust Fund will include any unrealized increase or decrease in the fair market value of the assets of the Trust Fund.

4.4.2 Method of Allocation

(a) With respect to Investment Funds which have a readily determinable fair market value as of the end of each business day during the calendar year, the share of net income or net loss of the Trust Fund to be credited to, or deducted from, each Account will be the allocable portion of the net income or net loss of the Trust Fund attributable to each Account determined by the Administrator as of each Valuation Date, based upon the ratio that each Account balance as of the previous Valuation Date bears to all Account balances after adjustment for withdrawals, distributions and other additions or subtractions. The share of net income or net loss to be credited to, or deducted from, any subaccount will be an allocable portion of the net income or net loss credited to or deducted from the Account under which the subaccount is established.

(b) With respect to Investment Funds which do not have a readily determinable fair market value as of the end of each business day during the calendar year, the Trustee shall determine a method of allocation which shall take into account the period over which a readily determinable fair market value is not available (using time weighted averages) and which the Trustee deems appropriate, and the Trustee's determination of such method of allocation will be conclusive on all interested persons for all purposes of the Plan.

(c) To the extent that Investment Funds are mutual funds or similar investments, share-based accounting may be used in keeping records for the Plan, and the provisions of this subsection shall be applied and interpreted accordingly.

4.4.3 Determination of Earnings and Losses on Forfeitures & Returned Contributions

The earnings and losses of the Trust Fund for the Plan Year allocable to Deferral Contributions or After-Tax Contributions or Roth Deferral Contributions to be returned to a Participant or Matching Contributions to be forfeited or returned to a Participant pursuant to subsection 3.2.2, 10.6.5, or 10.7.4, will be determined by multiplying the Trust Fund earnings or losses for the Plan Year allocable to the Participant’s Deferral Contribution Account, After-Tax Contribution Account, Roth Deferral Contribution Account, or Matching Contribution Account, as applicable, by a fraction, the numerator of which is the amount of Deferral Contributions, After-Tax Contributions, Roth Deferral Contributions or Matching Contributions to be distributed to the Participant or the amount of Matching Contributions to be forfeited by the Participant, as applicable, and the denominator of which is the balance of the Participant’s Deferral Contribution Account, After-Tax Contribution Account, Roth Deferral Contribution Account or Matching Contribution Account, as applicable, on the last day of the Plan Year, reduced by the earnings and increased by the losses allocable to such Account for the Plan Year. The earnings and losses of the Trust Fund allocable to the Deferral Contributions, After-Tax Contributions or Roth Deferral Contributions to be returned or Matching Contributions to be returned or forfeited shall not include earnings and losses for the period between the end of the Plan Year and the date of such distribution or forfeiture.

To the extent the Plan requires gap period income, the Administrator may use any reasonable method for computing the Trust Fund earnings and losses allocable to excess contributions, provided that the method does not violate Code section 401(a)(4), is used consistently for all Participants and for all corrective distributions under the Plan for the applicable year, and is used by the Plan for allocating Trust Fund earnings and losses to Participant's Accounts. A Plan will not fail to use a reasonable method for computing the Trust Fund earnings and losses allocable to excess contributions merely because the Trust Fund earnings and losses allocable to excess contributions are determined on a date that is no more than 7 days before the distribution of excess contributions.

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The Administrator may use the safe harbor method in this paragraph to determine Trust Fund Earnings and losses on excess contributions for the gap period. Under this method, Trust Fund earnings on excess contributions for the gap period are equal to 10 percent of the Trust Fund earnings and losses allocable to excess contributions for the applicable year that would be determined under subsection 4.4.3, multiplied by the number of calendar months that have elapsed since the end of the Plan Year. For purposes of calculating the number of calendar months that have so elapsed, a corrective distribution that is made on or before the fifteenth day of a month is treated as made on the last day of the preceding month and a distribution made after the fifteenth day of a month is treated as made on the last day of the month.

The Administrator may determine Trust Fund earnings and losses for the aggregate of the applicable year and the gap period by applying the method provided in subsection 4.4.3 to this aggregate period. This is accomplished by (A) substituting the Trust Fund earnings and losses for the applicable year and the gap period, for the Trust Fund earnings and losses for the applicable year, and (B) substituting the amounts taken into account under the ADP Test for the applicable year and the gap period, for the amounts taken into account under the ADP Test for the applicable year in determining the fraction that is multiplied by the Trust Fund earnings and losses.

"Applicable year" means the Plan Year to which the excess contributions relate.

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5. INVESTMENT OF CONTRIBUTIONS

5.1 Investment Funds

The Trust Fund will be divided into such Investment Funds (including an ESOP Company Stock Fund and Self-Directed Brokerage Funds, as identified below) as shall be designated by the Administrator from time to time, and a Participant's Account will be invested therein as provided in this Article. A Participant's Account will be invested and reinvested in such funds in accordance with the terms of the Trust Agreement and the provisions of this Article. Notwithstanding any provision of the Plan to the contrary, the Administrator in its sole discretion may direct the Trustee to keep such portion of each Investment Fund in cash or cash equivalents as the Administrator may from time to time deem to be advisable to maintain sufficient liquidity to meet the obligations of the Plan or for other reasons.

5.1.1 Company Stock Funds

There is no limitation under the Plan on the amount of qualifying employer securities within the meaning of ERISA section 407(d)(5) (including Company Stock) that can be held in the Trust Fund under the Plan, provided, however, that the Plan will not hold employer securities acquired with an exempt loan as defined in section 4975(d)(3) of the Code and Treasury Regulations thereunder.

Shares of Company Stock held or distributed by the Trustee may include such legend restrictions on transferability as the Company may reasonably require in order to assure compliance with applicable Federal and state securities laws. Except as otherwise provided in this Section, no shares of Company Stock held or distributed by the Trustee may be subject to a put, call or other option, or buy-sell or similar arrangement.

Company Stock held by the Plan shall be invested in the ESOP Company Stock Fund or such additional Company Stock Funds as established by the Administrator in its sole discretion. Such funds will be maintained on a share-based accounting method, and Participants will be credited with fractional shares, as appropriate. Dividends on Company Stock will be reinvested in Company Stock or paid to Participants in cash in accordance with Participant elections as provided for under Section 5.1.2 below.

A Participant may at any time there are amounts credited to his or her ESOP Company Stock Fund (or such other Company Stock Funds as are established by the Administrator in its sole discretion) direct a transfer of investment into any other Investment Fund under the Plan in accordance with written procedures established by the Administrator.

5.1.2 Cash Dividends Paid on Company Stock

In accordance with the Participant's election, any dividends payable on Company Stock allocated to the Account of a Participant will be (i) paid to the Plan and credited to the ESOP Company Stock Fund in the Account of the Participant and reinvested in Company Stock or (ii) paid to the Plan and credited to the ESOP Company Stock Fund in the Account of the Participant and distributed in cash to the Participant not later than 90 days after the close of the Plan Year in which the dividend is paid by the Company.

The election described in this Section 5.1.2 will be made by a Participant pursuant to written procedures established by the Administrator. Such election procedures will provide the Participant with a reasonable opportunity to make the dividend election before the dividend is paid or distributed to the Participant, and will provide the Participant with an opportunity to change the dividend election at least annually. The procedures will require that a Participant's dividend election will be irrevocable with respect to any particular dividend before that dividend is credited to the ESOP Company Stock Fund in the Account of the Participant for the purpose of either being reinvested in Company Stock or paid to the Participant within 90 days after the Plan Year in which the dividend is paid by the Company.

Notwithstanding the foregoing, the Administrator may identify one of the options described above to serve as a default election if a Participant fails to make an affirmative election with respect to the Participant's Company Stock dividend. Notwithstanding any other provisions of the Plan, the Administrator is authorized to direct the investment of dividends if they are accumulated pursuant to a Participant election to distribute them within 90 days after the close of the Plan Year in which the dividend is paid by the Company. Earnings on such accumulated dividends will be allocated to the Participant's Account when the dividends are distributed.

5.1.3 Self-Directed Brokerage Fund

The Administrator may (but is not required to) establish Self-Directed Brokerage Funds as additional Investment Funds for individual Participants, and may adopt rules and procedures for Self-Directed Brokerage Funds that are different from the rules and procedures that apply to other Investment Funds. If the Administrator establishes such Self-Directed Brokerage Funds, the Participant for whom a Self-Directed Brokerage Fund is established shall direct the Trustee to invest the assets of the Self-Directed Brokerage Fund in investments that the Participant chooses, subject to limitations imposed by the Administrator's rules and procedures. In no event, however, shall the Participant be allowed to direct the investment of such assets into any work of art, rug or antique, metal or gem, stamp or coin, alcoholic beverage or other similar tangible personal property if the Secretary of the Treasury shall have prohibited investment in such property.

In the event of distributions to a Participant from the Plan that are required by law or the terms of the Plan, including without limitation, distributions necessary to effect compliance with nondiscrimination testing, allocation limits and minimum required distributions, such distributions will be made first from Investment Funds other than the Participant's Self-Directed Brokerage Fund. If the assets in such Investment Funds are insufficient, the Administrator will direct the Trustee to effect a sale of securities in the Self-Directed Brokerage Fund and an investment exchange to the Plan's other investment options to provide sufficient funds for the distribution.

5.2 Investment Options

Each Participant will, by direction to the Administrator, direct that all Deferral Contributions, After-Tax Contributions, Roth Deferral Contributions, Matching Contributions and Rollover Contributions made by or for such Participant be invested in one or more of the Investment Funds (but not to a Self-Directed Brokerage Fund) in percentages which are multiples of 1 percent. If a Self-Directed Brokerage Fund has been established for a Participant, the Participant may direct the Administrator to have funds transferred from other Investment Funds into the Self-Directed Brokerage Fund, subject to the rules and procedures established by the Administrator. An investment option selected by a Participant will remain in effect unless and until an investment change is made by him or her and becomes effective pursuant to Section 5.3. In the absence of an effective investment direction, such contributions made by or for a Participant will be invested in the Investment Fund that maximizes the goals of liquidity and preservation of principal, as determined by the Administrator.

5.3 Change of Investment Option

A Participant may elect and change investment options in accordance with procedures established by the Administrator, which may, without limitation, provide for various notice periods, various methods (including telephonic or electronic, as permitted by applicable law) of making investment elections and changes and various times at which investment elections or changes may become effective.

5.4 Directions to Trustee

The Administrator shall give appropriate and timely directions to the Trustee in order to permit the Trustee to give effect to the investment choice and investment change elections made under this Article and to provide funds for distributions pursuant to Article 7.

5.5 Valuation of Trust Fund

The fair market value of the total net assets comprising the Trust Fund and of each Investment Fund will be determined by the Trustee as of the close of business on each Valuation Date. Each such valuation will be made on the basis of the market value (as determined by the Trustee) of the Trust assets, except that property which the Trustee determines does not have a readily determinable market value will be valued at fair market value as determined by the Trustee in such manner as it deems appropriate, and the Trustee’s determination of such value will be conclusive on all interested persons for all purposes of the Plan. In determining such value, the Trustee shall deduct all permissible expenses for which the Trustee has not yet obtained reimbursement from the Employer or the Trust Fund.

5.6 No Guarantee

The Employers, the Administrator and the Trustee do not guarantee the Participants or their Beneficiaries against loss or depreciation or fluctuation of the value of the assets of the Trust Fund or any Investment Fund.

5.7 Securities Laws Limitations

The Administrator may impose such investment and other restrictions under the Plan as the Administrator, in its sole discretion, deems necessary or appropriate to ensure compliance with the Securities Exchange Act of 1934, as amended (“Act”), or any other applicable law. Although Participants affected generally will include only those Participants subject to the reporting requirements of the Act, other participants may be affected in the discretion of the Administrator. No transfers will be permitted under the Plan that would result in a violation of the Company’s insider trading policy.

EXHIBIT IV

6. VESTING

6.1 Fully Vested Interests

Participants shall be fully vested in their Deferral Contribution, After-Tax Contribution, Rollover contribution, and Roth Accounts. A Participant shall have a 100 percent vested and nonforfeitable interest in his or her Matching Contribution Account upon completion of one year of service. A year of service for this purpose is a cumulative twelve month period commencing with the Participant's first date of employment, determined according to the elapsed time method set forth in DOL Regulation §2530.200b-9 and the vesting rules in subsection (d) of that regulation. Subject to the break in service rules of that regulation, nonsuccessive periods of service shall be aggregated and any periods of service of less than a whole year (whether or not consecutive) shall be aggregated on the basis that twelve months of service equals one year of service, and 30 days of service equals a month of service.

6.2 Forfeitures

Any balance in the Matching Contribution Account of a Participant who terminates his or her employment before being fully vested shall be forfeited, and shall be used to reduce the Employer's Matching Contributions under the Plan during the Plan Year following the Plan Year in which the forfeiture arose.

EXHIBIT IV

7. DISTRIBUTIONS

7.1 Distribution Events

Except as set forth in Sections 7.8, 7.9 or 7.10, and subject to the provisions and restrictions in Article 12, a Participant's interest in his or her Deferral Contribution Account, After-Tax Contribution Account, Roth Account, Matching Contribution Account and Rollover Account, may be distributed only after the Participant's Disability, termination of employment with all members of the Controlled Group, or death. Upon a Participant's Disability, he or she will be entitled to a distribution in the same form and at the same time as if he or she had terminated employment.

7.1.1 Distribution Notice

At least 30 days and, effective January 1, 2007, not more than 180 days prior to a distribution date, the Administrator must provide a written distribution notice (or a summary notice as permitted under Treasury regulations) to a Participant or Beneficiary. The distribution notice must explain the option forms of benefit in the Plan, including the material features and relative value of those options, the Participant's or Beneficiary's right to postpone distribution, and the consequences of failing to defer receipt of distribution.

7.1.2 Qualified Reservist Distribution

Notwithstanding any 401(k) distributions in this Plan, the Plan permits a Participant to elect a Qualified Reservist Distribution. A "Qualified Reservist Distribution" is any distribution to an individual who is ordered or called to active duty after September 11, 2001, if: (i) the distribution is from amounts attributable to elective deferrals in a 401(k) plan; (ii) the individual was (by reason of being a member of a reserve component, as defined in section 101 of title 37, United States Code) ordered or called to active duty for a period in excess of 179 days or for an indefinite period; and (iii) the Plan makes the distribution during the period beginning on the date of such order or call, and ending at the close of the active duty period.

7.2 Form of Distributions (and Small Account Cash Out)

Distributions will be made in the form provided in this and the following Sections of this Article. A Participant or Beneficiary eligible to receive a distribution under the Plan shall request such distribution in accordance with procedures (including telephonic or electronic, as permitted by law) established by the Administrator, including furnishing such information as the Administrator may reasonably require. Notwithstanding any other provision of this Article, but subject to the requirements of Section 12.2, if the value of a Participant's vested interest in his or her Accounts does not exceed $1,000, determined according to

Section 7.7 below, distribution to such Participant or Beneficiary will be made in the form of a single lump sum payment of the full value of the Accounts (or so much thereof to which a Beneficiary is entitled) as soon as practicable after the Participant's Disability, death, or termination of employment with the Controlled Group.

7.2.1 Right to Receive Company Stock

The Participant (or Beneficiary) may elect to receive any distribution of all or a portion of his or her Accounts in the form of whole shares of Company Stock (with the value of any fractional share paid in cash) by directing the investment of all or a portion of his or her Accounts in the Company Stock Fund prior to any distribution. Distributions from the Company Stock Fund will be made in kind unless otherwise elected; provided, however, (i) that fractional shares of Company Stock will in all cases be distributed in cash, and (ii) that partial withdrawals may not be made through a combination of stock and cash distributions. Shares of Company Stock distributed by the Trustee shall be readily tradable on an established securities market.

7.3 Distributions upon Termination of Employment

If a Participant's employment with the Controlled Group is terminated for any reason other than death, such Participant shall receive his or her Account balance in the form of a single lump sum or as periodic partial withdrawals, in accordance with the provisions of this Article 7 (including Section 7.5.1), as the participant elects.

7.4 Distributions upon Death

7.4.1 If the Beneficiary is not the Participant's Surviving Spouse and not a Designated Beneficiary

Upon the death of a Participant, if his or her Beneficiary is not his or her surviving Spouse, then the entire Account balance shall be paid to the Beneficiary within five years after the Participant's death, and after completion of procedures established by the Administrator. Prior to the end of the five year period and if the Beneficiary is otherwise eligible, the Beneficiary may elect to make partial withdrawals under the terms of this Article 7, provided the entire Account balance is distributed prior to the end of the five year period. If the Beneficiary is eligible for and makes partial withdrawals that are less than the minimum mandatory distributions required under Code section 401(a)(9) and applicable regulations, then the Administrator will direct the Trustee to make such additional distributions as are necessary to satisfy the mandatory minimum distribution requirements of the Code.

7.4.2 If the Beneficiary is the Participant's Surviving Spouse

Upon the death of a Participant, if his or her Beneficiary is his or her surviving Spouse, then the Beneficiary shall have the option of commencing distributions as soon as practicable after completion of procedures established by the Administrator, or delaying distributions, subject to the limitations in Appendix A. If the surviving Spouse is otherwise eligible, the surviving Spouse may elect to make partial withdrawals under the terms of this Article 7, provided that after the date by which distributions must commence as provided in this paragraph, if partial withdrawals are less than the minimum mandatory distributions required under Code section 401(a)(9) and applicable regulations, then the Administrator will direct the Trustee to make such additional distributions as necessary to satisfy the mandatory minimum distribution requirements of the Code.

7.4.3 If the Beneficiary is the Designated Beneficiary and not the Participant's Surviving Spouse

For distributions after December 31, 2006, a non-spouse beneficiary who is a "designated beneficiary" under Code §401(a)(9)(E) and the regulations thereunder, by a direct trustee-to-trustee transfer ("direct rollover"), may roll over all or any portion of his or her distribution to an individual retirement account the beneficiary establishes for purposes of receiving the distribution. In order to be able to roll over the distribution, the distribution otherwise must satisfy the definition of an eligible rollover distribution. If a non-spouse beneficiary receives a distribution from the Plan, the distribution is not eligible for a "60-day" rollover. If the Participant's named beneficiary is a trust, the Plan may make a direct rollover to an individual retirement account on behalf of the trust, provided the trust satisfies the requirements to be a designated beneficiary within the meaning of Code §401(a)(9)(E). A non-spouse beneficiary may not roll over an amount which is a required minimum distribution, as determined under applicable Treasury regulations and other Revenue Service guidance. If the Participant dies before his or her required beginning date and the non-spouse beneficiary rolls over to an IRA the maximum amount eligible for rollover, the beneficiary may elect to use either the 5-year rule or the life expectancy rule, pursuant to Treas. Reg. §1.401(a)(9)-3, A-4(c), in determining the required minimum distributions from the IRA that receives the non-spouse beneficiary's distribution.

