REALPAGE INC
Form 10-Q
August 04, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
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: 001-34846

RealPage, Inc.
(Exact name of registrant as specified in its charter)

Delaware	75-2788861
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2201 Lakeside Boulevard Richardson, Texas	75082-4305
(Address of principal executive offices)	(Zip Code)

(972) 820-3000
(Registrant's telephone number, including area code)
Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨
	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	July 21, 2017
Common Stock, $0.001 par value	82,654,544

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements.
RealPage, Inc.
Condensed Consolidated Balance Sheets
(in thousands, except share data)

	June 30, 2017 (unaudited)	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$324,591	$104,886
Restricted cash	106,479	83,654
Accounts receivable, less allowance for doubtful accounts of $2,553 and $2,468 at June 30, 2017 and December 31, 2016, respectively	89,727	92,367
Prepaid expenses	13,293	10,836
Other current assets	6,061	5,712
Total current assets	540,151	297,455
Property, equipment, and software, net	138,241	130,428
Goodwill	359,420	259,938
Identified intangible assets, net	110,318	74,976
Deferred tax assets, net	63,260	15,665
Other assets	10,057	9,636
Total assets	$1,221,447	$788,098
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$24,400	$21,421
Accrued expenses and other current liabilities	53,316	50,464
Current portion of deferred revenue	101,100	89,583
Current portion of term loan	3,833	5,469
Customer deposits held in restricted accounts	106,616	83,590
Total current liabilities	289,265	250,527
Deferred revenue	5,896	6,308
Term loan, net	116,143	116,657
Convertible notes, net	275,673	—
Other long-term liabilities	34,899	29,843
Total liabilities	721,876	403,335
Commitments and contingencies (Note 8)		
Stockholders' equity:		
Preferred stock, $0.001 par value: 10,000,000 shares authorized and zero shares issued and outstanding at June 30, 2017 and December 31, 2016, respectively	—	—
Common stock, $0.001 par value: 125,000,000 shares authorized, 86,801,958 and 86,062,191 shares issued and 82,964,638 and 81,087,353 shares outstanding at June 30, 2017 and December 31, 2016, respectively	87	86
Additional paid-in capital	601,836	534,348
Treasury stock, at cost: 3,837,320 and 4,974,838 shares at June 30, 2017 and December 31, 2016, respectively	(41,364)	(30,358)
Accumulated deficit	(61,015)	(119,260)
Accumulated other comprehensive income (loss)	27	(53)
Total stockholders' equity	499,571	384,763

Total liabilities and stockholders’ equity	$1,221,447	$788,098

See accompanying notes.

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RealPage, Inc.
Condensed Consolidated Statements of Operations
(in thousands, except per share data)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenue:				
On demand	$154,727	$136,610	$300,940	$260,021
On premise	659	687	1,334	1,459
Professional and other	5,920	5,422	11,951	9,622
Total revenue	161,306	142,719	314,225	271,102
Cost of revenue	67,544	62,078	130,586	116,826
Gross profit	93,762	80,641	183,639	154,276
Operating expenses:				
Product development	21,290	18,878	41,677	36,150
Sales and marketing	39,235	35,129	74,382	67,328
General and administrative	27,370	21,932	51,621	40,278
Total operating expenses	87,895	75,939	167,680	143,756
Operating income	5,867	4,702	15,959	10,520
Interest expense and other, net	(2,786)	(1,074)	(3,872)	(1,782)
Income before income taxes	3,081	3,628	12,087	8,738
Income tax (benefit) expense	(3,132)	1,545	(2,321)	3,659
Net income	$6,213	$2,083	$14,408	$5,079
Net income per share attributable to common stockholders:				
Basic	$0.08	$0.03	$0.18	$0.07
Diluted	$0.08	$0.03	$0.18	$0.07
Weighted average shares used in computing net income per share attributable to common stockholders:				
Basic	79,018	76,363	78,642	76,509
Diluted	81,925	77,161	81,644	77,120

See accompanying notes.

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RealPage, Inc.
Condensed Consolidated Statements of Comprehensive Income
(in thousands)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net income	$6,213	$2,083	$14,408	$5,079
(Loss) gain on interest rate swaps, net	(24)	(330)	82	(409)
Foreign currency translation adjustment	48	8	(2)	104
Comprehensive income	$6,237	$1,761	$14,488	$4,774

See accompanying notes.

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RealPage, Inc.
Condensed Consolidated Statements of Stockholders' Equity
(in thousands)
(unaudited)

	Common Stock		Additional Paid-in Capital	Accumulated other comprehensive income (loss)	Accumulated Deficit	Treasury Shares		Total Stockholders' Equity
	Shares	Amount				Shares	Amount	
Balance as of December 31, 2016	86,062	$ 86	$534,348	$ (53)	$(119,260)	(4,975)	$(30,358)	$384,763
Cumulative effect of adoption of ASU 2016-09	—	—	6	—	43,837	—	—	43,843
Issuance of common stock	640	1	13,150	—	—	—	—	13,151
Issuance of restricted stock	100	—	(2)	—	—	1,605	2	—
Treasury stock purchases, at cost	—	—	—	—	—	(467)	(11,008)	(11,008)
Stock-based expense	—	—	23,983	—	—	—	—	23,983
Interest rate swap agreements	—	—	—	73	—	—	—	73
Foreign currency translation	—	—	—	(2)	—	—	—	(2)
Reclassification of realized loss on cash flow hedge to earnings, net of tax	—	—	—	9	—	—	—	9
Equity component of convertible notes, net of issuance costs	—	—	61,401	—	—	—	—	61,401
Purchases of convertible note hedges	—	—	(62,549)	—	—	—	—	(62,549)
Issuance of warrants	—	—	31,499	—	—	—	—	31,499
Net income	—	—	—	—	14,408	—	—	14,408
Balance as of June 30, 2017	86,802	$ 87	$601,836	$ 27	$(61,015)	(3,837)	$(41,364)	$499,571

See accompanying notes.

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RealPage, Inc.
Condensed Consolidated Statements of Cash Flows
(in thousands)
(unaudited)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities:		
Net income	$14,408	$5,079
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	29,533	26,822
Amortization of debt discount and issuance costs	1,424	205
Deferred taxes	(3,088)	2,320
Stock-based expense	23,968	19,128
Loss on disposal and impairment of other long-lived assets	87	85
Acquisition-related consideration	1,024	(251)
Changes in assets and liabilities, net of assets acquired and liabilities assumed in business combinations:		
Accounts receivable	6,631	1,251
Prepaid expenses and other current assets	(1,369)	2,656
Other assets	(464)	(243)
Accounts payable	4,066	62
Accrued compensation, taxes, and benefits	(759)	1,828
Deferred revenue	3,607	(1,229)
Other current and long-term liabilities	1,396	2,888
Net cash provided by operating activities	80,464	60,601
Cash flows from investing activities:		
Purchases of property, equipment, and software	(27,129)	(38,486)
Acquisition of businesses, net of cash acquired	(130,878)	(71,305)
Net cash used in investing activities	(158,007)	(109,791)
Cash flows from financing activities:		
Proceeds from term loan	—	124,688
Payments on term loan	(767)	(781)
Payments on revolving line of credit	—	(40,000)
Proceeds from borrowings on convertible notes	345,000	—
Purchase of convertible note hedges	(62,549)	—
Proceeds from issuance of warrants	31,499	—
Deferred financing costs	(10,755)	(392)
Payments on capital lease obligations	(136)	(426)
Payments of acquisition-related consideration	(7,185)	(2,736)
Issuance of common stock	13,151	8,008
Purchase of treasury stock related to stock-based compensation	(11,008)	(2,179)
Purchase of treasury stock under share repurchase program	—	(21,244)
Net cash provided by financing activities	297,250	64,938
Net increase in cash and cash equivalents	219,707	15,748
Effect of exchange rate on cash	(2)	29
Cash and cash equivalents:		
Beginning of period	104,886	30,911
End of period	$324,591	$46,688

See accompanying notes.

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RealPage, Inc.
Condensed Consolidated Statements of Cash Flows, continued
(in thousands)
(unaudited)

	Six Months Ended June 30,	
	2017	2016
Supplemental cash flow information:		
Cash paid for interest	$1,976	$1,747
Cash paid for income taxes, net of refunds	$1,157	$1,200
Non-cash investing activities:		
Accrued property, equipment, and software	$951	$8,927

See accompanying notes.

RealPage, Inc.
Notes to the Condensed Consolidated Financial Statements
(unaudited)

1. The Company

RealPage, Inc., a Delaware corporation (together with its subsidiaries, the “Company” or “we” or “us”), is a technology leader to the real estate industry, helping owners, managers, and investors optimize both operational yields and investment returns. Our platform of data analytics and software solutions enables the rental real estate industry to manage property operations (such as marketing, pricing, screening, leasing, and accounting), identify opportunities through market intelligence, and obtain data-driven insight for better operational and financial decision-making. Our integrated, on demand platform provides a single point of access and a massive repository of real-time lease transaction data, including prospect, renter, and property data. By leveraging data as well as integrating and streamlining a wide range of complex processes and interactions among the apartment real estate ecosystem (owners, managers, prospects, renters, service providers, and investors), our platform helps our clients improve financial and operational performance and prudently place and harvest capital.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited Condensed Consolidated Financial Statements and footnotes have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). The unaudited Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. We believe that the disclosures made are appropriate and conform to those rules and regulations, and that the condensed or omitted information is not misleading.

The unaudited Condensed Consolidated Financial Statements included herein reflect all adjustments (consisting of normal, recurring adjustments) which are, in the opinion of management, necessary to state fairly the results for the interim periods presented. All intercompany balances and transactions have been eliminated in consolidation. The results of operations for the interim periods presented are not necessarily indicative of the operating results to be expected for any subsequent interim period or for the fiscal year.

These financial statements should be read in conjunction with the financial statements and the notes thereto included in our Annual Report on Form 10-K filed with the SEC on March 1, 2017 (“Form 10-K”).

Segment and Geographic Information

Our chief operating decision maker is our Chief Executive Officer, who reviews financial information presented on a company-wide basis. As a result, we determined that the Company has a single reporting segment and operating unit structure.

Principally, all of our revenue for the three and six months ended June 30, 2017 and 2016 was earned in the United States. Net property, equipment, and software held consisted of $132.4 million and $125.3 million located in the United States, and $5.8 million and $5.1 million in our international subsidiaries at June 30, 2017 and December 31, 2016, respectively. Substantially all of the net property, equipment, and software held in our international subsidiaries was located in the Philippines, Spain, and India at both June 30, 2017 and December 31, 2016.

Concentrations of Credit Risk

Our cash accounts are maintained at various financial institutions and may, from time to time, exceed federally insured limits. The Company has not experienced any losses in such accounts.

Concentrations of credit risk with respect to accounts receivable result from substantially all of our clients being in the residential rental housing market. Our clients, however, are dispersed across different geographic areas. We do not require collateral from clients. We maintain an allowance for doubtful accounts based upon the expected collectability of accounts receivable.

No single client accounted for 10% or more of our revenue or accounts receivable for the three or six months ended June 30, 2017 or 2016.

Accounting Policies and Use of Estimates

The preparation of financial statements in conformity with GAAP requires our management to make certain estimates and assumptions that 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 periods. Significant estimates include the allowance for doubtful accounts; the useful lives of intangible assets and the recoverability or impairment of tangible and intangible asset values; fair value measurements; contingent commissions related to the sale of insurance products; purchase accounting allocations and contingent consideration; revenue and deferred revenue and related

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reserves; stock-based expense; and our effective income tax rate and the recoverability of deferred tax assets, which are based upon our expectations of future taxable income and allowable deductions. Actual results could differ from these estimates. For greater detail regarding these accounting policies and estimates, refer to our Form 10-K.

Business Combinations

The Company applies the guidance contained in ASC Topic 805, Business Combinations ("ASC 805") in determining whether an acquisition transaction constitutes a business combination. ASC 805 defines a business as consisting of inputs and processes applied to those inputs that have the ability to create outputs. The acquisition transactions in Note 3 were determined to constitute business combinations and were accounted for under ASC 805.

Purchase consideration includes assets transferred, liabilities assumed, and/or equity interests issued by us, all of which are measured at their fair value as of the date of acquisition. Our business combination transactions may be structured to include an up-front cash payment and deferred and/or contingent cash payments to be made at specified dates subsequent to the date of acquisition. Deferred cash payments are included in the acquisition consideration based on their fair value as of the acquisition date. The fair value of these obligations is estimated based on the present value, as of the date of acquisition, of the anticipated future payments. The future payments are discounted using a rate that considers an estimate of the return expected by a market-participant and a measurement of the risk inherent in the cash flows, among other inputs. Deferred cash payments are generally subject to adjustments specified in the underlying purchase agreement related to the seller's indemnification obligations. Contingent cash payments are obligations to make future cash payments to the seller, the payment of which is contingent upon the achievement of stipulated operational or financial targets in the post-acquisition period. Contingent cash payments are included in the purchase consideration at their fair value as of the acquisition date. The fair value of these payments is estimated using a probability weighted discount model based on the achievement of the specified targets. The fair value of these liabilities is re-evaluated on a quarterly basis, and any change is reflected in the line "General and administrative" in the accompanying Condensed Consolidated Statements of Operations. These estimates are inherently uncertain and unpredictable. Unanticipated events and circumstances may occur that would affect the accuracy or validity of these estimates.

The total purchase consideration is allocated to the assets acquired and liabilities assumed based on their estimated fair values. Any excess consideration is classified as goodwill. Acquired intangibles are recorded at their estimated fair value based on the income approach using market-based estimates. Acquired intangibles generally include developed product technologies, which are amortized over their useful life on a straight-line basis, and client relationships, which are amortized over their useful life proportionately to the expected discounted cash flows derived from the asset. When trade names acquired are not classified as indefinite-lived, they are amortized on a straight-line basis over their expected useful life.

Acquisition costs are expensed as incurred and are included in the line "General and administrative" in the accompanying Condensed Consolidated Statements of Operations. We include the results of operations from acquired businesses in our Condensed Consolidated Financial Statements from the effective date of the acquisition.

Derivative Financial Instruments

The Company is exposed to interest rate risk related to our variable rate debt. The Company manages this risk through a program that includes the use of interest rate derivatives, the counterparties to which are major financial institutions. Our objective in using interest rate derivatives is to add stability to interest cost by reducing our exposure to interest rate movements. We do not use derivative instruments for trading or speculative purposes.

Our interest rate derivatives are designated as cash flow hedges and are carried in the Condensed Consolidated Balance Sheets at their fair value. Unrealized gains and losses resulting from changes in the fair value of these instruments are classified as either effective or ineffective. The effective portion of such gains or losses is recorded as a component of accumulated other comprehensive income ("AOCI"), while the ineffective portion is recorded as a component of interest expense in the period of change. Amounts reported in AOCI related to interest rate derivatives are reclassified into interest expense as interest payments are made on our variable-rate debt. If an interest rate derivative agreement is terminated prior to its maturity, the amounts previously recorded in AOCI are recognized into earnings over the period that the forecasted transactions impact earnings. If the hedging relationship is discontinued because it is probable that the forecasted transactions will not occur according to our original strategy, any related

amounts previously recorded in AOCI are recognized in earnings immediately.
Revenue Recognition
We derive our revenue from three primary sources: on demand software solutions, on premise software solutions, and professional services. We commence revenue recognition when all of the following conditions are met:
- there is persuasive evidence of an arrangement;
- the solution and/or service has been provided to the client;
- the collection of the fees is probable; and

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• the amount of fees to be paid by the client is fixed or determinable.

If the fees are not fixed or determinable, we recognize revenues as payments become due from clients or when amounts owed are collected, provided all other conditions for revenue recognition have been met. Accordingly, this may materially affect the timing of our revenue recognition and results of operations.

When arrangements with clients include multiple software solutions and/or services, we allocate arrangement consideration to each deliverable based on its relative selling price. In such circumstances, we determine the relative selling price for each deliverable based on vendor specific objective evidence of selling price ("VSOE"), if available, or our best estimate of selling price ("BESP"). We have determined that third-party evidence of selling price is not available as our solutions and services are not largely interchangeable with those of other vendors. Our process for determining BESP considers multiple factors, including prices charged by us for similar offerings when sold separately, pricing and discount strategies, and other business objectives.

Taxes collected from clients and remitted to governmental authorities are presented on a net basis.

On Demand Revenue

Our on demand revenue consists of license and subscription fees, transaction fees related to certain of our software-enabled value-added services, and commissions derived from our selling certain risk mitigation services.

License and subscription fees are composed of a charge billed at the initial order date and monthly or annual subscription fees for accessing our on demand software solutions. The license fee billed at the initial order date is recognized as revenue on a straight-line basis over the longer of the contractual term or the period in which the client is expected to benefit, which we consider to be three years. Recognition starts once the product has been activated. Revenue from monthly and annual subscription fees is recognized on a straight-line basis over the access period.

We recognize revenue from transaction fees derived from certain of our software-enabled value-added services as the related services are performed.

As part of our risk mitigation services to the rental housing industry, we act as an insurance agent and derive commission revenue from the sale of insurance products to individuals. The commissions are based upon a percentage of the premium that the insurance company charges to the policyholder and are subject to forfeiture in instances where a policyholder cancels prior to the end of the policy. Our contract with our underwriting partner provides for contingent commissions to be paid to us in accordance with the agreement. This agreement provides for a calculation that considers, on the policies sold by us, earned premiums less i) earned agent commissions; ii) a percent of premium retained by our underwriting partner; iii) incurred losses; and iv) profit retained by our underwriting partner during the time period. Our estimate of contingent commission revenue considers historical loss experience on the policies sold by us. If the policy is cancelled, our commissions are forfeited as a percent of the unearned premium. As a result, we recognize commissions related to these services as earned ratably over the policy term.

On Premise Revenue

Sales of our on premise software solutions consist of an annual term license, which includes maintenance and support. Clients can renew their annual term license for additional one-year terms at renewal price levels. We recognize revenue for the annual term license and support services on a straight-line basis over the contract term.

We also derive on premise revenue from multiple element arrangements that include perpetual licenses with maintenance and other services to be provided over a fixed term. Revenue is recognized for delivered items using the residual method when we have VSOE of fair value for the undelivered items and all other criteria for revenue recognition have been met.

When VSOE has not been asserted for the undelivered items, we recognize the arrangement fees ratably over the longer of the client support period or the period during which professional services are rendered.

Professional and Other Revenue

Professional services and other revenue are recognized as the services are rendered for time and materials contracts. Training revenues are recognized after the services are performed.

Fair Value Measurements

Certain assets and liabilities are carried at fair value under GAAP. Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

Legal Contingencies

We review the status of each matter and record a provision for a liability when we consider that it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We review these provisions quarterly and

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make adjustments where needed as additional information becomes available. If either or both of the criteria are not met, we assess whether there is at least a reasonable possibility that a loss, or additional losses beyond those already accrued, may be incurred. If there is a reasonable possibility that a material loss (or additional material loss in excess of any accrual) may be incurred, we disclose an estimate of the amount of loss or range of losses, either individually or in the aggregate, as appropriate, if such an estimate can be made, or disclose that an estimate of loss cannot be made.

Recently Adopted Accounting Standards

We adopted ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, in the first quarter of 2017. As a result of our adoption of this ASU, we recorded a deferred tax asset of $43.8 million, net of a $0.3 million valuation allowance, related to excess stock-based compensation deductions that arose but were not recognized in prior years. Additionally, we elected to account for forfeitures as they occur using a modified retrospective transition method that required us to record an immaterial cumulative-effect adjustment to accumulated deficit. We elected to account for the change in presentation of excess tax benefits in the statements of cash flows prospectively, and as a result, no prior periods were adjusted. We began to account for all excess tax benefits and deficits arising from current period stock transactions as income tax benefit or expense effective January 1, 2017. The remaining amendments to this standard did not have a material impact on our Condensed Consolidated Financial Statements.

Recently Issued Accounting Standards

In May 2017, the FASB issued ASU 2017-09, Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting, which provides clarification on when modification accounting should be used for changes to the terms or conditions of a share-based payment award. This ASU does not change the accounting for modifications but clarifies that modification accounting guidance should only be applied if there is a change to the fair value, vesting conditions, or award classification (as equity or liability) and would not be required if the changes are considered non-substantive. ASU 2017-09 requires the changes to be implemented on a prospective basis and is applicable for annual reporting periods beginning after December 15, 2017, including interim periods therein. Early application is permitted. We are currently evaluating the impact of adopting ASU 2017-09 on our consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business to assist entities with evaluating whether a set of transferred assets and activities ("set") is a business. Under the new guidance, an entity first determines whether substantially all of the fair value of the set is concentrated in a single identifiable asset or a group of similar identifiable assets. If this threshold is met, the set is not a business. If it is not met, the entity evaluates whether the set meets the requirements that a business include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs. The ASU requires the changes to be implemented on a prospective basis and is applicable for annual reporting periods beginning after December 15, 2017, including interim periods therein. Early application is permitted. We plan to adopt the changes contained in ASU 2017-01 effective January 1, 2018 and, as required by the ASU, will apply the new guidance on a prospective basis. We do not expect this ASU will have a significant impact on our classification of businesses and complementary technologies acquired.

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows - Restricted Cash, which requires entities to show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. This standard is effective for fiscal years beginning after December 15, 2017, including interim periods within, and must be applied retrospectively. Early adoption of this ASU is permitted, including adoption in an interim period, but any adjustments must be reflected as of the beginning of the fiscal year that includes that interim period. We will adopt ASU 2016-18 in the first quarter of 2018. After adoption, changes in customer deposits held in restricted accounts will result in an increase or reduction in cash flows from operating activities. Such changes do not have an impact on our consolidated financial statements under current rules.

In June 2016, the FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. The amendments in this ASU replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted in fiscal years beginning after December 15, 2018. The amendments in this ASU are to be applied through a cumulative-effect adjustment to retained earnings as of the first reporting period in which the ASU is effective. We have not yet selected a transition date and are currently evaluating the impact of adopting ASU 2016-13 on our consolidated financial statements.

On February 25, 2016, the FASB issued ASU 2016-02, Leases (Topic 842). Current GAAP requires lessees to classify their leases as either capital leases, for which the lessee recognizes a lease liability and a related leased asset, or operating leases, which are not reflected in the lessee’s balance sheet. Under the new guidance, a lessee will be required to recognize assets and liabilities for leases with a term of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease will depend primarily on its classification as a

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finance or an operating lease. However, unlike current GAAP, which requires only capital leases to be recognized on the balance sheet, ASU 2016-02 will require both operating and finance leases to be recognized on the balance sheet. Additionally, the ASU will require disclosures to help investors and other financial statement users better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements.

