# 2016
## ANNUAL REPORT

PINNACLE WEST CAPITAL CORPORATION

**THIS ANNUAL REPORT FEATURES PHOTOGRAPHY BY SUZANNE MATHIA**

Suzanne is a photographer and author whose work regularly appears in National Geographic and publications for the Nature Conservancy. Her photographs capture the diversity and intense beauty of Arizona's immense landscape and reflect her curiosity, patience and ability to see the world in new and creative ways.

Featured Work: Labyrinth (Cover), Paradise Found (Pg 5), Weathering Pit Ridge (Pg 8-9), Wotan's Throne (Pg 12), Desert Wave (Pg 15).

## PINNACLE WEST CAPITAL CORPORATION COMBINES A SOLID FOUNDATION AND A CLEAR STRATEGY TO BUILD SHAREHOLDER VALUE...

- Superior reliability and operating performance across our business
- Excellent customer service and deep community involvement
- Affordable electricity rates
- A balanced, high-performing power generation portfolio
- A constructive regulatory environment
- Targeted investments in innovative technologies
- Solid financial results

## ...WITH A SHARPENED FOCUS ON OUR CORE UTILITY BUSINESS.

**THE APS VISION »**

Creating a sustainable energy future for Arizona.

**THE APS MISSION »**

We safely and efficiently generate and deliver reliable energy to meet the changing needs of our customers.

DONALD E. BRANDT
CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER

"APS IS CONSISTENTLY AMONG THE **BEST-PERFORMING** ELECTRICITY COMPANIES IN AMERICA FOR **DEPENDABLE SERVICE.**"

# DEAR FELLOW SHAREHOLDERS...

Pinnacle West achieved another year of outstanding results in 2016 by consistently delivering on our commitments to the customers who depend on us, the communities we serve, our dedicated employees and the shareholders who trust us with their investments.

Through efficient operations and prudent financial management, your company recorded net income of $442 million, or $3.95 per share, in 2016. That compares favorably with net income of $437 million in 2015. The company's strong performance earned a consolidated return on average common equity of 9.44 percent.

For the fifth consecutive year, our Board of Directors approved an increase in the dividend, raising it by 5 percent to $2.62 per share annually. Our goal remains to provide investors with steady dividend growth of approximately 5 percent per year.

Pinnacle West stock hit new 52-week highs 27 times in 2016, and on July 5 reached what was then an all-time closing high of $82.56—a record that was eclipsed in early 2017. Total shareholder value increased $1.8 billion in 2016. Although general market conditions have contributed to our stock's record-setting performance, the real credit for this accomplishment goes to our dedicated employees who have worked hard for many years to position the company for success.

The appreciation of Pinnacle West stock, together with our dividend payout, provided shareholders with a total return of 25 percent in 2016. This significantly outpaced the return of the S&P 1500 Electric Utilities Index (16 percent) and the S&P 500 Index (12 percent). Pinnacle West shareholders have earned a total return of 65 percent over the last three years and 97 percent over the last five.

Our balance sheet remains strong, allowing us to earn A- ratings or better from each of the major credit rating agencies, a distinction that exceeds the majority of other electricity companies.

Reclaimed water accounted for 74 percent of the water used in our generating facilities in 2016.

## COMMITTED TO ARIZONA »

Arizona's economy continued to grow in 2016 and remains an integral part of our value proposition. Our home state offers desirable places to live, competitive low costs and an attractive business climate that combine to promise sustained long-term growth. The important positive economic factors include:

- The metropolitan Phoenix area, which represents two-thirds of our customer base, has placed third among the country's top 15 metro areas for growth.
- Construction, financial services and healthcare, among other sectors, are all producing job growth at above-average rates.
- Vacancy rates in office and retail space have fallen to pre-recession levels, and housing construction in 2016 reached levels not seen since 2007.

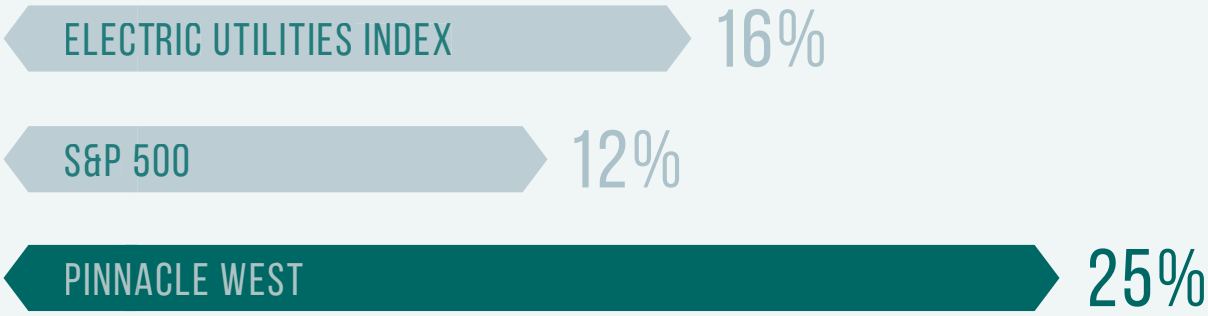
Our primary subsidiary, Arizona Public Service (APS), benefits from the state's growing economy while helping to power that growth. We provide the clean, reliable and affordable electricity an expanding economy requires, and we partner closely with economic development organizations to attract new businesses to the state. In 2016, those efforts brought more than 20 new companies to our service area, adding an estimated 5,000 new jobs.

Should the Arizona Corporation Commission (ACC) act favorably on our pending rate request, our planned investment of $3.5 billion in the energy grid over the next three years will further stimulate the economy, create opportunities for suppliers and generate tax revenue for local governments. And, we have proposed new economic development rate options to encourage more businesses to relocate or expand in our service territory.

## COMMITTED TO OUR CUSTOMERS »

APS consistently ranks among the best-performing electricity companies in America for dependable service, and in 2016 we continued to make investments that expand, maintain and modernize Arizona's energy grid. Through these efforts, we anticipate growth in rate base of 6 to 7 percent through 2019.

Through investments in the high-voltage transmission system, we strive to improve reliability and redundancy, increase access to power markets, and support the continued development of renewable energy. APS completed three transmission projects in 2016,




TOTAL SHAREHOLDER RETURN

# TWENTY-SEVEN

TIMES PINNACLE WEST STOCK HIT A 52-WEEK HIGH IN 2016

# PHOENIX IS THE THIRD FASTEST GROWING

AMONG AMERICA'S TOP 15 METRO AREAS

at a total investment of $147 million, enhancing reliability and encouraging customer growth in the thriving areas west of Phoenix. We anticipate capital expenditures of approximately $500 million in the transmission system through the end of 2019.

APS continues to build a stronger, smarter energy infrastructure for Arizona through thoughtful investments in advanced and effective grid technologies. In one instance, we deployed more than 200 advanced devices across the grid in 2016 that enable our employees to detect problems earlier and restore power faster, resulting in a 6-percent decrease in outage durations. We anticipate capital expenditures of approximately $1.3 billion in the distribution system through the end of 2019.

Modernization of our grid also includes industry-leading work on microgrids. Working in partnership with the Department of the Navy and the U.S. Marine Corps, APS in 2016 completed a 25-megawatt microgrid that provides enhanced energy security to the Marine Corps Air Station in Yuma, Arizona. The microgrid provides reliable backup power for base operations and, at other times, allows APS operators to call on the generation to serve Yuma customers when needed, thus improving regional reliability as well.

One noteworthy research initiative that is attracting national attention and shaping our grid modernization strategies is the APS Solar Partner Program, which is evaluating how smart inverters and battery storage can help maintain power reliability in communities with high levels of intermittent private rooftop solar generation. The $36 million initiative was named 2017 Project of the Year for Renewables Integration by the industry organization DistribuTECH.

Recognizing that our customers want more choices and control over their energy use, APS in 2016 launched a number of customer service enhancements including an upgraded mobile-friendly outage map and a new mobile app that allows customers to use their smartphones to view usage and pay bills. In the first quarter of 2017, we launched one of the largest information technology projects in company history—a new $106 million customer information system that will provide a stronger, more nimble platform to support continued innovations in the way we serve our customers.

## COMMITTED TO A CLEANER ENERGY MIX »

Palo Verde Nuclear Generating Station continues to break records, and Unit 2 produced the highest electricity output of any nuclear unit in the country in 2016—all of it clean, carbon-free energy.

When complete in 2019, our $500 million Ocotillo Modernization Project's cleaner, quick-starting natural gas power plants will provide reliable and flexible generation to serve the Valley of the Sun, supporting the continued growth of renewable energy while making more efficient use of fuel and water.

At Four Corners Power Plant, our investment of $400 million in Selective Catalytic Reduction environmental technology is expected to be complete in 2018. The new environmental controls are designed to reduce emissions of nitrogen oxide by more than 90 percent.

We celebrated a major milestone in May 2016 when APS surpassed one gigawatt of solar in the energy mix we provide to customers. Prior to last year, no other electricity company outside of California had achieved that distinction.

# ONE GIGAWATT

AMOUNT OF SOLAR IN THE ENERGY MIX WE PROVIDE TO CUSTOMERS

# 50%

OF ELECTRICITY WE DELIVER COMES FROM CARBON-FREE SOURCES

Our solar leadership continued in December with the startup of our innovative Red Rock Solar Plant. The plant demonstrates how electricity companies can help commercial customers realize their clean-energy goals. APS developed and owns the 40-megawatt plant, and entered into an agreement with two customers—Arizona State University and PayPal—that have committed to purchase renewable energy from APS over the next 20 years equivalent to the amount we estimate Red Rock will generate.

After signing an agreement with the California Independent System Operator in 2015 to join the Energy Imbalance Market, APS began participation with a smooth transition in October 2016. APS saved $6 million in its first three months in the market, all of which is passed along to customers. The market will also allow us to respond more quickly to variable renewable energy production and better incorporate renewable resources such as solar.

With Palo Verde's reliable nuclear generation and our company's solar leadership as the anchors, 50 percent of the electricity APS delivered to customers in 2016 came from carbon-free sources.

One final note on our efforts to reduce the environmental impact of our operations: conditions in Arizona require that sustainable and efficient usage of water ranks as a top priority.

Accordingly, each APS power plant has a unique water strategy—including Palo Verde, which remains the only nuclear plant in the world not located near a large body of water. Instead, it uses treated effluent from several area municipalities, recycling approximately 20 billion gallons of wastewater each year. Our 2016 water efficiency initiatives succeeded in reducing our total groundwater consumption by 28 percent below 2014 levels, far surpassing our goal of an 8-percent reduction.

### COMMITTED TO ARIZONA'S ENERGY FUTURE »

On March 1, 2017, we reached agreement on resolution of the company's first rate review in five years. The consensus group included ACC staff, consumer advocates, merchant generators, seniors, industrial groups, environmental groups, limited-income advocates, rural municipalities, schools, federal agencies, the business community, and solar groups—most notably, representatives of the national private solar leasing industry.

The agreement will now go to the ACC for review, including opportunities for public comment and a vote by commissioners, which we expect to occur this summer.

If approved, the agreement will provide a blueprint that will bring about more solar, a smarter energy infrastructure, a cleaner energy mix and more options for customers.

The agreement provides for an overall revenue increase of 3.3 percent, translating into an additional $95 million annually to support our operations and investments. Residential customers would experience a 4.5-percent bill increase, or about $6 per month. Under our previous request, customers would have seen a 7.96-percent, or $11 per month, increase.

**TWENTY-FIVE MEGAWATT**

MICROGRID BUILT IN PARTNERSHIP WITH THE U.S. DEPARTMENT OF THE NAVY

**RENEWABLES INTEGRATION PROJECT OF THE YEAR**

SOLAR PARTNER PROGRAM AWARD FROM DistribuTECH

**50,000 DOWNLOADS**

SINCE THE LAUNCH OF THE NEW APS MOBILE APP

We also agreed to refund customers $15 million of surplus energy efficiency program funds over the first year that new rates are in effect.

Recognizing that many Arizona customers still struggle with the effects of the previous economic downturn, we have requested increased program funding for limited-income customers from $35 million to $48 million, a simplified monthly bill discount, and a $1.25 million annual emergency bill assistance fund.

Under this agreement, we would not begin another request for a comprehensive review of our rates before June 1, 2019, meaning three years between rate reviews.

value-of-solar decision, the ACC established a mechanism for that rate to decline gradually over time. Banking energy—the "netting" part of net metering—has ended; any power sent to the grid from a rooftop solar system will receive compensation at this new export rate.

The agreement also allows private rooftop solar customers to choose from updated rate options that include a time-of-use plan with a grid access charge, or a demand-based plan without the grid access charge.