7.5 Timing of Distributions

Any distribution to a Participant or Beneficiary effected pursuant to this Article shall be made as soon as administratively feasible after an event of distribution described in Section 7.1 above, as the Participant or Beneficiary directs, subject to the rules set forth below and in Article 12.

7.5.1 Timing of Distributions upon Disability or Termination

If a Participant's Account balance exceeds $1,000 after the Participant's service with the Controlled Group terminates or the Participant becomes Disabled, distribution of the vested Account balance will not be made or commenced (subject to Section 12.4) unless he or she elects to receive such distribution. Subject to Section 12.2, a Participant can request a distribution at any time after termination of employment with the Controlled Group or Disability, and such distribution will be made as soon as administratively feasible after such request is received by the Administrator, subject to such further notices and elections which may be required under the terms of the Plan. If a Participant's Account balance is $1,000 or less, it will be distributed to him or her in a lump sum, as soon as administratively feasible after the applicable event.

7.5.2 Timing of Distributions to Beneficiaries

Distribution of a Participant's Account balance to the Participant's Beneficiary will be made or will commence as soon as administratively feasible following notification to the Administrator of the Participant's death.

7.6 Reemployment of Participant

If a Participant who terminated employment again becomes an Employee before receiving a distribution of his or her Account balance pursuant to this Article, no distribution from the Trust Fund will be made while he or she is an Employee, and amounts distributable on account of such termination will be held in the Trust Fund until he or she is again entitled to a distribution under the Plan.

7.7 Valuation of Accounts

A Participant's distributable Account balance will be valued as of the Valuation Date immediately preceding the date the Account is to be distributed, except that there will be added to the value of the Account the fair market value of any amounts allocated to the Account under Article 4 after that Valuation Date.

7.8 Hardship Distributions

7.8.1 Availability of Hardship Distributions

A Participant may request approval from the Administrator to have all or a portion of the value of the sum of (i) his or her Deferral Contribution Account (but excluding any earnings credited to the Deferral Contribution Account after December 31, 1988, Qualified Non-Elective Contributions and Qualified Matching Contributions), and (ii) his or her Rollover Account distributed to such Participant, provided that the Participant is suffering from hardship. A distribution will be on account of hardship only if the distribution is necessary to satisfy an immediate and heavy financial need of the Participant, as defined below, and satisfies all other requirements of this Section 7.8.

7.8.2 Immediate and Heavy Financial Need

A distribution shall be made on account of an immediate and heavy financial need of a Participant only if the distribution is on account of:

(a) Medical expenses described in section 213(d) of the Code incurred by or necessary for the care of the Participant, the Participant's Spouse, or any of the Participant's dependents (as defined in section 152 of the Code);

(b) The purchase (excluding mortgage payments) of a principal residence of the Participant;

(c) The payment of tuition, related educational fees, and room and board expenses, for the next 12 months (beginning with the date of distribution) of post secondary education for the Participant or the Participant's Spouse, children or dependents, provided that no withdrawal will be permitted for this purpose more than 6 months before payment is actually required to be made to the educational institution or other appropriate person;

(d) The need to prevent the eviction of the Participant from his or her principal residence or the foreclosure on the mortgage of the Participant's principal residence;

(e) Payments for burial or funeral expenses for the Participant's deceased parent, spouse, children or dependents;

(f) Expenses for repair of damage to the Participant's principal residence that would qualify for the casualty deduction under Code §165 (without regard to the 10 percent of AGI threshold); or

(g) Any other financial need which the Commissioner of Internal Revenue, through the publication of revenue rulings, notices and other documents of general applicability, may from time to time designate as a deemed immediate and heavy financial need as provided in section 1.401(k)-1(d)(2)(iv) of the Treasury Regulations.

7.8.3 Distributions Deemed Necessary

A distribution shall be deemed to be necessary to satisfy an immediate and heavy financial need only if:

(a) The distribution does not exceed the financial need of the Participant (including amounts necessary to pay any federal, state or local income taxes or penalties reasonably anticipated to result from the distribution);

(b) The Participant has obtained all distributions (other than hardship distributions) and all nontaxable loans currently available under all of the Employer's plans;

(c) The Participant's Deferral Contributions, After-Tax Contributions and Roth Contributions, and all similar employee contributions under all of the Employer's qualified and non-qualified plans of deferred compensation shall be suspended for a period of six months after the receipt of the hardship distribution.

7.8.4 Method of Requesting/Form of Distribution

The Participant's request for a hardship distribution shall be made in accordance with procedures (including telephonic or electronic, as permitted by law) established by the Plan Administrator from time to time, and the Participant shall furnish the Plan Administrator with such information as the Plan Administrator requests in its evaluation of the Participant's withdrawal request.

7.8.5 Amount and Timing of Distribution

The cumulative amount distributed to a Participant on account of hardship will not exceed the amount set forth in subsection 7.8.1 above that has not been previously distributed. Distributions pursuant to this subsection will be made as soon as administratively feasible after the Participant's request and amounts will be withdrawn first, from the Participant's Rollover Account (if any), and then from the Participant's Deferral Contribution account.

7.9 Distributions After Age 59½

A Participant who attains age 59½ and who is still employed by a Controlled Group Member may elect a distribution of all or a portion of the amount then credited to his or her Deferral Contribution Account, Matching Contribution Account and Rollover Account. Partial withdrawals will be permitted at such times and in accordance with such procedures as will be determined by the Administrator, provided they are permitted at least quarterly.

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7.10 Distributions From After-Tax Contribution Account

A Participant may elect a distribution of all or a portion of the amounts credited to his or her After-Tax Contribution Account. Partial withdrawals will be permitted at such times and in accordance with such procedures as will be determined by the Administrator, provided they are permitted at least quarterly. Distributions from a Participant's After-Tax Contribution Account (including amounts transferred from the prior Company Employee Stock Ownership Plan, which was merged into the Plan) shall be made, first, from such contributions made prior to January 1, 1987 (not including earnings thereon). A Participant may elect as to the order of distribution from his or her After-Tax Account, or from other pre-tax Deferral Accounts, or partly from each.

7.11 Direct Rollovers

7.11.1 Rollovers Permitted

Notwithstanding any other provision herein to the contrary, a Distributee entitled to a distribution may elect (in such form and at such time as the Administrator may prescribe) to have all or a portion of an Eligible Rollover Distribution paid to an Eligible Retirement Plan in a Direct Rollover.

7.11.2 Direct Rollover of Non-Spousal Distribution

A non-spouse beneficiary who is a "designated beneficiary" under Code §401(a)(9)(E) and the regulations thereunder, by a direct trustee-to-trustee transfer ("direct rollover"), may roll over all or any portion of his or her distribution to an individual retirement account the beneficiary establishes for purposes of receiving the distribution. In order to be able to roll over the distribution, the distribution otherwise must satisfy the definition of an eligible rollover distribution. If the Participant's named beneficiary is a trust, the Plan may make a direct rollover to an individual retirement account on behalf of the trust, provided the trust satisfies the requirements to be a designated beneficiary within the meaning of Code §401(a)(9)(E). A non-spouse beneficiary may not roll over an amount which is a required minimum distribution, as determined under applicable Treasury regulations and other Revenue Service guidance. If the Participant dies before his or her required beginning date and the non-spouse beneficiary rolls over to an IRA the maximum amount eligible for rollover, the beneficiary may elect to use either the 5-year rule or the life expectancy rule, pursuant to Treas. Reg. §1.401(a)(9)-3, A-4(c), in determining the required minimum distributions from the IRA that receives the non-spouse beneficiary's distribution.

7.11.3 Amount of Rollover

Notwithstanding the foregoing, a Distributee may make an election under this Section only if the total amount of all Eligible Rollover Distributions made to such Distributee during a year is reasonably expected to exceed $200. Furthermore, if a Distributee elects to have only a portion of an Eligible Rollover Distribution paid in a Direct Rollover, the portion paid in a Direct Rollover must equal at least $500. If a Distributee's Eligible Rollover Distribution is $500 or less, he or she may make an election only to have all of such distribution paid in a Direct Rollover. Effective January 1, 2015, if a Participant's Account includes both pre-tax and after-tax (including Roth) amounts, any Eligible Rollover Distribution which is paid in whole or in part in a Direct Rollover shall be allocated between the pre-tax and after-tax amounts in accordance with Notice 2014-54.

7.11.4 Waiver of Notice Period

Such distribution may commence less than 30 days after notice is given about the Participant's right to make a Direct Rollover, provided that the Administrator informs the Participant that he or she has at least 30 days after receiving such notice to consider whether or not to make a Direct Rollover and the Participant, after receiving the notice, affirmatively elects to receive the distribution.

7.12 Restrictions on Distributions

Article 12 sets forth certain rules under various provisions of the Code relating to restrictions on distributions to Participants and their Beneficiaries.

7.13 Unclaimed Distribution

If the Administrator cannot locate a person entitled to receive a benefit under the Plan within a reasonable period (as determined by the Administrator in its discretion), the amount of the benefit will be treated as a forfeiture during the Plan Year in which the period ends. Such forfeitures will be applied in the discretion of the Administrator (i) to pay administrative expenses under the Plan, (ii) to reduce or offset Employers' subsequent Matching Contributions required under the Plan, and (iii) to correct errors, omissions and exclusions as described in Section 9.10 below. If a person who was entitled to a benefit which has been forfeited under this Section makes a claim to the Administrator or the Trustee for his or her benefit, he or she will be entitled to receive, as soon as administratively feasible, a benefit in an amount equal to the value of the forfeited benefit on the date of forfeiture. This benefit will be reinstated first from forfeitures and second from Employer contributions for that Plan Year.

7.14 Partial Withdrawals

Any person otherwise entitled to a distribution under the Plan, to whom a lump-sum distribution of the balance of the Accounts (or portion thereof) to which he or she is entitled has not been made under the terms of Section 7.2, may elect to make partial withdrawals at such time and in accordance with such procedures as will be determined by the Administrator, provided such withdrawals are permitted at least quarterly.

7.15 Installment Distributions

In lieu of a lump sum distribution as provided in Section 7.3 and 7.4, and subject to the limitations in Article 12, a Participant may elect to receive distribution of his or her Account balance in monthly, quarterly, semi-annual or annual installments.

7.16 HEART Act

7.16.1 Death Benefits

In the case of a death occurring on or after January 1, 2007, if a Participant dies while performing qualified military service (as defined in Code section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of qualified military service) provided under the Plan as if the Participant had resumed and then terminated employment on account of death.

7.16.2 Differential Wage Payments

For years beginning after December 31, 2008, (i) an individual receiving a differential wage payment, as defined by Code section 3401(h)(2), is treated as an employee of the Employer making the payment, (ii) the differential wage payment is treated as Compensation, and (iii) the Plan is not treated as failing to meet the requirements of any provision described in Code section 414(u)(1)(C) by reason of any contribution or benefit which is based on the differential wage payment.

7.16.3 Severance From Employment

Notwithstanding Section 7.16.2(i), for years beginning after December 31, 2008, for purposes of Code section 401(k)(2)(B)(i)(I), an individual is treated as having been severed from employment during any period the individual is performing service in the uniformed services described in Code section 3401(h)(2)(A).

(a) Suspension of deferrals. If an individual elects to receive a distribution by reason of severance from employment, death or disability, the individual may not make an elective deferral or employee contribution during the 6-month period beginning on the date of the distribution.

(b) Nondiscrimination requirement. Section 7.16.2(iii) applies only if all employees of the Employer performing service in the uniformed services described in Code section 3401(h)(2)(A) are entitled to receive differential wage payments (as defined in Code section 3401(h)(2)) on reasonably equivalent terms and, if eligible to participate in a retirement plan maintained by the employer, to make contributions based on the payments on reasonably equivalent terms (taking into account Code sections 410(b)(3), (4), and (5)).

EXHIBIT IV

8. SPECIAL RULES REGARDING ACQUISITIONS, DISPOSITIONS & TRANSFERS

8.1 Service Crediting

The Administrator may, but is not required to, grant past service credit to those individuals who are employed by a business acquired by Controlled Group Members (referred to herein as an “Acquisition Business”) at the time it became a Controlled Group Member. Such grant would provide that the period of time that such individuals were in the employ of the Acquisition Business prior to its becoming part of the Controlled Group would count as a period of employment for purposes of eligibility for Matching Contributions. Any such grant shall be made either by an amendment to the Plan or by the Administrator maintaining a record of such service on the books of the Plan, and reflecting such grant in an appropriate document.

8.2 Transfer From Another Qualified Plan in Controlled Group

If a Participant is also a participant in another Qualified Plan which is sponsored by an Acquisition Business or Controlled Group Member, the Participant may direct the Trustee, subject to the approval of the Administrator, to accept from such Qualified Plan an amount representing such Participant’s interest in such plan, to be held by the Trustee subject to all of the terms and conditions of the Plan and Trust Agreement, in the Participant’s Rollover Account; provided, however, that property other than cash shall not be transferred to the Trustee without the Administrator’s approval, and provided, further, that the Administrator may establish such procedures (including but not limited to required notice periods) as the Administrator shall deem appropriate, which must be followed by the Participant as a condition to such a transfer of assets. The Administrator may not approve any transfer to the Plan if such transfer would require the Plan to offer benefits, rights and features not offered under the Plan in order to comply with the requirements of Code section 411(d) and the regulations thereunder. Amounts transferred to the Plan from another Qualified Plan, other than such amounts transferred in a direct rollover transfer within the meaning of Code section 401(a)(31), shall retain all benefits, rights, and features provided under the Qualified Plan and protected under Code section 411(d)(6), except to the extent that such benefits, rights and features may be eliminated under the regulations under Code section 411(d)(6).

EXHIBIT IV

9. ADMINISTRATION OF THE PLAN AND TRUST AGREEMENT

9.1 Administrator

The Company will have all authority, rights and responsibility of the Administrator hereunder. Any action taken by the Company as Administrator may be taken by any one of its officers authorized by the Board, or any other person authorized by such officers to act on the Company's behalf in its capacity as Administrator.

9.2 Employees of the Administrator

The Administrator may employ and suitably compensate such persons or organizations to render advice with respect to the duties of the Administrator under the Plan as the Administrator determines to be necessary or desirable.

9.3 Expenses and Compensation

The expenses of the Administrator properly incurred in the performance of its duties under the Plan will be paid from the Trust Fund, unless the Employers in their discretion pay such expenses. To the extent Plan expenses are paid from the Trust Fund, the Administrator will establish procedures for allocating such expenses to the Accounts of Participants, including procedures based on transactions which involve such Participant's Accounts.

9.4 General Powers and Duties of the Administrator

The Administrator will have the full power and responsibility to administer the Plan and the Trust Agreement and to construe and apply their provisions. For purposes of ERISA, the Administrator will be the Named Fiduciary with respect to the operation and administration of the Plan and the Trust Agreement; provided, however, that the Administrator shall have no responsibility for or control over the funding, investment or management of Plan assets, except as specifically provided in this Plan. In addition, the Administrator will have the powers and duties granted by the terms of the Trust Agreement. The Administrator, and all other persons with discretionary control respecting the operation, administration, control or management of the Plan, the Trust Agreement or the Trust Fund, will perform their duties under the Plan and the Trust Agreement solely in the interests of Participants and their Beneficiaries.

9.5 Specific Powers and Duties of the Administrator

The Administrator will administer the Plan and have all powers necessary to accomplish that purpose, including the following: (i) resolving all questions relating to the eligibility of Employees to become Participants; (ii) determining the amount of benefits payable to Participants or their Beneficiaries and determining the time and manner in which such benefits are to be paid; (iii) authorizing and directing all disbursements by the Trustee from the Trust Fund; (iv) engaging any administrative, legal, medical, accounting, clerical or other services it deems appropriate in administering the Plan or the Trust Agreement; (v) in its sole and absolute discretion construing and interpreting the Plan and the Trust Agreement (including, without limitation, by supplying omissions from, correcting deficiencies in, or resolving inconsistencies or ambiguities in, the language of the Plan and the Trust Agreement) and adopting and amending rules for administration of the Plan and the Trust Agreement which are not inconsistent with the terms of such documents; (vi) compiling and maintaining all records it determines to be necessary, appropriate or convenient in connection with the administration of the Plan and the Trust Agreement; and (vii) determining the disposition of assets in the Trust Fund if the Plan is terminated.

9.6 Allocation of Fiduciary Responsibility

The Administrator from time to time may delegate to any other persons or organizations any of its rights, powers, duties and responsibilities with respect to the operation and administration of the Plan and the Trust Agreement that are permitted to be delegated under ERISA. Any such allocation or delegation will be made in writing, will be reviewed periodically by the Administrator, and will be terminable upon such notice as the Administrator in its discretion deems reasonable and proper under the circumstances. Whenever a person or organization has the power and authority under the Plan or the Trust Agreement to delegate discretionary authority respecting the administration of the Plan or the Trust Fund to another person or organization, the delegating party’s responsibility with respect to such delegation is limited to the selection of the person to whom authority is delegated and the periodic review of such person’s performance and compliance with applicable law and regulations. Any breach of fiduciary responsibility by the person to whom authority has been delegated which is not proximately caused by the delegating party’s failure to properly select or supervise, and in which breach the delegating party does not otherwise participate, will not be considered a breach by the delegating party.

9.7 Notices, Statements and Reports

The Company will be the “administrator” of the Plan as defined in ERISA section 3(16)(A) for purposes of the reporting and disclosure requirements imposed by ERISA and the Code.

9.8 Claims Procedure

The claims procedure set forth in this Section 9.8 shall be the procedure for the resolution of disputes and disposition of claims arising under the Plan. For the purposes of this Section 9.8, a request for resolution of a dispute is considered a claim.