ASU 2016-02 is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients. Transition will require application of the new guidance to the beginning of the earliest comparative period presented. We have not yet selected a transition date and are currently evaluating the impact of adopting ASU 2016-02 on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09, as amended by certain supplementary ASU's released in 2016, will replace all current GAAP guidance on this topic and eliminate all industry-specific guidance. The new revenue recognition standard provides a unified model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration for which the entity expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. These may include identifying performance obligations in the contract, estimating the amount of variable consideration to include in the transaction price, and allocating the transaction price to each separate performance obligation. In August 2015, the FASB issued ASU 2015-14, Topic 606 - Deferral of Effective Date. ASU 2015-14 permitted public business entities to defer the adoption of ASU 2014-09 until interim and annual reporting periods beginning after December 15, 2017. We will adopt ASU 2014-09 in the first quarter of 2018 and expect to adopt on a modified retrospective basis. Under this method of adoption, we would recognize the cumulative effect of initially applying the standard as an adjustment to the opening balance of retained earnings in the period of initial adoption. Comparative prior year periods would not be adjusted.

Based on our preliminary analysis, we anticipate that commissions paid to our direct sales force will qualify as incremental costs of obtaining a contract and will be capitalized and subsequently amortized. Additionally, we anticipate limited changes in the timing of our revenue recognition and client accommodation credits. The standard will require a significant amount of new revenue disclosures in our consolidated financial statements, and we are currently evaluating the impact of these new disclosure requirements. We continue to evaluate the new standard against our existing accounting policies and our contracts with clients to determine the effect the guidance will have on our financial statements and what changes to systems and controls may be warranted.

3. Acquisitions

Current Acquisition Activity

American Utility Management

In June 2017, RealPage acquired substantially all of the assets of American Utility Management ("AUM"), a provider of utility and energy management services for the multifamily housing industry. AUM helps maximize cost recovery, reduces energy usage and expense, and provides the tools operators of rental real estate need to manage their utilities more effectively. Additionally, AUM's platform includes tools that enable operators to benchmark energy cost and consumption against their peers. The acquired assets will be integrated with our existing resident utility management platform and our data analytics tools.

We acquired AUM for a purchase price of $69.4 million. The purchase price consisted of a cash payment of $64.8 million at closing, net of cash acquired of $0.1 million, and a deferred cash obligation of up to $5.1 million. The fair value of the deferred cash obligation was $4.6 million at the date of acquisition, and is payable over a period of four years following the date of acquisition. This acquisition was financed using cash on hand.

The acquired identifiable intangible assets consisted of trade names, developed technology, non-compete agreements, and client relationships, which will be amortized over estimated useful lives of two, three, five, and ten years, respectively. Preliminary goodwill recognized of $45.3 million primarily arises from anticipated synergies from integrating the acquired assets with our existing resident utility management system and leveraging the energy cost and consumption benchmarking capabilities and data acquired. Goodwill and the acquired identified intangible assets are deductible for tax purposes.

The Company’s purchase accounting for AUM was incomplete as of June 30, 2017. We expect to complete the working capital adjustment and valuation of tangible assets, intangible assets, and liabilities assumed as of the acquisition date in the third quarter of 2017. The amounts reflected in the purchase price allocation table below are provisional in nature and may have a material change.

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Lease Rent Options

In February 2017, we entered into an agreement to acquire the assets that comprise the multifamily business (Lease Rent Options or “LRO”) of The Rainmaker Group Holdings, Inc. The closing of the proposed acquisition is subject to standard closing conditions, including the completion of the Hart-Scott-Rodino Antitrust Improvements Act review process. The acquisition of LRO will extend our revenue management footprint, augment our repository of real-time lease transaction data, and increase our data science talent and capabilities. We expect the acquisition of LRO to increase the market penetration of our YieldStar Revenue Management solution and drive revenue growth in our other asset optimization solutions.

Pursuant to the purchase agreement, consideration will consist of a cash payment at closing of approximately $298.5 million, subject to reduction for outstanding indebtedness, unpaid transaction expenses, and a working capital adjustment; and a deferred cash obligation of up to $1.5 million. The deferred cash obligation serves as security for our benefit against the sellers' indemnification obligations. Subject to any indemnification claims made, the deferred cash obligation will be released approximately twelve months following the acquisition date. We expect to finance this transaction with cash on hand and funds available under our Credit Facility.

Axiometrics LLC

In January 2017, we acquired substantially all of the assets of Axiometrics LLC (“Axiometrics”). Axiometrics provides its customers with timely market intelligence on apartment markets accumulated from survey and research data. Axiometrics also provides tools to analyze the data at an asset level by multiple variables such as asset class, age, and specific competitive floor plans. The acquisition of Axiometrics expanded our multifamily data analytics platform and was integrated with MPF Research, our market research database, to form Data Analytics.

We acquired Axiometrics for a purchase price of $73.8 million. The purchase price consisted of a cash payment of $66.1 million at closing; deferred cash obligations of up to $7.5 million, payable over a period of two years following the date of acquisition; and contingent cash obligations of up to $5.0 million if certain revenue targets are achieved during the twelve-month period ending December 31, 2018. The fair value of the deferred and contingent cash obligations was $6.9 million and $0.8 million, respectively, at the date of acquisition. This acquisition was financed using cash on hand.

The acquired identified intangible assets consisted of developed technology, client relationships, and trade names. These intangible assets were assigned estimated useful lives of five, ten, and three years, respectively. We recognized goodwill in the amount of $54.2 million related to this acquisition, which is primarily comprised of anticipated synergies with our existing multifamily data analytics platform. Goodwill and the acquired identified intangible assets are deductible for tax purposes.

We have adjusted our initial purchase price allocation based on management’s ongoing review of information available at the acquisition date. These measurement period adjustments resulted in an increase in goodwill, deferred revenue, and other liabilities of $1.3 million, $0.4 million, and $0.9 million, respectively.

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Purchase Price Allocation

The estimated fair values of assets acquired and liabilities assumed presented below are provisional and are based primarily on the information available as of the acquisition dates. We believe that information provides a reasonable basis for estimating the fair values of assets acquired and liabilities assumed, but the Company is awaiting additional information necessary to finalize those values. Therefore, the provisional measurements of fair value are subject to change, and such changes could be significant. We expect to finalize the valuation of these assets and liabilities as soon as practicable, but no later than one year from the acquisition dates. The preliminary allocation of each purchase price, including the effects of measurement period adjustments recorded as of June 30, 2017, was as follows:

	Axiometrics	AUM
	(in thousands)	
Restricted cash	$—	$7,637
Accounts receivable	1,642	2,183
Property, equipment, and software	416	341
Intangible assets:		
Developed product technologies	15,500	10,800
Client relationships	6,830	7,470
Trade names	3,200	208
Non-compete agreements	—	3,920
Goodwill	54,154	45,292
Other assets	273	1,149
Accounts payable and accrued liabilities	(368)	(1,630)
Client deposits held in restricted accounts	—	(7,637)
Deferred revenue	(7,115)	(321)
Other long-term liabilities	(774)	—
Total purchase price	$73,758	$69,412

At June 30, 2017, deferred cash obligations related to acquisitions completed in 2017 totaled $12.6 million and were carried net of a discount of $1.0 million. The aggregate fair value of contingent cash obligations related to these acquisitions was $0.6 million at June 30, 2017. During the three and six months ended June 30, 2017, we recognized a gain of $0.2 million due to changes in the fair value of contingent cash obligations related to acquisitions completed in 2017.

2016 Acquisitions

eSupply Systems, LLC

In June 2016, we acquired substantially all of the assets of eSupply Systems, LLC (“eSupply”) and those of certain entities related to eSupply. eSupply is an e-procurement software and group purchasing service which augmented our Spend Management solutions.

We acquired eSupply for a purchase price of $7.0 million, consisting of a cash payment of $5.5 million at closing and a deferred cash obligation of up to $1.6 million, payable over 18 months after the acquisition date. The fair value of the deferred cash obligation on the date of acquisition was $1.5 million. The first deferred cash payment was made in the fourth quarter of 2016. This acquisition was financed using proceeds from the Term Loan issued in February 2016. The acquired identified intangible assets primarily consisted of developed technology and client relationships. These intangible assets were assigned estimated useful lives of three and ten years, respectively. We recognized goodwill in the amount of $3.2 million related to this acquisition, which is primarily comprised of anticipated synergies with our existing Spend Management solutions. Goodwill and the acquired identified intangible assets are deductible for tax purposes.

AssetEye, Inc.

In May 2016, we acquired all of the issued and outstanding stock of AssetEye, Inc. (“AssetEye”). AssetEye is a data aggregation, reporting, and collaboration platform for institutions holding multiple real estate asset classes. This solution provides asset and portfolio managers with a solution to evaluate performance, trends, and operations across a portfolio with transparency into property-level data. The acquisition of AssetEye expanded our on demand solutions to serve all asset classes, including: commercial, hospitality, multifamily, single family, senior living, and student housing.

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We acquired AssetEye's issued and outstanding stock for a purchase price of $4.9 million. The purchase price consisted of a cash payment of $3.6 million at closing, net of cash acquired of $0.8 million; deferred cash obligations of $1.0 million, payable over a period of two years following the date of acquisition; contingent cash payments of up to $1.0 million if certain revenue targets are achieved during the three-month period ending September 30, 2017; and additional cash payments of $0.2 million due to former shareholders of AssetEye. The fair value of the deferred and contingent cash obligations was $0.9 million and $0.2 million, respectively, at the date of acquisition. This acquisition was financed with proceeds from the Term Loan issued in February 2016.

The acquired identified intangible assets primarily included developed technology and client relationships having useful lives of five and ten years, respectively. We recognized goodwill in the amount of $3.2 million related to this acquisition, which is primarily comprised of anticipated synergies between the AssetEye solution and our existing complementary solutions as well as our sales and marketing infrastructure. Goodwill and identified intangible assets recognized in connection with this transaction are not deductible for tax purposes.

NWP Services Corporation

In March 2016, we acquired all of the issued and outstanding stock of NWP Services Corporation ("NWP"). NWP provides a full range of utility management services, including: resident billing; payment processing; utility expense management; analytics and reporting; sub-metering and maintenance; and regulatory compliance. The primary products offered by NWP include Utility Logic, Utility Smart, Utility Genius, SmartSource, and NWP Sub-meter. We are primarily integrating NWP into our resident services product family. The integrated platform will enable property owners and managers to increase the collection of rent utilities and energy recovery. Goodwill arising from this acquisition consists of anticipated synergies from the integration of NWP into our existing structure.

We acquired NWP's issued and outstanding stock for a purchase price of $68.2 million. The purchase price consisted of a cash payment of $59.0 million at closing, net of cash acquired of $0.1 million; deferred cash obligations of $7.2 million, payable over a period of three years following the date of acquisition; and other amounts totaling $3.2 million, consisting of payments to certain employees and former shareholders of NWP. The acquisition-date fair value of the deferred cash obligation was $6.0 million. This acquisition was financed with proceeds from the Term Loan issued in February 2016. Acquisition costs associated with this transaction totaled $0.3 million and were expensed as incurred.

The acquired identified intangible assets were comprised of developed technologies, trade name, and client relationships having useful lives of five, three, and ten years, respectively. Goodwill and identified intangible assets acquired in this business combination, valued at $35.3 million and $16.3 million in our initial purchase price allocation, had carryover tax bases of $0.7 million and $11.0 million, respectively, which are deductible for tax purposes. Goodwill and identified intangible assets recognized in excess of those carryover tax basis amounts are not deductible for tax purposes. Accounts receivable acquired had a gross contractual value of $11.3 million at acquisition, of which $3.4 million was estimated to be uncollectible.

We assigned approximately $10.2 million of value to deferred tax assets in our initial purchase price allocation, consisting primarily of $9.9 million of federal and state net operating losses ("NOL"). This NOL amount reflects the tax benefit from approximately $27.3 million of NOLs we expect to realize after considering various limitations and restrictions on NWP's pre-acquisition NOLs.

In connection with the acquisition of NWP, we recorded an indemnification asset of $1.2 million, which represents the selling security holders' obligation under the purchase agreement to indemnify the Company for the outcome of certain accrued obligations. The indemnification asset was recognized on the same basis as the corresponding liability, which is based on its estimated fair value as of the date of acquisition.

Subsequent to the acquisition date, management continued to review information relating to events and circumstances that existed at the acquisition date. This review resulted in measurement period adjustments to the provisional amounts recorded at the acquisition date related to deferred cash obligations paid to the sellers and deferred tax assets associated with the transaction. These measurement period adjustments resulted in a change in goodwill, deferred tax assets, and the deferred cash obligation of $(1.8) million, $1.0 million, and $(0.8) million, respectively.

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Purchase Price Allocation

The allocation of each purchase price, including the effects of measurement period adjustments, was as follows:

	NWP	AssetEye	eSupply
	(in thousands)		
Restricted cash	$4,960	$—	$—
Accounts receivable	7,902	90	287
Property, equipment, and software	3,194	—	—
Intangible assets:			
Developed product technologies	2,740	1,638	2,160
Client relationships	12,900	1,041	1,390
Trade names	709	6	35
Goodwill	33,520	3,154	3,194
Deferred tax assets, net	11,173	—	—
Other assets, net of other liabilities	3,065	8	53
Accounts payable and accrued liabilities	(6,962)	—	(44)
Client deposits held in restricted accounts	(5,018)	—	—
Deferred revenue	—	(16)	(29)
Deferred tax liabilities, net	—	(1,010)	—
Total purchase price	$68,183	$4,911	$7,046

At June 30, 2017 and December 31, 2016, deferred cash obligations related to acquisitions completed in 2016 totaled $8.1 million and $8.7 million, and were carried net of a discount and indemnified obligations of $1.5 million and $1.2 million, respectively. The aggregate fair value of contingent cash obligations related to these acquisitions was $0.8 million and $0.5 million at June 30, 2017 and December 31, 2016, respectively. During the three and six months ended June 30, 2017, we recognized a loss of $0.1 million and $0.3 million, respectively, due to changes in the fair value of contingent cash obligations related to these acquisitions.

We made deferred cash payments of $0.6 million during the six months ended June 30, 2017, related to these acquisitions. There were no deferred cash payments during the same period in 2016. During the six months ended June 30, 2017 and 2016, we made payments totaling $0.1 million and $3.2 million, respectively, related to amounts due to certain employees and former shareholders of the acquired businesses described above.

Acquisition Activity Prior to 2016

At June 30, 2017 and December 31, 2016, the aggregate carrying value of deferred cash obligations related to acquisitions completed prior to 2016 totaled $0.1 million and $6.6 million, respectively. We paid deferred cash obligations related to these acquisitions in the amount of $6.4 million and $2.9 million during the six months ended June 30, 2017 and 2016, respectively.

The aggregate carrying value of contingent cash obligations related to acquisitions completed prior to 2016 was estimated to be $0.2 million at June 30, 2017 and zero at December 31, 2016. During the six months ended June 30, 2017, we paid contingent cash obligations in the amount of $0.5 million related to these acquisitions. A gain of $0.2 million and $0.4 million was recognized during the three and six months ended June 30, 2016, respectively, due to changes in the fair value of contingent cash obligations related to acquisitions completed prior to 2016. During the same period in 2017, a loss of $0.7 million was recognized related to these obligations.

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Pro Forma Results of Acquisitions

The following table presents unaudited pro forma results of operations for the three and six months ended June 30, 2017 and 2016, as if the aforementioned acquisitions, excluding the proposed LRO acquisition, had occurred at the beginning of each period presented. The pro forma information includes the business combination accounting effects resulting from these acquisitions, including interest expense, tax benefit, and additional amortization resulting from the valuation of amortizable intangible assets. We prepared the pro forma financial information for the combined entities for comparative purposes only, and it is not indicative of what actual results would have been if the acquisitions had occurred at the beginning of the periods presented, or of future results.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017 Pro Forma	2016 Pro Forma	2017 Pro Forma	2016 Pro Forma
	(in thousands, except per share amounts)			
Total revenue	$167,862	$153,831	$330,106	$293,167
Net income	6,222	351	12,647	1,483
Net income per share:				
Basic	$0.08	$—	$0.16	$0.02
Diluted	$0.08	$—	$0.15	$0.02

4. Property, Equipment, and Software

Property, equipment, and software consisted of the following at June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(in thousands)	
Leasehold improvements	$54,107	$ 51,242
Data processing and communications equipment	81,916	76,773
Furniture, fixtures, and other equipment	26,652	26,513
Software	97,636	86,983
Property, equipment, and software, gross	260,311	241,511
Less: Accumulated depreciation and amortization	(122,070)	(111,083)
Property, equipment, and software, net	$138,241	$ 130,428

Depreciation and amortization expense for property, equipment, and purchased software was $6.9 million and $6.5 million for the three months ended, and $13.5 million and $11.9 million for the six months ended June 30, 2017 and 2016, respectively.

The carrying amount of capitalized software development costs was $63.9 million and $55.4 million at June 30, 2017 and December 31, 2016, respectively. Total accumulated amortization related to these assets was $23.2 million and $19.8 million at June 30, 2017 and December 31, 2016, respectively. Amortization expense related to capitalized software development costs totaled $1.8 million and $1.4 million for the three months ended, and $3.4 million and $2.6 million for the six months ended June 30, 2017 and 2016, respectively.

5. Goodwill and Identified Intangible Assets

Changes in the carrying amount of goodwill during the six months ended June 30, 2017 were as follows, in thousands:

Balance as of December 31, 2016	$259,938
Goodwill acquired	99,446
Other	36
Balance as of June 30, 2017	$359,420

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Identified intangible assets consisted of the following at June 30, 2017 and December 31, 2016:

	June 30, 2017			December 31, 2016		
	Carrying Amount	Accumulated Amortization	Net	Carrying Amount	Accumulated Amortization	Net
	(in thousands)					
Finite-lived intangible assets:						
Developed technologies	$101,974	$(68,078)	$33,896	$75,671	$(62,249)	$13,422
Client relationships	122,768	(69,894)	52,874	108,468	(64,173)	44,295
Vendor relationships	5,650	(5,650)	—	5,650	(5,650)	—
Trade names	9,680	(2,229)	7,451	5,899	(1,225)	4,674
Non-compete agreements	4,173	(209)	3,964	253	(170)	83
Total finite-lived intangible assets	244,245	(146,060)	98,185	195,941	(133,467)	62,474
Indefinite-lived intangible assets:						
Trade names	12,133	—	12,133	12,502	—	12,502
Total identified intangible assets	$256,378	$(146,060)	$110,318	$208,443	$(133,467)	$74,976

Amortization expense related to finite-lived intangible assets was $6.5 million and $6.3 million for the three months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017 and 2016, amortization expense related to finite-lived intangible assets was $12.6 million and $12.3 million, respectively.

6. Debt

Credit Facility

On September 30, 2014, we entered into an agreement for a secured revolving credit facility (as amended by the amendments discussed below, the “Credit Facility”) to refinance our outstanding revolving loans. The Credit Facility provides an aggregate principal amount of up to $200.0 million of revolving loans, with sublimits of $10.0 million for the issuance of letters of credit and $20.0 million for swingline loans (“Revolving Facility”). The Credit Facility also allows us, subject to certain conditions, to request term loans or additional revolving commitments up to an aggregate principal amount of $150.0 million, plus an amount that would not cause our Consolidated Net Leverage Ratio, as defined below, to exceed 3.25 to 1.00. At our option, amounts outstanding under the Credit Facility accrued interest, prior to the amendments described below, at a per annum rate equal to either LIBOR, plus a margin ranging from 1.25% to 1.75%, or the Base Rate, plus a margin ranging from 0.25% to 0.75% (“Applicable Margin”). The base LIBOR rate is, at our discretion, equal to either one, two, three, or six month LIBOR. The Base Rate is defined as the greater of Wells Fargo's prime rate, the Federal Funds Rate plus 0.50%, or one month LIBOR plus 1.00%. In each case, the Applicable Margin is determined based upon our Consolidated Net Leverage Ratio, as defined below.

The Credit Facility is secured by substantially all of our assets, and certain of our existing and future material domestic subsidiaries are required to guarantee our obligations under the Credit Facility. The Credit Facility contains customary covenants, subject in each case to customary exceptions and qualifications. Our covenants include, among other limitations, a requirement that we comply with a maximum Consolidated Net Leverage Ratio and a minimum Consolidated Interest Coverage Ratio. Prior to amendments executed in 2016 and 2017, described below, the Consolidated Net Leverage Ratio, which is defined as the ratio of consolidated funded indebtedness on the last day of each fiscal quarter to the four previous consecutive fiscal quarters’ consolidated EBITDA, could not exceed 3.50 to 1.00, provided that we could elect to increase the ratio to 3.75 to 1.00 for a specified period following certain acquisitions. The Consolidated Interest Coverage Ratio, which is defined as the ratio of our four previous fiscal quarters’ consolidated EBITDA to our interest expense for the same period, must not be less than 3.00 to 1.00 on the last day of each fiscal quarter.

In February 2016, we entered into an amendment to the Credit Facility (“First Amendment”). The First Amendment provided for an incremental term loan in the amount of $125.0 million (“Term Loan”) that was coterminous with the existing Credit Facility, reducing the aggregate amount of term loans we were able to request under the Credit Facility to $25.0 million plus an amount that would not cause our Consolidated Net Leverage Ratio to exceed 3.25 to 1.00. Under the terms of the First Amendment, an additional pricing tier was added to the Applicable Margin which modified the range to 1.25% to 2.00% for LIBOR loans, and 0.25% to 1.00% for Base Rate loans. The First

Amendment also permitted the Company to elect to increase the maximum permitted Consolidated Net Leverage Ratio, on a one-time basis, to 4.00 to 1.00 following the issuance of convertible notes or high yield notes in an initial principal amount of at least $150.0 million. We incurred debt issuance costs in the amount of $0.7 million in conjunction with the execution of the First Amendment.

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In February 2017, we entered into the second and third amendments to the Credit Facility (“Second Amendment” and “Third Amendment,” respectively). Among other changes, the Second Amendment increased the aggregate amount of additional term loans or revolving commitments we are allowed to request to $150.0 million, plus an amount that would not cause our Consolidated Net Leverage Ratio to exceed 3.25 to 1.00. The Third Amendment provided for an incremental $200.0 million delayed draw term loan that was available to be drawn until May 31, 2017 (“Delayed Draw Term Loan”), extended the maturity of the Credit Facility to February 27, 2022, and amended the amortization schedule for the Term Loan. Under the amended amortization schedule, beginning on June 30, 2017, the Company will make quarterly principal payments of 0.6% of the outstanding principal of the Term Loan immediately prior to June 30, 2017. The quarterly payment percentage increases to 1.3% beginning on June 30, 2018, and to 2.5% beginning on June 30, 2020. These payment due dates and percentages will also apply to any amount drawn under the Delayed Draw Term Loan. Any remaining principal balance on the Term Loan and Delayed Draw Term Loan is due on the maturity date. We incurred debt issuance costs in the amount of $1.3 million in conjunction with the execution of the Second and Third Amendments. The availability period of the Delayed Draw Term Loan was extended through August 31, 2017 under the Fifth Amendment to the Credit Facility, which was executed in May 2017.