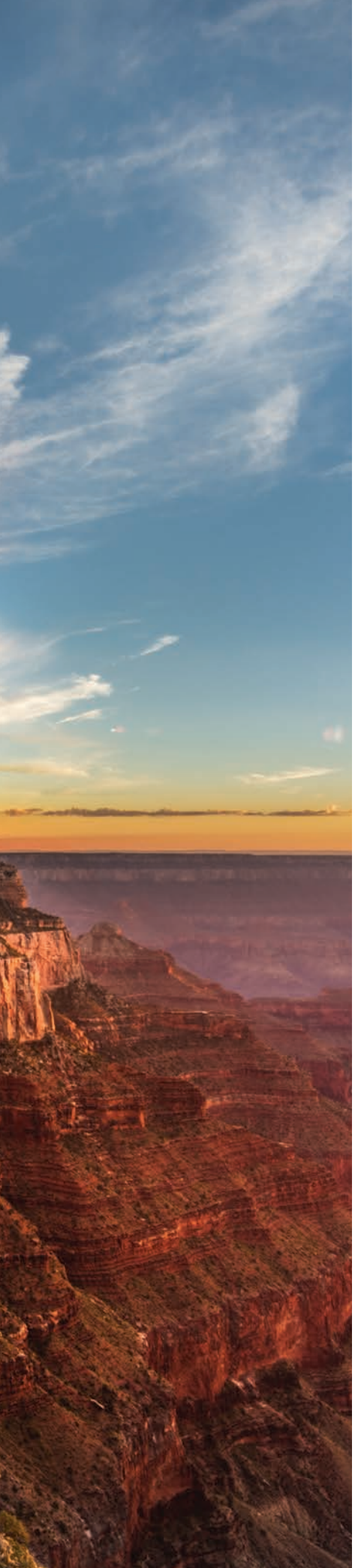
Through this agreement, Arizona's solar leadership is sustained with smart policies that should enable the continued growth of

32.2 million megawatt-hours of carbon-free energy produced at Palo Verde—the only U.S. generating facility to ever produce more than 30 million megawatt-hours in a year.

The agreement builds on the ACC's December decision regarding value and cost of solar. That decision ensures private rooftop solar customers are fairly compensated when they send electricity back to the grid, while reducing the generous subsidies paid by our non-solar customers.

We have proposed to protect our existing solar customers by grandfathering them under their current agreement, while future private solar customers would be compensated for their excess electricity at a credit starting at 12.9 cents/kilowatt-hour. In the December

solar and other new consumer technologies, while strengthening protections for non-solar customers. We have agreed to invest $10 million to $15 million per year in an AZ Sun rooftop program in which customers would receive a monthly credit to allow the company to install rooftop solar systems on their homes. This innovative program would expand access to solar for limited- and moderate-income customers throughout the APS service area.



Through a separate agreement, APS, industry representatives and solar advocates commit to stand by the settlement agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

Under our proposal, customers will have more choices and control through a menu of new rate options that include incentives for more efficient use of energy, and additional opportunities to save money. Time-of-use plans will become the standard for all customers, who will also have the option of choosing from two demand rates or a special demand pilot for customers with certain types of technology at their homes.

## COMMITTED TO OUR COMMUNITY »

The communities we serve know of APS and its employees' dedication to community service. Economically thriving and culturally vibrant communities translate into long-term success for our company, and investing in the growth, health and well-being of Arizona helps all our customers, too.

According to 2016 rankings calculated by the *Phoenix Business Journal*, APS was the top corporate philanthropist in Arizona and second on the list of the state's top volunteer programs. Last year, we gave more than $10 million to Arizona communities, $1.4 million of which funded STEM education programs across the state.

Our incredible employees contributed more than 120,000 volunteer hours to causes for which they have a passion and our annual Community Services Fund campaign yielded pledges of $2.5 million for deserving nonprofit organizations.

Time and again, I feel extraordinarily grateful for the work our employees do every day, at work and in their private lives helping others. Beyond their other accomplishments, I appreciate their commitment to safety. In 2016, APS employees recorded the fewest OSHA recordable incidents in the company's history. That performance placed us at the top of our industry peer group. We will continue to keep safety at the top of our priority list so that all APS employees go home without injury.

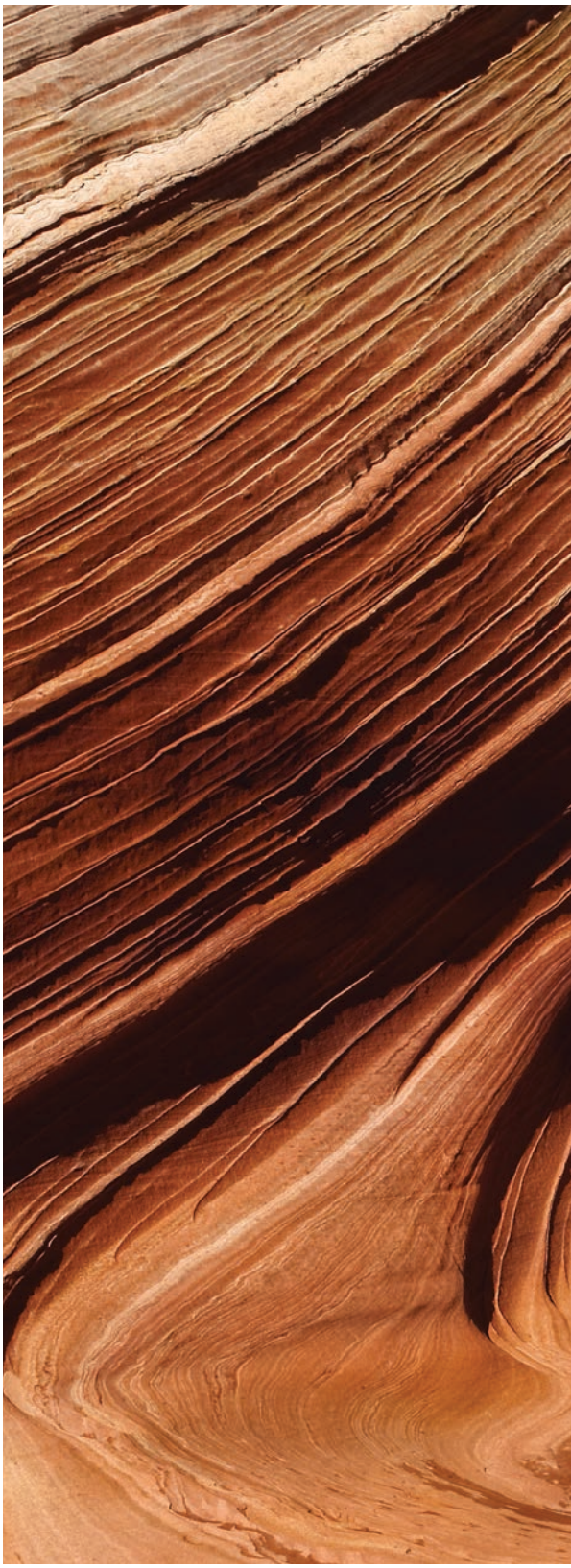
Before I close, I want to welcome our newest Board member, Paula Sims. Paula joined the Board in October, and is a valuable addition to the Pinnacle West and APS Boards of Directors. Her talent and perspective, deep industry experience and expertise in business development, operations and change management will benefit the company and its customers as we continue to focus on delivering long-term value for all we serve.

The coming year will certainly bring more changes in technology, the political arena and customer expectations. Your company will stay ahead of these changes, evolving and investing to ensure sustainable success in the years to come.

Our commitment to the relationships that matter most—our customers, our employees, our communities, and you, our shareholders—will not waver.

Thank you for your investment.

DONALD E. BRANDT
CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER



# FINANCIAL INFORMATION

# BOARD MEMBERS & OFFICERS

## PINNACLE WEST AND ARIZONA PUBLIC SERVICE BOARD MEMBERS »

**DONALD E. BRANDT 2009**
Chairman of the Board, President & Chief Executive Officer, Pinnacle West and APS

**DENIS A. CORTESE, M.D. 2010**
Director, Health Care Delivery and Policy Program, Arizona State University; Emeritus President & Chief Executive Officer, Mayo Clinic

**RICHARD P. FOX 2014**
Independent Business Consultant

**MICHAEL L. GALLAGHER 1997**
Chairman Emeritus, Gallagher & Kennedy, P.A.

**ROY A. HERBERGER, JR., PH.D. 1992**
President Emeritus, Thunderbird School of Global Management

**DALE E. KLEIN, PH.D. 2010**
Associate Vice Chancellor for Research, University of Texas System; Former Chairman, U.S. Nuclear Regulatory Commission

**HUMBERTO S. LOPEZ 1995**
Chairman, HSL Properties, Inc.

**KATHRYN L. MUNRO 1999**
Principal, BridgeWest, LLC

**BRUCE J. NORDSTROM 1997**
President & Certified Public Accountant, Nordstrom & Associates, P.C.

**PAULA J. SIMS 2016**
Professor of Practice and Executive Coach, University of North Carolina at Chapel Hill

**DAVID P. WAGENER 2014**
Managing Partner, Wagener Capital Management

## PINNACLE WEST OFFICERS »

**DONALD E. BRANDT 2002**
Chairman of the Board, President & Chief Executive Officer

**DAVID P. FALCK 2009**
Executive Vice President & General Counsel

**JAMES R. HATFIELD 2008**
Executive Vice President & Chief Financial Officer

**ROBERT S. AIKEN 1986**
Vice President, Federal Affairs

**DENISE R. DANNER 2009**
Vice President, Controller & Chief Accounting Officer

**LEE R. NICKLOY 2010**
Vice President & Treasurer

**DIANE WOOD 1998**
Secretary

## ARIZONA PUBLIC SERVICE OFFICERS »

**DONALD E. BRANDT**
Chairman of the Board, President & Chief Executive Officer

**DAVID P. FALCK**
Executive Vice President & General Counsel

**JAMES R. HATFIELD**
Executive Vice President & Chief Financial Officer

**MARK A. SCHIAVONI 2009**
Executive Vice President & Chief Operating Officer

**ROBERT S. BEMENT 2007**
Executive Vice President & Chief Nuclear Officer, Palo Verde Nuclear Generating Station

**JOHN J. CADOGAN 2009**
Senior Vice President, Site Operations, Palo Verde Nuclear Generating Station

**DANIEL T. FROETSCHER 1980**
Senior Vice President, Transmission, Distribution & Customers

**BARBARA M. GOMEZ 1978**
Senior Vice President, Human Resources & Ethics

**JEFFREY B. GULDNER 2004**
Senior Vice President, Public Policy

**MARIA L. LACAL 2007**
Senior Vice President, Regulatory & Oversight, Palo Verde Nuclear Generating Station

**ANN C. BECKER 2001**
Vice President & Chief Procurement Officer

**DENISE R. DANNER**
Vice President, Controller & Chief Accounting Officer

**STACY L. DERSTINE 1995**
Vice President, Customer Service & Chief Customer Officer

**PATRICK DINKEL 1986**
Vice President, Environmental & Chief Sustainability Officer

**DONNA M. EASTERLY 1984**
Vice President, Human Resources

**DAVID A. HANSEN 1980**
Vice President, Fossil Generation

**JOHN S. HATFIELD 2010**
Vice President, Communications

**BRYAN KEARNEY 2014**
Vice President & Chief Information Officer

**CHARLES KHARRL 2007**
Vice President, Site Operations & General Plant Manager, Palo Verde Nuclear Generating Station

**BARBARA D. LOCKWOOD 1999**
Vice President, Regulation

**MICHAEL E. McLAUGHLIN 2011**
Vice President, Operation Support, Palo Verde Nuclear Generating Station

**TAMMY D. McLEOD 1995**
Vice President, Resource Management

**LEE R. NICKLOY**
Vice President & Treasurer

**JESSICA M. PACHECO 2009**
Vice President, State & Local Affairs

**BRUCE RASH 2016**
Vice President, Nuclear Engineering, Palo Verde Nuclear Generating Station

**JACOB TETLOW 2001**
Vice President, Transmission & Distribution Operations

**DIANE WOOD**
Secretary

*The year shown indicates when the Officer was first employed by, or the individual first became a Director of, Pinnacle West or APS.*