9.8.1 Filing Claim for Benefits

If a Participant or Beneficiary does not receive the benefits which he or she believes he or she is entitled to receive under the Plan, he or she may file a claim for benefits with the Administrator. All claims will be made in writing and will be signed by the claimant. If the claimant does not furnish sufficient information to determine the validity of the claim, the Administrator will indicate to the claimant any additional information which is required.

9.8.2 Notification by the Administrator

Each claim will be approved or disapproved by the Administrator within 90 days following the receipt of the information necessary to process the claim. The 90 day claims review period may be extended an additional 90 days, provided that notice of such extension of time is given the claimant within the first 90 day period. If the Administrator denies a claim for benefits in whole or in part, the Administrator will notify the claimant in writing of the denial of the claim. Such notice by the Administrator will also set forth, in a manner calculated to be understood by the claimant, the specific reason for such denial, the specific Plan provisions on which the denial is based, a description of any additional material or information necessary to perfect the claim with an explanation of why such material or information is necessary, and an explanation of the Plan's claim review procedure as set forth in subsection 9.8.3. If no action is taken by the Administrator on a claim within 90 days, the claim will be deemed to be denied for purposes of the review procedure.

9.8.3 Review Procedure

A claimant may appeal a denial of his or her claim by requesting a review of the decision by the Administrator or a person designated by the Administrator, which person will be a Named Fiduciary for purposes of this Section. An appeal must be submitted in writing within 60 days after the denial and must (i) request a review of the claim for benefits under the Plan, (ii) set forth all of the grounds upon which the claimant's request for review is based and any facts in support thereof, and (iii) set forth any issues or comments which the claimant deems pertinent to the appeal. The Administrator or the Named Fiduciary designated by the Administrator will make a full and fair review of each appeal and any written materials submitted in connection with the appeal. The Administrator or the Named Fiduciary designated by the Administrator will act upon each appeal within 60 days after receipt thereof unless special circumstances require an extension of the time for processing, in which case a decision will be rendered as soon as possible but not later than 120 days after the appeal is received. The claimant will be given the opportunity to review pertinent documents or materials upon submission of a written request to the Administrator or Named Fiduciary, provided the Administrator or Named Fiduciary finds the requested documents or materials are pertinent to the appeal. On the basis of its review, the Administrator or Named Fiduciary will make an independent determination of the claimant's eligibility for benefits under the Plan. The decision of the Administrator or Named Fiduciary on any claim for benefits will be final and conclusive upon all parties thereto. If the Administrator or Named Fiduciary denies an appeal in whole or in part, it will give written notice of the decision to the claimant, which notice will set forth in a manner calculated to be understood by the claimant the specific reasons for such denial and which will make specific reference to the pertinent Plan provisions on which the decision was based.

9.8.4 Claims Must Be Timely

A claim may be denied if it is not timely. To be considered timely under the Plan's claim review procedure, a claim must be filed with the Administrator within one (1) year after the claimant knew or reasonably should have known of the principal facts upon which the claim is based. If or to the extent that the claim relates to a failure to effect a Participant's or Beneficiary's investment directions or a Participant's election regarding contributions, the one (1) year period shall be thirty (30) days.

9.9 Service of Process

The Administrator may from time to time designate an agent of the Plan for the service of legal process. In the absence of such a designation, the Company will be the agent of the Plan for the service of legal process.

9.10 Corrections

If an error or omission is discovered in the Accounts of a Participant, or in the amount distributed to a Participant, or if an Employee is determined to have been improperly or mistakenly excluded from participation in the Plan, the Administrator will make such equitable adjustments in the records of the Plan as may be necessary or appropriate to correct such error, omission or exclusion as of the Plan Year in which such error, omission or exclusion is discovered. Further, an Employer may, in its discretion, make a special contribution to the Plan, to be allocated by the Administrator only to the Account of one or more Employees or Participants to correct such error, omission or exclusion.

9.11 Payment to Minors or Persons Under Legal Disability

If any benefit becomes payable to a minor or to a person under a legal disability, payment of such benefit will be made only to the conservator or the guardian of the estate of such person appointed by a court of competent jurisdiction or such other person or in such other manner as the Administrator determines is necessary to ensure that the payment will legally discharge the Plan's obligation to such person.

9.12 Uniform Application of Rules and Policies

The Administrator in exercising its discretion granted under any of the provisions of the Plan or the Trust Agreement will do so only in accordance with rules and policies established by it which will be uniformly applicable to all Participants and Beneficiaries.

9.13 Funding Policy

The Plan is to be funded through Employer and Participant contributions and earnings on such contributions, and benefits will be paid to Participants and Beneficiaries as provided in the Plan.

9.14 The Trust Fund

The Trust Fund will be held by the Trustee for the exclusive benefit of Participants and Beneficiaries. The assets held in the Trust Fund will be invested and reinvested in accordance with the terms of the Trust Agreement, which is hereby incorporated into and made a part of the Plan. All benefits will be paid solely out of the Trust Fund, and no Employer will be otherwise liable for benefits payable under the Plan.

EXHIBIT IV

10. LIMITATIONS ON CONTRIBUTIONS AND ALLOCATIONS TO PARTICIPANTS' ACCOUNTS

10.1 Priority over Other Contribution and Allocation Provisions

The provisions set forth in this Article supersede any conflicting provisions of this Plan.

10.2 Definitions Used in this Article

The following words and phrases will have the meanings set forth below, for purposes of this Article only.

10.2.1 Annual Addition

" Annual Addition " means the sum of Deferral Contributions, After-Tax Contributions, Roth Contributions, Matching Contributions, and profit sharing contributions credited to the Participant under the Plan and all other defined contribution plans maintained by Controlled Group Members for the Limitation Year, and, if the Participant is a Key Employee (pursuant to subsection 13.2.8) for the applicable or any prior Limitation Year, medical benefits provided pursuant to Code section 419A(d)(1) ("Welfare Fund") for the Limitation Year.

A Participant's Annual Addition will not include (i) any amounts allocated to his Rollover Account, or (ii) Deferral Contributions (and corresponding Matching Contributions) that are in excess of the Code section 402(g) amount and that are refunded by April 15 of the following Plan Year. A corrective allocation pursuant to Section 9.10 will be considered an Annual Addition for the Limitation Year to which it relates.

A Participant's Annual Addition shall not exceed the amount provided under Code Section 415(c) and the regulations issued thereunder, including the Final 415 Regulations.

10.2.2 Compensation

" Compensation " shall be determined at the election of the Administrator as an definition of Compensation that satisfies Code section 414(s) and the Treasury Regulations thereunder. Compensation of an Employee taken into account for purposes of determining excess Deferral Contributions under Section 10.6 and excess Matching Contributions under Section 10.7 in any Plan Year shall be limited as set forth in subsection 1.10.1.

10.2.3 Defined Benefit Plan

" Defined Benefit Plan " means a Qualified Plan other than a Defined Contribution Plan.

EXHIBIT IV

10.2.4 Defined Contribution Plan

" Defined Contribution Plan " means a Qualified Plan described in Code section 414(i). References to a Defined Contribution Plan shall also refer to a Welfare Fund, as appropriate under Code section 415 and the regulations thereunder.

10.2.5 Eligible Employee and Eligible Highly Compensated Employee

" Eligible Employee and eligible Highly Compensated Employee " means an Employee eligible to become a Participant under the provisions of Article 2.

10.2.6 Highly Compensated Employee

" Highly Compensated Employee " includes any Employee who (1) was a five percent owner of the Employer at any time during the current Plan Year or the preceding Year, or (2) received more than $110,000 in compensation in the preceding Plan Year (as defined in Code section 414(q)(4) and adjusted under Code section 415(d)).

10.2.7 Includable Compensation

" Includable Compensation " means the Employee's compensation in the amount reported by the Employer or any Controlled Group Member as "Wages, tips, other compensation" for purposes of Internal Revenue Service Form W-2, Box 1, or any successor method of reporting under Code section 6041(d).

10.2.8 Limitation Year

" Limitation Year " means the 12 consecutive month period used by a Qualified Plan for purposes of computing the limitations on benefits and annual additions under Code section 415. The Limitation Year for this Plan is the Plan Year.

10.2.9 Maximum Annual Addition

" Maximum Annual Addition " means with respect to a Participant (except as otherwise permitted by Section 3.2.1(b) and Code section 414(v)), an Annual Addition equal to the lesser of (i) $49,000 (as adjusted for the cost of living pursuant to Code section 415(d)) or (ii) 100 percent of the Participant's Includable Compensation.

10.3 Excess Allocations

10.3.1 Correcting an Excess Annual Addition

If the amount otherwise allocable to a Participant's Account would exceed the Maximum Annual Addition (resulting from a reasonable error in estimating an employee's Compensation or in determining the amount of After-Tax Contributions or Deferral Contributions or other facts and circumstances acceptable to the Internal Revenue Service), the Administrator shall dispose of the excess amount in accordance with the Employee Plans Compliance Resolution System (EPCRS).

10.3.2 Correcting a Multiple Plan Excess

If, in addition to this Plan, the Participant is covered under another Defined Contribution Plan maintained by a Controlled Group Member during the Limitation Year the Annual Addition which may be credited to a Participant's Account under this Plan for any such Limitation Year will not exceed the Maximum Annual Addition reduced by the Annual Addition credited to a Participant's accounts under the other Defined Contribution Plans for the same Limitation Year.

10.4 Excess Deferral Contributions Under Code section 401(k)

10.4.1 Actual Deferral Percentage Test - Prior Year Testing Method

Notwithstanding the provisions of Article 3, for any Plan Year,

(a) the actual deferral percentage (as defined in subsection 10.4.3) for the group of eligible Highly Compensated Employees for the Plan Year shall not exceed the actual deferral percentage for the group comprised of all other eligible Employees for the preceding Plan Year multiplied by 1.25, or

(b) the excess of the actual deferral percentage for the group of eligible Highly Compensated Employees for the Plan Year over the actual deferral percentage for the group comprised of all other eligible Employees for the preceding Plan Year shall not exceed 2 percentage points; and the actual deferral percentage for the group of eligible Highly Compensated Employees for the Plan Year shall not exceed the actual deferral percentage for the group comprised of all other eligible Employees for the preceding Plan Year multiplied by 2.

10.4.2 Aggregation and Disaggregation of Plans

In the event that this Plan satisfies the requirements of Code sections 401(k), 401(a)(4), or 410(b) only if aggregated with one or more other plans, or if one or more other plans satisfy the requirements of such sections of the Code only if aggregated with this Plan, then this subsection shall be applied by determining the ADP of employees as if all such plans were a single plan. Such plans may be aggregated in order to satisfy Code section 401(k) only if they have the same Plan Year. If a Highly Compensated Employee also participates in another cash or deferred arrangement described in Code section 401(k) which is maintained by the Employer, then this Plan and such other arrangement shall be aggregated and treated as one cash or deferred arrangement for purposes of calculating such Participant's ADP. If a Highly Compensated Employee participates in two or more such cash or deferred arrangements that have different plan years, all such cash or deferred arrangements in which the Participant participates that have plan years ending with or within the same calendar year shall be treated as a single arrangement for purposes of calculating such Participant's ADP. Aggregation under Plan subsection 10.4.2 shall not occur for arrangements that are required to be disaggregated under the Treasury regulations. If the Plan benefits Employees who are covered by a collective bargaining agreement, the portion of the Plan covering such union Employees will be treated as a separate plan (or multiple plans for various union groups as determined by the Administrator) for the purposes of subsection 10.4.1.

10.4.3 Definition of Actual Deferral Percentage

For the purposes of this Section, the actual deferral percentage for a specified group of eligible Employees for a Plan Year shall be the average of the ratios (calculated separately for each eligible Employee in such group) of (i) the amount of Deferral Contributions actually paid to the Trust Fund for each such eligible employee for such Plan Year (including Roth Deferrals and any “excess deferrals” described in Section 3.2) to (ii) the eligible Employee’s Compensation (as defined in subsection 10.2.2 for such Plan Year). The actual deferral percentage for an eligible Employee who makes no Deferral Contribution during the Plan Year shall be taken into account and shall be zero.

10.4.4 Suspension of Deferral Contributions

If at any time during a Plan Year the Administrator determines, on the basis of estimates made from information then available, that the limitation described in subsection 10.4.1 above will not be met for the Plan Year, the Administrator in its discretion may reduce or suspend the Deferral Contributions of one or more Participants who are Highly Compensated Employees to the extent necessary (i) to enable the Plan to meet such limitation or (ii) to reduce the amount of excess Deferral Contributions that would otherwise be distributed pursuant to subsection 10.4.5 below.

10.4.5 Distribution of Excess Contributions

If the actual deferral percentage test of subsection 10.4.1 is not satisfied based upon the Deferral Contributions made for the Plan Year, the Administrator shall determine the “excess contributions” under the Plan for the Plan Year. “Excess contributions” means the aggregate of the excess of the Deferral Contributions allocated to the Account of each Highly Compensated Employee (including Roth Deferrals) over the maximum Deferral Contributions which may be allocated to such Account without failing the Actual Deferral Percentage ("ADP") Test. The amount of excess contributions shall be calculated by reducing the ADP of the Highly Compensated Employee with the highest ADP to the extent such reduction enables the Plan to satisfy the ADP Test or causes such Participant's ADP to equal the ADP of the Highly Compensated Employee with the next highest ADP. This process shall be repeated until the Plan satisfies the ADP Test. The Administrator shall direct the Trustee to distribute such “excess contributions” (adjusted for Trust Fund earnings and losses in the manner described in subsection 4.4.3, except that for Plan Years beginning after December 31, 2007, the Administrator will not calculate and the Trustee will not distribute allocable income for the gap period (i.e., the period after the close of the Plan Year in which the excess contribution occurred and prior to the distribution)) to the extent administratively feasible, on or before March 15th of the following Plan Year and in no event later than the end of the following Plan Year, in accordance with the following leveling method:

(a) The Administrator shall reduce the Deferral Contributions for the Highly Compensated Employee with the largest dollar amount of Deferral Contributions by the amount equal to the lesser of the total “excess contributions” for all Highly Compensated Employees or the dollar amount that would cause his or her Deferral Contribution dollar amount to equal that of the Highly Compensated Employee with the next largest Deferral Contribution dollar amount for the Plan Year. The Administrator shall then reduce equally the Deferral Contributions for the two Highly Compensated Employees with the largest Deferral Contribution dollar amounts, and then reduce equally for the three Highly Compensated Employees with the largest Deferral Contribution dollar amounts, and so forth, until the sum of all such reductions equals the “excess contributions” for the Plan Year.

(b) The Administrator shall thereupon direct the Trustee to refund the amounts by which Deferral Contributions are reduced under subparagraph (a) above (less any amount of such Deferral Contributions refunded under subsection 3.2.2) to the respective Highly Compensated Employees. The refunds shall first be made from Deferral Contributions not subject to Matching Contributions under Section 3.4. Any Matching Contributions shall be forfeited and applied to reduce any subsequent Employer Contribution.

10.4.6 Qualified Non-Elective Contributions

Notwithstanding the foregoing, within 12 months after the end of the Plan Year, an Employer may make a special Qualified Non-Elective Contribution on behalf of a class of Participants designated by the Employer in an amount sufficient to satisfy the actual deferral percentage test set forth in subsection 10.4.1.

10.5 Excess Matching Contributions Under Code Section 401(m)

10.5.1 Actual Contribution Percentage Test - Prior Year Testing Method

Notwithstanding the provisions of Article 3, for any Plan Year,

(a) the actual contribution percentage (as defined in subsection 10.5.3) for the group of eligible Highly Compensated Employees for the Plan Year shall not exceed the actual contribution percentage for the group comprised of all other eligible Employees for the preceding Plan Year multiplied by 1.25, or

(b) the excess of the actual contribution percentage for the group of eligible Highly Compensated Employees for the Plan Year over the actual contribution percentage for the group comprised of all other eligible Employees for the preceding Plan Year shall not exceed 2 percentage points; and the actual contribution percentage for the group of eligible Highly Compensated Employees for the Plan Year shall not exceed the actual contribution percentage for the group comprised of all other eligible Employees for the preceding Plan Year multiplied by 2.

10.5.2 Aggregation and Disaggregation of Plans

In the event that this Plan satisfies the requirements of Code sections 401(m),401(a)(4) or 410(b) only if aggregated with one or more other plans, or if one or more other plans satisfy the requirements of such sections of the Code only if aggregated with this Plan, then this subsection shall be applied by determining the ACP of employees as if all such plans were a single plan. Such plans may be aggregated in order to satisfy Code section 401(m) only if they have the same Plan Year. If a Highly Compensated Employee also participates in any other plan or arrangement (under Code sections 401(a) or 401(k)) which is maintained by the Employer and to which matching contributions, employee contributions or elective deferrals are made, then, for purposes of calculating that Participant's ACP, all the plans in which the Participant is eligible to participate shall be treated as one plan. If a Highly Compensated Employee participates in two or more such arrangements that have different plan years, all such arrangements ending with or within the same calendar year shall be treated as a single arrangement for purposes of calculating the Participant's ACP. Aggregation under this subsection shall not occur for arrangements that are required to be disaggregated under the Treasury regu1ations.

If the Plan benefits Employees who are covered by a collective bargaining agreement, the portion of the Plan covering such union Employees will be treated as a separate plan (or multiple plans for various union groups as determined by the Administrator) for the purposes of subsection 10.5.1.

10.5.3 Definition of Actual Contribution Percentage

For the purposes of this Section, the contribution percentage for a specified group of eligible Employees for a Plan Year shall be the average of the ratios (calculated separately for each eligible Employee in such group) of (i) the sum of the After-Tax Contributions, Roth Contributions and the Matching Contributions paid under the Plan by or on behalf of each such eligible Employee for such Plan Year to (ii) the eligible Employee’s Compensation for such Plan Year. The contribution percentage of an eligible Employee who makes no Deferral or After-Tax or Roth Contribution during the Plan Year shall be taken into account and shall be zero.

For purposes of determining whether the Plan satisfies the actual contribution percentage test of Code section 401(m), the requirements of section 401(m) of the Code and the Treasury Regulations thereunder (in particular concerning the aggregation of plans), are incorporated herein by this reference.