On April 3, 2017, we entered into a new amendment to the Credit Facility (“Fourth Amendment”). The Fourth Amendment modified certain terms of the Credit Facility to, among other things, increase the maximum Consolidated Net Leverage Ratio to 4.00 to 1.00, with an automatic increase to 5.00 to 1.00 following an acquisition having aggregate consideration equal to or greater than $150.0 million and occurring within a specified time period following an unsecured debt issuance equal to or greater than $225.0 million. The automatic increase may occur once during the term of the Credit Facility and lasts for two consecutive fiscal quarters, after which the amendment provides for incremental step downs until the ratio returns to 4.00 to 1.00. Additionally, the automatic increase may only occur during periods in which the referenced unsecured debt is outstanding. Related to this increase, the Fourth Amendment provided for an additional pricing tier for interest rates and fees if the Company’s Consolidated Net Leverage Ratio equals or exceeds 4.00 to 1.00, resulting in a new Applicable Margin range of 1.25% to 2.25% for LIBOR loans and 0.25% to 1.25% for Base Rate loans. The amendment also added a new financial covenant, requiring the Company to comply with a maximum Consolidated Senior Secured Net Leverage Ratio, defined as the ratio of consolidated secured funded indebtedness on the last day of each fiscal quarter to the four previous consecutive fiscal quarters’ consolidated EBITDA, of 3.50 to 1.00. At our option, this ratio may be increased to 3.75 to 1.00 for a period of one year following the completion of an acquisition having aggregate consideration greater than $50.0 million. We are not permitted to exercise this option more than one time during any consecutive eight quarter period. The Consolidated Interest Coverage Ratio was also amended to exclude non-cash interest attributable to the Convertible Notes, as defined below.

Revolving loans under the Credit Facility may be voluntarily prepaid and re-borrowed. Principal payments on the Term Loan and Delayed Draw Term Loan are due in quarterly installments, as described above, and may not be re-borrowed. Accumulated interest on amounts outstanding under the Credit Facility is due and payable quarterly, in arrears, for loans bearing interest at the Base Rate and at the end of the applicable interest period in the case of loans bearing interest at the adjusted LIBOR. All outstanding principal and accrued but unpaid interest is due on the maturity date. The Term Loan and Delayed Draw Term Loan are subject to mandatory repayment requirements in the event of certain asset sales or if certain insurance or condemnation events occur, subject to customary reinvestment provisions. The Company may prepay the Term Loan and Delayed Draw Term Loan in whole or in part at any time, without premium or penalty, with prepayment amounts to be applied to remaining scheduled principal amortization payments as specified by the Company.

We had $121.9 million and $122.6 million of principal outstanding under our Term Loan at June 30, 2017 and December 31, 2016, respectively. There were no outstanding borrowings under the Revolving Credit Facility at June 30, 2017 and December 31, 2016. As of June 30, 2017, we had $400.0 million of available credit under our Credit Facility, consisting of $200.0 million available under our Revolving Facility and $200.0 million available under our Delayed Draw Term Loan. We had unamortized debt issuance costs of $0.7 million and $0.8 million related to the Revolving Facility and $1.9 million and $0.5 million related to the Term and Delayed Draw Term Loans at June 30, 2017 and December 31, 2016, respectively. As of June 30, 2017, we were in compliance with the covenants under our

Credit Facility.

At June 30, 2017, future maturities of principal under the Term Loan were as follows for the years ending December 31, in thousands:

2017	$1,533
2018	5,366
2019	6,133
2020	10,732
2021	12,266
Thereafter	85,859
	$121,889

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Convertible Notes

In May 2017 the Company issued convertible senior notes with aggregate principal of $345.0 million (which included the underwriters' exercise in full of their over-allotment option of $45.0 million) which mature on November 15, 2022 ("Convertible Notes"). The Convertible Notes were issued under an indenture dated May 23, 2017 ("Indenture"), by and between the Company and Wells Fargo Bank, N.A., as Trustee. We received net proceeds from the offering of approximately $304.2 million after adjusting for debt issuance costs, including the underwriting discount, the net cash used to purchase the Note Hedges and the proceeds from the issuance of the Warrants which are discussed below.

The Convertible Notes accrue interest at a rate of 1.50%, payable semi-annually on May 15 and November 15 of each year beginning on November 15, 2017. On or after May 15, 2022, and until the close of business on the second scheduled trading day immediately preceding the maturity date, holders may convert their Convertible Notes at their option. The Convertible Notes are convertible at an initial rate of 23.84 shares per $1,000 of principal (equivalent to an initial conversion price of approximately $41.95 per share of our common stock). The conversion rate is subject to customary adjustments for certain events as described in the Indenture. Upon conversion, we will pay or deliver, as the case may be, cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. It is the Company's current intent to settle conversions of the Convertible Notes through combination settlement, which involves repayment of the principal portion in cash and any excess of the conversion value over the principal amount in shares of our common stock.

Holders may convert their Convertible Notes, at their option, prior to May 15, 2022 only under the following circumstances:

- during any calendar quarter commencing after the calendar quarter ending on June 30, 2017 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day;
- during the five business day period after any five consecutive trading day period (the "Measurement Period") in which the trading price per $1,000 principal amount of the Convertible Notes for each trading day of the Measurement Period was less than 98% of the product of the last reported sales price of our common stock and the conversion rate on each such trading day; or
- upon the occurrence of specified corporate events, as defined in the Indenture.

We may not redeem the Convertible Notes prior to their maturity date, and no sinking fund is provided for them. If we undergo a fundamental change, as described in the Indenture, subject to certain conditions, holders may require us to repurchase for cash all or any portion of their Convertible Notes. The fundamental change repurchase price is equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date. If holders elect to convert their Convertible Notes in connection with a make-whole fundamental change, as described in the Indenture, the Company will, to the extent provided in the Indenture, increase the conversion rate applicable to the Convertible Notes.

The Convertible Notes are senior unsecured obligations and rank senior in right of payment to any of our indebtedness that is expressly subordinated in right of payment to the Convertible Notes and equal in right of payment to any of our existing and future unsecured indebtedness that is not subordinated. The Convertible Notes are effectively junior in right of payment to any of our secured indebtedness (to the extent of the value of assets securing such indebtedness) and structurally junior to all existing and future indebtedness and other liabilities, including trade payables, of our subsidiaries. The Indenture does not limit the amount of debt that we or our subsidiaries may incur. The Convertible Notes are not guaranteed by any of our subsidiaries.

There are no financial or operating covenants related to the Convertible Notes. The Indenture contains customary events of default with respect to the Convertible Notes and provides that upon certain events of default occurring and continuing, the Trustee may, and the Trustee at the request of holders of at least 25% in principal amount of the Convertible Notes shall, declare all of principal and accrued and unpaid interest, if any, of the Convertible Notes to be due and payable. In case of certain events of bankruptcy, insolvency or reorganization, involving us or a significant subsidiary, all of the principal of and accrued and unpaid interest on the Convertible Notes will automatically become due and payable. Upon such a declaration of acceleration, any principal and accrued and unpaid interest will be due and payable immediately.

In accounting for the issuance of the Convertible Notes, the Company separated the Convertible Notes into liability and equity components. We allocated $282.5 million of the Convertible Notes to the liability component, and $62.5 million to the equity component. The excess of the principal amount of the liability component over its carrying amount is amortized to interest expense over the term of the Convertible Notes using the effective interest method. The equity component will not be remeasured as long as it continues to meet the conditions for equity classification.

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We incurred issuance costs of $9.7 million related to the Convertible Notes. Issuance costs were allocated to the liability and equity components based on their relative values. Issuance costs attributable to the liability component are being amortized to interest expense over the term of the Convertible Notes, and issuance costs attributable to the equity component are included along with the equity component in stockholders' equity.

The net carrying amount of the Convertible Notes at June 30, 2017, was as follows, in thousands:

Liability component:	
Principal amount	$345,000
Unamortized discount	(61,497)
Unamortized debt issuance costs	(7,830)
	$275,673
Equity component, net of issuance costs:	$61,401

The following table sets forth total interest expense related to the Convertible Notes for the three and six months ended June 30, 2017, in thousands:

Contractual interest expense	$561
Amortization of debt discount	1,052
Amortization of debt issuance costs	134
	$1,747
Effective interest rate of the liability component	5.87 %

Convertible Note Hedges and Warrants

On May 23, 2017, we entered into privately negotiated transactions to purchase hedge instruments (“Note Hedges”), covering approximately 8.2 million shares of our common stock at a cost of $62.5 million. The Note Hedges are subject to anti-dilution provisions substantially similar to those of the Convertible Notes, have a strike price of approximately $41.95 per share, are exercisable by us upon any conversion under the Convertible Notes, and expire on November 15, 2022.

The Note Hedges are generally expected to reduce the potential dilution to our common stock (or, in the event the conversion is settled in cash, to reduce our cash payment obligation) in the event that at the time of conversion our stock price exceeds the conversion price under the Convertible Notes. The cost of the Note Hedges is expected to be tax deductible as an original issue discount over the life of the Convertible Notes, as the Convertible Notes and the Note Hedges represent an integrated debt instrument for tax purposes. The cost of the Note Hedges was recorded as a reduction of our additional paid-in capital in the accompanying Condensed Consolidated Financial Statements.

On May 23, 2017, the Company also sold warrants for the purchase of up to 8.2 million shares of our common stock for aggregate proceeds of $31.5 million (“Warrants”). The Warrants have a strike price of $57.58 per share and are subject to customary anti-dilution provisions. The Warrants will expire in ratable portions on a series of expiration dates commencing on February 15, 2023. The proceeds from the issuance of the Warrants were recorded as an increase to our additional paid-in capital in the accompanying Condensed Consolidated Financial Statements.

The Note Hedges are transactions that are separate from the terms of the Notes and the Warrants, and holders of the Convertible Notes and the Warrants have no rights with respect to the Note Hedges. The Warrants are similarly separate in both terms and rights from the Note Hedges and the Convertible Notes. As of June 30, 2017, no Note Hedges or Warrants had been exercised.

7. Stock-based Expense

During the three and six months ended June 30, 2017, the Company made the following grants of time-based restricted stock:

Three Months Ended June 30, 2017	Six Months Ended June 30, 2017	Vesting

67,437	1,120,339	Shares vest ratably over a period of twelve quarters beginning on the first day of the second calendar quarter immediately following the grant date.
40,103	49,563	Shares vest ratably over a period of four quarters beginning on the first day of the calendar quarter immediately following the grant date.

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During the three and six months ended June 30, 2017, we also granted 9,404 and 535,441 shares of restricted stock, respectively, which require the achievement of certain market-based conditions to become eligible to vest. The shares become eligible to vest based on the achievement of the following conditions:

Three Months Ended June 30, 2017	Six Months Ended June 30, 2017	Condition to Become Eligible to Vest
3,134	178,480	After the grant date and prior to July 1, 2020, the average closing price per share of our common stock equals or exceeds $38.05 for twenty consecutive trading days.
3,134	178,480	After the grant date and prior to July 1, 2020, the average closing price per share of our common stock equals or exceeds $41.09 for twenty consecutive trading days.
3,136	178,481	After the grant date and prior to July 1, 2020, the average closing price per share of our common stock equals or exceeds $45.66 for twenty consecutive trading days.

Shares that become eligible to vest, if any, become Eligible Shares. These awards vest ratably over four calendar quarters beginning on the first day of the next calendar quarter immediately following the date on which they become Eligible Shares. Vesting is conditional upon the recipient remaining a service provider, as defined in the plan document, to the Company through each applicable vesting date.

Grants of restricted stock may be fulfilled through the issuance of previously authorized but unissued common stock shares, or the reissuance of shares held in Treasury. All awards were granted under the Amended and Restated 2010 Equity Incentive Plan, as amended.

8. Commitments and Contingencies

Lease Commitments

The Company leases office facilities and equipment for various terms under long-term, non-cancellable operating lease agreements. The leases expire at various dates through 2028 and provide for renewal options. The agreements generally require the Company to pay for executory costs such as real estate taxes, insurance, and repairs. At June 30, 2017, minimum annual rental commitments under non-cancellable operating leases were as follows for the years ending December 31, in thousands:

2017	$6,355
2018	12,771
2019	11,835
2020	9,651
2021	9,047
Thereafter	54,348
	$104,007

Guarantor Arrangements

We have agreements whereby we indemnify our officers and directors for certain events or occurrences while the officer or director is or was serving at our request in such capacity. The term of the indemnification period is for the officer or director’s lifetime. The maximum potential amount of future payments we could be required to make under these indemnification agreements is unlimited; however, we have a director and officer insurance policy that limits our exposure and enables us to recover a portion of any future amounts paid. As a result of our insurance policy coverage, we believe the estimated fair value of these indemnification agreements is minimal. Accordingly, we had no liabilities recorded for these agreements as of June 30, 2017 or December 31, 2016.

In the ordinary course of our business, we include standard indemnification provisions in our agreements with clients. Pursuant to these provisions, we indemnify our clients for losses suffered or incurred in connection with third-party claims that our products infringed upon any U.S. patent, copyright, trademark, or other intellectual property right. Where applicable, we generally limit such infringement indemnities to those claims directed solely to our products and not in combination with other software or products. With respect to our products, we also generally reserve the

right to resolve any such claims by designing a non-infringing alternative, by obtaining a license on reasonable terms, or by terminating our relationship with the client and refunding the client's fees.
The potential amount of future payments to defend lawsuits or settle indemnified claims under these indemnification provisions is unlimited in certain agreements; however, we believe the estimated fair value of these indemnification provisions is minimal, and, accordingly, we had no liabilities recorded for these agreements as of June 30, 2017 or December 31, 2016.

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Litigation

From time to time, in the normal course of our business, we are a party to litigation matters and claims. Litigation can be expensive and disruptive to our normal business operations. Moreover, the results of complex legal proceedings are difficult to predict and our view of these matters may change in the future as the litigation and events related thereto unfold. We expense legal fees as incurred. Insurance recoveries associated with legal costs incurred are recorded when they are deemed probable of recovery.

In March 2015, we were named in a purported class action lawsuit in the United States District Court for the Eastern District of Pennsylvania, styled Stokes v. RealPage, Inc., Case No. 2:15-cv-01520. The claims in this purported class action relate to alleged violations of the Fair Credit Reporting Act (“FCRA”) in connection with background screens of prospective tenants of our clients. On January 25, 2016, the court entered an order placing the case on hold until the United States Supreme Court issued its decision in Spokeo, Inc. v. Robins, which case addressed issues related to standing to bring claims related to the FCRA. On May 16, 2016, the U.S. Supreme Court issued its opinion in the Spokeo litigation, vacating the decision of the United States Court of Appeals for the Ninth Circuit, and remanding the case for further consideration by the U.S. Court of Appeals. Following the Supreme Court’s decision in Spokeo, the judge in the Stokes case lifted the stay. On June 24, 2016, we filed a motion to dismiss certain claims made in the case based upon the Spokeo decision. On October 19, 2016, the U.S. District Court denied the motion to dismiss.

In November 2014, we were named in a purported class action lawsuit in the United States District Court for the Eastern District of Virginia, styled Jenkins v. RealPage, Inc., Case No. 3:14cv758. The claims in this purported class action relate to alleged violations of the FCRA in connection with background screens of prospective tenants of our clients. This case has since been transferred to the United States District Court for the Eastern District of Pennsylvania. On January 25, 2016, the court entered an order placing the case on hold until the United States Supreme Court issued its decision in the Spokeo case. Following the Supreme Court’s decision in Spokeo, the judge in the Jenkins case lifted the stay. On June 24, 2016, we filed a motion to dismiss certain claims made in the case based upon the Spokeo decision. On October 19, 2016, the U.S. District Court denied the motion to dismiss.

On June 19, 2017, the court in both the Stokes case and Jenkins case consolidated the cases for purposes of settlement. On June 30, 2017, the parties signed a Settlement Agreement and Release covering both cases and the plaintiffs in the consolidated cases filed an uncontested motion for preliminary approval of the class action settlement and the notice to class. On August 3, 2017, the court issued a written order preliminarily approving the proposed class settlement. The final approval hearing is set for February 6, 2018.

On February 23, 2015, we received from the Federal Trade Commission (“FTC”) a Civil Investigative Demand consisting of interrogatories and a request to produce documents relating to our compliance with the FCRA. We have responded to the request and requests for additional information by the FTC. At this time, we do not have sufficient information to evaluate the likelihood or merits of any potential enforcement action, or to predict the outcome or costs of responding to, or the costs, if any, of resolving this investigation.

At June 30, 2017 and December 31, 2016, we had accrued amounts for estimated settlement losses related to legal matters. The Company does not believe there is a reasonable possibility that a material loss exceeding amounts already recognized may have been incurred as of the date of the balance sheets presented herein.

We are involved in other litigation matters not described above that are not likely to be material either individually or in the aggregate based on information available at this time. Our view of these matters may change as the litigation and events related thereto unfold.

9. Net Income per Share

Basic net income per share is computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted net income per share is computed by using the weighted average number of common shares outstanding, including potential dilutive shares of common stock assuming the dilutive effect of outstanding stock options and restricted stock using the treasury stock method. Weighted average shares from common share equivalents in the amount of 27,422 and 165,166 for the three months ended and 362,522 and 606,700 for the six months ended June 30, 2017 and 2016, respectively, were excluded from the dilutive shares outstanding because their effect was anti-dilutive.

For purposes of considering the Convertible Notes in determining diluted net income per share, it is the current intent of the Company to settle conversions of the Convertible Notes through combination settlement, which involves repayment of the principal portion in cash and any excess of the conversion value over the principal amount (the "conversion premium") in shares of our common stock. Therefore, only the impact of the conversion premium will be included in total dilutive weighted average shares outstanding using the treasury stock method. No conversion premium existed as of June 30, 2017, and as such, there was no dilutive impact from the Convertible Notes for the three and six month periods ended June 30, 2017. The Warrants sold in connection with the issuance of the Convertible Notes will not be considered in calculating the total dilutive weighted

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average shares outstanding until the price of the Company's common stock exceeds the strike price of $57.58, as described in Note 6. When the price of the Company's common stock exceeds the strike price of the Warrants, the effect of the additional shares that may be issued upon exercise of the Warrants will be included in total dilutive weighted average shares outstanding using the treasury stock method. The Note Hedges purchased in connection with the issuance of the Convertible Notes are considered to be anti-dilutive and therefore do not impact the Company's calculation of diluted net income per share. Refer to Note 6 for further discussion regarding the Convertible Notes.
As required by ASU 2016-09, the weighted average effect of dilutive securities for the three and six month periods ended June 30, 2017, was calculated without including consideration of windfall tax benefits, resulting in the repurchase of fewer hypothetical shares and a greater dilutive effect. This change was applied on a prospective basis, and dilutive securities for the same period in 2016 have not been adjusted.
The following table presents the calculation of basic and diluted net income per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands, except per share amounts)			
Numerator:				
Net income	$6,213	$2,083	$14,408	$5,079
Denominator:				
Basic:				
Weighted average common shares used in computing basic net income per share	79,018	76,363	78,642	76,509
Diluted:				
Add weighted average effect of dilutive securities:				
Stock options and restricted stock	2,907	798	3,002	611
Weighted average common shares used in computing diluted net income per share	81,925	77,161	81,644	77,120
Net income per share:				
Basic	$0.08	$0.03	$0.18	$0.07
Diluted	$0.08	$0.03	$0.18	$0.07

10. Income Taxes

We make estimates and judgments in determining our provision for income taxes for financial statement purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing of recognition of revenue and expense for tax and financial statement purposes.
Our provision for income taxes in interim periods is based on our estimated annual effective tax rate. We record cumulative adjustments in the quarter in which a change in the estimated annual effective rate is determined. The estimated annual effective tax rate calculation does not include the effect of discrete events that may occur during the year. The effect of these events, if any, is recorded in the quarter in which the event occurs.
Our effective income tax rate was (19.2)% and 41.9% for the six months ended June 30, 2017 and 2016, respectively. Our effective rate is lower than the statutory rate for the six months ended June 30, 2017, primarily because of excess tax benefits from stock-based compensation of $2.7 million and $4.5 million recognized as discrete items during, respectively, the first and second quarters of 2017, as required by ASU 2016-09. The effective rate is higher than the statutory rate for the six months ended June 30, 2016, primarily because of state income taxes and non-deductible expenses.
As a result of our adoption of ASU 2016-09, on January 1, 2017 we recorded a deferred tax asset of $43.8 million, net of a $0.3 million valuation allowance, with a corresponding increase to retained earnings. The deferred tax asset consisted of excess stock-based compensation deductions that arose but were not recognized in prior years. See additional discussion of our adoption of ASU 2016-09 in Note 2. During the three months ended June 30, 2017, we recorded a deferred tax asset of $0.6 million as a result of differences in the treatment of convertible debt issuance costs for financial reporting and tax purposes.

11. Fair Value Measurements

The Company records certain assets and financial liabilities at fair value on a recurring basis. The Company determines fair values based on the price it would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date and in the principal or most advantageous market for that asset or liability.

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The prescribed fair value hierarchy is as follows:
Level 1 - Inputs are quoted prices in active markets for identical assets or liabilities.
Level 2 - Inputs are quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable; and market-corroborated inputs which are derived principally from or corroborated by observable market data.
Level 3 - Inputs are derived from valuation techniques in which one or more of the significant inputs or value drivers are unobservable.

The categorization of an asset or liability within the fair value hierarchy is based on the inputs described above and does not necessarily correspond to the Company's perceived risk of that asset or liability. Moreover, the methods used by the Company may produce a fair value calculation that is not indicative of the net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments and non-financial assets and liabilities could result in a different fair value measurement at the reporting date.

Assets and liabilities measured at fair value on a recurring basis:

Interest rate swap agreements: The fair value of the Company's interest rate swap agreements are determined using widely accepted valuation techniques including discounted cash flow analysis on the expected cash flows of the swap agreements. This analysis reflects the contractual terms of the swap agreements, including the period to maturity, and uses observable market-based inputs, including interest rate curves. The Company incorporates credit valuation adjustments to appropriately reflect both its own nonperformance risk and the respective counterparty's nonperformance risk in the fair value measurements.

Although the Company has determined that the majority of the inputs used to value its swap agreements fall within Level 2 of the fair value hierarchy, the credit valuation adjustments associated with its swap agreements utilize Level 3 inputs, such as estimates of current credit spreads, to evaluate the likelihood of default by the Company and its counterparties. The Company has assessed the significance of the impact of the credit valuation adjustments on the overall valuation of its swap agreements' positions and has determined that the credit valuation adjustments are not significant to the overall valuation of its swap agreements. As a result, the Company determined that its valuation of the swap agreements in its entirety is classified in Level 2 of the fair value hierarchy.

Contingent consideration obligations: Contingent consideration obligations consist of potential obligations related to our acquisition activity. The amount to be paid under these obligations is contingent upon the achievement of stipulated operational or financial targets by the business subsequent to acquisition. The fair value of contingent consideration obligations is estimated using a probability weighted discount model which considers the achievement of the conditions upon which the respective contingent obligation is dependent. The probability of achieving the specified conditions is assessed by applying a Monte Carlo weighted-average model. Inputs into the valuation model include a discount rate specific to the acquired entity, a measure of the estimated volatility, and the risk free rate of return.