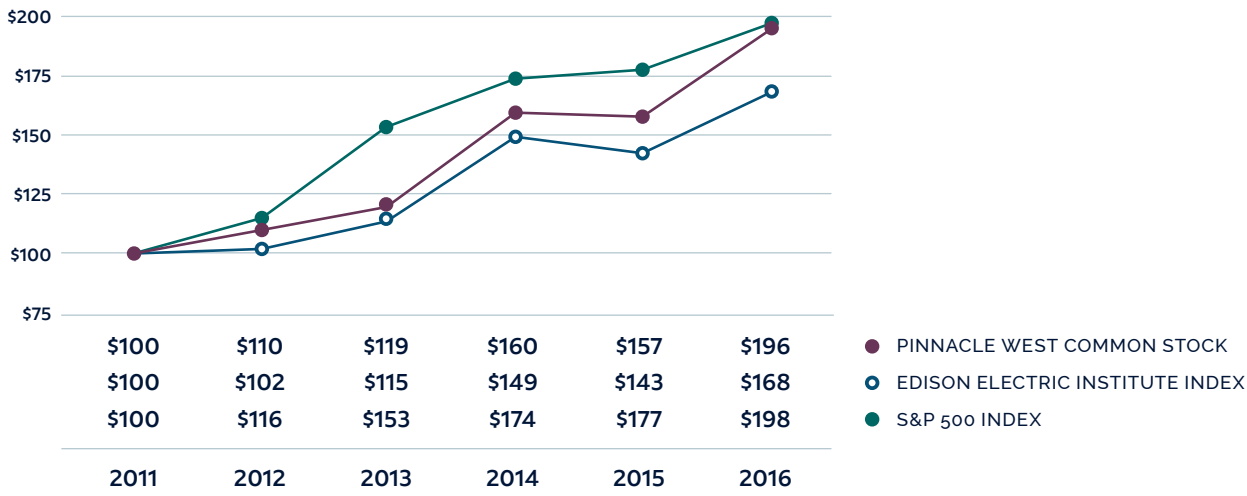
# PINNACLE WEST HIGHLIGHTS

(dollars and shares in millions, except per share amounts)

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| **STOCK SUMMARY** | | | |
| Stock price per share—year-end | $78.03 | $64.48 | $68.31 |
| Market capitalization—year-end | $8,688 | $7,156 | $7,553 |
| Common shares outstanding—year-end | 111.4 | 111.1 | 110.6 |
| **PER SHARE HIGHLIGHTS (DILUTED)** | | | |
| Earnings per share—net income attributable to common shareholders | $3.95 | $3.92 | $3.58 |
| Indicated annual dividend—year-end | $2.62 | $2.50 | $2.38 |
| **CAPITAL EXPENDITURES** | $1,254 | $1,060 | $883 |
| **OPERATING STATISTICS** | | | |
| Retail electric sales (GWh) | 28,022 | 27,951 | 27,585 |
| Total electric sales (GWh) | 31,789 | 34,291 | 32,781 |
| Average retail revenue (per kWh) | 11.90¢ | 11.76¢ | 11.60¢ |
| Generating capacity owned or leased—year-end (MW) | 6,236 | 6,186 | 6,426 |
| Generation output (GWh) | 24,849 | 27,452 | 26,922 |
| System peak load (MW) | 7,051 | 7,031 | 7,007 |
| Electric customers—year-end | 1,205,478 | 1,190,242 | 1,174,760 |
| Employees—year-end | 6,339 | 6,407 | 6,366 |

# STOCK PERFORMANCE COMPARISON

(value of $100 invested as of December 31, 2011, with dividends reinvested)



# CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(dollars in millions)

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| *Year Ended December 31,* | | | |
| **CONDENSED CONSOLIDATED STATEMENTS OF INCOME** | | | |
| Operating revenues | $3,499 | $3,496 | $3,492 |
| Fuel and purchased power | (1,076) | (1,101) | (1,180) |
| Other operating expenses | (1,567) | (1,540) | (1,501) |
| Operating income | 856 | 855 | 811 |
| Net other income | 27 | 18 | 19 |
| Interest expense | (186) | (179) | (185) |
| Income taxes | (236) | (238) | (221) |
| Net income | 461 | 456 | 424 |
| Less: Net income attributable to noncontrolling interests | 19 | 19 | 26 |
| **Net income attributable to common shareholders** | **$442** | **$437** | **$398** |
| *Year Ended December 31,* | | | |
| **CONDENSED CONSOLIDATED BALANCE SHEETS** | | | |
| ***Assets*** | | | |
| Current assets | $822 | $890 | $974 |
| Investments and other assets | 849 | 800 | 786 |
| Property, plant and equipment - net | 12,714 | 11,809 | 11,194 |
| Deferred debits | 1,619 | 1,529 | 1,335 |
| **Total assets** | **$16,004** | **$15,028** | **$14,289** |
| ***Liabilities and Equity*** | | | |
| Current liabilities, excluding current maturities of long-term debt | $1,167 | $1,085 | $1,176 |
| Long-term debt | 4,147 | 3,820 | 3,390 |
| Deferred credits and other | 5,754 | 5,404 | 5,204 |
| Total equity | 4,936 | 4,719 | 4,519 |
| **Total liabilities and equity** | **$16,004** | **$15,028** | **$14,289** |
| *Year Ended December 31,* | | | |
| **CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS** | | | |
| Cash and cash equivalents at beginning of year | $40 | $8 | $10 |
| Net cash flow provided by operating activities | 1,023 | 1,094 | 1,100 |
| Net cash flow used for investing activities | (1,252) | (1,066) | (923) |
| Net cash flow provided by (used for) financing activities | 198 | 4 | (179) |
| **Cash and cash equivalents at end of year** | **$9** | **$40** | **$8** |

***Complete audited consolidated financial statements are included in our Annual Report on Form 10-K.***

# FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution you not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by us. A discussion of some of these risks and uncertainties is contained in our Annual Report on Form 10-K and is available on our website at pinnaclewest.com, which you should review carefully before placing any reliance on our forward-looking statements, financial statements or disclosures. We assume no obligation to update any forward-looking statements, even if our internal estimates change, except as may be required by applicable law.

# SHAREHOLDER INFORMATION

## INVESTORS ADVANTAGE PLAN AND SHAREHOLDER ACCOUNT INFORMATION

Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling Computershare at (800) 457-2983, by visiting computershare.com/investor or by writing to:

Computershare
P.O. Box 43078
Providence, Rhode Island
02940-3078

## FORM 10-K

Pinnacle West's 2016 Annual Report on Form 10-K filed with the Securities and Exchange Commission is available on our website or by writing to the Office of the Secretary.

## STATISTICAL REPORT

A detailed Statistical Report for Financial Analysis for 2012 to 2016 is available on our website.

## CORPORATE RESPONSIBILITY REPORT

The Pinnacle West Corporate Responsibility Report is available on our website.

## INVESTOR RELATIONS CONTACT

Ted Geisler (602) 250-3200

## ADMINISTRATIVE INFORMATION

Company contact:
Jacqueline Patterson (602) 250-5511
jacqueline.patterson@pinnaclewest.com

## ANNUAL MEETING OF SHAREHOLDERS

May 17, 2017 10:30 a.m. (MST)

Shareholders may participate in the Annual Meeting by logging into the following website: virtualshareholdermeeting.com/PNW

## CORPORATE HEADQUARTERS

400 North 5th Street
Phoenix, Arizona 85004
Mailing address:
P.O. Box 53999
Phoenix, Arizona
85072-3999
Main telephone number:
(602) 250-1000

## CORPORATE WEBSITE

pinnaclewest.com

## STOCK LISTING

Ticker symbol:
PNW on New York Stock Exchange

## TRANSFER AGENT AND REGISTRAR

Computershare
P.O. Box 43078
Providence, Rhode Island
02940-3078
computershare.com/investor

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**WASHINGTON, D.C. 20549**

# FORM 10-K

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2016**

**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 | Registrants; State of Incorporation; Addresses; and Telephone Number | IRS Employer Identification No. |
|---|---|---|
| 1-8962 | **PINNACLE WEST CAPITAL CORPORATION**<br>(An Arizona corporation)<br>400 North Fifth Street, P.O. Box 53999<br>Phoenix, Arizona 85072-3999<br>(602) 250-1000 | 86-0512431 |
| 1-4473 | **ARIZONA PUBLIC SERVICE COMPANY**<br>(An Arizona corporation)<br>400 North Fifth Street, P.O. Box 53999<br>Phoenix, Arizona 85072-3999<br>(602) 250-1000 | 86-0011170 |

**Securities registered pursuant to Section 12(b) of the Act:**

| | Title Of Each Class | Name Of Each Exchange On Which Registered |
|---|---|---|
| PINNACLE WEST CAPITAL CORPORATION | Common Stock, No Par Value | New York Stock Exchange |
| ARIZONA PUBLIC SERVICE COMPANY | None | None |

**Securities registered pursuant to Section 12(g) of the Act:**
ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value $2.50 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY Yes ☒ No ☐

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

PINNACLE WEST CAPITAL CORPORATION Yes ☐ No ☒
ARIZONA PUBLIC SERVICE COMPANY Yes ☐ No ☒

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.

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY Yes ☒ 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

PINNACLE WEST CAPITAL CORPORATION
Large accelerated filer ☒ Accelerated filer ☐
Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

ARIZONA PUBLIC SERVICE COMPANY
Large accelerated filer ☐ Accelerated filer ☐
Non-accelerated filer ☒ Smaller reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant's most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION $8,961,361,256 as of June 30, 2016
ARIZONA PUBLIC SERVICE COMPANY $0 as of June 30, 2016

The number of shares outstanding of each registrant's common stock as of February 17, 2017

PINNACLE WEST CAPITAL CORPORATION 111,340,169 shares
ARIZONA PUBLIC SERVICE COMPANY Common Stock, $2.50 par value, 71,264,947 shares. Pinnacle West Capital Corporation is the sole holder of Arizona Public Service Company's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 17, 2017 are incorporated by reference into Part III hereof.

**Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.**

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**This combined Form 10-K is separately filed by Pinnacle West and APS. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 8 of this report includes Consolidated Financial Statements of Pinnacle West and Consolidated Financial Statements of APS. Item 8 also includes Combined Notes to Consolidated Financial Statements.**

## GLOSSARY OF NAMES AND TECHNICAL TERMS

| | |
|---|---|
| 4CA | 4C Acquisition, LLC, a wholly-owned subsidiary of Pinnacle West |
| ac | Alternating Current |
| ACC | Arizona Corporation Commission |
| ADEQ | Arizona Department of Environmental Quality |
| AFUDC | Allowance for Funds Used During Construction |
| ANPP | Arizona Nuclear Power Project, also known as Palo Verde |
| APS | Arizona Public Service Company, a subsidiary of the Company |
| ARO | Asset retirement obligations |
| ASU | Accounting Standards Update |
| BART | Best available retrofit technology |
| Base Fuel Rate | The portion of APS's retail base rates attributable to fuel and purchased power costs |
| BCE | Bright Canyon Energy Corporation, a subsidiary of the Company |
| BHP Billiton | BHP Billiton New Mexico Coal, Inc. |
| BNCC | BHP Navajo Coal Company |
| CAISO | California Independent System Operator |
| CCR | Coal combustion residuals |
| Cholla | Cholla Power Plant |
| dc | Direct Current |
| distributed energy systems | Small-scale renewable energy technologies that are located on customers' properties, such as rooftop solar systems |
| DOE | United States Department of Energy |
| DOI | United States Department of the Interior |
| DOJ | United States Department of Justice |
| DSM | Demand side management |
| DSMAC | Demand side management adjustment charge |
| EES | Energy Efficiency Standard |
| El Dorado | El Dorado Investment Company, a subsidiary of the Company |
| El Paso | El Paso Electric Company |
| EPA | United States Environmental Protection Agency |
| FERC | United States Federal Energy Regulatory Commission |
| Four Corners | Four Corners Power Plant |
| GWh | Gigawatt-hour, one billion watts per hour |
| kV | Kilovolt, one thousand volts |
| kWh | Kilowatt-hour, one thousand watts per hour |
| LFCR | Lost Fixed Cost Recovery Mechanism |
| MMBtu | One million British Thermal Units |
| MW | Megawatt, one million watts |
| MWh | Megawatt-hour, one million watts per hour |
| Native Load | Retail and wholesale sales supplied under traditional cost-based rate regulation |
| Navajo Plant | Navajo Generating Station |
| NERC | North American Electric Reliability Corporation |
| NRC | United States Nuclear Regulatory Commission |
| NTEC | Navajo Transitional Energy Company, LLC |
| OCI | Other comprehensive income |
| OSM | Office of Surface Mining Reclamation and Enforcement |
| Palo Verde | Palo Verde Nuclear Generating Station or PVNGS |
| Pinnacle West | Pinnacle West Capital Corporation (any use of the words "Company," "we," and "our" refer to Pinnacle West) |
| PSA | Power supply adjustor approved by the ACC to provide for recovery or refund of variations in actual fuel and purchased power costs compared with the Base Fuel Rate |
| RES | Arizona Renewable Energy Standard and Tariff |
| Salt River Project or SRP | Salt River Project Agricultural Improvement and Power District |
| SCE | Southern California Edison Company |
| TCA | Transmission cost adjustor |
| VIE | Variable interest entity |

## FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume," "project" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Item 1A and in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations," these factors include, but are not limited to:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, seasonality, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation, ballot initiatives and regulation, including those relating to environmental requirements, regulatory policy, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and ACC orders.