10.5.4 Treatment of Excess Aggregate Contributions

If the contribution percentage test of subsection 10.5.1 is not satisfied based upon the After-Tax and Matching Contributions made for the Plan Year, the Administrator shall determine the “excess aggregate contributions” under the Plan for the Plan Year. “Excess aggregate contributions” means the aggregate of the excess of the After-Tax and

Matching Contributions allocated to the Accounts of the Highly Compensated Employee over the maximum amount of such contributions which may be allocated to such Accounts without failing the Actual Contribution Percentage ("ACP") Test. The amount of excess aggregate contributions shall be calculated by reducing the ACP of the Highly Compensated Employee with the highest ACP to the extent such reduction enables the Plan to satisfy the ACP Test or causes such Participant's ACP to equal the ACP of the Highly Compensated Employee with the next highest ACP. This process shall be repeated until the Plan satisfies the ACP Test. The Administrator shall direct the Trustee to distribute such “excess aggregate contributions” (adjusted for Trust Fund earnings and losses in the manner described in subsection 4.4.3, except that for Plan Years beginning after December 31, 2007, the Administrator will not calculate and the Trustee will not distribute allocable income for the gap period (i.e., the period after the close of the Plan Year in which the excess aggregate contribution occurred and prior to the distribution)) to the extent administratively feasible on or before March 15th of the following Plan Year (and in no event later than the end of the Plan Year), in accordance with the following leveling method:

(a) The Administrator shall reduce the After-Tax and Matching Contributions for the Highly Compensated Employee with the largest dollar amount of After-Tax and Matching Contributions by the amount equal to the lesser of the total “excess aggregate contributions” for all Highly Compensated Employees or the dollar amount that would cause his or her After-Tax and Matching Contribution dollar amount to equal that of the Highly Compensated Employee with the next largest After-Tax and Matching Contribution dollar amount for the Plan Year. The Administrator shall then reduce equally the After-Tax and Matching Contributions for the two Highly Compensated Employees with the largest After-Tax and Matching Contribution dollar amounts, and then reduce equally for the three Highly Compensated Employees with the largest After-Tax and Matching Contribution dollar amounts, and so forth, until the sum of all such reductions equals the “excess aggregate contributions” for the Plan Year.

(b) The Administrator shall thereupon direct the Trustee to distribute the amounts by which After-Tax and Matching Contributions are reduced under subparagraph (a) above to the respective Highly Compensated Employees.

10.5.5 Order of Determinations

The determination of excess aggregate contributions under this Section shall be made after (i) first determining the excess deferrals under Section 3.2, and (ii) then determining the excess contributions under Section 10.4.

10.5.6 Qualified Matching Contribution

Notwithstanding the foregoing, within 12 months after the end of the Plan Year, an Employer may make a special Qualified Matching Contribution on behalf of a class of Participants designated by the Employer in an amount sufficient to satisfy the Actual Contribution Percentage test set forth in subsection 10.5.1.

10.6 Gap Period Income on Distributed Excess Contributions and Excess Aggregate Contributions

This Section applies to excess contributions (as defined in Code §401(k)(8)(B)) and excess aggregate contributions (as defined in Code §401(m)(6)(B)). The Plan Administrator will not calculate and distribute allocable income for the gap period (i.e., the period after the close of the Plan Year in which the excess contribution or excess aggregate contribution occurred and prior to the distribution).

10.7 Plan Termination Distribution Availability

For purposes of determining whether the Employer maintains an alternative defined contribution plan (described in Treas. Reg. §1.401(k)-1(d)(4)(i)) that would prevent the Employer from distributing elective deferrals (and other amounts, such as QNECs, that are subject to the distribution restrictions that apply to elective deferrals) from a terminating 401(k) plan, an alternative defined contribution plan does not include an employee stock ownership plan defined in Code §§4975(e)(7) or 409(a), a simplified employee pension as defined in Code §408(k), a SIMPLE IRA plan as defined in Code §408(p), a plan or contract that satisfies the requirements of Code §403(b), or a plan that is described in Code §§457(b) or (f).

EXHIBIT IV

11. PLAN LOANS

11.1 Authorization

The Administrator is authorized to administer the loan program, and to adopt from time to time such forms and procedures as it considers necessary or appropriate to administer the loan program. The Administrator may appoint an agent to administer the loan program in accordance with the Administrator's prescribed forms and procedures.

11.2 Conditions and Limitations

Plan loans made to Participants will be made on a reasonably equivalent basis. Plan loans may be subject to conditions and limitations adopted by the Administrator that are not inconsistent with the Plan and those conditions and limitations within this Section 11.2. Loans to a Participant shall not be made from such Participant's Roth Account.

11.2.1 Eligibility

Employees, and other Participants who are "parties in interest" within the meaning of ERISA section 3(14), who have an Account balance, may apply for loans. A Participant may have only one outstanding loan at any one time.

11.2.2 Maximum Principal Amount

The maximum principal amount of any loan is the lesser of (i) fifty percent (50%) of the balance of the Participant's Account, determined on the day of the loan, minus the balance of all other loans from all other qualified plans of the Employer, outstanding on that date, or (ii) $50,000, minus the highest outstanding principal balance of loans from the Plan, and from all other qualified plans of the Employer, to the Participant during the period of one year ending on the day preceding the origination of the loan being requested.

Amounts held in a Self-Directed Brokerage Fund, if any, and/or Roth Accounts will be included in the calculation of the maximum principal amount available for a loan but may not be used as a source for a loan. Therefore, if a Participant has amounts in a Self-Directed Brokerage Fund or a Roth Account, the maximum that the Participant may borrow is the lesser of the maximum available amount calculated according to the formula described above or the Participant's Account balance minus the portion held in the Participant's Self-Directed Brokerage Fund and/or Roth Account.

11.2.3 Minimum Principal Amount

The minimum principal amount of any loan is $1,000.

11.2.4 Duration

The repayment period of any general purpose loan will be no more than five (5) years. The repayment period of any primary residence loan will be no more than ten (10) years.

11.2.5 Repayment Method

A loan will generally be repaid in substantially equal installments by payroll deduction from each paycheck. If the Participant is not an active Employee or if the amount of the Participant's paycheck is insufficient to make any repayment when due, the Participant must make scheduled payments directly to the Trustee at the address provided by the Administrator.

11.2.6 Timing of Repayment

Repayment will begin with the first payroll as soon as administratively practicable following the loan issuance.

If a Participant is granted an authorized unpaid leave of absence as determined by the Administrator, the Participant's loan payments will be suspended for a period of up to one year upon request. When the Participant returns to active employment with the Employer, payments will resume through payroll deduction. The amount of each periodic payment will be adjusted, so that the unpaid balance will continue to be paid in equal installments in amounts sufficient to retire the entire loan indebtedness (principal and interest) by the original maturity date of the loan.

11.2.7 Plan Accounting

The distribution of the proceeds of a loan will be charged solely against the Participant's Account, and against the various investments within that Account (excluding a Self-Directed Brokerage Fund) on a pro rata basis. All repayments of principal and interest will be credited solely to the Participant's Account and invested in accordance with the Participant's then current election option for new contributions (excluding elections to invest in any Self-Directed Brokerage Fund) as determined in Section 5.2. The unpaid principal balance of a loan will be reflected as a receivable for the Participant's Account. The Participant will be required to pay the administrative expenses incurred by the Trustee and the Administrator in connection with a loan, and any such expenses not paid directly by the Participant will be charged against the Participant's Account.

11.2.8 Interest Rate

The rate of interest charged will be a reasonable rate that provides the Plan with a return commensurate with the interest rate charged by persons in the business of lending money for loans which would be made under similar circumstances. The rate will be determined in a manner prescribed in the Administrator's loan procedures as adopted from time to time. The interest rate so determined will remain fixed throughout the duration of the loan.

11.2.9 Security

Each loan will be secured by the assignment of up to fifty percent (50%) of the Participant's Account balance. No other security will be required or accepted.

11.3 Loan Default

Other than for payments suspended during an authorized unpaid leave of absence, if a Participant fails to make an installment payment on a loan when due, and this failure continues for thirty (30) days, the loan will be treated as in default. The Administrator will give the Participant written notice of the right to cure the default by making up missed payments or repaying the loan in full. If a failure to make an installment repayment is not cured by ninety (90) days from the date of the first missed payment, the default will be final. The Plan is authorized to offset the entire outstanding amount of the loan against the Participant's Account at the time the Participant is eligible for a distribution from the Plan. If a Participant experiences a default as described in this paragraph, that Participant will be ineligible for any future loans from the Plan.

If a distribution is required to be made under a QDRO affecting a Participant's Account, and the distribution would exceed the amount of that Participant's interest in the Plan, less the outstanding loan balance, then the loan will be deemed to be in default and will be immediately payable. The Participant will have ninety (90) days to cure this default. Failure to do so will result in the consequences outlined above, including ineligibility for any future loans from the Plan.

11.4 Termination of Employment

A Participant will have ninety (90) days from termination of employment to repay a loan in full (unless the Participant continues to be a "party in interest" within the meaning of ERISA section 3(14), in which case the Participant must continue to make scheduled payments directly to the Trustee when due). If the Participant is required to and does not repay a loan within ninety (90) days of termination, the unpaid loan balance will be treated as a distribution paid directly to the Participant. If a Participant takes a distribution of the Participant's Account balance before repaying the Participant's loan, the distribution will consist first of the unpaid loan balance and then of any remaining cash balance in the Participant's Account. For any amounts actually distributed in cash the Participant will continue to have the ability to request a distribution in the form of IDACORP, Inc. stock.

11.5 Procedure for Applying for and Accepting Loans

The Administrator will establish procedures for applying for and accepting loans, which will create a legally enforceable agreement between the Participant and the Plan. At a minimum, by agreeing to the terms of the loan, a Participant will make an irrevocable agreement to repay the loan through payroll deduction (provided the Participant is an active Employee at that time), and will assign and grant to the Plan a security interest of up to fifty percent (50%) of the balance of the Participant's Account.

11.6 Approval or Denial

The Administrator will approve or deny loans based solely on the basis of this Article 11. There shall be no discretion to grant or deny a loan request. Denials shall be processed under the claims procedure rules of the Plan listed in Section 9.8.

11.7 Repayment in Full

The entire balance of the loan may be repaid at any time, without penalty or service fee, by certified check made payable to the Trustee, and sent to the address provided by the Administrator.

11.8 Tax Reporting

To the extent required by section 72(p) of the Code, the Trustee shall report, from time to time, distributions of income in connection with loans made under this Plan. The operation of those tax rules is entirely independent of the rules of the Plan.

11.9 Truth in Lending

This Plan shall make all disclosures required under federal truth-in-lending regulations (Regulation Z issued by the Board of Governors of the Federal Reserve System).

EXHIBIT IV

12. RESTRICTIONS ON DISTRIBUTIONS TO PARTICIPANTS AND BENEFICIARIES

12.1 Priority over Other Distribution Provisions

The provisions set forth in this Article supersede any conflicting provisions of this Plan.

12.2 Restrictions on Distributions Prior to Severance from Employment

A Participant's Deferral Contributions, Matching Contributions, and earnings attributable to these contributions will be distributed on account of the Participant's severance from employment, regardless of when that severance from employment occurred; however, such a distribution shall be subject to the other provisions of the Plan regarding distributions.

12.3 Restrictions on Commencement of Distributions

Unless a Participant elects otherwise, distribution of the Participant's interest in his or her Accounts will begin no later than the 60th day after the close of the Plan Year in which occurs the latest of (i) the date on which the Participant attains age 65, (ii) the tenth anniversary of the Plan Year in which the Participant began participation in the Plan, and (iii) the Participant's termination of employment.

12.4 2009 Required Minimum Distributions

A Participant or Beneficiary who would have been required to receive minimum required distributions for 2009 but for the enactment of Section 401(a)(9)(H) of the Code ("2009 RMDs"), and who would have satisfied that requirement by receiving distributions that are (1) equal to the 2009 RMDs or (2) one or more payments in a series of substantially equal distributions (that include the 2009 RMDs) made at least annually and expected to last for the life (or life expectancy) of the Participant, the joint lives (or joint life expectancies) of the Participant and the Participant's designated Beneficiary, or for a period of at least 10 years ("Extended 2009 RMDs"), will not receive those distributions for 2009 unless the Participant or Beneficiary chooses to receive such distributions. 2009 RMDs and Extended 2009 RMDs will also be treated as eligible rollover distributions in 2009.

12.5 Restrictions in Connection with QDRO

No distribution (including but not limited to hardship distributions, rollovers, transfers to other plans, and loans) may be made to a Participant during the period in which the Administrator is making a determination of whether a domestic relations order affecting the Participant's Accounts is a QDRO. Furthermore, if the Administrator has received a written document indicating that a QDRO affecting a Participant's Accounts is being sought, it may prohibit such

Participant from commencing to receive a distribution (or from taking a loan) until the Administrator has determined that such distribution would not be inconsistent with any such order or that no such order will be submitted. If the Administrator is in receipt of a QDRO with respect to any Participant's benefits, it may prohibit such Participant from receiving a distribution until the Alternate Payee's rights under such order are satisfied. A domestic relations order that otherwise satisfies the requirements for a qualified domestic relations order ("QDRO") will not fail to be a QDRO: (i) solely because the order is issued after, or revises, another domestic relations order or QDRO; or (ii) solely because of the time at which the order is issued, including issuance after the annuity starting date or after the Participant's death.

EXHIBIT IV

13. TOP HEAVY PROVISIONS

13.1 Priority over Other Plan Provisions

If the Plan is or becomes a Top-Heavy Plan in any Plan Year, the provisions of this Article will supersede any conflicting provisions of the Plan. However, the provisions of this Article will not operate to increase the rights or benefits of Participants under the Plan except to the extent required by Code section 416 and other provisions of law applicable to Top Heavy Plans.

13.2 Definitions Used in this Article

The following words and phrases will have the meanings set forth below for purposes of this Article only.

13.2.1 Defined Benefit Dollar Limitation

" Defined Benefit Dollar Limitation " means $195,000 (or such larger amount as is determined by the Secretary of the Treasury in accordance with Code section 415(d)(1)).

13.2.2 Defined Benefit Plan

" Defined Benefit Plan " means the Qualified Plan described in subsection 10.2.3.

13.2.3 Defined Contribution Dollar Limitation

" Defined Contribution Dollar Limitation " means $49,000 (or such larger amount as is determined by the Secretary of Treasury in accordance with Code section 415(d)(1)).

13.2.4 Defined Contribution Plan

" Defined Contribution Plan " means the Qualified Plan described in subsection 10.2.4.

13.2.5 Determination Date

" Determination Date " means for the first Plan Year of the Plan the last day of the Plan Year and for any subsequent Plan Year the last day of the preceding Plan Year.

13.2.6 Determination Period

" Determination Period " means the Plan Year containing the Determination Date, and the prior Plan Year, except that, with respect to any distribution made for a reason other than separation from service, death, or disability, the Determination Period shall include the Plan Year containing the Determination Date and the previous five (5) Plan Years.

13.2.7 Includable Compensation

" Includable Compensation " means the compensation described in subsection 10.2.7, limited as set forth in subsection 1.10.1.

13.2.8 Key Employee

" Key Employee " means any employee or former employee (including any deceased employee) who at any time during the Plan Year that includes the Determination Date was an officer of a Controlled Group Member having Compensation greater than $150,000 (as adjusted under Code section 416(i)(1)), a 5-percent owner of a Controlled Group Member, or a 1-percent owner of a Controlled Group Member having Compensation of more than $150,000. The determination of who is a Key Employee will be made in accordance with Code section 416(i)(1) and the applicable regulations and other guidance of general applicability issued thereunder.

13.2.9 Minimum Allocation

" Minimum Allocation " means the allocation described in the first sentence of subsection 13.3.1.

13.2.10 Permissive Aggregation Group

" Permissive Aggregation Group " means the Required Aggregation Group of Qualified Plans plus any other Qualified Plan or Qualified Plans of a Controlled Group Member which, when considered as a group with the Required Aggregation Group, would continue to satisfy the requirements of Code Sections 401(a)(4) and 410.

13.2.11 Present Value

" Present Value " means present value based only on the interest and mortality rates specified in a Defined Benefit Plan.

13.2.12 Required Aggregation Group

" Required Aggregation Group " means the group of plans consisting of (i) each Qualified Plan of a Controlled Group Member in which at least one Key Employee participates or participated at any time during the Determination Period (regardless of whether the Qualified Plan has terminated) and (ii) any other Qualified Plan of a Controlled Group Member which enables a Qualified Plan to meet the requirements of Code Sections 401(a)(4) or 410.

13.2.13 Top-Heavy Plan

" Top-Heavy Plan " means the Plan for any Plan Year in which any of the following conditions exists: (i) if the Top-Heavy Ratio for the Plan exceeds 60% and the Plan is not a part of any Required Aggregation Group or Permissive Aggregation Group of Qualified Plans; (ii) if the Plan is a part of a Required Aggregation Group but not part of a Permissive Aggregation Group of Qualified Plans and the Top-Heavy Ratio for the Required Aggregation Group exceeds 60 percent; or (iii) if the Plan is a part of a Required Aggregation Group and part of a Permissive Aggregation Group of Qualified Plans and the Top-Heavy Ratio for the Permissive Aggregation Group exceeds 60 percent.

13.2.14 Top-Heavy Ratio

" Top-Heavy Ratio " means a fraction, the numerator of which is the sum of the Present Value of accrued benefits and the account balances (as required by Code section 416) of all Key Employees with respect to such Qualified Plans as of the Determination Date (including any part of any accrued benefit or Account balance distributed during the appropriate Determination Period as determined in accordance with Section 13.2.6), and the denominator of which is the sum of the Present Value of the accrued benefits and the account balances (including any part of any accrued benefit or Account balance distributed during the appropriate Determination Period as determined in accordance with Section 13.2.6) of all Employees with respect to such Qualified Plans as of the Determination Date. The value of account balances and the Present Value of accrued benefits will be determined as of the most recent Top-Heavy Valuation Date that falls within or ends with the 12 month period ending on the Determination Date, except as provided in Code section 416 for the first and second Plan Years of a Defined Benefit Plan. The account balances and accrued benefits of a participant who is not a Key Employee but who was a Key Employee in a prior year will be disregarded. The calculation of the Top-Heavy Ratio, and the extent to which distributions, rollovers, transfers and contributions unpaid as of the Determination Date are taken into account will be made in accordance with Code section 416. Employee contributions described in Code section 219(e)(2) will not be taken into account for purposes of computing the Top-Heavy Ratio. When aggregating plans, the value of account balances and accrued benefits will be calculated with reference to the Determination Dates that fall within the same calendar year. The accrued benefit of any Employee other than a Key Employee will be determined under the method, if any, that uniformly applies for accrual purposes under all Qualified Plans maintained by all Controlled Group Members and included in a Required Aggregation Group or a Permissive Aggregation Group or, if there is no such method, as if the benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional accrual rate of Code section 411(b)(1)(C).