In addition to the inputs described above, the fair value estimates consider the projected future operating or financial results for the factor upon which the respective contingent obligation is dependent. The fair value estimates are generally sensitive to changes in these projections. We develop the projected future operating results based on an analysis of historical results, market conditions, and the expected impact of anticipated changes in our overall business and/or product strategies.

Significant unobservable inputs used in the contingent consideration fair value measurements included the following at June 30, 2017 and December 31, 2016:

	June 30, 2017		December 31, 2016
Discount rates	16.3 - 28.0%		14.8 - 27.8%
Volatility rates	26.0	%	29.9%
Risk free rate of return	1.2 - 1.3%		0.7%

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The following tables disclose the assets and liabilities measured at fair value on a recurring basis as of June 30, 2017 and December 31, 2016, by the fair value hierarchy levels as described above:

	Fair value at June 30, 2017			
	Total	Level 1	Level 2	Level 3
	(in thousands)			
Assets:				
Interest rate swap agreements	$1,103	$ —	$1,103	$—
Liabilities:				
Contingent consideration related to the acquisition of:				
AssetEye	$771	$ —	$—	$771
Axiometrics	623	—	—	623
Total liabilities measured at fair value	$1,394	$ —	$—	$1,394

	Fair value at December 31, 2016			
	Total	Level 1	Level 2	Level 3
	(in thousands)			
Assets:				
Interest rate swap agreements	$1,098	$ —	$1,098	$—
Liabilities:				
Contingent consideration related to the acquisition of:				
Indatus	$2	$ —	$—	$2
AssetEye	539	—	—	539
Total liabilities measured at fair value	$541	$ —	$—	$541

There were no transfers between Level 1 and Level 2, or between Level 2 and Level 3 measurements during the six months ended June 30, 2017.

Changes in the fair value of Level 3 measurements were as follows for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016
	(in thousands)	
Balance at beginning of period	$541	$841
Initial contingent consideration	812	245
Net loss (gain) on change in fair value	41	(427)
Balance at end of period	$1,394	$659

Financial Instruments

The financial assets and liabilities that are not measured at fair value in our Condensed Consolidated Balance Sheets include cash and cash equivalents, restricted cash, accounts receivable, cost-method investments, accounts payable and accrued expenses, acquisition-related deferred cash obligations, obligations under the Term Loan, and Convertible Notes.

The carrying values of cash and cash equivalents; restricted cash; accounts receivable; and accounts payable and accrued expenses reported in our Condensed Consolidated Balance Sheets approximates fair value due to the short term nature of these instruments. Acquisition-related deferred cash obligations are recorded on the date of acquisition at their estimated fair value, based on the present value of the anticipated future cash flows. The difference between the amount of the deferred cash obligation to be paid and its estimated fair value on the date of acquisition is accreted over the obligation period. As a result, the carrying value of acquisition-related deferred cash obligations approximates their fair value.

The carrying value of the Term Loan approximates fair value since it is subject to a short-term floating interest rate that approximates borrowing rates currently available to the Company for debt of similar terms and maturities.
We estimated the fair value of the Convertible Notes based on quoted market prices as of the last trading day for the six months ended June 30, 2017; however, the Convertible Notes have only a limited trading volume and as such this fair value

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estimate is not necessarily the value at which the Convertible Notes could be retired or transferred. The Company concluded that this fair value measurement should be categorized within Level 2. The carrying value of the Convertible Notes is net of unamortized discount and issuance costs. The fair value and carrying value of the Convertible Notes were as follows at June 30, 2017:

	Fair Value	Carrying Value
	(in thousands)	
Convertible Notes	$375,612	$275,673

12. Stockholders' Equity

In May 2014, our board of directors approved a share repurchase program authorizing the repurchase of up to $50.0 million of our outstanding common stock for a period of up to one year after the approval date. Our board of directors approved a one year extension of this program in both 2015 and 2016. On April 28, 2017, our board of directors again approved a one year extension of the share repurchase program. The terms of this extension permit the repurchase of up to $50.0 million of our common stock during the period commencing on the extension day and ending on May 4, 2018.

Repurchase activity during the three and six months ended June 30, 2017 and 2016 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Number of shares repurchased	—	235,154	—	1,012,823
Weighted-average cost per share	$—	$21.71	$—	$20.98
Total cost of shares repurchased, in thousands	$—	$5,106	$—	$21,244

13. Derivative Financial Instruments

On March 31, 2016, the Company entered into two interest rate swap agreements (collectively the "Swap Agreements"), which are designed to mitigate our exposure to interest rate risk associated with a portion of our variable rate debt. The Swap Agreements cover an aggregate notional amount of $75.0 million from March 2016 to September 2019 by replacing the obligation's variable rate with a blended fixed rate of 0.89%. The Company designated the Swap Agreements as cash flow hedges of interest rate risk.

The effective portion of changes in the fair value of the Swap Agreements is recorded in accumulated other comprehensive income and is subsequently reclassified into earnings in the period that the hedged forecasted transaction affects earnings. The ineffective portion of the change in the fair value of the Swap Agreements is recognized directly in earnings. Amounts reported in accumulated other comprehensive income related to the Swap Agreements will be reclassified to interest expense as interest payments are made on our variable-rate debt. The Company estimates that an additional $0.4 million will be reclassified as a decrease of interest expense during the twelve-month period ending June 30, 2018.

As of June 30, 2017, the Swap Agreements were still outstanding. The table below presents the notional and fair value of the Swap Agreements as well as their classification on the Condensed Consolidated Balance Sheets as of June 30, 2017 and December 31, 2016:

	Balance Sheet Location	Notional	Fair Value
		(in thousands)	
Derivatives designated as cash flow hedging instruments:			
Swap agreements as of June 30, 2017	Other assets	$75,000	$1,103
Swap agreements as of December 31, 2016	Other assets	$75,000	$1,098

As of June 30, 2017, the Company has not posted any collateral related to the Swap Agreements. If the Company had breached any of the Swap Agreement's default provisions at June 30, 2017, it could have been required to settle its obligations under the Swap Agreements at their termination value of $1.1 million.

The table below presents the amount of gains and losses related to the effective and ineffective portions of the Swap Agreements and their location on the Condensed Consolidated Statements of Operations and the Condensed Consolidated Statements of Comprehensive Income for the three and six months ended June 30, 2017 and 2016, in thousands:

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Derivatives Designated as Cash Flow Hedges	Effective Portion Gain (Loss) Recognized in OCI	Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income	Ineffective Portion Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income
Three months ended June 30, 2017:					
Swap agreements, net of tax	$(21)	Interest expense and other	$ (3)	Interest expense and other	$ 10
Three months ended June 30, 2016:					
Swap agreements, net of tax	$(550)	Interest expense and other	$ (86)	Interest expense and other	$ —

Derivatives Designated as Cash Flow Hedges	Effective Portion Gain (Loss) Recognized in OCI	Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income	Ineffective Portion Location of Gain (Loss) Recognized in Income	Gain (Loss) Recognized in Income
Six months ended June 30, 2017:					
Swap agreements, net of tax	$73	Interest expense and other	$ 9	Interest expense and other	$ 28
Six months ended June 30, 2016:					
Swap agreements, net of tax	$(629)	Interest expense and other	$ (86)	Interest expense and other	$ —

14. Subsequent Events

Acquisition Activity

On-Site

On July 28, 2017, we entered into an agreement to acquire substantially all of the assets of On-Site Manager, Inc. and certain related entities ("On-Site"). On-Site is a leasing platform for property managers and renters that assimilates leads from any source and converts them into signed leases for both the multifamily and single family housing industries. Pursuant to the asset purchase agreement, the Company will pay approximately $250.0 million in cash, subject to reduction for outstanding indebtedness, unpaid transaction expenses, working capital, and other adjustments. A deferred cash obligation of $24.0 million will be withheld from the purchase consideration to serve as security for the benefit of the Company against the Sellers' indemnification obligations. Subject to any indemnification claims made, the majority of this deferred cash obligation will be released approximately twelve months following the acquisition date, with any remaining funds being released approximately 36 months following the acquisition date. The completion of the acquisition remains subject to certain conditions, including the completion of regulatory review.

Lease Rent Options

On August 1, 2017, the Company and the other parties to the agreement for the purchase of LRO, dated as of February 27, 2017, by and among The Rainmaker Group Holdings, Inc., a Georgia corporation ("Rainmaker"), the Company and the other parties thereto (as previously amended, the "Rainmaker Purchase Agreement"), entered into a second amendment to the Rainmaker Purchase Agreement pursuant to which the parties agreed that the Company will have the unilateral right to extend the Termination Date (as defined in the Rainmaker Purchase Agreement) beyond December 31, 2017 in the event that the U.S. Department of Justice files a complaint under applicable antitrust laws with respect to the transaction on or before December 31, 2017, and following consultation with counsel regarding the likelihood of a successful outcome of the litigation. Any such extension by the Company will effectively extend the Termination Date by six months or the earlier of (i) such time as a federal court issues a final non-appealable order or takes any other action permanently restraining, enjoining or otherwise prohibiting the closing, or otherwise rules that the transaction violates applicable antitrust laws, or (ii) such date as the Company notifies Rainmaker that it elects to terminate the extension. The amendment further provides that if the Company does not elect to extend the Termination Date, either party shall have the right to terminate the Rainmaker Purchase Agreement within 20 days after the U.S. Department of Justice files a complaint under applicable antitrust laws. In the event the Company elects to extend the Termination Date pursuant to the foregoing right, the Company will pay one-half of Rainmaker's legal and related fees and expenses reasonably incurred (from the date such extension is exercised to the Termination Date) in defending the transaction from any complaint filed pursuant to antitrust laws.

If the closing has not occurred by the Termination Date, either the Company or Rainmaker may terminate the Rainmaker Purchase Agreement and abandon the transactions contemplated thereby unless the breach or failure to perform by such party of its obligations under the Rainmaker Purchase Agreement, or the failure to act in good faith, is the principal cause of, or resulted in, the failure of the transactions contemplated under the Rainmaker Purchase Agreement to be consummated on or before such Termination Date.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

This Quarterly Report on Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (which Sections were adopted as part of the Private Securities Litigation Reform Act of 1995). Statements preceded by, followed by, or that otherwise include the words "anticipates," "believes," "could," "seeks," "estimates," "expects "intends," "may," "plans," "potential," "predicts," "projects," "should," "will," "would," or similar expressions and the negativ terms are generally forward-looking in nature and not historical facts. These forward-looking statements involve known and unknown risks, uncertainties, and other factors which may cause our actual results, performance, or achievements to be materially different from any anticipated results, performance, or achievements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in the section entitled "Risk Factors" in Part II, Item 1A of this report. You should carefully review the risks described herein and in the other documents we file from time to time with the Securities and Exchange Commission ("SEC"), including our Annual Report on Form 10-K for fiscal year 2016 previously filed with the SEC on March 1, 2017 and our Quarterly Report on Form 10-Q for the first quarter of 2017 filed on May 8, 2017. You should not place undue reliance on forward-looking statements herein, which speak only as of the date of this report. Except as required by law, we disclaim any intention, and undertake no obligation, to revise any forward-looking statements, whether as a result of new information, a future event, or otherwise.

Overview

We are a technology leader to the real estate industry, helping owners, managers, and investors optimize both operational yields and investment returns. By leveraging data as well as integrating and streamlining a wide range of complex processes and interactions among the apartment real estate ecosystem, our platform helps our clients improve financial and operational performance and prudently place and harvest capital.

The substantial majority of our revenue is derived from sales of our on demand software solutions. We also derive revenue from our professional and other services. A small percentage of our revenue is derived from sales of our on premise software solutions. Our on demand software solutions are sold pursuant to subscription license agreements and our on premise software solutions are sold pursuant to term or perpetual licenses and associated maintenance agreements. We price our solutions based primarily on the number of units the client manages with our solutions. For our insurance-based solutions, we earn revenue based on a commission rate that considers earned premiums; agent commission; incurred losses; and premiums and profits retained by our underwriter. Our transaction-based solutions are priced based on a fixed rate per transaction. We sell our solutions through our direct sales organization and derive substantially all of our revenue from sales in the United States.

We believe there is increasing demand for solutions that bring efficiency and precision to the rental real estate industry, which has historically lacked the tools available to other investment classes. While the use of, and transition to, data analytics and on demand software solutions in the rental real estate industry is growing rapidly, we believe it remains at a relatively early stage of adoption. Additionally, there is a low level of penetration of our on demand software solutions in our existing client base. These factors present us with significant opportunities to generate revenue through sales of additional data analytics and on demand software solutions.

Our company was formed in 1998 to acquire Rent Roll, Inc., which marketed and sold on premise property management systems for the conventional and affordable multifamily rental housing markets. In June 2001, we released OneSite, our first on demand property management system. Since 2002, we have expanded our platform of solutions to include property management, lease management, resident services, and asset optimization capabilities. In addition to the multifamily markets, we now serve the single family, senior living, student living, military housing, commercial, hospitality, and vacation rental markets. In addition, since July 2002, we have completed 37 acquisitions of complementary technologies to supplement our internal product development and sales and marketing efforts and expand the scope of our solutions, the types of rental housing and vacation rental properties served by our solutions, and our client base. In connection with this expansion and these acquisitions, we have committed greater resources to developing and increasing sales of our platform of data analytics and on demand solutions. As of June 30, 2017, we had approximately 5,000 employees.

Solutions and Services

Our platform is designed to serve as a single system of record for all of the constituents of the rental real estate ecosystem; to support the entire renter life cycle, from prospect to applicant to residency or guest to post-residency or post-stay; and to optimize operational yields and returns on investment. Common authentication, work flow, and user experience across solution categories enables each of these constituents to access different applications as appropriate for their roles.

Our platform consists of four primary categories of solutions: Property Management, Lease Management, Resident Services, and Asset Optimization. These solutions provide complementary asset performance and investment decision support; risk mitigation, billing and utility management; resident engagement, spend management, operations and facilities management; and lead generation and lease management capabilities that collectively enable our clients to manage all the stages of the renter life cycle. Each of our solution categories includes multiple product centers that provide distinct capabilities that can be bundled as a package or licensed separately. Each product center integrates with a central repository of lease transaction data, including prospect, renter, and property data. In addition, our open architecture allows third-party applications to access our solutions using our RealPage Exchange platform.

We offer different versions of our platform for different types of properties in different real estate markets. For example, our platform supports the specific and distinct requirements of:

- conventional single family properties;
- conventional multifamily properties;
- affordable Housing and Urban Development ("HUD") properties;
- affordable tax credit properties;
- rural housing properties;
- privatized military housing;
- commercial properties;
- student housing;
- senior living; and
- vacation rentals.

Property Management

Our property management solutions are referred to as ERP systems. These solutions manage core property management business processes, including leasing, accounting, budgeting, purchasing, facilities management, document management, and support and advisory services. It includes a central database of prospect, applicant, renter, and property information that is accessible in real time by our other solutions. Our property management solutions also interface with most popular general ledger accounting systems through our RealPage Exchange platform. This makes it possible for clients to deploy our solutions using our accounting system or a third-party accounting system. Our property management solution category consists of seven primary solutions including OneSite, Propertyware, Kigo, Spend Management Solutions, The RealPage Cloud, SmartSource, and EasyLMS.

Lease Management

Lease management solutions aim to optimize marketing spend and the leasing process. These solutions manage core leasing and marketing processes including websites and syndication, paid lead generation, organic lead generation, lead management, automated lead closure, lead analytics, real-time unit availability, automated online apartment leasing, and applicant screening. Our lease management solution category consists of six primary solutions: Online Leasing, Contact Center, Websites & Syndication, MyNewPlace, Lead2Lease, and Resident Screening.

Resident Services

Our resident services solutions provide a platform to optimize the transactional and social experience of prospects and renters, and enhance a property’s reputation. These solutions facilitate core renter management business processes including utility billing, renter payment processing, service requests, lease renewals, renters insurance, and consulting and advisory services. Our resident services solution category consists of five primary solutions: Resident & Utility Billing, Resident Payments, Resident Portal, Contact Center Maintenance, and Renter's Insurance.

Asset Optimization

Our asset optimization solutions aim to optimize property financial and operational performance, and provide comprehensive analytics-based decision support for optimum investment performance throughout the phases of real estate investment (e.g., acquisition, operation, renovation, and disposition). These solutions facilitate core asset management, business intelligence, performance benchmarking and investment analysis including, real-time yield management, revenue growth forecasting, key variable sensitivity forecasting, internal operating metric benchmarking and external market benchmarking. Our asset optimization solution category consists of four primary solutions: YieldStar Revenue Management, Business Intelligence, Data Analytics, and Asset and Investment Management.

Professional services

We have developed repeatable, cost-effective consulting and implementation services to assist our clients in taking advantage of the capabilities enabled by our asset optimization solutions. Our consulting and implementation methodology leverages the nature of our on demand software architecture, the industry-specific expertise of our professional services employees, and the design of our platform to simplify and expedite the implementation process.

Our consulting and implementation services include project and application management procedures, business process evaluation, business model

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development and data conversion. Our consulting teams work closely with customers to facilitate the smooth transition and operation of our solutions.

We offer training programs for training administrators and onsite property managers on the use of our solutions. Training options include regularly hosted classroom and online instruction (through our online learning courseware), as well as online webinars. Our clients can integrate their own training content with our content to deliver an integrated and customized training program for their on-site property managers.

Recent Developments

Convertible Notes

In May 2017, we raised approximately $304.2 million in net proceeds (after adjusting for debt issue costs, including the underwriting discount, and the net cash used to purchase the Note Hedges and sell the Warrants, discussed below) upon completion of a private offering of convertible senior notes ("Convertible Notes").

The Convertible Notes pay semi-annual interest at a rate of 1.50% per annum on the $345.0 million aggregate principal balance and mature in November 2022. On or after May 15, 2022, and until the close of business on the second scheduled trading day immediately preceding the maturity date, holders may convert their Convertible Notes to shares of our common stock at their option. Prior to May 15, 2022, holders may, at their option, convert their Convertible Notes only subsequent to the occurrence of certain specified circumstances. Upon conversion, we will pay or deliver, as the case may be, cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. It is our stated intention to settle the principal balance of the Convertible Notes in cash and any conversion obligation in excess of the principal portion in shares of our common stock.

We entered into hedging transactions designed to offset dilution to our common stock in the event of a conversion under the Convertible Notes. The note hedge instruments ("Note Hedges") have a strike price of $41.95 per share, which corresponds to the conversion price under the Convertible Notes, and expire in November 2022. To help offset the cost of the Note Hedges, we also issued warrants ("Warrants") for shares of our common stock. The Warrants have a strike price of $57.58 per share, and expire in ratable portions on a series of expiration dates commencing on February 15, 2023. The Note Hedges and Warrants each cover approximately 8.2 million shares of our common stock, subject to customary anti-dilutive provisions.

We intend to use the net offering proceeds for general corporate purposes which may include the acquisition of businesses or assets, or working capital needs. Refer to Note 6 of the accompanying Condensed Consolidated Financial Statements for further discussion of these transactions and their accounting implications.

Acquisition Activity

On-Site Manager, Inc.

In July 2017, we entered into an agreement to acquire substantially all of the assets of On-Site Manager, Inc. and certain related entities ("On-Site"). On-Site is a leasing platform for property managers and renters that assimilates leads from any source and converts them into signed leases for both the multifamily and single family housing industries. On-Site's platform offers solutions similar to our screening and document management business, and also includes prospect and resident portals, online and on premise leasing, payment processing, and eSignature lease execution solutions. We intend to continue to support the On-Site platform and integrate it with our screening and online leasing solutions over time.

Pursuant to the asset purchase agreement, the Company will pay approximately $250.0 million in cash, subject to reduction for outstanding indebtedness, unpaid transaction expenses, working capital, and other adjustments. A deferred cash obligation of $24.0 million will be withheld from the purchase consideration to serve as security for the benefit of the Company against the Sellers' indemnification obligations. Subject to any indemnification claims made, the deferred cash obligation will be paid over a period of 36 months following the acquisition date. The completion of the acquisition remains subject to certain conditions, including the completion of regulatory review. We expect to finance this transaction using cash on hand and amounts available under our Credit Facility.

American Utility Management

In June 2017, RealPage acquired substantially all of the assets of American Utility Management ("AUM"), a provider of utility and energy management services for the multifamily housing industry. AUM helps maximize cost recovery, reduces energy usage and expense, and provides the tools operators of rental real estate need to manage their utilities more effectively. Additionally, AUM’s platform includes tools that enable operators to benchmark energy cost and consumption against their peers. The acquired assets will be integrated with our existing resident utility management platform and our data analytics tools.

We acquired AUM for a purchase price of $69.4 million. The purchase price consisted of a cash payment of $64.8 million at closing, net of cash acquired of $0.1 million, and a deferred cash obligation of up to $5.1 million. The deferred cash obligation, subject to any adjustments related to working capital and the seller's indemnification obligations, will be paid over a period of four years following the date of acquisition.

Lease Rent Options

In February 2017, we entered into an agreement to acquire the assets that comprise the multifamily business (Lease Rent Options or "LRO") of The Rainmaker Group Holdings, Inc. The closing of the proposed acquisition is subject to standard closing conditions, including the completion of the Hart-Scott-Rodino Antitrust Improvements Act review process. The acquisition of LRO will extend our revenue management footprint, augment our repository of real-time lease transaction data, and increase our data science talent and capabilities. We expect the acquisition of LRO to increase the market penetration of our YieldStar Revenue Management solution and drive revenue growth in our other asset optimization solutions.

Pursuant to the purchase agreement, consideration will consist of a cash payment at closing of approximately $298.5 million, subject to reduction for outstanding indebtedness, unpaid transaction expenses, working capital adjustment, and a deferred cash obligation of up to $1.5 million. The deferred cash obligation serves as security for our benefit against the sellers' indemnification obligations. Subject to any indemnification claims made, the deferred cash obligation will be released approximately twelve months following the acquisition date. We expect to finance this transaction with cash on hand and funds available under our Credit Facility.

Axiometrics LLC

In January 2017, we acquired substantially all of the assets of Axiometrics LLC ("Axiometrics"), a leading provider of multifamily market data. This acquisition augmented our existing lease transaction data pool, further enhancing the accuracy and value of the analysis and forecasts provided to our clients through our data analytics solutions. We will integrate Axiometrics with our existing market research database, MPF Research, to form Data Analytics.

Purchase consideration was comprised of a cash payment at closing of $66.1 million, a deferred cash obligation of up to $7.5 million, and contingent cash payments of up to $5.0 million. The deferred cash obligation serves as security for our benefit against the sellers' indemnification obligation and, subject to any indemnification claims made, will be released over a period of two years following the acquisition date. Payment of the contingent cash obligation is dependent upon the achievement of certain revenue targets during the twelve-month period ending December 31, 2018.