These and other factors are discussed in the Risk Factors described in Item 1A of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

## PART I

## ITEM 1. BUSINESS

### Pinnacle West

Pinnacle West is a holding company that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

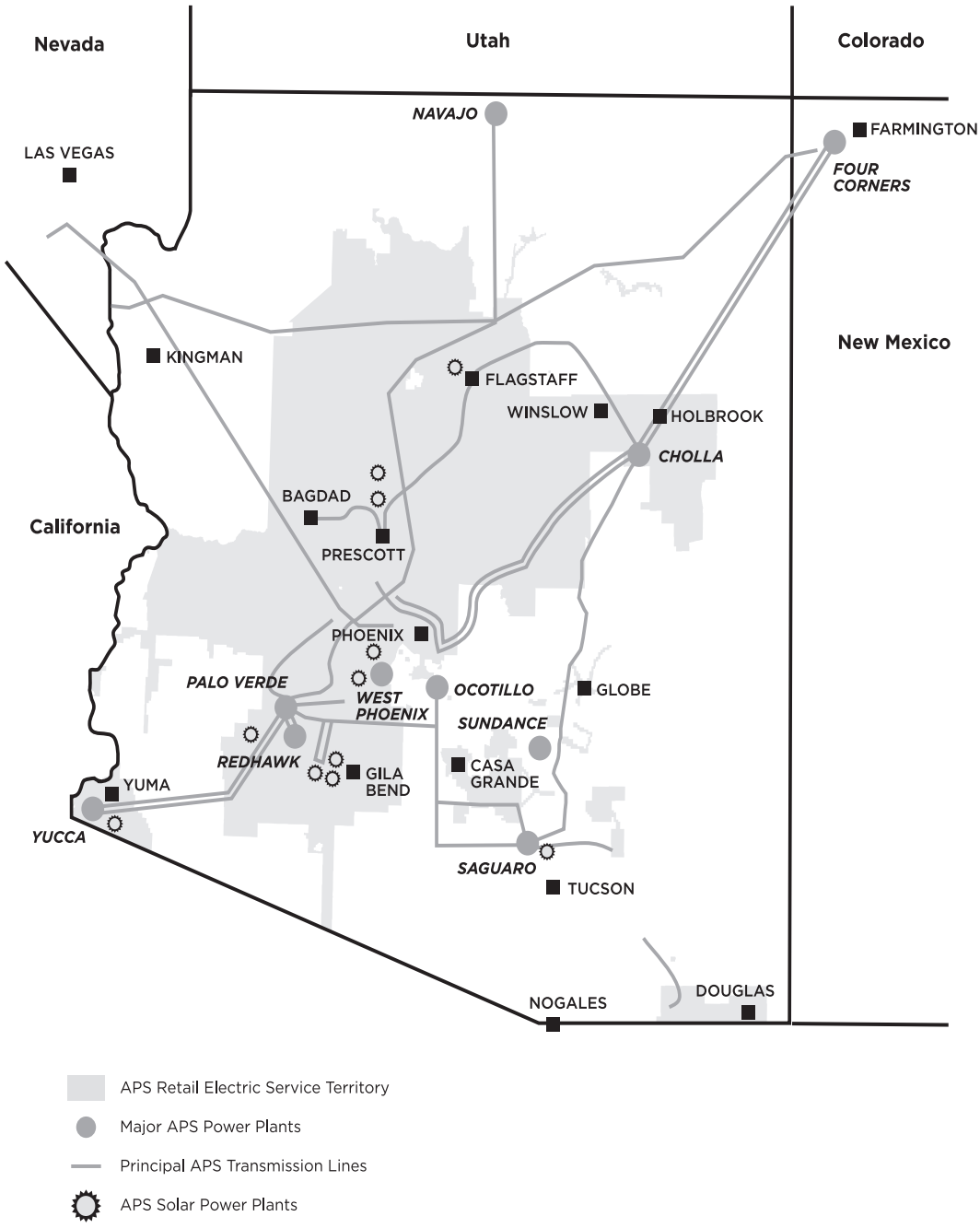
Pinnacle West's other subsidiaries are El Dorado, BCE and 4CA. Additional information related to these subsidiaries is provided later in this report.

Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission and distribution.

## BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

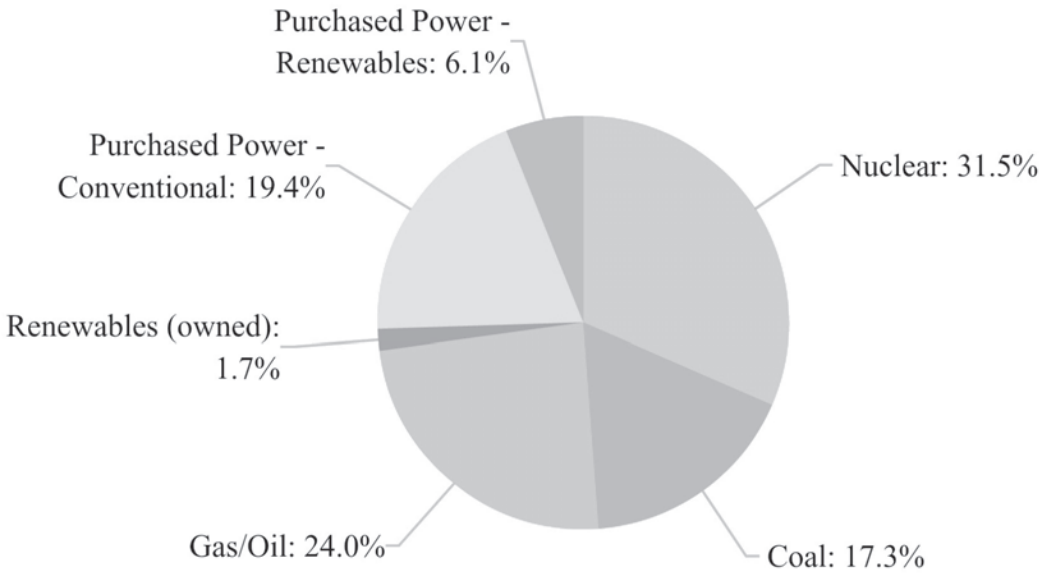
APS currently provides electric service to approximately 1.2 million customers. We own or lease 6,236 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2016, no single purchaser or user of energy accounted for more than 1.1% of our electric revenues.

The following map shows APS's retail service territory, including the locations of its generating facilities and principal transmission lines.



**Energy Sources and Resource Planning**

To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. Resource planning is an important function necessary to meet Arizona's future energy needs. APS's sources of energy by type used to supply energy to Native Load customers during 2016 were as follows:




**Generation Facilities**

APS has ownership interests in or leases the coal, nuclear, gas, oil and solar generating facilities described below. For additional information regarding these facilities, see Item 2.

**Coal-Fueled Generating Facilities**

*Four Corners* — Four Corners is located in the northwestern corner of New Mexico, and was originally a 5-unit coal-fired power plant. APS owns 100% of Units 1, 2 and 3, which were retired as of December 30, 2013. APS operates the plant and owns 63% of Four Corners Units 4 and 5 following the acquisition of SCE's interest in Units 4 and 5 described below. APS has a total entitlement from Four Corners of 970 MW. Additionally, 4CA, a wholly-owned subsidiary of Pinnacle West, owns 7% of Units 4 and 5 following its acquisition of El Paso's interest in these units described below.

On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS's prior retail

rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the System Improvement Benefits ("SIB") matter discussed in Note 3. On August 8, 2016, the Arizona Supreme Court issued its opinion in the SIB matter, and the Arizona Court of Appeals has now ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton was retained by NTEC under contract as the mine manager and operator through 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016 through 2031 (the "2016 Coal Supply Agreement"). El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC has the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at Four Corners and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

*Cholla* — Cholla was originally a 4-unit coal-fired power plant, which is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4,

and APS operates that unit for PacifiCorp. On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 387 MW.

On January 13, 2017, EPA approved a final rule incorporating APS's compromise approach. Once the final rule is published in the Federal Register, parties have 60 days to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict at this time whether such petitions will be filed or if they will be successful. In addition, under the terms of an executive memorandum issued on January 20, 2017, this final rule will not be published in the Federal Register until after it has been reviewed by an appointee of the President. We cannot predict when such review will occur and what may result from the additional review.

APS purchases all of Cholla's coal requirements from a coal supplier, an affiliate of Peabody Energy Corporation, that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. On April 13, 2016, Peabody Energy Corporation and certain affiliated entities filed a petition for relief under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Missouri. Under the Coal Supply Agreement, dated December 21, 2005, Peabody supplied coal to APS and PacifiCorp (collectively, the "Buyers") for use at Cholla. APS believes that the Coal Supply Agreement terminated automatically on April 13, 2016 as a result of Peabody's bankruptcy filing. The Buyers filed a motion requesting that the Bankruptcy Court enter an order determining that the Buyers are authorized to enforce the termination provisions in the Coal Supply Agreement.

On May 13, 2016, Peabody filed a complaint against the Buyers in the bankruptcy court in which Peabody alleged that the Buyers breached the Coal Supply Agreement. On January 27, 2017, the bankruptcy court approved a settlement between the parties, and on February 6, 2017 the parties executed an amendment to the Coal Supply Agreement that allows for continuation of the agreement with modified terms and conditions acceptable to the parties.

APS has a long-term coal transportation by rail contract that expires in 2017.

*Navajo Generating Station* — The Navajo Plant is a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operates the plant and APS owns a 14% interest in Navajo Units 1, 2 and 3. APS has a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Plant is under contract with its coal supplier through 2019, with extension rights through 2026. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. The current lease expires in 2019.

On February 13, 2017, the co-owners of the Navajo Plant voted not to pursue continued operation of the plant beyond December 2019, the expiration of the current lease term, and to pursue a new lease or lease extension with the Navajo Nation that would allow decommissioning activities to begin after December 2019 instead of later this year. Various stakeholders including regulators, tribal representatives and others interested in the continued operation of the plant intend to meet to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. We cannot predict whether any alternate solutions will be found that would be acceptable to all of the stakeholders and feasible to implement. APS is currently

recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($108 million as of December 31, 2016) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. We cannot predict whether APS would obtain such recovery.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

These coal-fueled plants face uncertainties, including those related to existing and potential legislation and regulation, that could significantly impact their economics and operations. See “Environmental Matters” below and “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Overview and Capital Expenditures” in Item 7 for developments impacting these coal-fueled facilities. See Note 10 for information regarding APS’s coal mine reclamation obligations.

**Nuclear**

*Palo Verde Nuclear Generating Station* — Palo Verde is a 3-unit nuclear power plant located approximately 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and approximately 17% of Unit 2. In addition, APS leases approximately 12.1% of Unit 2, resulting in a 29.1% combined ownership and leasehold interest in that unit. APS has a total entitlement from Palo Verde of 1,146 MW.

*Palo Verde Leases* — In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. The leaseback was originally scheduled to expire at the end of 2015 and contained options to renew the leases or to purchase the leased property for fair market value at the end of the lease terms. On July 7, 2014, APS exercised the fixed rate lease renewal options. The exercise of the renewal options resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. See Note 18 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

*Palo Verde Operating Licenses* — Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987, and issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2 and 3 to June 2045, April 2046 and November 2047, respectively.

*Palo Verde Fuel Cycle* — The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates and conversion services through 2018 and 45% of its requirements in 2019-2025. The participants have also contracted for 100% of Palo Verde's enrichment services through 2020 and 20% of its enrichment services for 2021-2026; and all of Palo Verde's fuel assembly fabrication services through 2024.

*Spent Nuclear Fuel and Waste Disposal* — The Nuclear Waste Policy Act of 1982 ("NWPA") required the DOE to accept, transport, and dispose of spent nuclear fuel and high level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the "Standard Contract") with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS is directly and indirectly involved in several legal proceedings related to DOE's failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high level waste.

*APS Lawsuit for Breach of Standard Contract* — In December 2003, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a lawsuit against DOE in the United States Court of Federal Claims ("Court of Federal Claims") for damages incurred due to DOE's breach of the Standard Contract. The Court of Federal Claims ruled in favor of APS and the Palo Verde participants in October 2010 and awarded $30.2 million in damages to APS and the Palo Verde participants for costs incurred through December 2006.

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the Court of Federal Claims. This lawsuit sought to recover damages incurred due to DOE's breach of the Standard Contract for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which has been extended to December 31, 2019.

APS has submitted two claims pursuant to the terms of the August 18, 2014 settlement agreement, for two separate time periods during July 1, 2011 through June 30, 2015. The DOE has approved and paid $53.9 million for these claims (APS's share is $15.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE on October 31, 2016, and approved on February 1, 2017, in the amount $11.3 million (APS's share is $3.3 million). Payment for the claim is expected in the second quarter of 2017.

*The One-Mill Fee* — In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE's 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the "one-mill fee") paid by the nation's commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by APS in its retail rates. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE ("Secretary") with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE's revised one-mill fee adequacy determination, the D.C. Circuit reopened the proceedings. On November 19, 2013, the D.C. Circuit found that the DOE did not conduct a legally adequate fee assessment and ordered the Secretary to notify Congress of his

intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the D.C. Circuit's order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress' disapproval. On May 16, 2014, the DOE notified all commercial nuclear power plant operators who are party to a Standard Contract that it reduced the one-mill fee to zero, thus effectively terminating the one-mill fee.