Notwithstanding the foregoing, the account balances and accrued benefits of any Employee who has not performed services for an employer maintaining any of the aggregated plans during the one-year period ending on the Determination Date will not be taken into account for purposes of this section.

13.2.15 Top-Heavy Valuation Date

"Top-Heavy Valuation Date" means the last day of each Plan Year.

13.3 Minimum Allocation

13.3.1 Calculation of Minimum Allocation

For any Plan Year in which the Plan is a Top-Heavy Plan, each Participant who is not a Key Employee will receive an allocation of Employer contributions and forfeitures of not less than the lesser of 3 percent of his or her Includable Compensation for such Plan Year or, if the Controlled Group Members maintain no Defined Benefit Plan which covers a Participant in this Plan, the percentage of Includable Compensation that equals the largest percentage of Employer contributions and forfeitures allocated to a Key Employee expressed as a percentage of the first $160,000 (or such other amount as is determined by the Secretary under Code section 401(a)(17) to be in effect for that year) of Includable Compensation received by such Key Employee in that Plan Year. The Minimum Allocation applies even though under other Plan provisions the Participant would not otherwise be entitled to receive an allocation, or would have received a lesser allocation for the Plan Year because (i) the non Key Employee fails to make mandatory contributions to the Plan, (ii) the non Key Employee's Compensation is less than a stated amount, or (iii) the non Key Employee fails to complete 3 months of service in the Plan Year. Matching Contributions shall be taken into account for purposes of satisfying the Minimum Allocation requirements of Code section 416(c)(2) and the Plan. Matching Contributions that are used to satisfy the Minimum Allocation requirements shall be treated as Matching Contributions for purposes of the actual contribution test of Section 10.7 and applicable provisions of Code section 401(m).

13.3.2 Limitation on Minimum Allocation

No Minimum Allocation will be provided pursuant to subsection 13.3.1 to a Participant who is not employed by a Controlled Group Member on the last day of the Plan Year.

13.3.3 Minimum Allocation When Participant is Covered by Another Qualified Plan

If a Controlled Group Member maintains one or more other Defined Contribution Plans covering Employees who are Participants in this Plan, the Minimum Allocation will be provided under this Plan, unless such other Defined Contribution Plans make explicit reference to this Plan and provide that the Minimum Allocation will not be provided under this Plan, in which case the provisions of subsection 13.3.1 will not apply to any Participant covered under such other Defined Contribution Plans. If a Controlled Group Member maintains one or more Defined Benefit Plans covering Employees who are Participants in this Plan, and such Defined Benefit Plans provide that Employees who are participants therein will accrue the minimum benefit applicable to top heavy Defined Benefit Plans notwithstanding their participation in this Plan (making explicit reference to this Plan), then the provisions of subsection 13.3.1 will not apply to any Participant covered under such Defined Benefit Plans. If a Controlled Group Member maintains one or more Defined Benefit Plans covering Employees who are Participants in this Plan, and the provisions of the preceding sentence do not apply, then each Participant who is not a Key Employee and who is covered by such Defined Benefit Plans will receive a Minimum Allocation determined by applying the provisions of subsection 13.3.1 with the substitution of “5 percent” in each place that “3 percent” occurs therein.

13.4 Modification of Aggregate Benefit Limit

13.4.1 Modification

Subject to the provisions of subsection 13.4.2, in any Plan Year in which the Top Heavy Ratio exceeds 60 percent, the aggregate benefit limit described in Article 10 will be modified by substituting “100 percent” for “125 percent” in subsections 10.2.3 and 10.2.4.

13.4.2 Exception

The modification of the aggregate benefit limit described in subsection 13.4.1 will not be required if the Top-Heavy Ratio does not exceed 90 percent and one of the following conditions is met: (i) Employees who are not Key Employees do not participate in both a Defined Benefit Plan and a Defined Contribution Plan which are in the Required Aggregation Group, and the Minimum Allocation requirements of subsection 13.3.1 are met when such requirements are applied with the substitution of “4 percent” for “3 percent”; (ii) the Minimum Allocation requirements of subsection 13.3.3 are met when such requirements are applied with the substitution of “7 ½ percent” for “5 percent”; or (iii) Employees who are not Key Employees accrue a benefit for such Plan

Year of not less than 3 percent of their average Includable Compensation for the five consecutive Plan Years in which they had the highest Includable Compensation (not to exceed a total such benefit of 30 percent), expressed as a life annuity commencing at the Participant’s normal retirement age in a Defined Benefit Plan which is in the Required Aggregation Group.

EXHIBIT IV

14. PARTICIPATING EMPLOYERS

14.1 Adoption Procedure

Notwithstanding anything herein to the contrary, with the consent of the Company, any Controlled Group Member may adopt this Plan and all of the provisions hereof, and participate herein and be known as a Participating Employer. The following are the Participating Employers:

- Idaho Power Company
- Ida West Energy Company
- IDACORP Financial Services, Inc.

14.2 Single Plan Status; Maintenance of Assets and Records

It is intended that the Plan constitute a “single Plan” within the meaning of Treas. Reg. section 1.414(l)-1(b)(1). Accordingly, the Trustee may, but shall not be required to, commingle, hold and invest as one Trust Fund all contributions made by Employers, as well as all increments thereon. However, the assets of the Plan shall be available at all times to pay benefits to all Participants and Beneficiaries under the Plan without regard to the Employer who contributed such assets.

14.3 Designation of Agent

Each Participating Employer shall be deemed to be a party to this Plan; provided, however, that with respect to all of its relations with the Trustee and Administrator for the purpose of this Plan and with respect to any amendment or termination of the Plan, each Participating Employer shall be deemed to have designated irrevocably Idaho Power Company as its agent. Unless the context of the Plan clearly indicates the contrary, the word “Employer” shall be deemed to include each Participating Employer as related to its adoption of the Plan.

14.4 Employee Transfers

It is anticipated that an Employee may be transferred between Participating Employers, and in the event of any such transfer, the Employee involved shall carry with him or her accumulated service and eligibility. No such transfer shall effect a termination of employment hereunder, and the Participating Employer to which the Employee is transferred shall thereupon become obligated hereunder with respect to such Employee in the same manner as was the Participating Employer from whom the Employee was transferred.

14.5 Discontinuance of Participation

Any Participating Employer shall be permitted to discontinue or revoke its participation in the Plan, but only with the consent of the Company. At the time of any such discontinuance or revocation, satisfactory evidence thereof and of any applicable conditions imposed shall be delivered to the Administrator. The Administrator shall thereafter direct the transfer of all Trust Fund assets allocable to the Participants of such Participating Employer to such new Trustee as shall have been designated by such Participating Employer, in the event that it has established a separate pension plan for its Employees, provided however, that no such transfer shall be made if the result is the elimination or reduction of any Code section 411(d)(6) protected benefits. If no successor is designated, the Trustee shall retain such assets for the Employees of said Participating Employer pursuant to the provisions of this Plan. In no such event shall any part of the corpus or income of the Trust as it relates to such Participating Employer be used for or diverted to purposes other than for the exclusive benefit of the Employees of such Participating Employer. A discontinuance or revocation of an Employer's participation in the Plan shall not, by itself, constitute a termination of employment with the Controlled Group for any Employee of such Employer.

14.6 Administrator's Authority

The Administrator shall have authority to make any and all necessary rules or regulations, binding upon all Participating Employers and all Participants, to effectuate the purpose of this Article.

EXHIBIT IV

15. AMENDMENT OF THE PLAN

15.1 Right of Company to Amend Plan

The Company reserves for itself, by and through one or more of its officers acting on behalf of the Company in its capacity as Plan Sponsor, the right to alter, amend, revoke or terminate this Plan. No amendment will (i) increase the duties or liabilities of the Trustee without its written consent; (ii) cause a reversion of Plan assets to the Employers not otherwise permitted under the Plan; (iii) have the effect of reducing the percentage of the vested and nonforfeitable interest of any Participant in his or her Accounts, (iv) amend the vesting provisions of the Plan unless each Participant with at least three Years of Service (including Years of Service disregarded pursuant to the reemployment provisions herein) is permitted to elect within 60 days after the latest of the date on which the amendment is adopted, the date on which the amendment is effective and the date on which the Participant is issued written notice of the amendment, to continue to have the prior vesting provisions apply; or (iv) be effective to the extent that it has the effect of decreasing a Participant's Account balance or eliminating an optional form of distribution as it applies to an existing Account balance, except as may be permitted by Treasury regulations.

15.2 Amendment Procedure

Any amendment to the Plan will be evidenced in writing. Upon execution of the amendment by an officer of the Company, the Plan shall be deemed amended as of the effective date specified in the amendment. If no effective date is specified, the effective date shall be the date of execution of the amendment. The effective date may be before, on or after the date of execution and before, on or after the date of any action taken with respect to such amendment.

15.3 Effect on Employers

Unless an amendment expressly provides otherwise, all Employers will be bound by any amendment to the Plan.

EXHIBIT IV

16. TERMINATION, PARTIAL TERMINATION AND COMPLETE DISCONTINUANCE OF CONTRIBUTIONS

16.1 Continuance of Plan

The Employers expect to continue the Plan indefinitely, but they do not assume an individual or collective contractual obligation to do so, and the right is reserved to the Company to terminate the Plan or to completely discontinue contributions thereto at any time. In addition, subject to the remaining provisions of this Article, any Employer at any time may discontinue its participation in the Plan with respect to its Employees.

16.2 Disposition of the Trust Fund

If the Plan is terminated, or if there is a complete discontinuance of contributions to the Plan, the Administrator will instruct the Trustee either (i) to continue to administer the Plan and pay benefits in accordance with the Plan until the Trust Fund has been depleted, or (ii) to distribute the assets remaining in the Trust Fund. If the Trust Fund is to be distributed, the Administrator will make, after deducting estimated expenses for termination of the Trust Fund and distribution of its assets, the allocations required under the Plan as though the date of completion of the Trust Fund termination were a Valuation Date. The Trustee will distribute to each Participant the amount credited to his or her Account as of the date of completion of the Trust Fund termination.

16.3 Withdrawal by a Participating Employer

See Section 13.5 for requirements for withdrawal by a Participating Employer.

16.4 Procedure for Termination

Any termination of the Plan shall be evidenced in writing and made either by action of the Board, or by the Company acting in accordance with any procedure authorized by the Board. Upon execution of the instrument of termination by the Company, the Plan shall be deemed terminated as of the effective date specified in such instrument. If no effective date is specified, the effective date shall be the date of execution of such instrument. The effective date may be before, on or after the date of execution and before, on or after the date of any action taken by the Board with respect to such termination.

EXHIBIT IV

17. MISCELLANEOUS

17.1 Reversion Prohibited

17.1.1 General Rule

Except as specifically provided otherwise herein, it will be impossible for any part of the Trust Fund either (i) to be used for or diverted to purposes other than those which are for the exclusive benefit of Participants and their Beneficiaries (except for the payment of taxes and administrative expenses) or (ii) to revert to a Controlled Group Member.

17.1.2 Disallowed Deductions

Each contribution of the Employers under the Plan is expressly conditioned upon the deductibility of the contribution under Code section 404. If all or part of an Employer's contribution is disallowed as a deduction under Code section 404, such disallowed amount (reduced by any Trust Fund losses attributable thereto) may be returned by the Trustee to the Employer with respect to which the deduction was disallowed (upon the direction of the Administrator) within one year after the disallowance.

17.1.3 Mistaken Contributions

If a contribution is made by an Employer by reason of a mistake of fact, then so much of the contribution as was made as a result of the mistake (reduced by any Trust Fund losses attributable thereto) may be returned by the Trustee to the Employer (upon direction of the Administrator) within one year after the mistaken contribution was made.

17.2 Merger, Consolidation or Transfer of Assets

There will be no merger or consolidation of all or any part of the Plan with, or transfer of the assets or liabilities of all or any part of the Plan to, any other Qualified Plan unless each Participant who remains a Participant hereunder and each Participant who becomes a participant in the other Qualified Plan would receive a benefit immediately after the merger, consolidation or transfer (determined as if the other Qualified Plan and the Plan were then terminated) which is equal to or greater than the benefit they would have been entitled to receive under the Plan immediately before the merger, consolidation or transfer if the Plan had then terminated.

17.3 Spendthrift Clause

The rights of any Participant or Beneficiary to and in any benefits under the Plan will not be subject to assignment or alienation, and no Participant or Beneficiary will have the power to assign, transfer or dispose of such rights, nor will any such rights to benefits be subject to attachment, execution, garnishment, sequestration, the laws of bankruptcy or any other legal or equitable process. Notwithstanding the foregoing, the Administrator and Trustee shall honor a QDRO and may distribute amounts from the Plan to an Alternate Payee described in any such order in accordance with the terms of the order and prior to the earliest retirement date specified in section 414(p)(4)(B) of the Code. The Administrator shall establish procedures to determine the qualified status of domestic relations orders and to administer the provisions of, and distributions under, such orders in accordance with section 414(p) of the Code.

17.4 Rights of Participants

Participation in the Plan will not give any Participant the right to be retained in the employ of a Controlled Group Member or any right or interest in the Plan or the Trust Fund except as expressly provided herein.

17.5 Headings

Headings of Articles, Sections and subsections as used herein are inserted solely for convenience and reference and constitute no part of the Plan.

7.6 Governing Law

The Plan will be construed and governed in all respects in accordance with applicable federal law and, to the extent not preempted by such federal law, in accordance with the laws of the State of Idaho applicable to contracts to be performed entirely within that State.

Executed this 14 th day of January, 2016.

Idaho Power Company

By *__/s/ Lonnie Krawl__*
Lonnie Krawl

Its: Senior Vice President of Human Resources, Administrative Services and Chief Information Officer

EXHIBIT IV

APPENDIX A
REQUIRED MINIMUM DISTRIBUTIONS

The following provisions are effective January 1, 2003 and are intended to ensure compliance with the Code Section 401(a)(9) final regulations, and therefore supersede the provisions of the Plan to the extent those provisions are inconsistent with the provisions of this Amendment as follows:

Section 1.1. Time and Manner of Distribution

(a) Required Beginning Date. The Participant's entire benefits must be distributed, or begin to be distributed, to the Participant no later than the Participant's Required Beginning Date.

(b) Death of Participant Before Distributions Begin. If the Participant dies before distributions begin (see below), the Participant's entire benefits will be distributed, or begin to be distributed, no later than as follows:

(i) If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, distributions to the surviving Spouse will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died, or by December 31 of the calendar year in which the Participant would have attained age 70 ½, if later.

(ii) If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, the Participant's entire benefits will be distributed to the Designated Beneficiary by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

(iii) If there is no Designated Beneficiary as of September 30 of the year following the year of the Participant's death, the Participant's entire benefits will be distributed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

(iv) If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary and the surviving Spouse dies after the Participant but before distributions to the surviving Spouse begin, this subsection 1.1(b), other than subsection 1.1(b)(i), will apply as if the surviving Spouse were the Participant.

EXHIBIT IV

For purposes of this subsection 1.1(b) and Section 1.3, unless subsection 1.1(b)(iv) applies, distributions are considered to begin on the Participant's Required Beginning Date. If subsection 1.1(b)(iv) applies, distributions are considered to begin on the date distributions are required to begin to the surviving Spouse under subsection 1.1(b)(i). If distributions under an annuity purchased from an insurance company irrevocably commence to the Participant before the Participant's Required Beginning Date (or to the Participant's surviving Spouse before the date distributions are required to begin to the surviving Spouse under subsection 1.1(b)(i)), the date distributions are considered to begin is the date distributions actually commence.

(c) Forms of Distribution. Unless the Participant's benefits are distributed in the form of an annuity purchased from an insurance company or in a single sum on or before the Required Beginning Date, as of the first Distribution Calendar Year distributions will be made in accordance with Sections 1.2 and 1.3. If the Participant's benefits are distributed in the form of an annuity purchased from an insurance company, distributions thereunder will be made in accordance with the requirements of Code §401(a)(9) and the Treasury Regulations.

Section 1.2. Required Minimum Distributions During Participant's Lifetime

(a) Amount of Required Minimum Distribution for Each Distribution Calendar Year. During the Participant's lifetime, the minimum amount that will be distributed for each Distribution Calendar Year is the lesser of:

(i)the quotient obtained by dividing the Participant's Account Balance by the distribution period in the Uniform Lifetime Table set forth in§ 1.401(a)(9)-9 of the Treasury Regulations, using the Participant's age as of the Participant's birthday in the Distribution Calendar Year; or

(ii)if the Participant's sole Designated Beneficiary for the Distribution Calendar Year is the Participant's Spouse, the quotient obtained by dividing the Participant's Account Balance by the number in the Joint and Last Survivor Table set forth in § 1.401(a)(9)-9 of the Treasury Regulations, using the Participant's and Spouse's attained ages as of the Participant's and Spouse's birthdays in the Distribution Calendar Year.

(b) Lifetime Required Minimum Distributions Continue Through Year of Participant's Death. Required minimum distributions will be determined

(c) under this Section 1.2 beginning with the first Distribution Calendar Year and up to and including the Distribution Calendar Year that includes the Participant's date of death.

Section 1.3. Required Minimum Distributions After Participant's Death

(a) Death On or After Date Distributions Begin

(i) Participant Survived by Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is a Designated Beneficiary, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the longer of the remaining life expectancy of the Participant or the remaining life expectancy of the Participant's Designated Beneficiary, determined as follows:

(A) The Participant's remaining life expectancy is calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

(B) If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, the remaining life expectancy of the surviving Spouse is calculated for each Distribution Calendar Year after the year of the Participant's death using the surviving Spouse's age as of the Spouse's birthday in that year. For Distribution Calendar Years after the year of the surviving Spouse's death, the remaining life expectancy of the surviving Spouse is calculated using the age of the surviving Spouse as of the Spouse's birthday in the calendar year of the Spouse's death, reduced by one for each subsequent calendar year.