2016 Acquisitions

eSupply Systems, LLC

In June 2016, we acquired substantially all of the assets of eSupply Systems, LLC ("eSupply") and those of certain entities related to eSupply. eSupply is an e-procurement software and group purchasing service which augments our existing spend management solutions. The addition of this group purchasing organization provides increased purchasing power and highly competitive pricing structures for our clients. The addition of eSupply's assets rounds out our spend management offering by adding a powerful group purchasing service to an already robust e-procurement platform, a large network of vendors, a vendor credentialing service, and purchasing advisory services.

We acquired eSupply for a purchase price of $7.0 million, consisting of a cash payment of $5.5 million at closing and deferred cash obligations of up to $1.6 million, payable over 18 months after the acquisition date. The deferred cash obligation is subject to adjustments specified in the purchase agreement related to the sellers' indemnification obligations.

AssetEye, Inc.

In May 2016, we acquired all of the issued and outstanding stock of AssetEye, Inc. ("AssetEye"). AssetEye is a data aggregation, reporting, and collaboration platform for institutions holding multiple real estate asset classes. This acquisition expanded our on demand offerings to serve all asset classes, including commercial, hospitality, multifamily, single family, senior living, and student housing. The AssetEye software provides asset and portfolio managers with a solution to evaluate performance, trends, and operations across a portfolio with transparency into property-level data. On demand analytics allow stakeholders to quickly combine financial results and operating metrics based upon portfolio attributes that help evaluate asset management strategies.

We acquired AssetEye's issued and outstanding stock for a purchase price of $4.9 million. The purchase price consisted of a cash payment of $3.6 million at closing, net of cash acquired of $0.8 million; deferred cash obligations of up to $1.0 million, payable over a period of two years following the date of acquisition; contingent cash payments of up to $1.0 million if certain revenue targets are achieved during the three-month period ending September 30, 2017; and additional cash payments of $0.2 million due to former shareholders of AssetEye.

NWP Services Corporation

In March 2016, we acquired all of the issued and outstanding stock of NWP Services Corporation (“NWP”). NWP provides a full range of utility management services, including resident billing; payment processing; utility expense

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management; analytics and reporting; sub-metering and maintenance; and regulatory compliance. The primary products offered by NWP include Utility Logic, Utility Smart, Utility Genius, SmartSource, and NWP Sub-meter. We are integrating NWP into our resident services product family. The integrated platform will enable property owners and managers to increase the collection of rent utilities and energy recovery. We acquired NWP's issued and outstanding stock for a purchase price of $68.2 million. The purchase price consisted of a cash payment of $59.0 million at closing, net of cash acquired of $0.1 million; deferred cash obligations of $7.2 million, payable over a period of three years following the date of acquisition; and other amounts totaling $3.2 million, consisting of payments to certain employees and shareholders of NWP. Through the NWP acquisition, we have obtained a significantly larger share of the utility metering services market. We expect to realize significant synergies by integrating NWP into our existing operating structure and with our Velocity product.

Key Business Metrics

In addition to traditional financial measures, we monitor our operating performance using a number of financially and non-financially derived metrics that are not included in our Condensed Consolidated Financial Statements. We monitor the key performance indicators reflected in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands, except dollar per unit data and percentages)			
Revenue:				
Total revenue	$161,306	$142,719	$314,225	$271,102
On demand revenue	$154,727	$136,610	$300,940	$260,021
On demand revenue as a percentage of total revenue	95.9 %	95.7 %	95.8 %	96.0 %
Non-GAAP total revenue	$162,251	$142,461	$315,875	$270,501
Non-GAAP on demand revenue	$155,672	$136,352	$302,590	$259,420
Adjusted EBITDA	$39,444	$30,662	$76,522	$58,114
Ending on demand units	11,485	11,141		
Average on demand units	11,298	11,070		
On demand annual client value	$649,017	$548,917		
Annualized on demand revenue per average on demand unit	$56.51	$49.27		

On demand revenue: This metric represents the GAAP revenue derived from license and subscription fees relating to our on demand software solutions, typically licensed over one year terms; commission income from sales of renter's insurance policies; and transaction fees for certain of our on demand software solutions. We consider on demand revenue to be a key business metric because we believe the market for our on demand software solutions represents the largest growth opportunity for our business.

On demand revenue as a percentage of total revenue: This metric represents on demand revenue for the period presented divided by total revenue for the same period. We use on demand revenue as a percentage of total revenue to measure our success executing our strategy to increase the penetration of our on demand software solutions and expand our recurring revenue streams attributable to these solutions. We expect our on demand revenue to remain a significant percentage of our total revenue although the actual percentage may vary from period to period due to a number of factors, including the timing of acquisitions; professional and other revenues; and on premise perpetual license sales and maintenance fees.

Ending on demand units: This metric represents the number of rental housing units managed by our clients with one or more of our on demand software solutions at the end of the period. We use ending on demand units to measure the success of our strategy of increasing the number of rental housing units managed with our on demand software solutions. Property unit counts are provided to us by our clients as new sales orders are processed. Property unit counts may be adjusted periodically as information related to our clients' properties is updated or supplemented, which could result in adjustments to the number of units previously reported.

Average on demand units: We calculate average on demand units as the average of the beginning and ending on demand units for each quarter in the period presented. This metric is a measure of our success increasing the number of on demand software solutions utilized by our clients to manage their rental housing units, our overall revenue, and profitability.

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Non-GAAP total revenue: This metric is calculated by adding acquisition-related and other deferred revenue adjustments to total revenue. We believe it is useful to include deferred revenue written down for GAAP purposes under purchase accounting rules and revenue deferred due to a lack of historical experience determining the settlement of the contractual obligation in order to appropriately measure the underlying performance of our business operations in the period of activity and associated expense. Further, we believe this measure is useful to investors as a way to evaluate the Company’s ongoing performance.

The following provides a reconciliation of GAAP to non-GAAP total revenue:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Total revenue	$161,306	$142,719	$314,225	$271,102
Acquisition-related and other deferred revenue adjustments	945	(258)	1,650	(601)
Non-GAAP total revenue	$162,251	$142,461	$315,875	$270,501

Non-GAAP on demand revenue: This metric reflects total on demand revenue plus acquisition-related and other deferred revenue adjustments, as defined below. We believe inclusion of these items provides a useful measure of the underlying performance of our on demand business operations in the period of activity and associated expense. Further, we believe that investors and financial analysts find this measure to be useful in evaluating the Company’s ongoing performance because it provides a more accurate depiction of on demand revenue.

The following provides a reconciliation of GAAP to non-GAAP on demand revenue:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
On demand revenue	$154,727	$136,610	$300,940	$260,021
Acquisition-related and other deferred revenue adjustments	945	(258)	1,650	(601)
Non-GAAP on demand revenue	$155,672	$136,352	$302,590	$259,420

On demand annual client value (“ACV”): ACV represents our estimate of the annual value of our on demand revenue contracts at a point in time. We monitor this metric to measure our success in increasing the number of on demand units, and the amount of software solutions utilized by our clients to manage their rental housing units.

On demand revenue per average on demand unit (“RPU”): We define RPU as ACV divided by average on demand units. We monitor this metric to measure our success in increasing the penetration of on demand software solutions utilized by our clients to manage their rental housing units.

Adjusted EBITDA: We define Adjusted EBITDA as net income, plus (1) acquisition-related and other deferred revenue adjustments, (2) depreciation, asset impairment, and the loss on disposal of assets, (3) amortization of intangible assets, (4) acquisition-related expense (income), (5) costs arising from the Hart-Scott-Rodino review process, (6) interest expense, net, (7) income tax (benefit) expense, (8) headquarters relocation costs, and (9) stock-based expense. We believe that investors and financial analysts find this non-GAAP financial measure to be useful in analyzing the Company’s financial and operational performance, comparing this performance to the Company’s peers and competitors, and understanding the Company’s ability to generate income from ongoing business operations.

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The following provides a reconciliation of net income to Adjusted EBITDA:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Net income	$6,213	$2,083	$14,408	$5,079
Acquisition-related and other deferred revenue adjustments	945	(258)	1,650	(601)
Depreciation, asset impairment, and loss on disposal of assets	6,929	6,563	13,604	12,059
Amortization of intangible assets	8,227	7,737	16,016	14,848
Acquisition-related expense (income)	1,354	(9)	2,564	(66)
Costs arising from Hart-Scott-Rodino review process	2,228	—	2,709	—
Interest expense, net	2,804	1,090	3,924	1,809
Income tax (benefit) expense	(3,132)	1,545	(2,321)	3,659
Headquarters relocation costs	—	1,174	—	2,199
Stock-based expense	13,876	10,737	23,968	19,128
Adjusted EBITDA	$39,444	$30,662	$76,522	$58,114

Non-GAAP Financial Measures

We report our financial results in accordance with GAAP; however, we believe that, in order to properly understand the Company's short-term and long-term financial, operational, and strategic trends, it may be helpful for investors to exclude certain non-cash or non-recurring items when used as a supplement to financial performance measures in accordance with GAAP. These non-cash or non-recurring items result from facts and circumstances that vary in both frequency and impact on continuing operations. We also use results of operations excluding such items to evaluate our operating performance compared against prior periods, make operating decisions, determine executive compensation, and serve as a basis for long-term strategic planning. These non-GAAP financial measures provide us with additional means to understand and evaluate the operating results and trends in our ongoing business by eliminating certain non-cash expenses and other items that we believe might otherwise make comparisons of our ongoing business with prior periods more difficult, obscure trends in ongoing operations, reduce our ability to make useful forecasts, or obscure the ability to evaluate the effectiveness of certain business strategies, and management incentive structures. In addition, we also believe that investors and financial analysts find this information helpful in analyzing our financial and operational performance and comparing this performance to our peers and competitors. These non-GAAP financial measures are used in conjunction with traditional GAAP financial measures as part of our overall assessment of our performance.

We do not place undue reliance on non-GAAP financial measures as measures of operating performance. Non-GAAP financial measures should not be considered substitutes for other measures of financial performance or liquidity reported in accordance with GAAP. There are limitations to using non-GAAP financial measures, including that other companies may calculate these measures differently than we do; that they do not reflect changes in, or cash requirements for, our working capital; and that they do not reflect our capital expenditures or future requirements for capital expenditures. We compensate for the inherent limitations associated with using non-GAAP financial measures through disclosure of these limitations, presentation of our financial statements in accordance with GAAP, and reconciliation of non-GAAP financial measures to the most directly comparable GAAP financial measures.

We exclude or adjust each of the items identified below from the applicable non-GAAP financial measure referenced above for the reasons set forth with respect to each excluded item:

Acquisition-related and other deferred revenue: These items are included to reflect deferred revenue written down for GAAP purposes under purchase accounting rules and revenue deferred due to a lack of historical experience determining the settlement of the contractual obligation in order to appropriately measure the underlying performance of our business operations in the period of activity and associated expense.

Asset impairment and loss on disposal of assets: These items comprise gains and/or losses on the disposal and impairment of long-lived assets, which are not reflective of our ongoing operations. We believe exclusion of these items facilitates a more accurate comparison of our results of operations between periods.

Depreciation of long-lived assets: Long-lived assets are depreciated over their estimated useful lives in a manner reflecting the pattern in which the economic benefit is consumed. Management is limited in its ability to change or influence these charges after the asset has been acquired and placed in service. We do not believe that depreciation expense accurately

reflects the performance of the Company's ongoing operations for the period in which the charges are incurred, and are therefore not considered by management in making operating decisions.
Amortization of intangible assets: These items are amortized over their estimated useful lives and generally cannot be changed or influenced by management after acquisition. Accordingly, these items are not considered by us in making operating decisions. We do not believe such charges accurately reflect the performance of the Company's ongoing operations for the period in which such charges are incurred.
Acquisition-related expense (income): These items consist of direct costs incurred in our business acquisition transactions and the impact of changes in the fair value of acquisition-related contingent consideration obligations. We believe exclusion of these items facilitates a more accurate comparison of the results of the Company's ongoing operations across periods and eliminates volatility related to changes in the fair value of acquisition-related contingent consideration obligations.
Costs arising from Hart-Scott-Rodino review process: This item consists of direct costs incurred related to reviews by the United States Federal Trade Commission and Department of Justice of our anticipated acquisition of LRO under the Hart-Scott-Rodino Antitrust Improvements Act. We believe that these costs are not reflective of the Company's ongoing operations or our normal acquisition activity. Exclusion of these costs facilitates a more accurate comparison of the Company's results across periods.
Headquarters relocation costs: These items consist of duplicative rent and other expenses related to the relocation of our corporate headquarters and data center, which was substantially completed in the third quarter of 2016. These costs are not reflective of the Company's ongoing operations due to their non-recurring nature.
Stock-based expense: This item is excluded because these are non-cash expenditures that we do not consider part of ongoing operating results when assessing the performance of our business, and also because the total amount of the expenditure is partially outside of management's control because it is based on factors such as stock price, volatility, and interest rates, which may be unrelated to the Company's performance during the period in which the expenses are incurred.
Key Components of Our Results of Operations
Revenue
We derive our revenue from three primary sources: our on demand software solutions, our on premise software solutions, and our professional and other services.
On demand revenue: Revenue from our on demand software solutions is comprised of license and subscription fees relating to our on demand software solutions, typically licensed for one year terms; commission income from sales of renter's insurance policies; and transaction fees for certain on demand software solutions, such as payment processing, spend management, and billing services. Typically, we price our on demand software solutions based primarily on the number of units the client manages with our solutions. For our insurance based solutions, our agreement provides for a fixed commission on earned premiums related to the policies sold by us. The agreement also provides for a contingent commission to be paid to us in accordance with the agreement. Our transaction-based solutions are priced based on a fixed rate per transaction.
On premise revenue: Our on premise software solutions are distributed to our clients and maintained locally on the client's hardware. Revenue from our on premise software solutions is comprised of license fees under term and perpetual license agreements. Typically, we have licensed our on premise software solutions pursuant to term license agreements with an initial term of one year that include maintenance and support. Clients can renew their term license agreement for additional one-year terms at renewal price levels.
We no longer actively market our legacy on premise software solutions to new clients, and only license these solutions to a small portion of our existing on premise clients as they expand their porarantee 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 June 30, 2018, 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 condensed consolidated balance sheets with respect to these indemnification obligations.

9. 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, some of which 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

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when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. 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.

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business 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 and executive orders related to environmental matters 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.

10. BENEFIT PLANS

Idaho Power has a noncontributory defined benefit pension plan (pension plan) and two nonqualified defined benefit plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (collectively, 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 the pension plan are based on years of service and the employee's final average earnings. Idaho Power also 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. The following table shows the components of net periodic benefit costs for the pension, SMSP, and postretirement benefits plans for the three months ended June 30, 2018 and 2017 (in thousands).

	Pension Plan		SMSP		Postretirement Benefits		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Service cost	$9,742	$8,245	$(79)	$190	$242	$197	$9,905	$8,632
Interest cost	9,683	9,716	1,061	1,079	656	702	11,400	11,497
Expected return on plan assets	(13,056)	(11,181)	—	—	(605)	(584)	(13,661)	(11,765)
Amortization of prior service cost	2	7	25	32	12	17	39	56
Amortization of net loss	3,394	3,212	947	740	—	—	4,341	3,952
Net periodic benefit cost	9,765	9,999	1,954	2,041	305	332	12,024	12,372
Regulatory deferral of net periodic benefit cost[1]	(9,309)	(9,488)	—	—	—	—	(9,309)	(9,488)
Previously deferred pension costs recognized[1]	4,289	4,289	—	—	—	—	4,289	4,289
Net periodic benefit cost recognized for financial reporting[1][2]	$4,745	$4,800	$1,954	$2,041	$305	$332	$7,004	$7,173

[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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those costs are recovered through rates.

(2) Of total net periodic benefit cost recognized for financial reporting, $4.1 million and $4.4 million, respectively, was recognized in "Other operations and maintenance" and $2.9 million and $2.8 million, respectively, was recognized in "Other expense, net" on the condensed consolidated statements of income of the companies for the three months ended June 30, 2018 and 2017.

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The following table shows the components of net periodic benefit costs for the pension, SMSP, and postretirement benefits plans for the six months ended June 30, 2018 and 2017 (in thousands).

	Pension Plan		SMSP		Postretirement Benefits		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Service cost	$19,485	$16,871	$(158)	$380	$526	$486	$19,853	$17,737
Interest cost	19,365	19,479	2,124	2,157	1,322	1,392	22,811	23,028
Expected return on plan assets	(26,111)	(22,569)	—	—	(1,234)	(1,154)	(27,345)	(23,723)
Amortization of prior service cost	3	14	49	64	24	24	76	102
Amortization of net loss	6,788	6,595	1,894	1,481	—	—	8,682	8,076
Net periodic benefit cost	19,530	20,390	3,909	4,082	638	748	24,077	25,220
Regulatory deferral of net periodic benefit cost(1)	(18,616)	(19,284)	—	—	—	—	(18,616)	(19,284)
Previously deferred pension costs recognized(1)	8,577	8,577	—	—	—	—	8,577	8,577
Net periodic benefit cost recognized for financial reporting(1)(2)	$9,491	$9,683	$3,909	$4,082	$638	$748	$14,038	$14,513

(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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those costs are recovered through rates.

(2) Of total net periodic benefit cost recognized for financial reporting, $8.2 million and $8.9 million, respectively, was recognized in "Other operations and maintenance" and $5.8 million and $5.6 million, respectively, was recognized in "Other expense, net" on the condensed consolidated statements of income of the companies for the six months ended June 30, 2018 and 2017.

Idaho Power has no minimum contribution requirement to its defined benefit pension plan in 2018. However, during the six months ended June 30, 2018, Idaho Power made $20 million of discretionary contributions to its defined benefit pension plan, in a continued effort to 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. The primary impact of pension contributions is on the timing of cash flows, as the timing of cost recovery lags behind contributions.

Idaho Power also has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the Employee Savings Plan.

11. 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 that follows.

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The table below presents the gains and losses on derivatives not designated as hedging instruments for the three and six months ended June 30, 2018 and 2017 (in thousands).

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[1] Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Financial swaps	Operating revenues	$27	$(305)	$266	$1,173
Financial swaps	Purchased power	13	(287)	(189)	(735)
Financial swaps	Fuel expense	(112)	(4)	(800)	666
Financial swaps	Other operations and maintenance	31	(55)	38	(81)
Forward contracts	Operating revenues	—	—	2	—
Forward contracts	Purchased power	(7)	(8)	(20)	(10)
Forward contracts	Fuel expense	10	3	24	3

[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 revenues from contracts with customers 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 12 - "Fair Value Measurements" 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 June 30, 2018, and December 31, 2017 (in thousands).

	Balance Sheet Location	Asset Derivatives Gross Fair Value	Amounts Offset	Net Assets	Liability Derivatives Gross Fair Value	Amounts Offset	Net Liabilities
June 30, 2018							
Current:							
Financial swaps	Other current assets	$1,545	$(791)	$ 754	$791	$(791)	$ —
Financial swaps	Other current liabilities	195	(195)	—	1,051	(195)	856
Forward contracts	Other current assets	3	—	3	—	—	—
Long-term:							
Financial swaps	Other assets	49	(1)	48	1	(1)	—
Financial swaps	Other liabilities	15	(15)	—	354	(15)	339
Total		$1,807	$(1,002)	$ 805	$2,197	$(1,002)	$ 1,195
December 31, 2017							
Current:							

Financial swaps	Other current assets	$18	$—	$ 18	$—	$—	$ —
Financial swaps	Other current liabilities	553	(553)	—	1,971	(748)[(1)]	1,223
Forward contracts	Other current liabilities	—	—	—	2	—	2
Long-term:							
Financial swaps	Other assets	4	—	4	—	—	—
Total		$575	$(553)	$ 22	$1,973	$(748)	$ 1,225

(1) Current liability derivative amount offset includes $0.2 million of collateral receivable for the period ended December 31, 2017.

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The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at June 30, 2018 and 2017 (in thousands of units).

		June 30,	
Commodity	Units	2018	2017
Electricity purchases	MWh	323	194
Electricity sales	MWh	58	38
Natural gas purchases	MMBtu	12,371	10,297
Natural gas sales	MMBtu	233	75
Diesel purchases	Gallons	451	605

Credit Risk

At June 30, 2018, 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 Idaho Power 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 June 30, 2018 was $2.2 million. Idaho Power posted $0.8 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on June 30, 2018, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $3.0 million to cover the open liability positions as well as completed transactions that have not yet been paid.

12. 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 condensed 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 have the ability to access.

• Level 2: Financial assets and liabilities whose values are based on the following:
a) quoted prices for similar assets or liabilities in active markets;
b) quoted prices for identical or similar assets or liabilities in non-active markets;
c) pricing models whose inputs are observable for substantially the full term of the asset or liability; 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.

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• 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 six months ended June 30, 2018.

The table below presents information about IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of June 30, 2018, and December 31, 2017 (in thousands).

	June 30, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds								
IDACORP [1]	$30,611	$ —	$ —	$30,611	$28,038	$ —	$ —	$28,038
Idaho Power	80,593	—	—	80,593	10,260	—	—	10,260
Derivatives	802	3	—	805	22	—	—	22
Equity securities	27,916	—	—	27,916	30,266	—	—	30,266
Liabilities:								
Derivatives	1,195	—	—	1,195	1,223	2	—	1,225

[1] Holding company only. Does not include amounts held by Idaho Power.

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 with quoted prices in an active market. Natural gas and diesel derivatives are valued using New York Mercantile Exchange and Intercontinental Exchange pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. Equity securities consist of employee-directed investments related to an executive deferred compensation plan and actively traded money market and exchange traded funds related to the SMSP. The investments are measured using quoted prices in active markets 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 June 30, 2018, and December 31, 2017, using available market information and appropriate valuation methodologies (in thousands).

	June 30, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
IDACORP				
Assets:				
Notes receivable[1]	$3,804	$ 3,804	$3,804	$ 3,804
Liabilities:				
Long-term debt[1]	1,834,055	1,946,794	1,746,121	1,915,459
Idaho Power				

Liabilities:				
Long-term debt[(1)]	1,834,055	1,946,794	1,746,121	1,915,459

[(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 12.

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.

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13. SEGMENT INFORMATION

IDACORP’s only reportable segment is utility operations. The utility operations segment’s primary source of revenue is the regulated operations of 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 one-third 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 projects, 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).

	Utility Operations	All Other	Eliminations	Consolidated Total
Three months ended June 30, 2018:				
Revenues	$ 338,699	$ 1,253	$ —	$ 339,952
Net income attributable to IDACORP, Inc.	60,637	1,651	—	62,288
Total assets as of June 30, 2018	6,133,502	153,529	(80,914)	6,206,117
Three months ended June 30, 2017:				
Revenues	$ 331,768	$ 1,238	$ —	$ 333,006
Net income attributable to IDACORP, Inc.	48,381	1,450	—	49,831
Six months ended June 30, 2018:				
Revenues	$ 648,160	$ 1,898	$ —	$ 650,058
Net income attributable to IDACORP, Inc.	96,493	1,937	—	98,430
Six months ended June 30, 2017:				
Revenues	$ 633,732	$ 1,818	$ —	$ 635,550
Net income attributable to IDACORP, Inc.	80,863	2,070	—	82,933

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14. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the three and six months ended June 30, 2018 and 2017 (in thousands). Items in parentheses indicate charges to AOCI.