*DOE's Construction Authorization Application for Yucca Mountain* — The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction authorization application. Several interested parties have also intervened in the NRC proceeding. Additionally, a number of interested parties filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application and NRC's cessation of its review of the Yucca Mountain construction authorization application. The cases have been consolidated into one matter at the D.C. Circuit. In August 2013, the D.C. Circuit ordered the NRC to resume its review of the application with available appropriated funds.

On October 16, 2014, the NRC issued Volume 3 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume addresses repository safety after permanent closure, and its issuance is a key milestone in the Yucca Mountain licensing process. Volume 3 contains the staff's finding that the DOE's repository design meets the requirements that apply after the repository is permanently closed, including but not limited to the post-closure performance objectives in NRC's regulations.

On December 18, 2014, the NRC issued Volume 4 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume covers administrative and programmatic requirements for the repository. It documents the staff's evaluation of whether the DOE's research and development and performance confirmation programs, as well as other administrative controls and systems, meet applicable NRC requirements. Volume 4 contains the staff's finding that most administrative and programmatic requirements in NRC regulations are met, except for certain requirements relating to ownership of land and water rights.

Publication of Volumes 3 and 4 does not signal whether or when the NRC might authorize construction of the repository.

*Waste Confidence and Continued Storage* — On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRC's rulemaking regarding temporary storage and permanent disposal of high level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC's 2010 update to the agency's Waste Confidence Decision and temporary storage rule ("Waste Confidence Decision").

The D.C. Circuit found that the agency's 2010 Waste Confidence Decision update constituted a major federal action, which, consistent with NEPA, requires either an environmental impact statement or a finding of no significant impact from the agency's actions. The D.C. Circuit found that the NRC's evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the 2010 Waste Confidence Decision update for further action consistent with NEPA.

On September 6, 2012, the NRC Commissioners issued a directive to the NRC staff to proceed directly with development of a generic environmental impact statement to support an updated Waste Confidence

Decision. The NRC Commissioners also directed the staff to establish a schedule to publish a final rule and environmental impact study within 24 months of September 6, 2012.

In September 2013, the NRC issued its draft Generic Environmental Impact Statement ("GEIS") to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. Renamed as the Continued Storage Rule, the NRC's decision adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. Although Palo Verde had not been involved in any licensing actions affected by the D.C. Circuit's June 8, 2012, decision, the NRC lifted its suspension on final licensing actions on all nuclear power plant licenses and renewals that went into effect when the D.C. Circuit issued its June 2012 decision. The final Continued Storage Rule was subject to continuing legal challenges before the NRC and the Court of Appeals. In June 2016, the D.C. Circuit issued its final decision, rejecting all remaining legal challenges to the Continued Storage Rule. On August 8, 2016, the D.C. Circuit denied a petition for rehearing.

Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation ("ISFSI") to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

*Nuclear Decommissioning Costs* — APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS's ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). Based on current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projections on the asset portfolios over the expected remaining operating life of the facility, we are on track to meet the current site specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned. See Note 19 for additional information about APS's nuclear decommissioning trusts.

*Palo Verde Liability and Insurance Matters* — See "Palo Verde Nuclear Generating Station — Nuclear Insurance" in Note 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

**Natural Gas and Oil Fueled Generating Facilities**

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe (discussed below); Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has one oil-only power plant, Douglas, located in the town of Douglas, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,179 MW. Gas for these plants is financially hedged up to three years in advance of purchasing and the gas is generally purchased one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of

which are effective through 2024. Fuel oil is acquired under short-term purchases delivered primarily to West Phoenix, where it is distributed to APS's other oil power plants by truck.

Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. (See Note 3 for proposed rate recovery in our current retail rate case.) On September 9, 2016, Maricopa County issued a final permit decision that authorizes construction of the Ocotillo modernization project and construction will begin in early 2017.

**Solar Facilities**

APS developed utility scale solar resources through the 170 MW ACC-approved AZ Sun Program. APS invested approximately $675 million in its AZ Sun Program. These facilities are owned by APS and are located in multiple locations throughout Arizona. In 2016, APS developed the 40MW Red Rock Solar Plant, which it owns and operates. Two of our large customers will purchase renewable energy credits from APS that is equivalent to the amount of renewable energy that Red Rock is projected to generate.

Additionally, APS owns and operates more than forty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar in various locations across Arizona. APS has also developed solar photovoltaic distributed energy systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, is a pilot program through which APS owns, operates and receives energy from approximately 1 MW of solar photovoltaic distributed energy systems located within a certain test area in Flagstaff, Arizona. Additionally, APS owns 12 MW of solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes would not be made until the project was fully in service, and APS has requested cost recovery for the project in its currently pending rate case. On September 30, 2016, APS presented its preliminary findings from the residential rooftop solar program in a filing with the ACC.

**Purchased Power Contracts**

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. (See Note 16.) APS continually assesses its need for additional capacity resources to assure system reliability.

*Purchased Power Capacity* — APS's purchased power capacity under long-term contracts as of December 31, 2016 is summarized in the table below. All capacity values are based on net capacity unless otherwise noted.

| Type | Dates Available | Capacity (MW) |
|---|---|---|
| Purchase Agreement (a) | Year-round through June 14, 2020 | 60 |
| Exchange Agreement (b) | May 15 to September 15 annually through February 2021 | 480 |
| Tolling Agreement | Year-round through May 2017 | 514 |
| Tolling Agreement | Summer seasons through October 2019 | 560 |
| Demand Response Agreement (c) | Summer seasons through 2024 | 25 |
| Tolling Agreement (d) | Summer seasons from Summer 2020 through Summer 2025 | 565 |
| Renewable Energy (e) | Various | 629 |

(a) Up to 60 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.
(b) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).
(c) The capacity under this agreement may be increased in 5 MW increments in each of 2015 and 2016 and 10 MW increments in years 2017 through 2024, up to a maximum of 50 MW.
(d) This agreement was signed in response to APS's 2016 all source request for proposal seeking capacity resources.
(e) Renewable energy purchased power agreements are described in detail below under "Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio."

## Current and Future Resources

### Current Demand and Reserve Margin

Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APS's 2016 peak one-hour demand on its electric system was recorded on June 19, 2016 at 7,051 MW, compared to the 2015 peak of 7,031 MW recorded on August 15, 2015. APS's reserve margin at the time of the 2016 peak demand, calculated using system load serving capacity, was 30%. For 2017, due to expiring purchase contracts, APS is procuring market resources to maintain its minimum 15% planning reserve criteria.

### Future Resources and Resource Plan

APS filed its preliminary 2017 Integrated Resource Plan on March 1, 2016 and an updated preliminary 2017 Integrated Resource Plan on September 30, 2016. APS also held stakeholder meetings in February and November 2016 in addition to an ACC-led Integrated Resource Plan workshop in July 2016. The preliminary Integrated Resource Plan and associated stakeholder meetings are part of a modified planning process that allows time to incorporate implications of the Clean Power Plan as well as input from stakeholder meetings. The final Integrated Resource Plan will be submitted by or on April 3, 2017 and the ACC is expected to complete its review by February 1, 2018.

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla

Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and is seeking recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its current retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($116 million as of December 31, 2016), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted. (See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Cholla" above for details regarding the status of the EPA's rule related to Cholla.)

See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Navajo Generating Station" above for information regarding future plans for the Navajo Plant.

**Energy Imbalance Market**

In 2015, APS and the CAISO, the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in the Energy Imbalance Market ("EIM"). APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS expects that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources.

**Renewable Energy Standard**

In 2006, the ACC adopted the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 7% of retail electric sales in 2017 and increases annually until it reaches 15% in 2025. In APS's 2009 retail rate case settlement agreement (the "2009 Settlement Agreement"), APS committed to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2016.

A component of the RES is focused on stimulating development of distributed energy systems. Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed energy requirement is 30% of the overall RES requirement of 7% in 2017. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

| | 2017 | 2020 | 2025 |
|---|---|---|---|
| RES as a % of retail electric sales | 7% | 10% | 15% |
| Percent of RES to be supplied from distributed energy resources | 30% | 30% | 30% |

On April 21, 2015, the RES rules were amended to require utilities to report on all eligible renewable resources in their service territory, irrespective of whether the utility owns renewable energy credits associated with such renewable energy. The rules allow the ACC to consider such information in determining whether APS has satisfied the requirements of the RES.

***Renewable Energy Portfolio.*** To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,480 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,440 MW are currently in operation and 40 MW are under contract for development or are under construction. Renewable resources in operation include 239 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 539 MW of customer-sited, third-party owned distributed energy resources.

APS's strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. See "Energy Sources and Resource Planning - Generation Facilities - Solar Facilities" above for information regarding APS-owned solar facilities.

The following table summarizes APS's renewable energy sources currently in operation and under development. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

| | Location | Actual/ Target Commercial Operation Date | Term (Years) | Net Capacity In Operation (MW AC) | Net Capacity Planned/ Under Development (MW AC) |
|---|---|---|---|---|---|
| **APS Owned** | | | | | |
| *Solar:* | | | | | |
| AZ Sun Program: | | | | | |
| Paloma | **Gila Bend, AZ** | **2011** | | **17** | |
| Cotton Center | **Gila Bend, AZ** | **2011** | | **17** | |
| Hyder Phase 1 | **Hyder, AZ** | **2011** | | **11** | |
| Hyder Phase 2 | **Hyder, AZ** | **2012** | | **5** | |
| Chino Valley | **Chino Valley, AZ** | **2012** | | **19** | |
| Hyder II | **Hyder, AZ** | **2013** | | **14** | |
| Foothills | **Yuma, AZ** | **2013** | | **35** | |
| Gila Bend | **Gila Bend, AZ** | **2014** | | **32** | |
| Luke AFB | **Glendale, AZ** | **2015** | | **10** | |
| Desert Star | **Buckeye, AZ** | **2015** | | **10** | |
| Subtotal AZ Sun Program | | | | **170** | — |
| Multiple Facilities | **AZ** | **Various** | | **4** | |
| Red Rock | **Red Rock, AZ** | **2016** | | **40** | |
| *Distributed Energy:* | | | | | |
| APS Owned (a) | **AZ** | **Various** | | **25** | |
| **Total APS Owned** | | | | **239** | — |
| **Purchased Power Agreements** | | | | | |
| *Solar:* | | | | | |
| Solana | **Gila Bend, AZ** | **2013** | **30** | **250** | |
| RE Ajo | **Ajo, AZ** | **2011** | **25** | **5** | |
| Sun E AZ 1 | **Prescott, AZ** | **2011** | **30** | **10** | |
| Saddle Mountain | **Tonopah, AZ** | **2012** | **30** | **15** | |
| Badger | **Tonopah, AZ** | **2013** | **30** | **15** | |
| Gillespie | **Maricopa County, AZ** | **2013** | **30** | **15** | |
| *Wind:* | | | | | |
| Aragonne Mesa | **Santa Rosa, NM** | **2006** | **20** | **90** | |
| High Lonesome | **Mountainair, NM** | **2009** | **30** | **100** | |
| Perrin Ranch Wind | **Williams, AZ** | **2012** | **25** | **99** | |
| *Geothermal:* | | | | | |
| Salton Sea | **Imperial County, CA** | **2006** | **23** | **10** | |
| *Biomass:* | | | | | |
| Snowflake | **Snowflake, AZ** | **2008** | **15** | **14** | |
| *Biogas:* | | | | | |
| Glendale Landfill | **Glendale, AZ** | **2010** | **20** | **3** | |
| NW Regional Landfill | **Surprise, AZ** | **2012** | **20** | **3** | |
| **Total Purchased Power Agreements** | | | | **629** | — |
| **Distributed Energy** | | | | | |
| *Solar* (b) | | | | | |
| Third-party Owned | **AZ** | **Various** | | **539** | **40** |
| Agreement 1 | **Bagdad, AZ** | **2011** | **25** | **15** | |
| Agreement 2 | **AZ** | **2011-2012** | **20-21** | **18** | |
| **Total Distributed Energy** | | | | **572** | **40** |
| **Total Renewable Portfolio** | | | | **1,440** | **40** |

(a) Includes Flagstaff Community Power Project, APS School and Government Program and APS Solar Partner Program.

(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in DC and is converted to AC for reporting purposes.

**Demand Side Management**

In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated its Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard ("EES") of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This standard will likely impact Arizona's future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations).

**Competitive Environment and Regulatory Oversight**

**Retail**

The ACC regulates APS's retail electric rates and its issuance of securities. The ACC must also approve any significant transfer or encumbrance of APS's property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS and their respective affiliates.

APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as rooftop solar panels to meet or supplement their energy needs.

On April 14, 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. APS cannot predict when, and the extent to which, additional electric service providers will enter or re-enter APS's service territory.

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations was whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. A series of workshops in this docket were held in 2014 and another in February of 2015. No further workshops are scheduled and no actions were taken as a result of these workshops.

### Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2016, approximately 3.5% of APS's electric operating revenues resulted from such sales and services. APS's wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS's Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and fuels. The majority of these activities are undertaken to mitigate risk in APS's portfolio.

### Subpoena from Arizona Corporation Commissioner Robert Burns

On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, filed subpoenas in APS's current retail rate proceeding to APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for APS to produce all information previously requested through the subpoenas. Commissioner Burns has also scheduled a workshop in this matter for March 17, 2017. APS and Pinnacle West cannot predict the outcome of this matter.

## Environmental Matters

### Climate Change

***Legislative Initiatives.*** There have been no recent attempts by Congress to pass legislation that would regulate greenhouse gas ("GHG") emissions, and it is doubtful whether the 115th Congress will consider a climate change bill. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is written, enacted and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and

whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide ("$CO_2$") equivalent emitted.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation and no proposed agency rule regulating GHGs in Arizona, the California legislature enacted AB 32 and SB 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013 and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover GHG emissions associated with electricity sales into California from outside the state. APS is authorized to recover the cost of these carbon allowances through the PSA.

***Regulatory Initiatives.*** In 2009, EPA determined that GHG emissions endanger public health and welfare. As a result of this "endangerment finding," EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review ("NSR") analysis for new major sources and major modifications to existing plants.

On June 2, 2014, EPA issued two proposed rules to regulate GHG emissions from modified and reconstructed electric generating units ("EGUs") pursuant to Section 111(b) of the Clean Air Act and existing fossil fuel-fired power plants pursuant to Clean Air Act Section 111(d).

On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed EGUs. EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in $CO_2$ emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, this timing will be impacted by the court-imposed stay described below.

Prior to the court-imposed stay described below, ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, was working to develop a compliance plan for submittal to EPA. Since the imposition of the stay, ADEQ is continuing to assess alternatives while completing outreach and soliciting feedback from stakeholders. In addition to these ongoing state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S.

Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of the delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output or potential plant closures, as alternatives to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains ongoing, and additional information or considerations may arise that change our expectations.

***Company Response to Climate Change Initiatives***. We have undertaken a number of initiatives that address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. (See "Energy Sources and Resource Planning - Current and Future Resources" above for details of these plans and

initiatives.) APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass, and we expect the percentage of renewable energy in our resource portfolio to increase over the coming years.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

**EPA Environmental Regulation**

***Regional Haze Rules***. In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the BART for certain older major stationary sources, including fossil-fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

The Four Corners and Navajo Plant participants' obligations to comply with EPA's final BART determinations (and Cholla's obligations to comply with ADEQ's and EPA's determinations), coupled with the financial impact of potential future climate change legislation, other environmental regulations, and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

*Cholla.* APS believes that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of selective catalytic reduction ("SCR") controls with a cost to APS of approximately $100 million is unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a Federal Implementation Plan ("FIP") that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy. Pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015.

On October 16, 2015, ADEQ issued a revised operating permit for Cholla, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. On June 30, 2016, EPA issued a proposed rule approving a revision to the Arizona SIP that incorporates APS's compromise approach for compliance with the Regional Haze program. EPA signed the final rule approving the Agency's proposal on January 13, 2017. Once the final rule is published in the Federal Register, parties have 60 days to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot

predict at this time whether such petitions will be filed or if they will be successful. In addition, under the terms of an executive memorandum issued on January 20, 2017, this final rule will not be published in the Federal Register until after it has been reviewed by an appointee of the President. We cannot predict when such review will occur and what may result from the additional review.

*Four Corners*. Based on EPA's final standards, APS estimates that its 63% share of the cost of required controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted to NTEC. In December 2015, NTEC provided notice of its intent to exercise the option. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

*Navajo Plant*. On July 28, 2014, EPA issued a final Navajo Plant BART rule. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process. See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Navajo Generating Station" above for information regarding future plans for the Navajo Plant.

***Mercury and other Hazardous Air Pollutants.*** In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla. No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million, the majority of which has already been incurred. Litigation concerning the rules, including supplemental analyses EPA has prepared in support of the MATS regulation, is ongoing. These proceedings do not materially impact APS. Regardless of the results from further judicial or administrative proceedings concerning the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

***Coal Combustion Waste.*** On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds. Because EPA has yet to undertake rulemaking proceedings to implement the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects the CCR provisions of the WIIN Act will have on APS's management of CCR.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million. APS is currently evaluating compliance alternatives for Cholla and estimates that its share of incremental costs to comply with the CCR rule for this plant is in the range of $5 million to $40 million based upon which compliance alternatives are ultimately selected. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million, the majority of which has already been incurred. Additionally, the CCR rule requires ongoing groundwater monitoring. Depending upon the results of such monitoring at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions, the costs of which we are unable to reasonably estimate at this time.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA's CCR regulations, within the next three years EPA is required to complete a rulemaking proceeding concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA's CCR rules. EPA is not required to take final action approving the inclusion of boron, but EPA must propose and consider its inclusion. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time, though, APS cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

***Effluent Limitation Guidelines.*** On September 30, 2015, EPA finalized revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPA's final regulation targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero discharge" from fly ash and bottom ash handling, and impoundment for coal ash disposal leachate. Compliance with these limitations will be required in connection with National Pollution Discharge Elimination System ("NPDES") discharge permit renewals, which occur in five-year intervals, that arise between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed during that timeframe, we are uncertain what will be required to control these discharges in compliance with the finalized effluent limitations at that facility. Cholla and the Navajo Plant do not require NPDES permitting.

***Ozone National Ambient Air Quality Standards.*** On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards ("NAAQS") at a level of 70 parts per billion

("ppb"). With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA is expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. Depending on when EPA approves attainment designations for the Arizona and Navajo Nation jurisdictions in which our fossil generation units are located, revisions to SIPs and FIPs, respectively, implementing required controls to achieve the new 70 ppb standard are expected to be in place between 2020 and 2021. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

***Superfund-Related Matters.*** The Comprehensive Environmental Response Compensation and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan ("RI/FS"). The OU3 working group parties have agreed to a schedule with EPA that calls for the submission of a revised draft RI/FS by June 2017. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID contractors filed ancillary lawsuits for recovery of costs against APS and the other defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

***Manufactured Gas Plant Sites.*** Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations or cash flows.

**Federal Agency Environmental Lawsuit Related to Four Corners**

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and

the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

**Navajo Nation Environmental Issues**

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under easements granted by the federal government, as well as leases from the Navajo Nation. See "Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities" above for additional information regarding these plants.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Navajo Acts"). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, SRP, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

**Water Supply**

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its needs. The Four Corners region, in which Four Corners is located, has historically experienced drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. However, during the past 12 months the region has received snowfall and precipitation sufficient to recover the Navajo Reservoir to an optimum operating level, reducing the probability of shortage in future years. Although the watershed and reservoirs are in a good condition at this time, APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future drought conditions that could have an impact on operations of its plants.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS's operations.

***San Juan River Adjudication.*** Both groundwater and surface water in areas important to APS's operations have been the subject of inquiries, claims, and legal proceedings, which will require a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss. In addition, APS is a party to a water contract that allows the company to secure water for Four Corners in the event of a water shortage and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to Four Corners in the event of a water shortage in the San Juan River Basin.

***Gila River Adjudication.*** A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APS's rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As operating agent of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APS's other power plants are also located within the geographic area subject to the summons. APS's claims dispute the court's jurisdiction over APS's groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS's water rights claims has been set in this matter.

***Little Colorado River Adjudication.*** APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS's groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS's claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning APS's water rights claims has been set in this matter.

Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial position, results of operations, or cash flows.

## BUSINESS OF OTHER SUBSIDIARIES

### Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with Pacific Gas and Electric Company ("PG&E") to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

### El Dorado

El Dorado owns minority interests in several energy-related investments and Arizona community-based ventures. El Dorado's short-term goal is to prudently realize the value of its existing investments. As of December 31, 2016, El Dorado had total assets of approximately $11 million. El Dorado is not expected to contribute in any material way to our future financial performance, nor will it require any material amounts of capital over the next three years.

### 4CA

See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generating Facilities - Coal-Fueled Generating Facilities - Four Corners" above for information regarding 4CA. As of December 31, 2016, 4CA had total assets of approximately $69 million.

## OTHER INFORMATION

### Subpoenas

Pinnacle West has received grand jury subpoenas issued in connection with an investigation by the office of the United States Attorney for the District of Arizona. The subpoenas seek information principally pertaining to the 2014 statewide election races in Arizona for Secretary of State and for positions on the ACC. The subpoenas request records involving certain Pinnacle West officers and employees, including the Company's Chief Executive Officer, as well as communications between Pinnacle West personnel and a former ACC Commissioner. Pinnacle West is cooperating fully with the United States Attorney's office in this matter.

## Other Information

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE and 4CA are incorporated in Delaware. Additional information for each of these companies is provided below:

| | Principal Executive Office Address | Year of Incorporation | Approximate Number of Employees at December 31, 2016 |
|---|---|---|---|
| Pinnacle West | 400 North Fifth Street<br>Phoenix, AZ 85004 | 1985 | 89 |
| APS | 400 North Fifth Street<br>P.O. Box 53999<br>Phoenix, AZ 85072-3999 | 1920 | 6,244 |
| BCE | 400 East Van Buren<br>Phoenix, AZ 85004 | 2014 | 6 |
| El Dorado | 400 East Van Buren<br>Phoenix, AZ 85004 | 1983 | — |
| 4CA | 400 North Fifth Street<br>Phoenix, AZ 85004 | 2016 | — |
| Total | | | 6,339 |

The APS number includes employees at jointly-owned generating facilities (approximately 2,628 employees) for which APS serves as the generating facility manager. Approximately 1,613 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW") or the United Security Professionals of America ("USPA"). APS concluded negotiations with IBEW representatives over the new collective bargaining agreement in April 2015, and the new agreement is in place until March 31, 2018. The contract provides an average wage increase of 2.0% for the first year, 2.25% for the second year and 3.0% for the third year. The Company concluded negotiations with the USPA over the terms of a new collective bargaining agreement in May of 2014, and the new agreement is in place until May 31, 2017.

## WHERE TO FIND MORE INFORMATION

We use our website (*www.pinnaclewest.com)* as a channel of distribution for material Company information. The following filings are available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission (“SEC”): Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. Our board and committee charters, Code of Ethics for Financial Executives, Code of Ethics and Business Practices and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Code of Ethics and Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange, on its website. The information on Pinnacle West’s website is not incorporated by reference into this report.

You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Corporate Secretary, Mail Station 8602, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-4400).

## ITEM 1A. RISK FACTORS

In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS.

### REGULATORY RISKS

***Our financial condition depends upon APS's ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy.***

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity, results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS's retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings and ancillary matters which may come before the ACC and FERC, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances.

APS is currently pursuing certain activities, such as microgrid investments and construction of renewable facilities intended for specific customers. To date, APS has not received regulatory assurance of cost recovery for such investments. As APS engages in these activities, we will have to demonstrate to regulators, as we do with all other capital investments, that these investments are both prudent and useful in providing electric service to customers.

The ACC must also approve APS's issuance of securities and any significant transfer or encumbrance of APS property used to provide retail electric service, and must approve or receive prior notification of certain transactions between us, APS and our respective affiliates. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations or cash flows.

***APS's ability to conduct its business operations and avoid fines and penalties depends upon compliance with federal, state or local statutes, regulations and ACC requirements, and obtaining and maintaining certain regulatory permits, approvals and certificates.***

APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of agencies that regulate APS's business, including FERC, NRC, EPA, the ACC, and state and local governmental agencies. These agencies regulate many aspects of APS's utility operations, including safety and performance, emissions, siting and construction of facilities, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, FERC can impose penalties (up to one million dollars per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS's business is conducted in accordance with applicable laws in all material respects. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

***The operation of APS's nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures.***

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including Palo Verde. In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increased inspection regime that could ultimately result in the shut-down of a unit or civil penalties, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APS's financial condition, results of operations and cash flows.

***APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APS's cost of operations or impact its business plans.***

APS is, or may become, subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of conventional pollutants and greenhouse gases, water quality, discharges of wastewater and streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if APS fails to obtain, maintain, or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability as a result of government enforcement actions or private claims or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise.

*Environmental Clean Up.* APS has been named as a PRP for a Superfund site in Phoenix, Arizona, and it could be named a PRP in the future for other environmental clean-up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

*Regional Haze.* APS has received final rulemakings imposing new requirements on Four Corners, Cholla and the Navajo Plant. Pursuant to these rules, EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants. The financial impact of installing and operating the required pollution control equipment could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

*Coal Ash.* In December 2014, EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners and in a dry landfill storage area at the Navajo Plant. To the extent

the rule requires the closure or modification of these CCR units or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal.

*Ozone National Ambient Air Quality Standards.* In 2015, EPA finalized revisions to the national ambient air quality standards for nitrogen oxides, which set new, more stringent standards intended to protect human health and human welfare. Depending on the final attainment designations for the new standards and the state implementation requirements, APS may be required to invest in new pollution control technologies and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas.

APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APS's customers, could have a material adverse effect on its financial condition, results of operations or cash flows. Due to current or potential future regulations or legislation coupled with trends in natural gas and coal prices, the economics of continuing to own certain resources, particularly coal facilities, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

***APS faces potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions, as well as physical and operational risks related to climate effects.***

Concern over climate change has led to significant legislative and regulatory efforts to limit CO2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

*Potential Financial Risks - Greenhouse Gas Regulation, the Clean Power Plan and Potential Litigation.* In 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants. The implementation of this rule within the jurisdictions where APS operates could result in a shift in in-state generation from coal to natural gas and renewable generation. Such a substantial change in APS's generation portfolio could require additional capital investments and increased operating costs, and thus have a significant financial impact on the Company. See Note 10 for additional risks and uncertainties resulting from the Clean Power Plan.

Depending on the final outcome of the pending judicial review of the Clean Power Plan, or any related legislative or regulatory activity, the utility industry may face alternative efforts from private parties seeking to establish alternative GHG emission limitations from power plants. Alternative GHG emission limitations may arise from litigation under either federal or state common laws or citizen suit provisions of federal environmental statutes that attempt to force federal agency rulemaking or imposing direct facility emission limitations. Such lawsuits may also seek damages from harm alleged to have resulted from power plant GHG emissions.

*Physical and Operational Risks.* Weather extremes such as drought and high temperature variations are common occurrences in the Southwest's desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and represent a greater challenge.

***Co-owners of our jointly owned generation facilities may have unaligned goals and positions due to the effects of legislation, regulations, economic conditions or changes in our industry, which could have a significant impact on our ability to continue operations of such facilities.***

APS owns certain of our power plants jointly with other owners with varying ownership interests in such facilities. Changes in the nature of our industry and the economic viability of certain plants, including impacts resulting from types and availability of other resources, fuel costs, legislation and regulation, together with timing considerations related to expiration of leases or other agreements for such facilities, could result in unaligned positions among co-owners. Such differences in the co-owners' willingness or ability to continue their participation could ultimately lead to disagreements among the parties as to how and whether to continue operation of such plants, which could lead to eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets.

***Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on APS's business and its results of operations.***

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APS's service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition.

One of these options would be a continuation or expansion of APS's existing AG (Alternative Generation) - 1 pilot program, which essentially allows up to 200 MW of cumulative load to be served via a buy-through arrangement with competitive suppliers of generation. On November 25, 2015, the ACC issued an order approving a request by several AG-1 customers and suppliers to extend the term of the program from July 1, 2016 to the conclusion of APS's pending general rate case. The order also authorized APS to defer for future recovery unmitigated unrecovered costs attributable to the program at 90% of the first $10 million per year and at 100% of amounts above $10 million per year.

Proposals to enable or support retail electric competition may be made from time to time through ballot initiatives, legislative or other forums in Arizona. We cannot predict future regulatory or legislative action that might result in increased competition.

***Changes in tax legislation or regulation may affect our financial results.***

We are subject to taxation by various taxing authorities at the federal, state and local levels. Legislation or regulation could be enacted by any of these governmental authorities which could affect the Company's tax positions. The prospects for broad-based federal tax reform have increased due to the results of the 2016 elections. Any such reform may impact the Company's effective tax rate, cash taxes paid and other financial results such as earnings per share, gross revenues and cash flows. We cannot predict the timing or extent of

such tax-related developments which, absent appropriate regulatory treatment, could have a negative impact on our financial results.

## OPERATIONAL RISKS

***APS's results of operations can be adversely affected by various factors impacting demand for electricity.***

*Weather Conditions.* Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APS's overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APS's financial condition, results of operations and cash flows.

Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of forest fires. Forest fires could threaten APS's communities and electric transmission lines and facilities. Any damage caused as a result of forest fires could negatively impact APS's financial condition, results of operations or cash flows.

*Effects of Energy Conservation Measures and Distributed Energy Resources.* The ACC has enacted rules regarding energy efficiency that mandate a 22% cumulative annual energy savings requirement by 2020. This will likely increase participation by APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn will impact the demand for electricity. The rules also include a requirement for the ACC to review and address financial disincentives, recovery of fixed costs and the recovery of net lost income/revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the settlement agreement in APS's most recent retail rate case (the "2012 Settlement Agreement") includes a mechanism, the LFCR, to address these matters.

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement was 25% of the overall RES requirement of 3% in 2011 and increased to 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some of their own energy needs.

In addition to these rules and requirements, energy efficiency technologies and distributed energy resources continue to evolve, which may have similar impacts on demand for electricity. Reduced demand due to these energy efficiency requirements, distributed energy requirements and other emerging technologies, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

*Actual and Projected Customer and Sales Growth.* Retail customers in APS's service territory increased 1.4% for the year ended December 31, 2016 compared with the prior year. For the three years 2014 through 2016, APS's retail customer growth averaged 1.3% per year. We currently project annual customer growth to be 1.5-2.5% for 2017 and to average in the range of 2.0-3.0% for 2017 through 2019 based on our assessment of modestly improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, were flat for the year ended December 31, 2016 compared with the prior year. Improving economic conditions and customer growth and an additional day of sales due to leap year were equally offset by energy savings driven by

customer conservation, energy efficiency and distributed renewable generation initiatives. For the three years 2014 through 2016, APS experienced annual increases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 0-1.0% for 2017 and increase on average in the range of 0.5-1.5% during 2017 through 2019, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations.

Actual customer and sales growth may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed renewable generation, and responses to retail price changes. Additionally, recovery of a substantial portion of our fixed costs of providing service is based upon the volumetric amount of our sales. If our customer growth rate does not continue to improve as projected, or if we experience acceleration of expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives, we may be unable to reach our estimated sales projections, which could have a negative impact on our financial condition, results of operations and cash flows.

***The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages, which could materially affect APS's results of operations.***

The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS's business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. Concerns over physical security of these assets include damage to certain of our facilities due to vandalism or other deliberate acts that could lead to outages or other adverse effects. If APS's facilities operate below expectations, especially during its peak seasons, it may lose revenue or incur additional expenses, including increased purchased power expenses.

***The inability to successfully develop or acquire generation resources to meet reliability requirements and other new or evolving standards or regulations could adversely impact our business.***

Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain various regulatory approvals create uncertainty surrounding our generation portfolio. The current abundance of low, stably priced natural gas, together with environmental and other concerns surrounding coal-fired generation resources, create strategic challenges as to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements, including those related to renewables development and energy efficiency measures. The development of any generation facility is subject to many risks, including those related to financing, siting, permitting, new and evolving technology, the construction of sufficient transmission capacity to support these facilities and stresses to generation and transmission resources from the intermittent generation characteristics of renewable resources. APS's inability to adequately develop or acquire the necessary generation resources could have a material adverse impact on our business and results of operations.

In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting and construction of fossil fuel

infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of Federal environmental regulation and the increasing financial resources devoted to these opposition activities. APS cannot predict the effect that any such opposition may have on our ability to develop and construct fossil fuel infrastructure projects in the future.

***The lack of access to sufficient supplies of water could have a material adverse impact on APS's business and results of operations.***

Assured supplies of water are important for APS's generating plants. Water in the southwestern United States is limited, and various parties have made conflicting claims regarding the right to access and use such limited supply of water. Both groundwater and surface water in areas important to APS's generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the region in which APS's power plants are located is prone to drought conditions, which could potentially affect the plants' water supplies. APS's inability to access sufficient supplies of water could have a material adverse impact on our business and results of operations.

***We are subject to cybersecurity risks and risks of unauthorized access to our systems.***

In the regular course of our business, we handle a range of sensitive security, customer and business systems information. A security breach of our information systems such as theft or the inappropriate release of certain types of information, including confidential customer, employee, financial or system operating information, could have a material adverse impact on our financial condition, results of operations or cash flows. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, our technology systems are vulnerable to disability, failures or unauthorized access. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems and physical assets could be targets of such unauthorized access. Failures or breaches of our systems could impact the reliability of our generation, transmission and distribution systems and also subject us to financial harm. If our technology systems were to fail or be breached and if we are unable to recover in a timely way, we may not be able to fulfill critical business functions and sensitive confidential data could be compromised, which could have a material adverse impact on our financial condition, results of operations or cash flows.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer and business information. One of these agencies, NERC, has issued comprehensive regulations and standards surrounding the security of bulk power systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The increasing promulgation of NERC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards, which includes potential financial penalties.

We have experienced, and expect to continue to experience, threats and attempted intrusions to our information technology systems and we could experience such threats and attempted intrusions to our operational control systems. The implementation of additional security measures could increase costs and have a material adverse impact on our financial results. We have obtained cyber insurance to provide coverage for a portion of the losses and damages that may result from a security breach of our information technology systems, but such insurance may not cover the total loss or damage caused by a breach. These types of events could also require significant management attention and resources, and could adversely affect Pinnacle West's and APS's reputation with customers and the public.

***The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements and rights-of-way, which could have a significant impact on our business.***

Certain APS power plants and portions of certain APS transmission lines are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is unable to predict the final outcomes of pending and future approvals by the applicable sovereign governing bodies with respect to renewals of these leases, easements and rights-of-way.

***There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack.***

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 18% of our owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $111 million (but not more than $16.6 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power plant in the United States. Although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

***The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.***

APS's operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas and coal to the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") contains measures aimed at increasing the transparency and stability of the over-the counter, or OTC, derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APS's trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period.

***Changes in technology could create challenges for APS's existing business.***

Alternative energy technologies that produce power or reduce power consumption or emissions are being developed and commercialized, including renewable technologies such as photovoltaic (solar) cells, customer-sited generation, energy storage (batteries), and efficiency technologies. Advances in technology and equipment/appliance efficiency could reduce the demand for supply from conventional generation and increase the complexity of managing APS's information technology and power system operations, which could adversely affect APS's business.

APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as established or mature as APS's existing technologies and equipment. The implementation of new and additional technologies adds complexity to the information technology and operational technology systems, which could require additional infrastructure and resources. Widespread installation and acceptance of new technologies could also enable the entry of new market participants, such as technology companies, into the interface between APS and its customers and could have other unpredictable effects on APS's traditional business model.

Deployment of renewable energy technologies is expected to continue across the western states and result in a larger portion of the overall energy production coming from these sources. These trends, which have benefited from historical and continuing government support for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APS's existing generating facilities less economical and impact their operational patterns and long-term viability.

***We are subject to employee workforce factors that could adversely affect our business and financial condition.***

Like most companies in the electric utility industry, our workforce is maturing, with approximately 35% of employees eligible to retire by the end of 2019. Although we have undertaken efforts to recruit and train new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability of qualified personnel, the need to negotiate collective bargaining agreements with union employees and potential work stoppages. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

## FINANCIAL RISKS

***Financial market disruptions or new rules or regulations may increase our financing costs or limit our access to various financial markets, which may adversely affect our liquidity and our ability to implement our financial strategy.***

Pinnacle West and APS rely on access to credit markets as a significant source of liquidity and the capital markets for capital requirements not satisfied by cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions or rules or regulations may cause our cost of borrowing to increase generally, and/or otherwise adversely affect our ability to access these financial markets.

In addition, the credit commitments of our lenders under our bank facilities may not be satisfied or continued beyond current commitment periods for a variety of reasons, including new rules and regulations, periods of financial distress or liquidity issues affecting our lenders or financial markets, which could materially adversely affect the adequacy of our liquidity sources and the cost of maintaining these sources.

Changes in economic conditions, monetary policy, financial regulation or other factors could result in higher interest rates, which would increase interest expense on our existing variable rate debt and new debt we expect to issue in the future, and thus reduce funds available to us for our current plans.

Additionally, an increase in our leverage, whether as a result of these factors or otherwise, could adversely affect us by:

- causing a downgrade of our credit ratings;
- increasing the cost of future debt financing and refinancing;
- increasing our vulnerability to adverse economic and industry conditions; and
- requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future investment in our business or other purposes.

***A downgrade of our credit ratings could materially and adversely affect our business, financial condition and results of operations.***

Our current ratings are set forth in “Liquidity and Capital Resources — Credit Ratings” in Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle West’s and APS’s securities, limit our access to capital and increase our borrowing costs, which would diminish our financial results. We would be required to pay a higher interest rate for future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could severely limit access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

***Investment performance, changing interest rates and other economic, social and political factors could decrease the value of our benefit plan assets and nuclear decommissioning trust funds or increase the valuation of our related obligations, resulting in significant additional funding requirements. We are subject to risks related to the provision of employee healthcare benefits and healthcare reform legislation. Any inability to fully recover these costs in our utility rates would negatively impact our financial condition.***

We have significant pension plan and other postretirement benefits plan obligations to our employees and retirees, and legal obligations to fund nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements into the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates decrease the discount rate, increase the valuation of the plan liabilities and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased number of retirements or changes in life expectancy and changes in other actuarial assumptions, may also result in similar impacts. The minimum contributions required under these plans are impacted by federal legislation. Increasing liabilities or otherwise increasing funding requirements under these plans, resulting from adverse changes in legislation or otherwise, could result in significant cash funding obligations that could have a material impact on our financial position, results of operations or cash flows.