(C) If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, the Designated Beneficiary's remaining life expectancy is calculated using the age of the Beneficiary in the year following the year of the Participant's death, reduced by one for each subsequent year.

(ii) No Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is no Designated Beneficiary as of September 30 of the year after the year of the Participant's death, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the Participant's remaining life expectancy calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

(b) Death Before Date Distributions Begin

(i) Participant Survived by Spousal Designated Beneficiary. If the Participant dies before the date distributions begin and the Designated Beneficiary is the Participant's surviving Spouse, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account Balance by the remaining life expectancy of the Participant's Designated Beneficiary, determined as provided in subsection 1.3(a).

(ii) Death of Surviving Spouse Before Distributions to Surviving Spouse Are Required to Begin. If the Participant dies before the date distributions begin, the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, and the surviving Spouse dies before distributions are required to begin to the surviving Spouse under subsection 1.1(b)(i), this subsection 1.3(b) will apply as if the surviving Spouse were the Participant.

Section 1.4. Definitions

(a) "Designated Beneficiary" means the individual who is designated as the Beneficiary under the Plan and is the designated beneficiary under § 401(a)(9) of the Code and § 1.401(a)(9)-1, Q&A-4, of the Treasury Regulations.

(b) "Distribution Calendar Year" means a calendar year for which a minimum distribution is required. For distributions beginning before the Participant's death, the first Distribution Calendar Year is the calendar year immediately preceding the calendar year which contains the Participant's Required Beginning Date. For distributions beginning after the Participant's death, the first Distribution Calendar Year is the calendar year in which distributions are required to begin under subsection 1.1(b). The required minimum distribution for the Participant's first Distribution Calendar Year will be made on or before the Participant's Required Beginning Date. The required minimum distribution for other Distribution Calendar Years, including the required minimum distribution for the Distribution Calendar Year in which the Participant's Required Beginning Date occurs, will be made on or before December 31 of that Distribution Calendar Year.

(c) "Life expectancy" means the life expectancy as computed by use of the Single Life Table in § 1.401(a)(9)-9 of the Treasury Regulations.

(d) "Participant's Account Balance" means the Account Balance of all the Participant's Accounts as of the last Valuation Date in the calendar year immediately preceding the Distribution Calendar Year ("Valuation Calendar Year") increased by the amount of any Contributions made and allocated or Forfeitures allocated to the Accounts as of dates in the Valuation Calendar Year after the Valuation Date and decreased by distributions made in the Valuation Calendar Year after the Valuation Date. The Account Balance for the Valuation Calendar Year includes any amounts rolled over or transferred to the Plan either in the Valuation Calendar Year or in the Distribution Calendar Year if distributed or transferred in the Valuation Calendar Year.

(e) Required Beginning Date

(i) Non-5 percent Owners. The Required Beginning Date of a Participant who is not a 5 percent owner is April 1st of the calendar year following the calendar year in which the later of retirement or attainment of age 70 ½ occurs.

(ii) 5 percent Owners. The Required Beginning Date of a Participant who is a 5 percent owner is April 1st following the calendar year in which the Participant attains age 70 ½.

(iii) Transitional Rules. The Plan hereby incorporates any transitional rules that apply to the definition of Required Beginning Date. In particular, in connection with the Small Business Job Protection Act of 1996, Participants who after the enactment of such Act were at least age 70 ½, were not 5 percent owners, and who were still employed by the Employer, were given the option to not receive the minimum distributions required under the law as the law existed prior to such Act (and instead such Participants will receive such minimum distributions that are required under the Plan as hereby restated under the Act (e.g., when the over-age-70 ½ Participant retires pursuant to subsection 1.4(e)(i))).

(iv) "5 percent Owner" means, for purposes of this Section, a Participant who is a 5 percent owner of the Employer as defined in Code § 416(i) (but determined without regard to whether the Plan is Top-Heavy) at any time during the Plan Year ending with or within the calendar year in which such owner attains age 70 ½, (or any other Plan Year as required by the Code or regulations thereunder).

Section 1.5. Construction Except as otherwise provided, the requirements of this Section 1 shall apply to any distribution of a Participant's benefits and shall take precedence over any inconsistent provisions of this Plan. All distributions required under this Section 1 shall be determined and made in accordance with Treasury Regulations under § 401(a)(9), including the minimum distribution incidental benefit requirement of § 1.401(a)(9)-2 of said Regulations, and those Regulations govern to the extent a conflict exists.

If the amount of a distribution required to begin on a date determined under the applicable provisions of the Plan cannot be ascertained by such date, or if it is not possible to make such payment on such date because the Administrator has been unable to locate a Participant or Beneficiary after making reasonable efforts to do so, a payment retroactive to such date may be made no later than 60 days after the earliest date on which the amount of such payment can be ascertained or the date on which the Participant or Beneficiary is located (whichever is applicable).

Any payments to a Beneficiary must conform to the “incidental benefit” rules of Code section 401(a)(9)(G) and any regulations promulgated thereunder.

Section 1.6. TEFRA § 242(b) Transitional Rule In accordance with§ 242(b) of The Tax Equity and Fiscal Responsibility Act of 1982 ("TEFRA"), the following transitional rule shall apply:

(a) Notwithstanding anything in this Section 1 to the contrary and subject to Code § 417, a distribution on behalf of any Participant, including a 5 percent Owner, may be made in accordance with the following requirements (regardless of when such distribution commences):

(i) the distribution is one which would not have disqualified this Plan and Trust under Code § 401(a)(9) as in effect prior to amendment by the Deficit Reduction Act of 1984;

(ii) the distribution is in accordance with a method of distribution designated by the Participant whose benefits in the Trust are being distributed or, if the Participant is deceased, by a Beneficiary of such Participant;

(iii) such designation was in writing, signed by the Participant or the Beneficiary , and made before January 1, 1984;

(iv) the Participant had accrued a benefit under the Plan as of December 31, 1983; and

(v) the method of distribution designated specifies the time at which distributions will commence, the period over which distributions will be made, and in the case of any distribution upon the Participant's death, the Beneficiaries of the Participant listed in order of priority.

(b) A distribution upon death will not be covered by the transitional rule contained in this subsection unless the designation contains the information described in subsection (a) with respect to the distributions to be made upon the death of the Participant.

(c) For any distribution which commences before January 1, 1984 but continues after December 31, 1983, the Participant or the Beneficiary to whom such distribution is being made will be presumed to have designated the method of distribution under which the distribution is being made if the method of distribution was specified in writing and the distribution satisfies the requirements in subsections (a)(i) and (v).

(d) Any changes in the designation will be considered to be a revocation of the designation. However, the mere substitution or addition of another Beneficiary (one not named in the designation) under the designation will not be considered to be a revocation of the designation, so long as such substitution or addition does not alter the period over which distributions are to be made under the designation, directly or indirectly (for example, by altering the relevant measuring life).

(e) If a designation is revoked, any subsequent distribution must satisfy the requirements of Code § 40l(a)(9) and the regulations thereunder. If a designation is revoked subsequent to the date when distributions are required to begin, the Trust must distribute by the end of the calendar year following the calendar year in which the revocation occurs the total amount not yet distributed which would have been required to have been distributed to satisfy Code § 401(a)(9) and the regulations thereunder, but for the TEFRA § 242(b)(2) election hereunder. Such distributions must also meet the minimum distribution incidental benefit requirements in Treasury Regulations §1.401(a)(9)-2.

(f) If an amount is transferred or rolled over from one plan to another plan (including this Plan), the rules in Q&A J-2 and Q&A J-3 of Treasury Regulations §1.401(a)(9)-1 shall apply.

EXHIBIT IV

Exhibit 12.1

IDACORP, Inc.
Consolidated Financial Information
Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
(Thousands of Dollars)

	Twelve Months Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
RATIO OF EARNINGS TO FIXED CHARGES					
Earnings, as defined:					
Income from continuing operations before income taxes	$ 240,235	$ 210,526	$ 254,520	$ 206,992	$ 125,795
Adjust for distributed income of equity investees	1,330	(6,797)	4,812	7,704	(8,993)
Fixed charges, as below	93,409	90,012	90,236	87,635	86,758
Total earnings, as defined	$ 334,974	$ 293,741	$ 349,568	$ 302,331	$ 203,560
Fixed charges, as defined:					
Interest charges [1]	$ 91,978	$ 88,265	$ 88,695	$ 85,799	$ 85,097
Rental interest factor	1,431	1,747	1,541	1,836	1,661
Total fixed charges, as defined	$ 93,409	$ 90,012	$ 90,236	$ 87,635	$ 86,758
Ratio of earnings to fixed charges	3.59x	3.26x	3.87x	3.45x	2.35x
SUPPLEMENTAL RATIO OF EARNINGS TO FIXED CHARGES					
Earnings, as defined:					
Income from continuing operations before income taxes	$ 240,235	$ 210,526	$ 254,520	$ 206,992	$ 125,795
Adjust for distributed income of equity investees	1,330	(6,797)	4,812	7,704	(8,993)
Supplemental fixed charges, as below	93,651	90,356	90,741	88,266	87,544
Total earnings, as defined	$ 335,216	$ 294,085	$ 350,073	$ 302,962	$ 204,346
Supplemental fixed charges:					
Interest charges [1]	$ 91,978	$ 88,265	$ 88,695	$ 85,799	$ 85,097
Rental interest factor	1,431	1,747	1,541	1,836	1,661
Supplemental increment to fixed charges [2]	242	344	505	631	786
Total supplemental fixed charges	$ 93,651	$ 90,356	$ 90,741	$ 88,266	$ 87,544
Supplemental ratio of earnings to fixed charges	3.58x	3.25x	3.86x	3.43x	2.33x

[1] FIN 48 interest is not included in interest charges.

[2] Explanation of increment - Interest on the guaranty of American Falls Reservoir District bonds and Milner Dam, Inc. notes which are already included in operation expenses.

EXHIBIT IV

Exhibit 12.2

Idaho Power Company
Consolidated Financial Information
Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
(Thousands of Dollars)

	Twelve Months Ended December 31, 2015	2014	2013	2012	2011
RATIO OF EARNINGS TO FIXED CHARGES					
Earnings, as defined:					
Income from continuing operations before income taxes	$ 239,211	$ 208,903	$ 253,001	$ 204,138	$ 123,351
Adjust for distributed income of equity investees	1,060	(7,228)	4,659	8,509	(9,018)
Fixed charges, as below	93,164	89,751	89,819	87,162	86,249
Total earnings, as defined	$ 333,435	$ 291,426	$ 347,479	$ 299,809	$ 200,582
Fixed charges, as defined:					
Interest charges [1]	$ 91,762	$ 88,034	$ 88,309	$ 85,359	$ 84,626
Rental interest factor	1,402	1,717	1,510	1,803	1,623
Total fixed charges, as defined	$ 93,164	$ 89,751	$ 89,819	$ 87,162	$ 86,249
Ratio of earnings to fixed charges	3.58x	3.25x	3.87x	3.44x	2.33x
SUPPLEMENTAL RATIO OF EARNINGS TO FIXED CHARGES					
Earnings, as defined:					
Income from continuing operations before income taxes	$ 239,211	$ 208,903	$ 253,001	$ 204,138	$ 123,351
Adjust for distributed income of equity investees	1,060	(7,228)	4,659	8,509	(9,018)
Supplemental fixed charges, as below	93,406	90,095	90,324	87,793	87,035
Total earnings, as defined	$ 333,677	$ 291,770	$ 347,984	$ 300,440	$ 201,368
Supplemental fixed charges:					
Interest charges [1]	$ 91,762	$ 88,034	$ 88,309	$ 85,359	$ 84,626
Rental interest factor	1,402	1,717	1,510	1,803	1,623
Supplemental increment to fixed charges [2]	242	344	505	631	786
Total supplemental fixed charges	$ 93,406	$ 90,095	$ 90,324	$ 87,793	$ 87,035
Supplemental ratio of earnings to fixed charges	3.57x	3.24x	3.85x	3.42x	2.31x

[1] FIN 48 interest is not included in interest charges.

[2] Explanation of increment - Interest on the guaranty of American Falls Reservoir District bonds and Milner Dam, Inc. notes which are already included in operation expenses.

EXHIBIT IV

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-200399 and 333-188768 on Form S-3 and Registration Statement Nos. 333-65406, 333-125259, 333-143404, and 333-159855 on Form S-8 of our reports dated February 18, 2016 , relating to the consolidated financial statements and financial statement schedules of IDACORP, Inc. (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company’s change in the method of presentation for deferred income taxes), and the effectiveness of IDACORP, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of IDACORP, Inc. for the year ended December 31, 2015 .

/s/ DELOITTE & TOUCHE LLP
Boise, Idaho
February 18, 2016

EXHIBIT IV

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-188768-01 on Form S-3 and Registration Statement No. 333-66496 on Form S-8 of our reports dated February 18, 2016 , relating to the consolidated financial statements and financial statement schedule of Idaho Power Company (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company’s change in the method of presentation for deferred income taxes), and the effectiveness of Idaho Power Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Idaho Power Company for the year ended December 31, 2015 .

/s/ DELOITTE & TOUCHE LLP
Boise, Idaho
February 18, 2016

EXHIBIT IV

Exhibit 31.1

CERTIFICATION

I, Darrel T. Anderson, certify that:

1. I have reviewed this Annual Report on Form 10-K of IDACORP, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

By: */s/ Darrel T. Anderson*

Darrel T. Anderson

President and Chief Executive Officer

EXHIBIT IV

Exhibit 31.2

CERTIFICATION

I, Steven R. Keen, certify that:

1. I have reviewed this Annual Report on Form 10-K of IDACORP, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

By: */s/ Steven R. Keen*
Steven R. Keen
Senior Vice President, Chief Financial Officer, and Treasurer

EXHIBIT IV

Exhibit 31.3

CERTIFICATION

I, Darrel T. Anderson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Idaho Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

By: */s/ Darrel T. Anderson*

Darrel T. Anderson

President and Chief Executive Officer

EXHIBIT IV

Exhibit 31.4

CERTIFICATION

I, Steven R. Keen, certify that:

1. I have reviewed this Annual Report on Form 10-K of Idaho Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

By: */s/ Steven R. Keen*

Steven R. Keen

Senior Vice President, Chief Financial Officer, and Treasurer

EXHIBIT IV

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of IDACORP, Inc. (the "Company") on Form 10-K for the year ended December 31, 2015 (the "Report"), I, Darrel T. Anderson, President and Chief Executive Officer of the Company, certify that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Darrel T. Anderson

Darrel T. Anderson
President and Chief Executive Officer
February 18, 2016

EXHIBIT IV

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of IDACORP, Inc. (the "Company") on Form 10-K for the year ended December 31, 2015 (the "Report"), I, Steven R. Keen, Senior Vice President, Chief Financial Officer, and Treasurer of the Company, certify that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven R. Keen

Steven R. Keen
Senior Vice President, Chief Financial Officer, and Treasurer
February 18, 2016

EXHIBIT IV

Exhibit 32.3

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Idaho Power Company (the "Company") on Form 10-K for the year ended December 31, 2015 (the "Report"), I, Darrel T. Anderson, President and Chief Executive Officer of the Company, certify that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Darrel T. Anderson

Darrel T. Anderson
President and Chief Executive Officer
February 18, 2016

EXHIBIT IV

Exhibit 32.4

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Idaho Power Company (the "Company") on Form 10-K for the year ended December 31, 2015 (the "Report"), I, Steven R. Keen, Senior Vice President, Chief Financial Officer, and Treasurer of the Company, certify that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven R. Keen

Steven R. Keen
Senior Vice President, Chief Financial Officer, and Treasurer
February 18, 2016

EXHIBIT IV

Exhibit 95.1

Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

Idaho Power is the parent company of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines coal at the Bridger Coal Mine and processing facility (Mine) near Rock Springs, Wyoming. IERCo owns a one-third interest in BCC. The Mine is comprised of the Bridger surface and underground operations. Day-to-day operation and management of coal mining and processing operations at the Mine are conducted through IERCo's joint venture partner. Operation of the Mine is regulated by the Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). MSHA inspects the Mine on a regular basis and may issue citations, notices, orders, or any combination thereof, when it believes a violation has occurred under the Mine Safety Act. Monetary penalties are assessed by MSHA for citations. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether BCC has challenged or appealed the matter.

The table below summarizes the number of citations, notices, and orders issued, and penalties assessed, by MSHA for the Mine under the indicated provisions of the Mine Safety Act, and other data for the Mine, during the year ended December 31, 2015 . Legal actions pending before the Federal Mine Safety and Health Review Commission (FMSHRC) are as of December 31, 2015 .

	Twelve-month period ended December 31, 2015 (unaudited)	
	(surface)	(underground)
Mine Safety Act Citations and Orders:		
Section 104(a) Significant & Substantial Citations [1]	7	34
Section 104(b) Orders [2]	—	—
Section 104(d) Citations & Orders [3]	1	—
Section 107(a) Imminent Danger Orders [4]	—	1
Total Value of Proposed MSHA Assessments (in thousands)	$ 224	$ 176
Legal Actions Pending [5]	6	5
Legal Actions Issued During Period	5	10
Legal Actions Closed During Period	2	16
Number of Fatalities	—	—

(1) For alleged violations of a mandatory mining safety standard or regulation where such violation contributed to a discrete safety hazard and there exists a reasonable likelihood that the hazard will result in an injury or illness and there is a reasonable likelihood that such injury will be of a reasonably serious nature.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation or as subsequently extended.

(3) For an alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mining safety standard or regulation.

(4) The existence of any condition or practice in a coal or other mine that could reasonably be expected to cause death or serious physical harm if normal mining operations were permitted to proceed in the area before such condition or practice is eliminated.

(5) For the surface mine, two of the pending legal actions as of December 31, 2015 were categorized as contests of citations or orders under Subpart B of the FMSHRC Procedural Rules and four of the pending legal actions were categorized as contests of proposed civil penalties for violations contained in a citation or order under Subpart C of the FMSHRC Procedural Rules. For the underground mine, the five pending legal actions were categorized as contests of proposed civil penalties for violations contained in a citation or order under Subpart C of the FMSHRC Procedural Rules.