	Defined Benefit Pension Items			
	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Balance at beginning of period	$(30,243)	$(20,411)	$(30,964)	$(20,882)
Amounts reclassified out of AOCI	722	470	1,443	941
Balance at end of period	$(29,521)	$(19,941)	$(29,521)	$(19,941)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the three and six months ended June 30, 2018 and 2017 (in thousands). Items in parentheses indicate increases to net income.

Details About AOCI	Amount Reclassified from AOCI			
	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Amortization of defined benefit pension items[1]				
Prior service cost	$25	$32	$49	$64
Net loss	947	740	1,894	1,481
Total before tax	972	772	1,943	1,545
Tax benefit[2]	(250)	(302)	(500)	(604)
Net of tax	722	470	1,443	941
Total reclassification for the period	$722	$470	$1,443	$941

[1] Amortization of these items is included in IDACORP's condensed consolidated income statements in other operating expenses and in Idaho Power's condensed consolidated statements of income in other expense, net.
[2] The tax benefit is included in income tax expense in the condensed consolidated statements of income of both IDACORP and Idaho Power.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of IDACORP, Inc.

Results of Review of Interim Financial Information

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the “Company”) as of June 30, 2018, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2018 and 2017 and of equity and cash flows for the six-month periods ended June 30, 2018 and 2017, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2017, and the related consolidated statements of income, comprehensive income, equity, and cash flows for the year then ended (not presented herein); and in our report dated February 22, 2018, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2017, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

Basis for Review Results

This interim financial information is the responsibility of the Company’s management. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
August 2, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Idaho Power Company

Results of Review of Interim Financial Information

We have reviewed the accompanying condensed consolidated balance sheet of Idaho Power Company and subsidiary (the “Company”) as of June 30, 2018, the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2018 and 2017 and cash flows for the six-month periods ended June 30, 2018 and 2017, and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2017, and the related consolidated statements of income, comprehensive income, retained earnings and cash flows for the year then ended (not presented herein); and in our report dated February 22, 2018, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2017, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

Basis for Review Results

This interim financial information is the responsibility of the Company’s management. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
August 2, 2018

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ITEM 2. 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 condensed consolidated financial statements of IDACORP and Idaho Power. Also refer to "Cautionary Note Regarding Forward-Looking Statements" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2017, and should also be read in conjunction with the information in that report. The results of operations for an interim period generally will not be indicative of results for the full year, particularly in light of the seasonality of Idaho Power's sales volumes, as discussed below.

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 (Jim Bridger plant). IDACORP’s other significant subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments, and 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).

EXECUTIVE OVERVIEW

Management's Outlook and Company Initiatives

In the Annual Report on Form 10-K for the year ended December 31, 2017, IDACORP's and Idaho Power's management included a brief overview of their initiatives and strategies for the companies for 2018 and beyond, under the heading "Executive Overview - 2018 Initiatives and Strategy" in the MD&A. As of the date of this report, management's outlook and strategy remain consistent with that discussion. Most notably:

- Idaho Power continues to expect positive customer growth in its service area, and continues to participate in and support state and local economic development initiatives aimed at responsible and sustainable growth. During the first six months of 2018, Idaho Power's customer count grew by approximately 5,700 customers, and for the twelve months ended June 30, 2018, the customer growth rate was 2.2 percent.
- Idaho Power anticipates substantial capital investments, with expected total capital expenditures of approximately $1.5 billion over the five-year period from 2018 (including the expenditures incurred so far in 2018) through 2022.
- Idaho Power continues to execute on its four strategic areas: growing to enhance financial strength, improving Idaho Power's core business, enhancing Idaho Power’s brand, and focusing on safety and employee engagement.

- Idaho Power continues to focus on timely recovery of costs and earning a reasonable return on investment, including working to evaluate and ensure that its rate design and regulatory mechanisms properly reflect the cost to provide electric service.

During the first six months of 2018, Idaho Power reached various regulatory settlements that were approved by the IPUC and OPUC. These approved settlements related to recent income tax reform, the indefinite extension, with modifications, of the current earnings support and sharing mechanism, the prudence of certain Hells Canyon Complex (HCC) relicensing costs, and the treatment of costs incurred to join the energy imbalance market implemented in the western United States (Western EIM). In May 2018, the IPUC issued an order authorizing the creation of new customer classes for customers with on-site generation, and in June 2018, the IPUC issued an order requiring further investigation to resolve eligibility issues for the new

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customer classes. Idaho Power believes that these regulatory actions are positive outcomes as they reduce future uncertainty for both shareholders and customers. Refer to "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings.

Summary of 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 three and six months ended June 30, 2018 and 2017 (in thousands, except earnings per share amounts):

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Idaho Power net income	$60,637	$48,381	$96,493	$80,863
Net income attributable to IDACORP, Inc.	$62,288	$49,831	$98,430	$82,933
Average outstanding shares – diluted	50,481	50,407	50,472	50,402
IDACORP, Inc. earnings per diluted share	$1.23	$0.99	$1.95	$1.65

The table below provides a reconciliation of net income attributable to IDACORP for the three and six months ended June 30, 2018, from the same periods in 2017 (items are in millions and are before related income tax impact unless otherwise noted).

	Three months ended		Six months ended	
Net income attributable to IDACORP, Inc. - June 30, 2017		$49.8		$82.9
Increase (decrease) in Idaho Power net income:				
Customer growth, net of associated power supply costs and power cost adjustment mechanisms	1.8		4.2	
Usage per retail customer, net of associated power supply costs and power cost adjustment mechanisms	4.7		(6.9)	
Idaho fixed cost adjustment (FCA) revenues	2.3		11.0	
Retail revenues per megawatt-hour (MWh), net of associated power supply costs and power cost adjustment mechanisms	(6.8)		(9.4)	
Transmission services (wheeling) and other revenues	1.3		4.0	
Other operations and maintenance (O&M) expense	(5.6)		(4.8)	
Depreciation expense	3.9		0.6	
Other changes in operating revenues and expenses, net	(0.7)		(1.1)	
Increase (decrease) in Idaho Power operating income	0.9		(2.4)	
Earnings of equity-method investments	1.0		3.9	
Non-operating income and expenses	0.7		1.2	
Additional accumulated deferred investment tax credits (ADITC) amortization	1.4		—	
Tax benefit from make-whole premium for early bond redemption	1.3		1.3	
Income tax expense (excluding additional ADITC amortization and tax benefit from early bond redemption)	7.0		11.6	
Total increase in Idaho Power net income		12.3		15.6
Other IDACORP changes (net of tax)		0.2		(0.1)
Net income attributable to IDACORP, Inc. - June 30, 2018		$62.3		$98.4

Net Income - Second Quarter 2018

IDACORP's net income increased $12.5 million for the second quarter of 2018 compared with the second quarter of 2017, primarily due to higher net income at Idaho Power.
Customer growth increased operating income by $1.8 million in the second quarter of 2018 compared with the second quarter of 2017, as the number of Idaho Power customers grew by 2.2 percent during the twelve months ended June 30, 2018. Sales volumes on a per-customer basis also increased operating income by $4.7 million in the second quarter of 2018 compared with

the second quarter of 2017. Precipitation in Idaho Power's service area was near normal in the second quarter of 2018, but was significantly less than precipitation in the second quarter of 2017. This resulted in a 15 percent increase in usage per agricultural irrigation customer, who use electricity to operate irrigation pumps. The increase in sales volumes to irrigation customers was partially offset by a decrease in usage per residential customer as milder temperatures in the second quarter of 2018 compared with the second quarter of 2017 caused residential customers to use less electricity for cooling and heating. The decrease in residential sales volumes was partially offset by the FCA mechanism, which increased revenues by $2.3 million during the second quarter of 2018 compared with the second quarter of 2017.

The net decrease in retail revenues per MWh decreased operating income by $6.8 million in the second quarter of 2018 compared with the second quarter of 2017. The settlement stipulations approved by the IPUC and OPUC during the second quarter of 2018 relating to recent income tax reform (discussed in more detail below), reduced revenues in the second quarter of 2018. In the second quarter of 2017, the IPUC and OPUC each approved settlement stipulations related to Idaho Power’s plan to end its participation in coal-fired operations at Idaho Power’s jointly-owned North Valmy coal-fired power plant (Valmy Plant) by the end of 2025. The Valmy Plant settlement stipulations provided for an accrual of six months of the increase in retail revenues, depreciation expense, and associated income tax expense in the second quarter of 2017, resulting in a decrease in these items in the second quarter of 2018 compared with the same period in 2017.

Other O&M expenses were $5.6 million higher in the second quarter of 2018 compared with the second quarter of 2017. As provided by the settlement stipulation approved by the IPUC related to income tax reform, O&M expenses in the second quarter of 2018 included $1.1 million of non-cash amortization expense of regulatory deferrals that would otherwise be a future liability of Idaho customers. Also, transmission and distribution asset maintenance expense increased $0.9 million in the second quarter of 2018 compared with 2017 due to higher maintenance service costs. Labor and benefit costs increased $3.1 million, primarily related to the timing of accruals for variable employee-related costs which resulted in earlier recognition of expense in the second quarter of 2018 compared with 2017.

Depreciation expense was $3.9 million lower in the second quarter of 2018 compared with the second quarter of 2017, due mostly to the effect of recognizing six months of the accelerated depreciation during the second quarter of 2017 as provided by the 2017 Valmy Plant settlement stipulation described above. This decrease was partially offset by higher depreciation expense from an increase in electric plant in service.

Idaho Power income tax expense, excluding additional ADITC amortization and the $1.3 million flow-through benefit of tax deductible make-whole premiums that Idaho Power paid in connection with the early redemption of long-term debt in April 2018, decreased $7.0 million in the second quarter of 2018 compared with the second quarter of 2017, due primarily to the lower federal and state statutory income tax rates resulting from income tax reform discussed in further detail below. In addition, the Valmy Plant settlement stipulation described above increased income tax expense in the second quarter of 2017. Idaho Power reversed $0.5 million of previously recorded additional ADITC amortization under its Idaho regulatory settlement stipulation during the second quarter of 2018, compared with a reversal of $1.9 million during the second quarter of 2017. Based on Idaho Power's current expectations of full-year 2018 results, Idaho Power does not expect to record additional ADITC amortization in 2018.

Net Income - Year-to-Date 2018
IDACORP's net income increased $15.5 million for the first half of 2018 compared with the same period in 2017, primarily due to higher net income at Idaho Power. Customer growth added $4.2 million to Idaho Power operating income, compared with the first half of 2017. Lower usage per residential customer in the first six months of 2018 reduced operating income by $6.9 million, due primarily to milder temperatures, compared with the first six months of 2017. The lower residential customer usage was partially offset by higher usage per irrigation customer in the second

quarter of 2018, due to lower precipitation, compared with the same period in 2017. However, due to the lower usage by residential customers, the FCA mechanism added $11.0 million to operating income during the first six months of 2018, compared with the first six months of 2017.

The net decrease in retail revenues per MWh decreased operating income by $9.4 million in the first six months of 2018 compared with the same period in 2017. The settlement stipulations approved by the IPUC and OPUC during the second quarter of 2018 relating to recent income tax reform (discussed in more detail below) reduced revenue in the first six months of 2018.

During the first six months of 2018, Idaho Power benefited from a $4.0 million increase in third-party use of electric property, wheeling, and other revenue, compared with the first six months of 2017. This change was largely due to an increase in Idaho Power's open access transmission tariff (OATT) rates that became effective in October 2017.

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Other O&M expenses were $4.8 million higher in the first six months of 2018 compared with the first six months of 2017. As noted above, related to recent income tax reform regulatory settlements, O&M expenses in the first six months of 2018 included $1.1 million of non-cash amortization expense of regulatory deferrals that would otherwise be a future liability of Idaho customers. Also, transmission and distribution asset maintenance expense increased $2.0 million in the second quarter of 2018 compared with the first half of 2017 due to higher maintenance service costs. Labor and benefit costs increased $1.7 million primarily related to the timing of accruals for variable employee-related costs, which resulted in earlier recognition of expense in the first six months of 2018 compared with 2017.

Idaho Power's income tax expense, excluding the $1.3 million flow-through benefit of tax deductible make-whole premiums that Idaho Power paid in connection with the early redemption of long-term debt in April 2018, was $11.6 million lower during the first six months of 2018 compared with the first six months of 2017, due mostly to the lower federal and state statutory income tax rates resulting from income tax reform discussed in further detail below.
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 below in this MD&A. To provide context for the discussion elsewhere in this report, some of the more notable factors are summarized below:

- Income Tax Reform: In December 2017, the Tax Cuts and Jobs Act was signed into law, which lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. The majority of the changes, including the rate reduction, became effective on January 1, 2018. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. In May 2018, the IPUC issued an order approving a settlement stipulation (May 2018 Idaho Tax Reform Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the settlement stipulation provides an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through the Idaho-jurisdiction power cost adjustment (PCA) mechanism during the period from June 1, 2018, through May 31, 2019, for the income tax reform benefits accrued from January 1, 2018 to May 31, 2018, and the income tax reform benefits related to Idaho Power's OATT. The amount provided via the PCA mechanism will decrease to $2.7 million on June 1, 2019, for income tax reform benefits related to Idaho Power's OATT and will cease on June 1, 2020, to reflect the impact of a full year of reduced OATT third-party transmission revenues. The May 2018 Idaho Tax Reform Settlement Stipulation was designed to return to Idaho customers their share of the estimated annual pro forma tax expense reductions resulting from income tax reform, based on the full-year 2017 as required by the IPUC. Idaho Power financial results from 2018 forward will be affected by any differences between annual income tax expense and the pro forma 2017 income tax expense used in the settlement until affected by a future rate proceeding or rate case. The May 2018 Idaho Tax Reform Settlement Stipulation also provides for the indefinite extension of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation beyond its termination date of December 31, 2019. Refer to "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings.

- 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. Idaho Power focuses on timely recovery of its costs through filings with its regulators, working to put in place innovative regulatory mechanisms, and on the prudent management of expenses and investments. Idaho Power currently has a regulatory settlement stipulation in Idaho that includes provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent Idaho ROE. The settlement stipulation also provides for the potential sharing between Idaho Power and customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. In May 2018, the IPUC approved an Idaho settlement stipulation that provides for the indefinite extension of the current mechanism with the modification of certain terms, which are described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report. During 2018, Idaho Power will continue to assess the need to file a general rate case to reset base rates, but does not anticipate filing a rate case in the next twelve months.

- Economic Conditions and Loads: Economic conditions impact consumer demand for energy, revenues, collectability of accounts, the volume of wholesale energy sales, and the need to construct and improve infrastructure, purchase

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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. Over the 12 months ended June 30, 2018, Idaho Power's customer count grew by 2.2 percent. Idaho Power expects its number of customers to continue to increase in the foreseeable future. Employment in Idaho Power's service area grew by approximately 3.2 percent during the twelve months ended June 30, 2018, based on Idaho Department of Labor preliminary June 2018 data. Idaho Power has in recent years supported State of Idaho-coordinated efforts to promote economic development with an emphasis on attracting industrial and commercial customers to its service area.

Idaho Power’s system is dual peaking, with the larger peak demand occurring in the summer. On July 9, 2018, Idaho Power reached its highest system peak demand so far in 2018 of 3,392 MW, which was 30 MW below the all-time system peak demand. The all-time system peak demand was 3,422 MW, set on July 7, 2017.

In June 2017, Idaho Power filed its Integrated Resource Plan (IRP), Idaho Power's long-term forecast of loads and resources. The load forecast assumptions Idaho Power used in the 2017 IRP are included in the table below. For comparison purposes, the analogous average annual growth rates used in the prior two IRPs are included.

	5-Year Forecast		20-Year Forecast	
	Annual Growth Rate: Retail Sales (Billed MWh)	Annual Growth Rate: Annual Peak (Peak Demand)	Annual Growth Rate: Retail Sales (Billed MWh)	Annual Growth Rate: Annual Peak (Peak Demand)
2017 IRP	1.1%	1.6%	0.9%	1.4%
2015 IRP	1.1%	1.5%	1.1%	1.4%
2013 IRP	1.2%	1.5%	1.0%	1.3%

• Weather Conditions: Weather and agricultural growing conditions have a significant impact on Idaho Power's energy 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 extent 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. Much of the adverse or favorable impact of weather on sales of energy to residential and small commercial customers is mitigated through the Idaho FCA mechanism, which is described in Note 3 - "Regulatory Matters" to the condensed consolidated financial statements in this report.

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 wholesale energy 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 mechanisms. For 2018, Idaho Power expects generation from its hydroelectric resources to be in the range of 8.0 to 9.0 million MWh, compared with 20-year average annual hydroelectric generation of 7.6 million MWh.

• 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 and certain other assets, 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 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

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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.

- Mitigation of Impact of Fuel and Purchased Power Expense: In addition to hydroelectric generation, Idaho Power relies significantly on natural gas and coal 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 decreased 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. The Idaho and Oregon power cost adjustment mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power.

- 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, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council. 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. 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: 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 involved, Idaho Power's relicensing costs have been and are expected to continue to be substantial. Idaho Power cannot currently determine the ultimate terms of, and costs associated with, any resulting long-term license.

RESULTS OF OPERATIONS

This section of MD&A takes a closer look at the significant factors that affected IDACORP’s and Idaho Power’s earnings during the three and six months ended June 30, 2018. In this analysis, the results for the three and six months ended June 30, 2018, are compared with the same period in 2017.

The table below presents Idaho Power’s energy sales and supply (in thousands of MWh) for the three and six months ended June 30, 2018 and 2017.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Retail energy sales	3,576	3,464	6,822	6,872
Wholesale energy sales	821	751	1,681	1,439
Bundled energy sales	73	85	297	151
Total energy sales	4,470	4,300	8,800	8,462
Hydroelectric generation	2,847	2,815	5,571	5,177
Coal generation	459	505	1,067	1,342

Natural gas and other generation	124	68	228	399
Total system generation	3,430	3,388	6,866	6,918
Purchased power	1,383	1,246	2,572	2,154
Line losses	(343)	(334)	(638)	(610)
Total energy supply	4,470	4,300	8,800	8,462

Sales Volume and Generation: In the second quarter of 2018, retail sales volumes increased 112 thousand MWh, or 3 percent, compared with the second quarter of 2017. During the first six months of 2018, retail sales volumes decreased 50 thousand MWh, or 1 percent, compared with the same period in the prior year. Customer growth increased sales volumes during the three and six months ended June 30, 2018 compared with the same periods in 2017, with the number of Idaho Power's customers growing by 2.2 percent over the prior twelve months. During the second quarter of 2018, usage per irrigation customer was approximately 15 percent higher compared with the same period in 2017. Precipitation in the Idaho Power service area during the three months ended June 30, 2018 was significantly less than in the same period of 2017, which increased usage by irrigation customers. Usage per residential customer was approximately 4 percent and 8 percent lower in the second quarter and the first six months of 2018, respectively, compared with the second quarter and first six months of 2017. The decrease in residential usage was primarily due to more moderate weather during the first six months of 2018 compared with the first six months of 2017, which decreased the use of electricity for heating and cooling purposes. Heating degree-days were 16 percent lower during the six months ended June 30, 2018 compared with the six months ended June 30, 2017, and 13 percent below normal during the six months ended June 30, 2018.

Wholesale energy sales volumes increased 70 thousand MWh, or 9 percent, and 242 thousand MWh, or 17 percent, in the second quarter and first six months of 2018, respectively, compared with the second quarter and first six months of 2017, due primarily to an increase in hydroelectric generation and purchased power resulting in increased energy available for wholesale energy sales. For the second quarter and first six months of 2018, hydroelectric generation comprised 83 percent and 81 percent of Idaho Power's total system generation, respectively, compared with 83 percent and 75 percent, respectively, for the second quarter and first six months of 2017. Generation from Idaho Power's hydroelectric plants increased due to strong reservoir storage attributable to above-normal snowpack from 2017 and near-normal snowpack in 2018.

The financial impacts of fluctuations in wholesale energy sales, purchased power, fuel expense, and other power supply-related expenses are addressed in Idaho Power's Idaho and Oregon power cost adjustment mechanisms, which are described later in this MD&A.

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Operating Revenues

Retail Revenues: The table below presents Idaho Power's retail revenues (in thousands) and MWh sales volumes (in thousands) for the three and six months ended June 30, 2018 and 2017, and the number of customers as of June 30, 2018 and 2017.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Retail revenues:				
Residential (includes $5,508, $3,205, $19,052 and $8,331, respectively, related to the FCA[1])	$109,155	$112,534	$255,838	$264,689
Commercial (includes $291, $276, $652 and $387, respectively, related to the FCA[1])	76,965	78,982	151,191	153,260
Industrial	48,868	49,766	94,660	95,224
Irrigation	65,065	56,068	65,471	56,993
Deferred revenue related to HCC relicensing AFUDC[2]	(1,462)	(2,349)	(4,046)	(4,933)
Total retail revenues	$298,591	$295,001	$563,114	$565,233
Volume of retail sales (MWh)				
Residential	1,036	1,057	2,439	2,597
Commercial	969	952	1,970	1,980
Industrial	815	811	1,648	1,641
Irrigation	756	644	765	654
Total retail MWh sales	3,576	3,464	6,822	6,872
Number of retail customers at period end				
Residential	458,448	448,159		
Commercial	71,074	69,818		
Industrial	116	121		
Irrigation	21,165	20,886		
Total customers	550,803	538,984		

[1] The FCA mechanism is an alternative revenue program and does not represent revenue from contracts with customers.

[2] As part of its January 30, 2009 general rate case order, the IPUC is allowing Idaho Power to recover a portion of the allowance for funds used during construction (AFUDC) on construction work in progress related to the HCC relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting approximately $8.8 million annually in the Idaho jurisdiction but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs approved for recovery are placed in service. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation described in Note 3 - "Regulatory Matters," Idaho Power was collecting $10.7 million annually.

Changes in rates, changes in customer demand, and changes in FCA mechanism revenues are the primary reasons for fluctuations in retail revenues from period to period. The primary influences on customer demand for electricity are weather and economic conditions. 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. Rates are also seasonally adjusted, providing for higher rates during peak load periods, and residential customer rates are tiered, providing for higher rates based on higher levels of usage. The seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings. For purposes of illustration, Boise, Idaho weather-related information for the three and six months ended June 30, 2018 and 2017, is presented in the table that follows.