For the year ended December 31, 2015 , the Mine did not receive written notice from MSHA of (i) a flagrant violation under Section 110(b)(2) of the Mine Safety Act; (ii) a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act; or (iii) the potential to have such a pattern.

EXHIBIT V

EXHIBIT V

IDACORP, Inc. Consolidated Balance Sheets
Side-By-Side Format
Assets
December 31, 2016

	Idaho Power Consolidated Total	IDACORP	**I27-IdaCorp** Energy	**I30** Ida-West	**I46** IFS	**Total** Eliminations	**IDACORP** Consolidated
CURRENT ASSETS:							
Cash and cash equivalents	44,140,435	15,119,416	-	2,220,192	-	-	61,480,043
Receivables:							
Customer (net of allowance of $968K)	71,557,287	-	7,600,000	-	-	-	79,157,287
Other (net of allowance of $164K)	7,555,337	2,024,578	-	963,489	17,121,281	(19,984,273)	7,680,412
Income taxes receivable	-					-	-
Accrued unbilled revenues	80,738,420	-	-	-	-	-	80,738,420
Materials and supplies (at average cost)	57,858,481	-	-	-	-	-	57,858,481
Fuel stock (at average cost)	53,697,819	-	-	-	-	-	53,697,819
Prepayments	18,269,814	100,527	-	18,702	-	-	18,389,043
Deferred income taxes	-	-	-	-	-	-	-
Current regulatory assets	-	-	-	-	-	-	-
Other	5,960,847	-	-	-	-	-	5,960,847
Total current assets	339,778,441	17,244,521	7,600,000	3,202,383	17,121,281	(19,984,273)	364,962,353
INVESTMENTS	106,307,831	2,098,818,486	-	11,213,284	7,642,623	(2,098,818,487)	125,163,737
PROPERTY, PLANT AND EQUIPMENT:							
Utility plant in service	5,732,043,843	-	-	-	-	-	5,732,043,843
Accumulated provision for depreciation	(1,988,476,659)	-	-	-	-	-	(1,988,476,659)
Utility plant in service - net	3,743,567,184	-	-	-	-	-	3,743,567,184
Contsruction work in progress	405,068,524	-	-	-	-	-	405,068,524
Utility plant held for future use	7,440,603	-	-	-	-	-	7,440,603
Other property, net of accumulated depreciation	1,071,638	-	-	14,850,477	-	-	15,922,115
Property, plant and equipment - net	4,157,147,950	-	-	14,850,477	-	-	4,171,998,426
OTHER ASSETS:							
American Falls and Milner water rights	9,486,540	-	-	-	-	-	9,486,540
Company-owned life insurance	57,553,158	-	-	-	-	-	57,553,158
Regulatory assets	1,466,388,842	-	-	-	-	-	1,466,388,842
Long-term receivables	19,677,477	-	-	3,804,354	-	-	23,481,831
Other	51,559,134	385,628	-	624,708	-	-	52,569,470
Total other assets	1,604,665,152	385,628	-	4,429,062	-	-	1,609,479,842
Total Assets	6,207,899,373	2,116,448,635	7,600,000	33,695,205	24,763,903	(2,118,802,759)	6,271,604,358

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EXHIBIT V

IDACORP, Inc. Consolidated Balance Sheets
Side-By-Side Format
Liabilities & Shareholders' Equity
December 31, 2016

	Idaho Power Consolidated Total	IDACORP	**I27-IdaCorp** Energy	**I30** Ida-West	**I46** IFS	**Total** Eliminations	Consolidated
CURRENT LIABILITIES:							
Current maturities of long-term debt	1,063,637	-	-	-	(0)	-	1,063,637
Notes payable	21,800,000	17,833,632	-	-	-	(17,833,632)	21,800,000
Accounts payable	106,902,215	965,769	302,495	144,022	30,362	(2,150,640)	106,194,222
Taxes accrued	(11,986,424)	8,476,105	2,482,585	(361,601)	(43,944)	-	(1,433,279)
Interest accrued	22,376,595	-	-	-	-	-	22,376,595
Accrued compensation	45,622,169	-	-	152,113	12,500	-	45,786,782
Current regulatory liabilities	7,831,417	-	-	-	-	-	7,831,417
Advances from customers	21,438,149	-	-	-	-	-	21,438,149
Other	9,102,868	659,994	-	-	-	-	9,762,862
Total current liabilities	224,150,625	27,935,501	2,785,080	(65,466)	(1,082)	(19,984,273)	234,820,384
OTHER LIABILITIES:							
Deferred income taxes	1,351,415,102	(66,410,650)	-	6,816,826	(47,571,481)	-	1,244,249,797
Regulatory liabilities	433,447,882	-	-	-	-	-	433,447,882
Pension and other postretirement benefits	411,522,731	-	-	-	-	-	411,522,731
Other	44,045,838	1,017,500	-	-	20,223	-	45,083,560
Total other liabilities	2,240,431,553	(65,393,150)	-	6,816,826	(47,551,258)	-	2,134,303,970
LONG-TERM DEBT	1,744,613,969	-	-	-	0	-	1,744,613,969
COMMITMENTS AND CONTINGENCIES							
SHAREHOLDERS' EQUITY:							
IDACORP Inc. shareholders equity							
Common stock, no par value (shares authorized 120,000,000 50,420,017 shares issued)	808,037,541	851,833,010	4,478,325	20,000,000	6,500,000	(839,015,866)	851,833,010
Retained earnings	1,211,547,306	1,323,197,555	336,595	2,984,096	65,816,244	(1,280,684,241)	1,323,197,555
Accumulated other comprehensive income (loss)	(20,881,620)	(20,881,620)	-	-	-	20,881,620	(20,881,620)
Treasury Stock (23,244 shares at cost)	-	(242,660)	-	-	-	-	(242,660)
Total IDACORP, Inc. shareholders' equity	1,998,703,227	2,153,906,285	4,814,920	22,984,096	72,316,244	(2,098,818,487)	2,153,906,285
Noncontrolling interest	-	-	-	3,959,749	-	-	3,959,749
Total shareholders' equity	1,998,703,227	2,153,906,285	4,814,920	26,943,845	72,316,244	(2,098,818,487)	2,157,866,034
							-
TOTAL	6,207,899,373	2,116,448,635	7,600,000	33,695,205	24,763,903	(2,118,802,759)	6,271,604,358

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EXHIBIT V

IDACORP, Inc. Consolidated Balance Sheets
Side-By-Side Format
Assets
December 31, 2016

	Idaho Power	I15 IERCO	Eliminations	**Idaho Power** Consolidated Total
CURRENT ASSETS:				
Cash and cash equivalents	44,140,435	-	-	44,140,435
Receivables:				
Customer (net of allowance of $968K)	71,557,287	-	-	71,557,287
Other (net of allowance of $164K)	7,555,337	244,435	(244,435)	7,555,337
Income taxes receivable				-
Accrued unbilled revenues	80,738,420	-	-	80,738,420
Materials and supplies (at average cost)	57,858,481	-	-	57,858,481
Fuel stock (at average cost)	53,697,819	-	-	53,697,819
Prepayments	18,269,814	-	-	18,269,814
Deferred income taxes	-	-	-	-
Current regulatory assets	-	-	-	-
Other	5,960,847	-	-	5,960,847
Total current assets	339,778,441	244,435	(244,435)	339,778,441
INVESTMENTS	101,139,883	82,298,875	(77,130,927)	106,307,831
PROPERTY, PLANT AND EQUIPMENT:				
Utility plant in service	5,732,043,843	-	-	5,732,043,843
Accumulated provision for depreciation	(2,175,085,495)	-	186,608,837	(1,988,476,659)
Utility plant in service - net	3,556,958,348	-	186,608,837	3,743,567,184
Contsruction work in progress	405,068,524	-	-	405,068,524
Utility plant held for future use	7,440,603	-	-	7,440,603
Other property, net of accumulated depreciation	1,071,638	-	-	1,071,638
Property, plant and equipment - net	3,970,539,113	-	186,608,837	4,157,147,950
OTHER ASSETS:				
American Falls and Milner water rights	9,486,540	-	-	9,486,540
Company-owned life insurance	57,553,158	-	-	57,553,158
Regulatory assets	1,466,388,842	-	-	1,466,388,842
Long-term receivables	19,677,477	-	-	19,677,477
Other	51,559,134	-	-	51,559,134
Total other assets	1,604,665,152	-	-	1,604,665,152
Total Assets	6,016,122,588	82,543,310	109,233,475	6,207,899,373

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EXHIBIT V

IDACORP, Inc. Consolidated Balance Sheets
Side-By-Side Format
Liabilities & Shareholders' Equity
December 31, 2016

	Idaho Power	I15 IERCO	Eliminations	**Idaho Power** Consolidated Total
CURRENT LIABILITIES:				
Current maturities of long-term debt	1,063,637	-	-	1,063,637
Notes payable	22,044,435	-	(244,435)	21,800,000
Accounts payable	106,902,215	-	-	106,902,215
Taxes accrued	(11,945,257)	(41,167)	-	(11,986,424)
Interest accrued	22,376,595	-	-	22,376,595
Accrued compensation	45,622,169	-	-	45,622,169
Current regulatory liabilities	7,831,417	-	-	7,831,417
Advances from customers	21,438,149	-	-	21,438,149
Other	9,102,868	-	-	9,102,868
Total current liabilities	224,436,226	(41,167)	(244,435)	224,150,625
OTHER LIABILITIES:				
Deferred income taxes	1,345,961,552	5,453,550	-	1,351,415,102
Regulatory liabilities	246,839,045	-	186,608,837	433,447,882
Pension and other postretirement benefits	411,522,731	-	-	411,522,731
Other	44,045,838	-	-	44,045,838
Total other liabilities	2,048,369,166	5,453,550	186,608,837	2,240,431,553
LONG-TERM DEBT	1,744,613,969	-	-	1,744,613,969
COMMITMENTS AND CONTINGENCIES				
SHAREHOLDERS' EQUITY:				
IDACORP Inc. shareholders equity				
Common stock, no par value (shares authorized 120,000,000; 50,420,017 shares issued)	808,037,541	2,463,094	(2,463,094)	808,037,541
Retained earnings	1,211,547,306	74,667,833	(74,667,833)	1,211,547,306
Accumulated other comprehensive income (loss)	(20,881,620)	-	-	(20,881,620)
Treasury Stock (23,244 shares at cost)	-	-	-	-
Total IDACORP, Inc. shareholders' equity	1,998,703,227	77,130,927	(77,130,927)	1,998,703,227
Noncontrolling interest	-	-	-	-
Total shareholders' equity	1,998,703,227	77,130,927	(77,130,927)	1,998,703,227
TOTAL	6,016,122,588	82,543,310	109,233,475	6,207,899,373

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EXHIBIT VI

EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Month of December 31, 2016				
	Idaho Power	I15 IERCO	Total Idaho Power	ELM Elimination	Idaho Power Consolidated Total
Operating Revenues:					
Electric utility:					
General business	104,959,098	-	104,959,098	-	104,959,098
Off-system sales	3,591,330	-	3,591,330	-	3,591,330
Other revenues	9,188,369	-	9,188,369	-	9,188,369
Total electric utility revenues	117,738,798	-	117,738,798	-	117,738,798
Other	2,529	-	2,529	-	2,529
Total operating revenues	117,741,327	-	117,741,327	-	117,741,327
Operating Expenses:					
Electric utility:					
Purchased power	29,869,328	-	29,869,328	-	29,869,328
Fuel expense	17,368,668	-	17,368,668	-	17,368,668
Power cost adjustment	(8,509,977)	-	(8,509,977)	-	(8,509,977)
Other operations and maintenance	37,704,102	-	37,704,102	-	37,704,102
Energy efficiency programs	4,552,152	-	4,552,152	-	4,552,152
Depreciation	12,112,776	-	12,112,776	-	12,112,776
Taxes other than income taxes	2,184,255	-	2,184,255	-	2,184,255
Total electric utility expenses	95,281,304	-	95,281,304	-	95,281,304
Other	1,054,563	-	1,054,563	-	1,054,563
Total operating expenses	96,335,867	-	96,335,867	-	96,335,867
Operating Income	21,405,459	-	21,405,459	-	21,405,459
Other Income, Net	1,893,569	9,357	1,902,926	(761,554)	1,141,373
Allowance for equity funds used during construction	1,766,179	-	1,766,179	-	1,766,179
Earnings (Losses) of Unconsolidated Equity-Method Investments	-	909,403	909,403	-	909,403
Interest Expense:					
Interest on long-term debt	6,766,654	-	6,766,654	-	6,766,654
Other interest	917,658	-	917,658	(9,357)	908,301
Allowance for borrowed funds used during construction	(1,196,442)	-	(1,196,442)	-	(1,196,442)
Total interest expense, net	6,487,870	-	6,487,870	(9,357)	6,478,513
Income Before Income Taxes	18,577,338	918,760	19,496,097	(752,197)	18,743,901
Income Tax (Benefit) Expense	4,036,445	166,563	4,203,008	-	4,203,008
Net Income	14,540,893	752,197	15,293,090	(752,197)	14,540,893
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	-	-
Net Income attributable to IDACORP, Inc.	14,540,893	752,197	15,293,090	(752,197)	14,540,893
Weighted Average Common Shares Outstanding - Basic (000's)	50,296	50,296	50,296	50,296	50,296
Earnings Per Share of Common Stock:					
Earnings Attributable to IDACORP, Inc. - Basic	$ 0.29	$ 0.01	$ 0.30	$ (0.01)	$ 0.29
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	21.73%	18.13%	21.56%	0.00%	22.42%

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EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Month of December 31, 2016						
	Idaho Power Consolidated Total	IDACORP	I27 IDACORP Energy	I30 Ida-West	I46 IFS	Total Subsidiary Elimination	Consolidated IDACORP
Operating Revenues:							
Electric utility:							
General business	104,959,098	-	-	-	-	-	104,959,098
Off-system sales	3,591,330	-	-	-	-	-	3,591,330
Other revenues	9,188,369	-	-	-	-	-	9,188,369
Total electric utility revenues	117,738,798	-	-	-	-	-	117,738,798
Other	2,529	-	-	138,015	-	-	140,543
Total operating revenues	117,741,327	-	-	138,015	-	-	117,879,341
Operating Expenses:							
Electric utility:							
Purchased power	29,869,328	-	-	-	-	-	29,869,328
Fuel expense	17,368,668	-	-	-	-	-	17,368,668
Power cost adjustment	(8,509,977)	-	-	-	-	-	(8,509,977)
Other operations and maintenance	37,704,102	-	-	-	-	-	37,704,102
Energy efficiency programs	4,552,152	-	-	-	-	-	4,552,152
Depreciation	12,112,776	-	-	-	-	-	12,112,776
Taxes other than income taxes	2,184,255	-	-	-	-	-	2,184,255
Total electric utility expenses	95,281,304	-	-	-	-	-	95,281,304
Other	1,054,563	126,224	(6,221,040)	190,741	12,862	-	(4,836,650)
Total operating expenses	96,335,867	126,224	(6,221,040)	190,741	12,862	-	90,444,655
Operating Income	21,405,459	(126,224)	6,221,040	(52,727)	(12,862)	-	27,434,687
Other Income, Net	1,141,373	18,673,211	-	1,176	5,351	(18,678,176)	1,142,935
Allowance for equity funds used during construction	1,766,179	-	-	-	-	-	1,766,179
Earnings (Losses) of Unconsolidated Equity-Method Investments	909,403	-	-	1,468	-	-	910,870
Interest Expense:							
Interest on long-term debt	6,766,654	-	-	-	-	-	6,766,654
Other interest	908,301	12,171	-	-	304	(6,215)	914,561
Allowance for borrowed funds used during construction	(1,196,442)	-	-	-	-	-	(1,196,442)
Total interest expense, net	6,478,513	12,171	-	-	304	(6,215)	6,484,773
Income Before Income Taxes	18,743,901	18,534,816	6,221,040	(50,083)	(7,815)	(18,671,961)	24,769,898
Income Tax (Benefit) Expense	4,203,008	(293,905)	2,468,882	(29,463)	(329,083)	-	6,019,439
Net Income	14,540,893	18,828,721	3,752,158	(20,620)	321,268	(18,671,961)	18,750,459
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	78,261	-	-	78,261
Net Income attributable to IDACORP, Inc.	14,540,893	18,828,721	3,752,158	57,642	321,268	(18,671,961)	18,828,721
Weighted Average Common Shares Outstanding - Basic (000's)	50,296	50,296	50,296	50,296	50,296	50,296	50,296
Earnings Per Share of Common Stock:							
Earnings Attributable to IDACORP, Inc. - Basic	$ 0.29	$ 0.37	$ 0.07	$ 0.00	$ 0.01	$ (0.37)	$ 0.37
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	22.42%	-1.59%	39.69%	-104.56%	4210.99%	0.00%	24.22%

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EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Three Months Ended December 31				
	Idaho Power	I15 IERCO	Total Idaho Power	ELM Elimination	Idaho Power Consolidated Total
Operating Revenues:					
Electric utility:					
General business	260,506,800	-	260,506,800	-	260,506,800
Off-system sales	8,672,628	-	8,672,628	-	8,672,628
Other revenues	23,722,244	-	23,722,244	-	23,722,244
Total electric utility revenues	292,901,672	-	292,901,672	-	292,901,672
Other	7,415	-	7,415	-	7,415
Total operating revenues	292,909,087	-	292,909,087	-	292,909,087
Operating Expenses:					
Electric utility:					
Purchased power	75,089,162	-	75,089,162	-	75,089,162
Fuel expense	39,833,726	-	39,833,726	-	39,833,726
Power cost adjustment	(17,244,449)	-	(17,244,449)	-	(17,244,449)
Other operations and maintenance	92,080,796	-	92,080,796	-	92,080,796
Energy efficiency programs	9,498,134	-	9,498,134	-	9,498,134
Depreciation	36,213,615	-	36,213,615	-	36,213,615
Taxes other than income taxes	7,595,770	-	7,595,770	-	7,595,770
Total electric utility expenses	243,066,753	-	243,066,753	-	243,066,753
Other	2,902,974	-	2,902,974	-	2,902,974
Total operating expenses	245,969,728	-	245,969,728	-	245,969,728
Operating Income	46,939,359	-	46,939,359	-	46,939,359
Other Income, Net	2,529,970	21,569	2,551,539	246,958	2,798,498
Allowance for equity funds used during construction	5,877,340	-	5,877,340	-	5,877,340
Earnings (Losses) of Unconsolidated Equity-Method Investments	-	(673,154)	(673,154)	-	(673,154)
Interest Expense:					
Interest on long-term debt	20,297,308	-	20,297,308	-	20,297,308
Other interest	2,673,118	-	2,673,118	(21,569)	2,651,549
Allowance for borrowed funds used during construction	(2,967,483)	-	(2,967,483)	-	(2,967,483)
Total interest expense, net	20,002,942	-	20,002,942	(21,569)	19,981,373
Income Before Income Taxes	35,343,727	(651,585)	34,692,142	268,527	34,960,669
Income Tax (Benefit) Expense	4,913,557	(383,058)	4,530,499	1,557,943	6,088,442
Net Income	30,430,170	(268,527)	30,161,643	(1,289,416)	28,872,227
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	-	-
Net Income attributable to IDACORP, Inc.	30,430,170	(268,527)	30,161,643	(1,289,416)	28,872,227
Weighted Average Common Shares Outstanding - Basic (000's)	50,296	50,296	50,296	50,296	50,296
Earnings Per Share of Common Stock:					
Earnings Attributable to IDACORP, Inc. - Basic	$ 0.61	$ (0.01)	$ 0.60	$ (0.03)	$ 0.57
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	13.90%	58.79%	13.06%	580.18%	17.42%

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EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Idaho Power Consolidated Total	IdaCorp	I27-Idacorp Energy	I30 Ida -West	I46 IFS	Eliminate Totals	Consolidated IdaCorp
	Three Months Ended December 31						
Operating Revenues:							
Electric utility:							
General business	260,506,800	-	-	-	-	-	260,506,800
Off-system sales	8,672,628	-	-	-	-	-	8,672,628
Other revenues	23,722,244	-	-	-	-	-	23,722,244
Total electric utility revenues	292,901,672	-	-	-	-	-	292,901,672
Other	7,415	-	-	674,033	-	-	681,448
Total operating revenues	292,909,087	-	-	674,033	-	-	293,583,120
Operating Expenses:							
Electric utility:							
Purchased power	75,089,162	-	-	-	-	-	75,089,162
Fuel expense	39,833,726	-	-	-	-	-	39,833,726
Power cost adjustment	(17,244,449)	-	-	-	-	-	(17,244,449)
Other operations and maintenance	92,080,796	-	-	-	-	-	92,080,796
Energy efficiency programs	9,498,134	-	-	-	-	-	9,498,134
Depreciation	36,213,615	-	-	-	-	-	36,213,615
Taxes other than income taxes	7,595,770	-	-	-	-	-	7,595,770
Total electric utility expenses	243,066,753	-	-	-	-	-	243,066,753
Other	2,902,974	264,795	(6,201,695)	452,677	20,793	-	(2,560,457)
Total operating expenses	245,969,728	264,795	(6,201,695)	452,677	20,793	-	240,506,296
Operating Income	46,939,359	(264,795)	6,201,695	221,357	(20,793)	-	53,076,824
Other Income, Net	2,798,498	34,721,162	-	3,154	14,034	(34,736,224)	2,800,624
Allowance for equity funds used during construction	5,877,340	-	-	-	-	-	5,877,340
Earnings (Losses) of Unconsolidated Equity-Method Investments	(673,154)	-	-	(105,644)	-	-	(778,798)
Interest Expense:							
Interest on long-term debt	20,297,308	-	-	-	-	-	20,297,308
Other interest	2,651,549	48,932	-	-	885	(16,311)	2,685,054
Allowance for borrowed funds used during construction	(2,967,483)	-	-	-	-	-	(2,967,483)
Total interest expense, net	19,981,373	48,932	-	-	885	(16,311)	20,014,879
Income Before Income Taxes	34,960,669	34,407,436	6,201,695	118,867	(7,644)	(34,719,912)	40,961,111
Income Tax (Benefit) Expense	6,088,442	(363,705)	2,468,882	30,414	(417,019)	-	7,807,014
Net Income	28,872,227	34,771,141	3,732,813	88,453	409,375	(34,719,912)	33,154,097
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	59,101	-	-	59,101
Net Income attributable to IDACORP, Inc.	28,872,227	34,771,141	3,732,813	147,554	409,375	(34,719,912)	33,213,198
Weighted Average Common Shares Outstanding - Basic (000's)	50,296	50,296	50,296	50,296	50,296	50,296	50,296
Earnings Per Share of Common Stock:							
Earnings Attributable to IDACORP, Inc. - Basic	$ 0.57	$ 0.69	$ 0.07	$ 0.00	$ 0.01	$ (0.69)	$ 0.66
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	17.42%	-1.06%	39.81%	17.09%	5455.52%	0.00%	19.03%

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EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Year-To-Date Ended December 31				
	Idaho Power	I15 IERCO	Total Idaho Power	ELM Elimination	Idaho Power Consolidated Total
Operating Revenues:					
Electric utility:					
General business	1,145,993,172	-	1,145,993,172	-	1,145,993,172
Off-system sales	25,204,985	-	25,204,985	-	25,204,985
Other revenues	88,154,862	-	88,154,862	-	88,154,862
Total electric utility revenues	1,259,353,019	-	1,259,353,019	-	1,259,353,019
Other	31,177	-	31,177	-	31,177
Total operating revenues	1,259,384,196	-	1,259,384,196	-	1,259,384,196
Operating Expenses:					
Electric utility:					
Purchased power	245,763,849	-	245,763,849	-	245,763,849
Fuel expense	179,491,004	-	179,491,004	-	179,491,004
Power cost adjustment	(5,330,167)	-	(5,330,167)	-	(5,330,167)
Other operations and maintenance	351,893,518	-	351,893,518	-	351,893,518
Energy efficiency programs	33,754,061	-	33,754,061	-	33,754,061
Depreciation	143,660,733	-	143,660,733	-	143,660,733
Taxes other than income taxes	32,823,311	-	32,823,311	-	32,823,311
Total electric utility expenses	982,056,309	-	982,056,309	-	982,056,309
Other	11,837,035	-	11,837,035	-	11,837,035
Total operating expenses	993,893,344	-	993,893,344	-	993,893,344
Operating Income	265,490,851	-	265,490,851	-	265,490,851
Other Income, Net	17,862,455	27,285	17,889,741	(8,027,267)	9,862,474
Allowance for equity funds used during construction	22,030,622	-	22,030,622	-	22,030,622
Earnings (Losses) of Unconsolidated Equity-Method Investments	-	10,855,271	10,855,271	-	10,855,271
Interest Expense:					
Interest on long-term debt	81,956,468	-	81,956,468	-	81,956,468
Other interest	10,076,716	6,119	10,082,835	(33,741)	10,049,094
Allowance for borrowed funds used during construction	(10,193,622)	-	(10,193,622)	-	(10,193,622)
Total interest expense, net	81,839,562	6,119	81,845,681	(33,741)	81,811,940
Income Before Income Taxes	223,544,367	10,876,438	234,420,804	(7,993,526)	226,427,279
Income Tax (Benefit) Expense	34,302,445	2,882,912	37,185,357	-	37,185,357
Net Income	189,241,922	7,993,526	197,235,447	(7,993,526)	189,241,922
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	-	-
Net Income attributable to IDACORP, Inc.	189,241,922	7,993,526	197,235,447	(7,993,526)	189,241,922
Weighted Average Common Shares Outstanding - Basic (000's)	50,298	50,298	50,298	50,298	50,298
Earnings Per Share of Common Stock:					
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.76	$ 0.16	$ 3.92	$ (0.16)	$ 3.76
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	15.34%	26.51%	15.86%	0.00%	16.42%

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EXHIBIT VI

IDACORP, Inc.
Consolidated Statements of Income
Month of December 31, 2016

	Year-To-Date Ended December 31						
	Idaho Power Consolidated Total	IdaCorp	I27-Idacorp Energy	I30 Ida -West	I46 IFS	Eliminate Totals	Consolidated IdaCorp
Operating Revenues:							
Electric utility:							
General business	1,145,993,172	-	-	-	-	-	1,145,993,172
Off-system sales	25,204,985	-	-	-	-	-	25,204,985
Other revenues	88,154,862	-	-	-	-	-	88,154,862
Total electric utility revenues	1,259,353,019	-	-	-	-	-	1,259,353,019
Other	31,177	-	-	2,635,822	-	-	2,666,999
Total operating revenues	1,259,384,196	-	-	2,635,822	-	-	1,262,020,017
Operating Expenses:							
Electric utility:							
Purchased power	245,763,849	-	-	-	-	-	245,763,849
Fuel expense	179,491,004	-	-	-	-	-	179,491,004
Power cost adjustment	(5,330,167)	-	-	-	-	-	(5,330,167)
Other operations and maintenance	351,893,518	-	-	-	-	-	351,893,518
Energy efficiency programs	33,754,061	-	-	-	-	-	33,754,061
Depreciation	143,660,733	-	-	-	-	-	143,660,733
Taxes other than income taxes	32,823,311	-	-	-	-	-	32,823,311
Total electric utility expenses	982,056,309	-	-	-	-	-	982,056,309
Other	11,837,035	760,481	(6,098,429)	1,606,843	81,638	-	8,187,569
Total operating expenses	993,893,344	760,481	(6,098,429)	1,606,843	81,638	-	990,243,877
Operating Income	265,490,851	(760,481)	6,098,429	1,028,978	(81,638)	-	271,776,140
Other Income, Net	9,862,474	198,063,850	-	17,940	112,206	(198,181,599)	9,874,871
Allowance for equity funds used during construction	22,030,622	-	-	-	-	-	22,030,622
Earnings (Losses) of Unconsolidated Equity-Method Investments	10,855,271	-	-	2,015,621	-	-	12,870,893
Interest Expense:							
Interest on long-term debt	81,956,468	-	-	-	-	-	81,956,468
Other interest	10,049,094	333,168	-	-	10,594	(120,626)	10,272,230
Allowance for borrowed funds used during construction	(10,193,622)	-	-	-	-	-	(10,193,622)
Total interest expense, net	81,811,940	333,168	-	-	10,594	(120,626)	82,035,076
Income Before Income Taxes	226,427,279	196,970,201	6,098,429	3,062,539	19,974	(198,060,973)	234,517,449
Income Tax (Benefit) Expense	37,185,357	(1,318,263)	2,427,791	1,208,477	(3,073,886)	-	36,429,476
Net Income	189,241,922	198,288,464	3,670,638	1,854,062	3,093,860	(198,060,973)	198,087,973
Adjust for (income) loss attributable to noncontrolling interests	-	-	-	200,491	-	-	200,491
Net Income attributable to IDACORP, Inc.	189,241,922	198,288,464	3,670,638	2,054,554	3,093,860	(198,060,973)	198,288,464
Weighted Average Common Shares Outstanding - Basic (000's)	50,298	50,298	50,298	50,298	50,298	50,298	50,298
Earnings Per Share of Common Stock:							
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.76	$ 3.94	$ 0.07	$ 0.04	$ 0.06	$ (3.94)	$ 3.94
Cumulative Dividend Paid YTD Per Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Annual Dividend Declared Per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Effective Tax Rate	16.42%	-0.67%	39.81%	37.04%	-15389.30%	0.00%	15.52%

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EXHIBIT VII

Idaho Power Company
Cost Allocation Manual
For the Year 2016

Overview

The purpose of Idaho Power Company's (IPC) Cost Allocation Manual is to describe the methodologies for allocating direct, shared service, and indirect costs between IPC and its non-regulated or non-utility affiliates and activities.

- **Transfer Prices** between IPC and IDACORP include direct and incremental costs of Services provided, plus a charge for fixed overhead costs.

- **Direct and Incremental Costs** include labor, materials, purchased services, and miscellaneous expenses incurred in providing Services. Labor costs include a payroll loading factor for payroll taxes and benefits such as leave, health and welfare benefits, and pension.

- **Fixed Overhead Costs** consist of an overhead factor that charges indirect costs of Services based on productive hours available to employees. Indirect costs include administration, building, and information technology (IT) costs to support provided Service labor. The accumulated indirect costs are divided by the annual number of productive work hours to arrive at an overhead rate. The productive work hour calculation includes an allowance for average leave and administrative duties. Fixed overhead costs are applied to direct labor hours of Services provided.

The transfer pricing mechanisms used to charge fully loaded costs associated with IPC and IDACORP employees providing Services are Service Level Agreements, Affiliated Shared Service Charges, and Special Projects. The mechanisms include monthly invoicing and payment.

Non-Regulated Activities and Affiliates

The following is a list of IPC's non-regulated activities:

Senior Management Security Plans
Company-Owned Life Insurance
Executive Deferred Compensation
Corporate Philanthropy
Lobbying, Civic, and Political Contributions
Other Miscellaneous Income and Deductions

The following is a list of IPC's affiliates and subsidiaries that meet the requirements of ORS 757.015:

IDACORP, Inc.
Idaho Energy Resources Company (IERCO)
Ida-West Energy Company
IDACORP Financial Services (IFS)

Labor Allocation Methods

Service Level Agreements - Service Level Agreements control transfer pricing related to ongoing Services provided between IPC and IDACORP. Direct and incremental costs are based on actual current year IPC cost center amounts. Activities that logically relate to a specific Service are analyzed and combined to determine the direct and incremental cost of the Service. Fixed overhead costs as described below are included for distribution to IDACORP. The costs are distributed by a defined measure based on a causal relationship such as activity level, input level, number of participants, resource consumption, or time survey. The various IPC administrative units providing Services to IDACORP prepare an allocation based on one or more of the above measures. The allocations are provided by the cost center manager and are a result of time and/or cost studies based on actual costs of the administrative unit.

Descriptions of Services provided by IPC cost centers and the allocation bases used for Service Level Agreement charges:

- **IT Telephone Support** - IPC telephone support to affiliates includes local dial tone and intercompany dialing, long distance services, and voicemail. The Service charge to the affiliate is based on staffing used to perform telephone support provided by IT management. The Service price is allocated to the affiliate based on its number of users.

- **Record Storage** - IPC provides the storage and management of historical records for its affiliates. The Service includes warehousing, data retrieval, and document retention. The Service charge to the affiliate is based on box counts from Documents Management cost center management.

Affiliated Shared Service Charges – Affiliated Shared Service Charges from IPC to IDACORP include actual direct and incremental costs that arise outside of the scope of the Service Level Agreement. Direct and incremental costs are accumulated, reviewed and approved by IPC cost center managers. An overhead factor is added to direct labor hours as described below.

Basically, the two methods of charging Affiliated Shared Services are direct and allocation. Direct costs are separately identifiable, and allocation costs are those that benefit some or all of the affiliates in the IDACORP holding company structure. Items that are contemplated by this charge-out arrangement include but are not limited to:

- **<u>Direct Costs</u>**
  700 – Treasury Admin
  701 – Finance Admin
  702 – Corporate Controller
  724 – Corporate Tax
  727 – Financial Accounting & Reporting
  745 – Strategic Analysis
  800 – Executives
  801 – Audit Services
  807 – Corporate Communications
  810 – Legal
  829 – President
  830 – Human Resources Admin
  860 – Information Services Administration
  886 – Admin/Corp IT Business Systems

- **<u>Allocation Costs</u>**
  741 – Investor Relations
  742 – Treasury Services
  743 – Insurance Services
  824 – Conduct & SOX
  835 – Health & Disability & Retirement
  837 – Employment
  838 – Compensation & Payroll
  766 – External Reporting
  768 – Corporate Accounting & Reporting
  720 – Cash Management
  722 – Accounts Payable

Special Projects - The Special Projects process accounts for Services provided by IPC to IDACORP that are nonrecurring or unusual, and not included in the Service Level Agreement or Affiliated Shared Service Charge mechanisms. Special Project requests require IPC personnel to complete a bid that is signed by the recipient. A unique work order is established to accumulate associated expenses. When the actual Special Project costs have been reviewed and approved by IPC cost center managers, the total charges are billed to IDACORP on the subsequent monthly invoice, including an overhead factor applied to direct labor hours as discussed below.

Payroll Expenses and Loadings

Payroll expenses and loadings follow the direct charging of labor hours by IPC employees. Components of Indirect Loads and Direct Expenses follow:

- **<u>Indirect Loads</u>** - Includes health (medical, dental, accidental death and dismemberment, life, and employee assistance program costs), FTO (vacation, sick, and personal time-off), pension (includes costs of defined contribution and defined benefit programs), and employee support represents (tuition reimbursement program).

- **Direct Expenses** – Includes payroll taxes (Social Security, Medicare, and federal and state unemployment), cafeteria credits (amounts given to employees to spend on health benefits), and non-FTO charges (holidays, military leave, and jury duty).

Fixed Overhead Allocation

The overhead factor charges indirect costs of Services performed by IPC for IDACORP based on productive hours available to employees. The productive work hour calculation includes an allowance for the prior year's actual average paid time off and a 12% administrative factor. The productive time per employee is calculated annually. Indirect costs are based on prior year IPC actual amounts and include administration, building, and IT costs, which are necessary to support IPC employees in performing their jobs. These indirect costs are divided by the annual number of productive work hours for IPC to arrive at overhead rate applied per labor hour.

Included in the fixed overhead cost calculation are depreciation, property tax, and insurance costs associated with corporate buildings, workstations, IT networks, and personal computers. Cost centers included in the fixed overhead cost calculation:

- **Administration Support**
  743 – Insurance Services
  807 – Corporate Communications
  826 – Corporate Security Admin
  820 – Information Security
  821 – Physical Security
  834 – Corporate Development
  835 – Health, Disability & Retirement
  836 – Employee Relations
  837 – Employment
  838 – Compensation & Payroll

- **Building Support**
  849 – Facilities Maintenance
  854 – Facilities Operations & Construction

- **IT Support**
  841 – Decision Support
  860 – IT Administration
  862 – IT Services
  865 - Records Management
  870 – IT Operations Process Office
  871 – Application & Web Development
  874 – IT Desktop Services
  876 – PMO

EXHIBIT VII

879 – Asset Suite PeopleSoft & HR
880 – IT Operations
882 – IT Service Desk and Operations Center
883 – Enterprise SA and DBA
885 – Operations IT Business Systems
886 – Admin/Corp IT Business Systems
891 – IT Infrastructure Design
892 – IT Infrastructure