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	Three months ended June 30,			Six months ended June 30,		
	2018	2017	Normal	2018	2017	Normal (2)
Heating degree-days(1)	486	720	719	2,783	3,311	3,199
Cooling degree-days(1)	192	233	183	192	233	183
Precipitation (inches)	3.1	4.2	3.3	6.9	11.2	6.9

(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.
(2) Normal heating degree-days and cooling degree-days elements are, by convention, the arithmetic mean of the elements computed over 30 consecutive years. The normal amounts are the sum of the monthly normal amounts. These normal amounts are computed by the National Oceanic and Atmospheric Administration.

Retail revenues increased $3.6 million during the second quarter of 2018, but decreased $2.1 million during the first six months of 2018, compared with the same periods in 2017. The factors affecting retail revenues during the period are discussed below.

- Rates: Rate changes, including the revenue accruals provided for in the 2017 Valmy Plant settlement stipulations and the revenue reductions due to the settlement stipulations related to recent income tax reform, decreased retail revenues by $7.3 million and $6.6 million for the three and six months ended June 30, 2018, respectively, compared with the same periods in 2017. In the second quarter of 2017, the IPUC and OPUC each approved settlement stipulations related to Idaho Power’s plan to end its participation in coal-fired operations at the Valmy Plant by the end of 2025. The Valmy Plant settlement stipulations provided for an accrual of six months of the increase in retail revenues, depreciation expense, and associated income tax expenses in the second quarter of 2017, resulting in a decrease in these items in the second quarter of 2018 compared with the same period in 2017. As a direct result of settlement stipulations approved by the IPUC and OPUC during the second quarter of 2018 relating to income tax reform, Idaho Power's revenues decreased in the second quarter of 2018. Also, more moderate winter and spring temperatures in the first half of 2018 compared with the first half of 2017 led to a lower proportion of residential sales in higher rate categories under Idaho Power's tiered rate structure in the first half of 2018. The customer rates include collection of amounts related to the PCA mechanism, which decreased revenue $0.8 million in the three months ended June 30, 2018, but increased revenue $2.5 million in the six months ended June 30, 2018, compared with the first three and six months of 2017. The collection of amounts related to the PCA mechanism in rates has no effect on operating income as a corresponding amount is recorded as expense in the same period it is collected through rates.
- Customers: Continued customer growth increased retail revenues $2.2 million and $5.6 million in the first three and six months of 2018, respectively, compared with the same periods in 2017.
- Usage: Higher usage (on a per customer basis), primarily by irrigation customers, increased retail revenues by $6.3 million during the second quarter of 2018 when compared with the second quarter of 2017. Increased usage was primarily the result of lower precipitation in the Idaho Power service area during the second quarter of 2018 compared with the second quarter of 2017, which led to increased usage by irrigation customers. For the six months ended June 30, 2018, a 15 percent increase in usage per irrigation customer was more than offset by an 8 percent decrease in usage per residential customer, compared with the same period in 2017, resulting in a decrease in retail revenues of $12.0 million. Decreased usage per residential customer was primarily the result of more moderate winter and spring temperatures in Idaho Power's service area, which led to decreased usage by residential customers for heating and cooling. Heating degree-days were 16 percent lower during the first half of 2018 compared with the first half of 2017.

FCA Revenue: The FCA mechanism adjusts revenue each year to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power through volume-based rates during the year. Lower usage (on a per customer basis) by residential and small general service customers during the three and six months ended June 30, 2018 increased the amount of FCA revenue accrued by $2.3 million and $11.0 million, respectively, compared with the same periods in 2017.

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Wholesale Energy Sales: Wholesale energy sales consist primarily of long-term sales contracts, opportunity sales of surplus system energy, and sales into the Western EIM, and do not include derivative transactions. The table below presents Idaho Power’s wholesale energy sales for the three and six months ended June 30, 2018 and 2017 (in thousands, except for per MWh amounts).

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Wholesale energy revenues	$10,214	$6,003	$24,283	$13,967
Wholesale MWh sold	821	751	1,681	1,439
Wholesale energy revenues per MWh	$12.44	$7.99	$14.45	$9.71

In the first three and six months of 2018, wholesale energy revenue increased by $4.2 million, or 70 percent, and $10.3 million, or 74 percent, respectively, compared with the same periods of 2017. The average price of wholesale energy sales was 56 percent and 49 percent higher for the three and six months ended June 30, 2018, respectively, compared with the same periods of 2017. Wholesale energy sales volumes increased 9 percent and 17 percent in the first three and six months of 2018, respectively, compared with the same periods of 2017, as generation from Idaho Power's hydroelectric plants increased due to strong reservoir storage attributable to above-normal snowpack from 2017 and near-normal snowpack in 2018. The increase in hydroelectric generation resulted in additional energy available for wholesale sales in the first three and six months of 2018 compared with the same periods of 2017. The increase in wholesale energy sales volumes was also due to transactions in the Western EIM, which commenced in April 2018.

Transmission Services (Wheeling) Revenues: Revenue from transmission services increased $1.2 million and $3.8 million during the first three and six months of 2018, respectively, compared with the same periods of 2017, largely due to Idaho Power's OATT rates that increased in October 2017.

Energy Efficiency Program Revenues: In both Idaho and Oregon, energy efficiency riders fund energy efficiency program expenditures. Expenditures funded through the riders are reported as an operating expense with an equal amount recorded in revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected. At June 30, 2018, Idaho Power's energy efficiency rider balances were a $2.6 million regulatory liability in the Idaho jurisdiction and a $6.5 million regulatory asset in the Oregon jurisdiction.

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Operating Expenses

Purchased Power: The table below presents Idaho Power’s purchased power expenses and volumes for the three and six months ended June 30, 2018 and 2017 (in thousands, except for per MWh amounts).

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Expense				
PURPA contracts	$47,867	$46,397	$89,805	$77,237
Other purchased power (including wheeling)	15,113	15,109	35,103	33,385
Total purchased power expense	$62,980	$61,506	$124,908	$110,622
MWh purchased				
PURPA contracts	908	916	1,619	1,435
Other purchased power	475	330	953	719
Total MWh purchased	1,383	1,246	2,572	2,154
Cost per MWh from PURPA contracts	$52.72	$50.65	$55.47	$53.82
Cost per MWh from other sources	$31.82	$45.78	$36.83	$46.43
Weighted average - all sources	$45.54	$49.36	$48.56	$51.36

Purchased power expense increased $1.5 million, or 2 percent, and $14.3 million, or 13 percent, in the first three and six months of 2018, respectively, compared with the same periods of 2017. The increase for the first six months of 2018 was primarily due to an increase of 13 percent in MWh purchased from generation projects under PURPA contracts, offset partially by decreases in costs per MWh of other purchased power.

Idaho Power is required by federal 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. The intermittent, non-dispatchable nature of most PURPA generation 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 its excess power in the wholesale power market at a significant loss. The other purchased power cost per MWh often exceeds the wholesale energy 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 wholesale energy 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 transactions that Idaho Power makes at current market prices may be noticeably different than the advance 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 power cost adjustment mechanisms.

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Fuel Expense: The table below presents Idaho Power’s fuel expenses and thermal generation for the three and six months ended June 30, 2018 and 2017 (in thousands, except for per MWh amounts).

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Expense				
Coal	$18,092	$16,638	$41,373	$44,494
Natural gas[1]	3,423	3,778	7,877	12,174
Total fuel expense	$21,515	$20,416	$49,250	$56,668
MWh generated				
Coal	459	505	1,067	1,342
Natural gas[1]	124	68	228	399
Total MWh generated	583	573	1,295	1,741
Cost per MWh - Coal	$39.42	$32.95	$38.78	$33.15
Cost per MWh - Natural gas	$27.60	$55.56	$34.55	$30.51
Weighted average, all sources	$36.90	$35.63	$38.03	$32.55

[1] Includes a negligible amount of expense and generation related to the Salmon diesel-fired generation plant.

The majority of the fuel for Idaho Power’s jointly-owned coal-fired plants is purchased through long-term contracts, including purchases from BCC, a one-third owned joint venture of IERCo. The price of coal from BCC is subject to fluctuations in mine operating expenses, geologic conditions, and production levels. BCC supplies up to two-thirds of the coal used by the Jim Bridger plant. Natural gas is mainly purchased on the regional wholesale spot market at published index prices. In addition to commodity (variable) costs, both natural gas and coal expenses 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 increased $1.1 million, or 5 percent, in the second quarter of 2018, but decreased $7.4 million, or 13 percent, in the first six months of 2018, compared with the same periods of 2017. The increase in the second quarter of 2018 compared with the second quarter of 2017 was due to an increase in the prices of coal purchased from BCC. BCC shipped fewer tons to the Jim Bridger plant, which resulted in a higher price per ton as fixed costs were spread over fewer tons. The decrease in the first half of 2018 compared with 2017 was primarily due to increased output from Idaho Power's hydroelectric plants, which reduced utilization of gas and coal generation. Generation from the hydroelectric plants increased 1 percent and 8 percent during the first three and six months of 2018, respectively, compared with the same periods of 2017. Generation from Idaho Power's hydroelectric plants increased due to strong reservoir storage attributable to above-normal snowpack from 2017 and near-normal snowpack in 2018.

Power Cost Adjustment Mechanisms: Idaho Power's power supply costs (primarily purchased power and fuel expense, less wholesale energy sales) can vary significantly from year to year. Volatility of power supply costs arises from factors such as weather conditions, wholesale market prices, 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 power cost adjustment mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from customers, 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 Idaho Power (5 percent), with the exception of PURPA power purchases and demand response program incentives, which are allocated 100 percent to customers. The Idaho deferral period, or PCA year, runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

Because of the power cost adjustment 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.

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The table that follows presents the components of the Idaho and Oregon power cost adjustment mechanisms for the three and six months ended June 30, 2018 and 2017 (in thousands).

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Idaho power supply cost accrual	$16,353	$7,981	$33,899	$21,844
Amortization of prior year authorized balances	3,610	8,761	11,602	18,385
Total power cost adjustment expense	$19,963	$16,742	$45,501	$40,229

The power supply accruals represent the portion of the power supply cost fluctuations accrued under the power cost adjustment mechanisms. When actual power supply costs are lower than the amount forecasted in power cost adjustment rates, which was the case for all periods presented, most of the difference is accrued. When actual power supply costs are higher than the amount forecasted in power cost adjustment 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 power cost adjustment year that were deferred or accrued in the prior power cost adjustment year (the true-up component of the power cost adjustment mechanism).

Other O&M Expenses: Other O&M expenses increased $5.6 million, or 6 percent, and $4.7 million, or 3 percent, in the first three and six months of 2018, respectively, compared with the same periods of 2017. Transmission and distribution asset maintenance expense increased $0.9 million and $2.0 million in the first three and six months of 2018, respectively, compared with the same periods in 2017, primarily due to higher maintenance service costs. As provided by the settlement stipulation approved by the IPUC related to recent income tax reform, O&M expenses in the second quarter of 2018 also included $1.1 million of non-cash amortization expense of regulatory deferrals that would otherwise be a future liability of Idaho customers. Labor and benefit costs increased $3.1 million and $1.7 million in the second quarter and first six months of 2018, respectively, primarily related to the timing of accruals for variable employee-related costs which resulted in earlier recognition of expense compared with the same periods of 2017.

Income Taxes

IDACORP's and Idaho Power's income tax expense for the six months ended June 30, 2018, when compared with the same period in 2017, decreased $13.1 million and $12.9 million, respectively, primarily due to lower statutory tax rates and a $1.3 million flow-through income tax benefit related to the tax deduction for bond redemption costs incurred in the second quarter of 2018. The lower statutory tax rates were the result of the Tax Cuts and Jobs Act, which reduced the U.S. federal corporate income tax rate from 35 percent to 21 percent, and Idaho House Bill 463, which lowered the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. The new tax rates were effective on January 1, 2018. For information relating to IDACORP's and Idaho Power's computation of income tax expense and estimated annual effective tax rate, see Note 2 - "Income Taxes" to the condensed 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 anticipates these substantial capital expenditures to continue, with expected total capital expenditures of approximately $1.5 billion over the five-year period from 2018 (including expenditures incurred to-date in 2018) through 2022.

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. Idaho Power periodically files for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators. Idaho Power uses operating and capital budgets to control operating costs and capital expenditures. During the first six months of 2018, Idaho Power 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.

As of July 27, 2018, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

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- 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 20, 2016, which may be used for the issuance of debt securities and common stock;
- Idaho Power's shelf registration statement filed with the SEC on May 20, 2016, which may be used for the issuance of first mortgage bonds and debt securities; $280 million remains available for issuance 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.

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 common stock, and Idaho Power may issue debt securities or first mortgage bonds, if the companies believe terms available in the capital markets are favorable and that issuances would be financially prudent.

In March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, Series K, maturing on March 1, 2048. In April 2018, Idaho Power redeemed, prior to maturity, its $130 million in principal amount of 4.50% first mortgage bonds, medium-term notes due March 2020. 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 $4.6 million. Idaho Power used a portion of the net proceeds of the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

Based on planned capital expenditures and O&M expenses, the companies believe they will be able to meet capital and debt service requirements and fund corporate expenses during at least the next twelve months with a combination of existing cash, operating cash flows generated by Idaho Power's utility business, availability under existing credit facilities, and access to commercial paper and long-term debt markets.

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 June 30, 2018, IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

	IDACORP	Idaho Power
Debt	44%	46%
Equity	56%	54%

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 operating cash inflows for the six months ended June 30, 2018, were $196 million and $191 million, respectively, an increase of $7 million and a decrease of $10 million, respectively, compared with the same period in 2017. Significant items that affected the comparability of the companies' operating cash flows in the first six months of 2018 compared with the same period in 2017 were as follows:

- net income increased $16 million, for the reasons described in "Results of Operations" above in this MD&A;
- changes in deferred taxes and in taxes accrued and receivable combined to decrease cash flows by $12 million and increase by $8 million at IDACORP and Idaho Power, respectively;
- Idaho Power made $25 million of benefit plan contributions during the first six months of 2018, while it made contributions of $4 million for the same period in 2017; and

- changes in working capital balances due primarily to timing, including fluctuations in accounts receivable, other current assets, and accounts payable, as follows:

timing of collections of accounts receivable balances increased operating cash flows by $8 million for IDACORP and Idaho Power. For IDACORP, the increase was offset by IDACORP's collection in 2017 of $8 million from a legal settlement; and

timing of accounts payable payments increased operating cash flows by $18 million for IDACORP and decreased operating cash flows by $26 million for Idaho Power (the difference relates to a $44 million payable from Idaho Power to IDACORP relating to estimated income tax payments).

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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. IDACORP’s and Idaho Power’s net investing cash outflows for the six months ended June 30, 2018, were $109 million. Investing cash outflows for 2018 and 2017 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. During the six months ended June 30, 2018, Idaho Power received $20 million in payments from transmission project co-participants pursuant to the terms of the joint funding arrangements for their share of costs.

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 expenses allocated to IDACORP, through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities.

IDACORP's and Idaho Power's net financing cash inflows for the six months ended June 30, 2018 were $19 million and $23 million, respectively. In March 2018, Idaho Power issued $220 million in first mortgage bonds. In April 2018, Idaho Power redeemed, prior to maturity, $130 million in principal amount of 4.50% first mortgage bonds, medium-term notes due March 2020. 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 $4.6 million. Idaho Power also expects to receive an incremental net benefit to net income as a result of the lower interest rate of the notes issued in March 2018 compared to the interest rate associated with the redeemed notes. Financing cash flows also included the payment of $60 million of dividends on common stock during the first six months of 2018.

Financing Programs and Available Liquidity

IDACORP Equity Programs: In recent years, IDACORP has entered into sales agency agreements under which IDACORP could offer and sell shares of its common stock from time to time through a third-party agent. The most recent sales agency agreement terminated in May 2016. In May 2016, IDACORP filed a shelf registration statement with the SEC, which became effective upon filing, for the potential offer and sale of an unspecified amount of shares of common stock. IDACORP has no current plans to issue equity securities other than under its equity compensation plans during 2018, and as of the date of this report, IDACORP has not pursued the execution of a new sales agency agreement.

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 and May 2016, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company 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 is effective through May 31, 2019, subject to extension upon request to the IPUC. 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 requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum interest rate limit of seven percent.

In September 2016, Idaho Power entered into a selling agency agreement with seven 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, secured medium term notes, Series K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture (Forty-eighth Supplemental Indenture). The Forty-eighth Supplemental Indenture provides for, among other items, (a) the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture and (b) the increase of the maximum amount of obligations to be secured by the Indenture to $2.5 billion (which maximum amount may be further increased or decreased by Idaho Power without the consent of the holders of first mortgage bonds). As of the date of this report, Idaho Power has $280 million available for the issuance of first mortgage bonds, including Series K Notes, or debt securities under the selling agency agreement.

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The Indenture limits the amount of first mortgage bonds at any one time outstanding to $2.5 billion, and as a result, the maximum amount of additional first mortgage bonds Idaho Power could issue as of June 30, 2018 was limited to approximately $669 million. 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 June 30, 2018, Idaho Power could issue approximately $1.8 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

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, replacing prior credit agreements. 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 one time outstanding. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. The credit facilities currently provide for a maturity date of November 4, 2022. Other terms and conditions of the credit facilities are described in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017, in Part II, Item 7 - "MD&A - Liquidity and Capital Resources."

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 June 30, 2018, the leverage ratios for IDACORP and Idaho Power were 44 percent and 46 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 June 30, 2018, IDACORP and Idaho Power believed 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 2018.

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 table below outlines available short-term borrowing liquidity as of the dates specified (in thousands).

	June 30, 2018		December 31, 2017	
	IDACORP[2]	Idaho Power	IDACORP[2]	Idaho Power
Revolving credit facility	$100,000	$300,000	$100,000	$300,000
Commercial paper outstanding	—	—	—	—
Identified for other use[1]	—	(24,245)	—	(24,245)
Net balance available	$100,000	$275,755	$100,000	$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 is unable to sell the bonds to third parties.
[2] Holding company only.

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At July 27, 2018, IDACORP had no loans outstanding under its credit facilities and had no commercial paper outstanding. Idaho Power had no loans outstanding under its credit facilities and no commercial paper outstanding. During the three and six months ended June 30, 2018, no short-term commercial paper was borrowed at IDACORP or Idaho Power.

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, depend in part on their respective credit ratings. There have been no changes to IDACORP's or Idaho Power's ratings or ratings outlook by Standard & Poor's Ratings Services or Moody's Investors Service from those included in the companies' Annual Report on Form 10-K for the year ended December 31, 2017. However, 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.

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 June 30, 2018, Idaho Power had posted $0.8 million of performance assurance collateral related to these contracts. 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 June 30, 2018, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $4.2 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 $129 million during the six months ended June 30, 2018. The table below presents Idaho Power's expected cash requirements for construction, excluding AFUDC, for 2018 (including amounts incurred to-date) through 2022 (in millions).

	2018	2019	2020-2022
Expected capital expenditures (excluding AFUDC)	$280-290	$285-300	$850-900

Major Infrastructure Projects: Idaho Power is engaged in the development of a number of significant projects and has entered into arrangements with third parties concerning joint infrastructure development. The discussion below provides a summary of developments in certain of those projects since the discussion of these matters included in Part II, Item 7 - "MD&A - Capital Requirements" in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017. The discussion below should be read in conjunction with that report.

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. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration 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. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including Idaho Power's AFUDC. This cost estimate is preliminary and excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate.

Approximately $97 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through June 30, 2018. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $69 million as of June 30, 2018, including $20 million received in 2018, due from project co-participants for their share of costs. As of the date of this report, no material co-participant reimbursements are outstanding. Joint permitting participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

The permitting phase of the Boardman-to-Hemingway project is subject to federal review and approval by the U.S. Bureau of Land Management (BLM), the U.S. Forest Service, the Department of the Navy, and certain other federal agencies. The BLM

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issued its record of decision for the project in November 2017. The U.S. Forest Service released its draft record of decision in June 2018 for the 6.8 miles across National Forest lands consistent with the preferred route in the BLM's final environmental impact statement. Idaho Power expects the Department of the Navy to issue its decision in 2018. In the separate Oregon state permitting process, in June 2017, Idaho Power submitted its amended preliminary application for site certificate and expects the Oregon Department of Energy to issue a draft proposed order on the application in 2018. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2025 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 located near Boise, Idaho. Idaho Power and PacifiCorp have a joint funding agreement for permitting of the project. Idaho Power has expended approximately $37 million, including AFUDC, for its share of the permitting phase of the project through June 30, 2018. 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 $250 million and $450 million, including AFUDC.

The permitting phase of the Gateway West project is subject to review and approval of the BLM. The BLM released its record of decision in November 2013 for eight of the ten transmission line segments. In May 2017, a federal bill was signed into law that issued a right-of-way for certain portions of the remaining Gateway West segments. In April 2018, the BLM published its record of decision for the outstanding portions of the remaining segments. Idaho Power and PacifiCorp continue to coordinate the timing of next steps to best meet customer and system needs.

Defined Benefit Pension Plan Contributions

Idaho Power has no minimum contribution requirement to its defined benefit pension plan in 2018; however, Idaho Power contributed $20 million to the plan during the first six months of 2018. Depending on market conditions and cash flow considerations during the remainder of 2018, Idaho Power may contribute up to an additional $20 million to the pension plan during 2018. 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 and to mitigate the cost of being in an underfunded position. The primary impact of pension contributions is on the timing of cash flows, as the timing of cost recovery lags behind contributions.

Contractual Obligations

During the six months ended June 30, 2018, IDACORP's and Idaho Power's contractual obligations, outside the ordinary course of business, did not change materially from the amounts disclosed in their Annual Report on Form 10-K for the year ended December 31, 2017, except that Idaho Power entered into power purchase agreements with solar and biomass PURPA-qualifying facilities that increased Idaho Power's contractual payment obligations by approximately $51 million over the 20-year terms of the contracts.

Off-Balance Sheet Arrangements

IDACORP's and Idaho Power's off-balance sheet arrangements have not changed materially from those reported in MD&A in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017.

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REGULATORY MATTERS

Introduction

Idaho Power's development of regulatory filings 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, the in-service dates of major capital investments, the timing and magnitude 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 customer growth, power cost adjustment mechanisms, tariff riders, and other mechanisms to mitigate the impact of 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. Idaho Power continues to assess the need and timing of filing a general rate case in its two retail jurisdictions, based on its consideration of factors such as those described above, but does not anticipate filing a general rate case in the next twelve months.

The outcomes of significant proceedings are described in part in this report and further in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017. In addition to the discussion below, which includes notable regulatory developments since the discussion of these matters in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017, refer to Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report for additional information relating to Idaho Power's regulatory matters and recent regulatory filings and orders.

Notable Rate Changes During 2018

During 2018, Idaho Power received orders authorizing the rate changes summarized in the table below.

Description	Status	Estimated Rate Impact[1]	Notes
Power Cost Adjustment Mechanism - Idaho	New PCA rate became effective June 1, 2018	$22.6 million PCA decrease for the period from June 1, 2018 to May 31, 2019	The potential revenue impact of rate increases and decreases associated with the Idaho PCA mechanism is largely offset by associated increases and decreases in actual power supply costs and amortization of deferred power supply costs.
Fixed Cost Adjustment Mechanism - Idaho	New FCA rate became effective June 1, 2018	$19.4 million FCA decrease for the period from June 1, 2018 to May 31, 2019	The FCA is designed to remove a portion of Idaho Power’s financial disincentive to invest in energy efficiency programs by partially separating (or decoupling) the recovery of fixed costs from the volumetric kilowatt-hour charge and instead linking it to a set amount per customer.
Tax Cuts and Jobs Act Settlement Stipulation - Idaho	New base rate became effective June 1, 2018	On an annual basis, $18.7 million reduction of customer base rates, commencing on June 1, 2018	See "Income Tax Reform - Impact and Regulatory Treatment" below for more information.
Tax Cuts and Jobs Act	New PCA rate became	One-time benefit of a $7.8 million decrease to be provided	For the income tax benefits accrued from January 1, 2018 to May 31, 2018, and the income tax

Settlement Stipulation - Idaho	effective June 1, 2018	through PCA mechanism rates for the period from June 1, 2018 through May 31, 2019	benefits related to Idaho Power's OATT. See "Income Tax Reform - Impact and Regulatory Treatment" below for more information.

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

Customer-Owned Generation Filing

In July 2017, Idaho Power filed an application with the IPUC related to customers who install their own on-site generation, seeking the creation of two new classes of customers, with no request to change pricing or compensation. In May 2018, the IPUC issued an order authorizing the creation of the new customer classes. In that order, the IPUC also stated its intent to open

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an Idaho Power-specific docket to comprehensively study on-site generation and ordered Idaho Power to file a study with the IPUC exploring fixed-cost recovery prior to its next general rate case. In June 2018, the IPUC issued an order requiring further investigation to resolve eligibility issues for the new customer classes.

Idaho Earnings Support and Sharing from Idaho Settlement Stipulation

In October 2014, the IPUC issued an order (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation) approving an extension, with modifications, of the terms of a 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 amortization contemplated by the settlement stipulation has been amortized. The more specific terms and conditions of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation are described in Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report. IDACORP and Idaho Power believe that the terms allowing additional amortization of ADITC in the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect.

Under the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation, during the second quarter of 2018, Idaho Power reversed the $0.5 million of additional ADITC amortization recorded during the first quarter of 2018, based on Idaho Power's then-current estimate of return on year-end equity in the Idaho jurisdiction (Idaho ROE) for the full-year 2018. During the second quarter of 2017, Idaho Power reversed $1.9 million of additional ADITC amortization recorded during the first quarter of 2017, as actual financial results exceeded Idaho Power's early estimates.

Income Tax Reform - Impact and Regulatory Treatment

In December 2017, the Tax Cuts and Jobs Act was signed into law, which, among other things, lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. In January 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to (1) record a regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in federal income tax law under the Tax Cuts and Jobs Act, and (2) file a report with the IPUC by March 30, 2018, identifying and quantifying the financial impact of the income tax changes on the utility, along with proposed tariff schedule changes that would adjust the utility's rates to reflect the utility's modified federal tax obligations under the Tax Cuts and Jobs Act. The IPUC order required Idaho Power to estimate the income tax reform changes by comparing actual 2017 federal income tax components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full year of 2017.

In March 2018, Idaho Power made a filing with the IPUC providing the results of its pro forma analysis indicating pro forma annual income tax reform expense reductions, composed of a current income tax expense reduction and a deferred income tax expense reduction. In May 2018, the IPUC issued an order approving a settlement stipulation (May 2018 Idaho Tax Reform Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the settlement stipulation provides an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through PCA mechanism rates for the period from June 1, 2018 through May 31, 2019, for the income tax reform benefits accrued from January 1, 2018 to May 31, 2018, and the income tax reform benefits related to Idaho Power's OATT. The amount provided via the PCA mechanism will decrease to $2.7 million on June 1, 2019, for income tax reform benefits related to Idaho Power's OATT and will cease on June 1, 2020, to reflect the impact of a full year of reduced OATT third-party transmission revenues.

The May 2018 Idaho Tax Reform Settlement Stipulation provides for the extension of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation described above beyond the initial termination date of December 31, 2019, with modified terms related to the ADITC and revenue sharing mechanism to become effective beginning January 1, 2020. Neither the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation nor the May 2018 Idaho Tax Reform Settlement Stipulation impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during their respective terms.

Also in May 2018, the OPUC issued an order approving a settlement stipulation that provides for an annual $1.5 million reduction to Oregon customer base rates beginning June 1, 2018, through May 31, 2020, related to income tax reform. Unless resolved in a regulatory proceeding before, the settlement stipulation requires Idaho Power to file a deferral request with the

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OPUC by December 31, 2019, to begin tracking tax reform benefits beginning January 1, 2020, at which time Idaho Power, the OPUC staff, and other interested parties will discuss the methodology to quantify potential future tax reform benefits. The settlement stipulation also deemed prudent Idaho Power's decision to pursue the end of its participation in coal-fired operations of Unit 1 at Idaho Power's jointly-owned North Valmy coal-fired plant and approved Idaho Power's request to recover $2.5 million of annual incremental accelerated depreciation relating to Unit 1, beginning June 1, 2018 and ending December 31, 2019.

For more information on the settlement stipulations and their impacts on results, see Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report.

Change in Deferred Net Power Supply Costs and the Power Cost Adjustment Mechanisms

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.

The table that follows summarizes the change in deferred net power supply costs during the six months ended June 30, 2018 (in thousands).

	Idaho	Oregon	Total
Deferred net power supply costs at December 31, 2017	$(2,201)	$(105)	$(2,306)
Current period net power supply costs accrued	(33,227)	—	(33,227)
Prior amounts recovered through rates	(6,402)	—	(6,402)
Tax reform revenue accrual transferred to Idaho PCA mechanism	(4,244)	—	(4,244)
SO_2 allowance and renewable energy certificate sales	(2,263)	(93)	(2,356)
Interest and other	(82)	4	(78)
Deferred net power supply costs at June 30, 2018	$(48,419)	$(194)	$(48,613)

Idaho Power's power cost adjustment mechanisms in its Idaho and Oregon jurisdictions address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers. The power cost adjustment mechanisms and associated financial impacts are described in "Results of Operations" in this MD&A and in Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report. With the exception of power supply expenses incurred under PURPA and certain demand response program costs that are passed through to customers substantially in full, the Idaho PCA mechanism allows Idaho Power to pass through to customers 95 percent of the differences in actual net power supply expenses as compared with base net power supply expenses, whether positive or negative. Thus, the primary financial statement impact of power supply cost deferrals or accruals is that the timing of when cash is paid out for power supply expenses differs from when those costs are recovered from customers, impacting operating cash flows from year to year.

Open Access Transmission Tariff Draft Posting

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. In June 2018, Idaho Power publicly posted its 2018 draft transmission rate, reflecting a transmission rate of $31.26 per "kW-year," to be effective for the period from October 1, 2018 to September 30, 2019. A "kW-year" is a unit of electrical capacity equivalent to 1 kilowatt of power used for 8,760 hours. Idaho Power's draft rate was based on a net annual transmission revenue requirement of $123.1 million. The existing OATT rate in effect from October 1, 2017 to September 30, 2018, is $34.90 per kW-year based on a net annual transmission revenue requirement of $130.4 million. The decrease in the OATT rate is largely attributable to an increase in short-term firm and non-firm transmission revenues in 2017, which serves as an offset to the transmission revenue requirement.

Western Energy Imbalance Market Costs
Idaho Power's participation in the Western EIM commenced on April 4, 2018. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch within the hour of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. In August 2016, Idaho Power filed an application with the IPUC requesting specified regulatory accounting treatment associated with its participation in the Western EIM. In January 2017, the IPUC issued an order authorizing deferral accounting treatment for costs associated with joining the Western EIM. Idaho Power deferred $1.0 million of incremental other O&M costs incurred through

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April 1, 2018. In November 2017, Idaho Power filed an application with the IPUC requesting approval to establish an interim method of recovery for Western EIM-related costs. In July 2018, the IPUC issued an order approving a settlement stipulation that provides for a recovery mechanism administered through Idaho Power's PCA mechanism. For more information on the order and its impact on financial results, see Note 3 - "Regulatory Matters" to the condensed consolidated financial statements included in this report.

Renewable and Other Energy Contracts

Idaho Power has contracts for the purchase of electricity produced by third-party owned generation facilities, most of which produce energy with the use of renewable generation sources such as wind, solar, biomass, small hydroelectric and geothermal. The majority of these contracts are entered into as mandatory purchases under PURPA. As of June 30, 2018, Idaho Power had contracts to purchase energy from 128 on-line PURPA projects. An additional three contracts are with non-PURPA projects, including the Elkhorn Valley wind project with a 101-MW nameplate capacity. The following table sets forth, as of June 30, 2018, the resource type and nameplate capacity of Idaho Power's signed agreements for power purchases from PURPA and non-PURPA generating facilities. These agreements have original contract terms ranging from one to 35 years.

Resource Type	Total On-line mega-watts (MW)	Under Contract but not yet On-line (MW)	Total Projects under Contract (MW)
PURPA:			
Wind	627	—	627
Solar	290	27	317
Hydroelectric	147	2	149
Other	56	—	56
Total	1,120	29	1,149
Non-PURPA:			
Wind	101	—	101
Geothermal	35	—	35
Total	136	—	136

Of the six projects not yet on-line, one hydroelectric project and five solar projects are scheduled to be on-line in 2019.

Relicensing of Hydroelectric Projects

In connection with Idaho Power's efforts to relicense the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, as described in more detail in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017, in Part II, Item 7 - "Regulatory Matters," Idaho Power has filed water quality certification applications, required under Section 401 of the Clean Water Act (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 the 2016 Section 401 certification application process, Oregon required Idaho

Power to comply with fish passage and reintroduction conditions. Idaho's water quality certification, however, provides that Idaho Power shall take no action that may result in the reintroduction or establishment of spawning populations of any fish species into Idaho's waters without consultation with and express approval of the State of Idaho. In November 2016, Idaho Power filed a petition with the FERC requesting that the FERC resolve the conflict between Oregon's and Idaho's conditions and declare that the Federal Power Act pre-empts the Oregon state law. In January 2017, the FERC issued an order denying Idaho Power’s petition, stating that the petition for a declaratory order was premature, cannot realistically be considered separately from the issue of the states’ certification authority under the CWA Section 401, and raises issues that are beyond the FERC’s authority to decide. In February 2017, Idaho Power sought rehearing before the FERC on the January 2017 order, which the FERC denied. In February 2018, Idaho Power filed an appeal of the FERC's January 2017 order with the D.C. Circuit Court, which is pending.

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In April 2017, the governors of Oregon and Idaho jointly requested that Idaho Power withdraw and resubmit its Section 401 certification applications in both states to allow the states additional time to negotiate a potential resolution of the disputed issues. Idaho Power subsequently withdrew its Section 401 certification applications in both states and since that time the states have been negotiating towards a mutually agreeable solution. Idaho Power most recently resubmitted its application to both states in June 2018 with the intent to allow additional time for the states to continue negotiating.

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. Idaho Power expects to seek recovery of relicensing costs through the ratemaking process. Relicensing costs of $282 million (including AFUDC) for the HCC were included in construction work in progress at June 30, 2018. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates $8.8 million of AFUDC annually relating to the HCC relicensing project. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation described in Note 3 - "Regulatory Matters," Idaho Power was collecting $10.7 million annually. Collecting these amounts currently will reduce future collections when HCC relicensing costs are approved for recovery in base rates. As of June 30, 2018, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was approximately $127 million. Idaho Power is unable to predict the timing of issuance of a new license for the HCC, or the financial or operational requirements of a new license.

In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for future inclusion in retail rates in a future regulatory proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third party intervenor, recognizing that a total of $216.5 million in expenditures were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in the fourth quarter of 2017, which included $4.3 million for costs incurred through 2015, as well as $0.7 million related to associated costs incurred in 2016 and 2017. In April 2018, the IPUC issued an order approving the settlement stipulation as filed with the IPUC and determined the associated costs to be reasonably and prudently incurred.

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, 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, 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 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 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 generation 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 may 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. Beyond 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 - "Business - Environmental Regulation and Costs" in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017, includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2018 to 2020. Given the uncertainty of future environmental regulations, Idaho Power is unable to predict its environmental-related expenditures beyond that time, though they could be substantial.

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A summary of notable environmental matters impacting, or expected to potentially impact, IDACORP and Idaho Power, is included in Part II, Item 7 - "MD&A - Environmental Issues" and "MD&A - Liquidity and Capital Resources - Capital Requirements - Environmental Regulation Costs" in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017.

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 U.S. Fish and Wildlife Service (USFWS) and the NMFS issued a set of regulatory and policy changes relating to critical habitat and adverse modification determinations under the ESA (2016 ESA Rules). While the ultimate impact of implementation of those changes is yet to be determined, taken as a whole, Idaho Power believes that the 2016 ESA Rules could result in the applicable agencies having greater authority in making designations of critical habitat and could increase the likelihood of adverse modification determinations.

On July 19, 2018, the USFWS and the NMFS issued three proposals to revise ESA regulations (2018 ESA Regulations) related to the process and standards for listing species and designating critical habitat, the process for consultations with federal agencies under Section 7 of the ESA (including the definition of "destructive or adverse modification" of designated critical habitat), and the scope of protection of threatened species. Idaho Power believes that if the 2018 ESA Regulations are enacted, the regulations could reduce Idaho Power’s obligations for mitigation under the ESA related to various construction and relicensing projects.

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. 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.

Developments in Regulation of Sage Grouse Habitat: In February 2016, a lawsuit was filed in the U.S. District Court of Idaho challenging the BLM's sage grouse resource management and land use plan revisions that became effective in 2015 under the Federal Land Policy and Management Act. The lawsuit challenges the plans and associated environmental impact statements across the sage grouse range and alleges that the plans fail to ensure that sage grouse populations and habitats will be protected and restored in accordance with the best available science and legal mandates. Further, the complaint challenges certain exemptions provided for the Boardman-to-Hemingway and

Gateway West transmission line projects. Idaho Power has intervened in the proceedings in an effort to support the exemptions provided for in the BLM's plans. If the exemptions are overturned, Idaho Power may be required to re-route the projects, which could lead to substantially higher construction and permitting costs and could delay construction.

In May 2016, a separate lawsuit was filed in the U.S. District Court of North Dakota, challenging the BLM's sage grouse resource management and land use plan revisions, including the exemptions provided for the Boardman-to-Hemingway and Gateway West transmission line projects. In October 2016, the plaintiffs amended their complaint to no longer challenge the exemptions; however, in December 2016, the North Dakota court transferred claims challenging certain Idaho land use plan amendments to the U.S. District Court for the District of Columbia. Idaho Power is participating in the proceedings in an effort to protect its interests.

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In June 2017, the Secretary of the Interior issued an order directing the BLM to review the 2015 sage grouse resource management and land use plan revisions and to identify provisions that may require modification or rescission to address energy and other development of public lands. In October 2017, the Secretary of the Interior issued a notice of intent declaring the Department of the Interior’s intent to consider amending the 2015 sage grouse resource management and land use plan revisions. In May 2018, the BLM issued draft resource management plan amendments and draft environmental impact statements to modify the 2015 sage grouse plans to better align the plans with state plans, conservation measures and the Department of the Interior and BLM policy. The public comment period runs through August 2, 2018. As of the date of this report, the above lawsuits are stayed as the parties and the courts consider the Department of the Interior’s review of the sage grouse resource management and land use plan revisions.

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 (WOTUS Rule). Idaho Power believes that the final rule potentially expanded 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. The WOTUS Rule was widely challenged in both federal district and circuit courts. The State of Idaho, and several other parties, challenged the rule in North Dakota federal court. That court held that it had jurisdiction and enjoined the implementation of the WOTUS Rule. In February 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to rescind the WOTUS Rule. In July 2017, the EPA and the U.S. Army Corps of Engineers issued a notice of their intent to rescind and replace the definition of "waters of the United States" under the CWA, which Idaho Power expects would reduce the number of waters in Idaho Power's service area subject to the WOTUS Rule. In November 2017, the EPA issued a notice that it will delay the effectiveness of the WOTUS Rule until 2020 while the U.S. Army Corps of Engineers considers a replacement rule. In January 2018, the U.S. Supreme Court issued a unanimous ruling that challenges to the WOTUS Rule must begin with the federal district courts, effectively negating a nationwide stay issued by the Sixth Circuit in 2016. However, because the State of Idaho remains a party to the federal court action in North Dakota, that court’s enjoinder remains in effect, meaning the WOTUS Rule currently does not apply to actions brought in Idaho. On July 12, 2018, the EPA and the U.S. Army Corps of Engineers issued a supplemental notice seeking additional comment on their 2017 proposal to repeal the definition of the term WOTUS Rule under the CWA.

Idaho Power has analyzed the WOTUS Rule and expects that, even if the WOTUS Rule is reinstated in Idaho, while it may cause Idaho Power to incur additional permitting, regulatory requirements, 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. Similarly, because the CWA, as interpreted even prior to the WOTUS Rule, applies to most of Idaho Power's facilities, including its hydroelectric plants, Idaho Power does not expect that the repeal of the WOTUS Rule will have a material benefit to Idaho Power's operations or financial condition.

OTHER MATTERS

Critical Accounting Policies and Estimates

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

IDACORP’s and Idaho Power’s critical accounting policies are reviewed by the audit committees of the boards of directors. These policies have not changed materially from the discussion of those policies included under "Critical Accounting Policies and Estimates" in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017.

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Recently Issued Accounting Pronouncements

For a listing of new and recently adopted accounting standards, see Note 1 - "Summary of Significant Accounting Policies" to the notes to the condensed consolidated financial statements included in this report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP is exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk, and equity price risk. The following discussion summarizes material changes in these risks since December 31, 2017, and the financial instruments, derivative instruments, and derivative commodity instruments sensitive to changes in interest rates, commodity prices, and equity prices that were held at June 30, 2018. IDACORP has not entered into any of these market-risk-sensitive instruments for trading purposes.

Interest Rate Risk

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

Variable Rate Debt: As of June 30, 2018, IDACORP had no net floating rate debt, as the carrying value of short-term investments exceeded the carrying value of outstanding variable-rate debt.

Fixed Rate Debt: As of June 30, 2018, IDACORP had $1.8 billion in fixed rate debt, with a fair market value of approximately $1.9 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 $281.2 million if market interest rates were to decline by one percentage point from their June 30, 2018 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 changes in commodity prices are mitigated in large part by Idaho Power's Idaho and Oregon power cost adjustment 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. IDACORP's commodity price risk as of June 30, 2018, had not changed materially from that reported in Item 7A of IDACORP's Annual Report on Form 10-K for the year ended December 31, 2017. Information regarding Idaho Power’s use of derivative instruments to manage commodity price risk can be found in Note 11 - "Derivative Financial Instruments" to the condensed consolidated financial statements included in this report.

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 June 30, 2018, Idaho Power had posted $0.8 million performance assurance collateral related to these contracts. 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 June 30, 2018, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $4.2 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.

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IDACORP's credit risk related to uncollectible accounts, net of amounts reserved, as of June 30, 2018, had not changed materially from that reported in Item 7A of IDACORP's Annual Report on Form 10-K for the year ended December 31, 2017. Additional information regarding Idaho Power’s management of credit risk and credit contingent features can be found in Note 11 - "Derivative Financial Instruments" to the condensed consolidated financial statements included in this report.

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 10 - "Benefit Plans" to the consolidated financial statements included in IDACORP's Annual Report on Form 10-K for the year ended December 31, 2017.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

IDACORP: The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP’s disclosure controls and procedures (pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934 (Exchange Act)) as of June 30, 2018, have concluded that IDACORP’s disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) are effective as of that date.

Idaho Power: The Chief Executive Officer and the Chief Financial Officer of Idaho Power, based on their evaluation of Idaho Power’s disclosure controls and procedures (pursuant to Rule 13a-15(b) of the Exchange Act) as of June 30, 2018, have concluded that Idaho Power’s disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) are effective as of that date.

Changes in Internal Control over Financial Reporting

There have been no changes in IDACORP's or Idaho Power's internal control over financial reporting during the quarter ended June 30, 2018, that have materially affected, or are reasonably likely to materially affect, IDACORP's or Idaho Power's internal control over financial reporting.

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PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None

ITEM 1A. RISK FACTORS

The factors discussed in Part I - Item 1A - "Risk Factors" in IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2017, could materially affect IDACORP’s and Idaho Power's business, financial condition, or future results. In addition to those risk factors and other risks discussed in this report, see "Cautionary Note Regarding Forward-Looking Statements" in this report for additional factors that could have a significant impact on IDACORP's or Idaho Power's operations, results of operations, or financial condition and could cause actual results to differ materially from those anticipated in forward-looking statements.

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

Restrictions on Dividends

See Note 6 - "Common Stock" to the condensed consolidated financial statements included in this report for a description of restrictions on IDACORP's and Idaho Power's payment of dividends.

Issuer Purchases of Equity Securities

IDACORP did not repurchase any shares of its common stock during the quarter ended June 30, 2018.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

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, which is incorporated herein by reference.

ITEM 5. OTHER INFORMATION

None

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ITEM 6. EXHIBITS

The following exhibits are filed or furnished, as applicable, with the Quarterly Report on Form 10-Q for the quarter ended June 30, 2018:

		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
10.1 (1)	Third Amendment to the Idaho Power Company Employee Savings Plan, executed April 26, 2018 and effective January 1, 2018	10-Q	1-14465; 1-3198	10.4	5/3/2018	
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
15.1	Letter Re: Unaudited Interim Financial Information					X
15.2	Letter Re: Unaudited Interim Financial Information					X
31.1	Certification of IDACORP, Inc. Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
31.2	Certification of IDACORP, Inc. Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
31.3	Certification of Idaho Power Company Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
31.4	Certification of Idaho Power Company Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
32.1	Certification of IDACORP, Inc. Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002					X
32.2	Certification of IDACORP, Inc. Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002					X
32.3	Certification of Idaho Power Company Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002					X
32.4	Certification of Idaho Power Company Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002					X
95.1	Mine Safety Disclosures					X
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						X

	XBRL Taxonomy Extension Presentation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	X

(1) Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

IDACORP, INC.
(Registrant)

Date: August 2, 2018 By: /s/ Darrel T. Anderson
Darrel T. Anderson
President and Chief Executive Officer

Date: August 2, 2018 By: /s/ Steven R. Keen
Steven R. Keen
Senior Vice President, Chief Financial Officer, and Treasurer

IDAHO POWER COMPANY
(Registrant)

Date: August 2, 2018 By: /s/ Darrel T. Anderson
Darrel T. Anderson
President and Chief Executive Officer

Date: August 2, 2018 By: /s/ Steven R. Keen
Steven R. Keen
Senior Vice President, Chief Financial Officer, and Treasurer