We recover most of the pension costs and other postretirement benefit costs and all of the nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner would have a material negative impact on our financial condition, results of operations or cash flows.

Employee healthcare costs in recent years have continued to rise. While most of the Patient Protection and Affordable Care Act provisions have been implemented, changes to the Act or other potential legislation could increase costs of providing medical insurance for our employees. Any potential changes and resulting cost impacts cannot be determined with certainty at this time.

***Our cash flow depends on the performance of APS.***

We derive essentially all of our revenues and earnings from our wholly owned subsidiary, APS. Accordingly, our cash flow and our ability to pay dividends on our common stock is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us.

APS's financing agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

***Pinnacle West's ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries.***

Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

***The market price of our common stock may be volatile.***

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;
- developments generally affecting industries in which we operate;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

***Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts.***

These provisions, which could preclude our shareholders from receiving a change of control premium, include the following:

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of the Board of Directors and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise; and

- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

While these provisions have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board of Directors to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2016 fiscal year and that remain unresolved.

## ITEM 2. PROPERTIES

### Generation Facilities

#### APS

APS's portfolio of owned and leased generating facilities is provided in the table below:

| Name | No. of Units | % Owned (a) | Principal Fuels Used | Primary Dispatch Type | Owned Capacity (MW) |
|---|---|---|---|---|---|
| ***Nuclear:*** | | | | | |
| Palo Verde (b) | 3 | 29.1% | Uranium | Base Load | 1,146 |
| **Total Nuclear** | | | | | 1,146 |
| ***Steam:*** | | | | | |
| Four Corners 4, 5 (c) | 2 | 63% | Coal | Base Load | 970 |
| Cholla 1,3 (d) | 2 | | Coal | Base Load | 387 |
| Navajo (e) | 3 | 14% | Coal | Base Load | 315 |
| Ocotillo | 2 | | Gas | Peaking | 220 |
| **Total Steam** | | | | | 1,892 |
| ***Combined Cycle:*** | | | | | |
| Redhawk | 2 | | Gas | Load Following | 984 |
| West Phoenix | 5 | | Gas | Load Following | 887 |
| **Total Combined Cycle** | | | | | 1,871 |
| ***Combustion Turbine:*** | | | | | |
| Ocotillo | 2 | | Gas | Peaking | 110 |
| Saguaro | 3 | | Gas | Peaking | 189 |
| Douglas | 1 | | Oil | Peaking | 16 |
| Sundance | 10 | | Gas | Peaking | 420 |
| West Phoenix | 2 | | Gas | Peaking | 110 |
| Yucca 1, 2, 3 | 3 | | Gas | Peaking | 93 |
| Yucca 4 | 1 | | Oil | Peaking | 54 |
| Yucca 5, 6 | 2 | | Gas | Peaking | 96 |
| **Total Combustion Turbine** | | | | | 1,088 |
| ***Solar:*** | | | | | |
| Cotton Center | 1 | | Solar | As Available | 17 |
| Hyder I | 1 | | Solar | As Available | 16 |
| Paloma | 1 | | Solar | As Available | 17 |
| Chino Valley | 1 | | Solar | As Available | 19 |
| Gila Bend | 1 | | Solar | As Available | 32 |
| Hyder II | 1 | | Solar | As Available | 14 |
| Foothills | 1 | | Solar | As Available | 35 |
| Luke AFB | 1 | | Solar | As Available | 10 |
| Desert Star | 1 | | Solar | As Available | 10 |
| Red Rock | 1 | | Solar | As Available | 40 |
| APS Owned Distributed Energy | | | Solar | As Available | 25 |
| Multiple facilities | | | Solar | As Available | 4 |
| **Total Solar** | | | | | 239 |
| **Total Capacity** | | | | | 6,236 |

(a) 100% unless otherwise noted.
(b) See “Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Nuclear” in Item 1 for details regarding leased interests in Palo Verde. The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.
(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and 4CA (7%). The plant is operated by APS.
(d) Cholla Unit 2's last day of service was on October 1, 2015.
(e) The other participants are Salt River Project (42.9%), Nevada Power Company (11.3%), the United States Government (24.3%) and Tucson Electric Power Company (7.5%). The plant is operated by Salt River Project. In July 2016, Salt River Project purchased Los Angeles Department of Water & Power's share in this plant (21.2%).

See “Business of Arizona Public Service Company — Environmental Matters” in Item 1 with respect to matters having a possible impact on the operation of certain of APS’s generating facilities.

See “Business of Arizona Public Service Company” in Item 1 for a map detailing the location of APS’s major power plants and principal transmission lines.

**4CA**

4CA, a wholly-owned subsidiary of Pinnacle West, purchased El Paso's 7% interest in Units 4 and 5 of Four Corners on July 6, 2016. See "Areas of Business Focus - Operational Performance, Reliability and Recent Developments - Four Corners - Asset Purchase Agreement and Coal Supply Matters" in Item 7 for additional information about 4CA's interest in Four Corners.

**Transmission and Distribution Facilities**

***Current Facilities.*** APS’s transmission facilities consist of approximately 6,140 pole miles of overhead lines and approximately 49 miles of underground lines, 5,917 miles of which are located in Arizona. APS’s distribution facilities consist of approximately 11,144 miles of overhead lines and approximately 21,128 miles of underground primary cable, all of which are located in Arizona. APS distribution facilities reflect an actual net gain of 3,124 miles in 2016. APS shares ownership of some of its transmission facilities with other companies.

The following table shows APS's jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2016:

| | Percent Owned (Weighted-Average) |
|---|---|
| Morgan — Pinnacle Peak System | 65.2% |
| Palo Verde — Rudd 500kV System | 50.0% |
| Round Valley System | 50.0% |
| ANPP 500kV System | 33.6% |
| Navajo Southern System | 22.5% |
| Four Corners Switchyards | 51.3% |
| Palo Verde — Yuma 500kV System | 19.0% |
| Phoenix — Mead System | 17.1% |
| Palo Verde — Morgan System | 85.8% |
| Hassayampa — North Gila System | 80.0% |
| Cholla 500 Switchyard | 85.7% |
| Saguaro 500 Switchyard | 75.0% |

***Expansion.*** Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2017 plan, APS projects it will develop 52 miles of new transmission lines over the next ten years. One significant project currently under development is a new 500kV path that will span from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminate at a bulk substation in the northeast part of Phoenix. The Palo Verde to Morgan System includes Palo Verde-Delaney-Sun Valley-Morgan-Pinnacle Peak. The project consists of four phases. The first three phases, Morgan to Pinnacle Peak 500kV, Palo Verde to Delaney 500kV, and Delaney to Sun Valley 500kV are currently in-service. The fourth phase, Morgan to Sun Valley 500kV, has started construction and is expected to be energized by May 2018. In total, the projects consist of over 100 miles of new 500kV lines, with many of those miles constructed with the capability to string a 230kV line as a second circuit.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which have been completed and were included in previous APS transmission plans, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which support the transmission of renewable energy to Phoenix and California. The North Gila to Hassayampa line went into service in May 2015 and the Delaney to Palo Verde line went into service in May 2016.

***Physical Security Standards.*** On July 14, 2015, FERC approved version 2 of the proposed Physical Security Reliability Standard CIP-014 (CIP-014-2). As a result, CIP-014-2, the Physical Security Reliability Standard that requires transmission owners and operators to protect those critical transmission stations and substations and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack, could result in widespread instability, uncontrolled separation or cascading within an interconnection, became effective on October 2, 2015, triggering a series of staggered, but interdependent obligations for APS. As required by the Physical Security Reliability Standard, APS determined its critical transmission stations and substations and associated primary control centers that were required to comply with the standard by October 2, 2015. However, as contemplated under CIP-014-2, this verification triggered additional requirements and obligations within the Physical Security Reliability Standard. These remaining obligations, which consist of a risk evaluation and development and verification of a physical security plan, were largely completed in 2016 and the remaining activities are projected to be completed in the second and fourth quarters of 2017. Until APS has completed all required activities under the Physical Security Reliability Standard, we cannot predict the extent of any financial or operational impacts on APS.

***NERC Critical Infrastructure Protection Reliability Standards***. In 2014, APS initiated a comprehensive project to ensure compliance with Version 5 of NERC's Critical Infrastructure Protection Reliability Standards (CIP V.5), which will become effective pursuant to various implementation dates through 2018. APS completed a significant portion of its compliance implementation activities in June 2016, meeting an initial compliance date of July 1, 2016. APS will be incurring incremental capital expenditures through 2018 to meet further upcoming compliance deadlines associated with CIP V.5. Total expenditures are estimated to be approximately $52 million.

**Plant and Transmission Line Leases and Rights-of-Way on Indian Lands**

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under rights-of-way from the federal government. The right-of-way and lease for the Navajo Plant expire in 2019 and the right-of-way and lease for Four Corners were scheduled to expire in 2016. APS, on behalf of the Four Corners participants, negotiated amendments to the facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. See "Areas of Business Focus - Operational Performance, Reliability and Recent Developments - Four Corners - Lease Extension" in Item 7 for additional information about the Four Corners right-of-way and lease matters. See "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

Certain portions of our transmission lines are located on Indian lands pursuant to rights-of-way that are effective for specified periods. Some of these rights-of-way have expired and our renewal applications have not yet been acted upon by the appropriate Indian tribes or federal agencies. Other rights expire at various times in the future and renewal action by the applicable tribe or federal agencies will be required at that time. In recent negotiations, certain of the affected Indian tribes have required payments substantially in excess of amounts that we have paid in the past for such rights-of-way. The ultimate cost of renewal of certain of the rights-of-way for our transmission lines is therefore uncertain.

## ITEM 3. LEGAL PROCEEDINGS

See “Business of Arizona Public Service Company — Environmental Matters” in Item 1 with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 10 for information regarding environmental matters and Superfund–related matters.

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

## EXECUTIVE OFFICERS OF PINNACLE WEST

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The executive officers, their ages at February 24, 2017, current positions and principal occupations for the past five years are as follows:

| Name | Age | Position | Period |
|---|---|---|---|
| Donald E. Brandt | 62 | Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS | 2009-Present |
| | | President of APS | 2013-Present |
| | | President of Pinnacle West | 2008-Present |
| | | Chief Executive Officer of APS | 2008-Present |
| Robert S. Bement | 61 | Executive Vice President and Chief Nuclear Officer, PVNGS, of APS | 2016-Present |
| | | Senior Vice President, Site Operations, PVNGS, of APS | 2011-2016 |
| Denise R. Danner | 61 | Vice President, Controller and Chief Accounting Officer of Pinnacle West; Chief Accounting Officer of APS | 2010-Present |
| | | Vice President and Controller of APS | 2009-Present |
| Randall K. Edington (a) | 63 | Advisor to the CEO of APS | 2016-Present |
| | | Executive Vice President of APS | 2007-Present |
| | | Chief Nuclear Officer, PVNGS, of APS | 2007-2016 |
| David P. Falck | 63 | Executive Vice President and General Counsel of Pinnacle West and APS | 2009-Present |
| | | Secretary of Pinnacle West and APS | 2009-2012 |
| Daniel T. Froetscher | 55 | Senior Vice President, Transmission, Distribution & Customers of APS | 2014-Present |
| | | Vice President, Energy Delivery of APS | 2008-2014 |
| Barbara M. Gomez (b) | 62 | Senior Vice President, Human Resources of APS | 2016-Present |
| | | Vice President, Human Resources of APS | 2014-2016 |
| | | Vice President, Chief Procurement Officer of APS | 2013-2014 |
| | | Vice President, Supply Chain Management of APS | 2010-2013 |
| Jeffrey B. Guldner | 51 | Senior Vice President, Public Policy of APS | 2014-Present |
| | | Senior Vice President, Customers and Regulation of APS | 2012-2014 |
| | | Vice President, Rates and Regulation of APS | 2007-2012 |
| James R. Hatfield | 59 | Executive Vice President of Pinnacle West and APS | 2012-Present |
| | | Chief Financial Officer of Pinnacle West and APS | 2008-Present |
| | | Senior Vice President of Pinnacle West and APS | 2008-2012 |
| John S. Hatfield | 51 | Vice President, Communications of APS | 2010-Present |
| Lee R. Nickloy | 50 | Vice President and Treasurer of Pinnacle West and APS | 2010-Present |
| Mark A. Schiavoni | 61 | Executive Vice President and Chief Operating Officer of APS | 2014-Present |
| | | Executive Vice President, Operations of APS | 2012-2014 |
| | | Senior Vice President, Fossil Operations of APS | 2009-2012 |

(a) Randall K. Edington is retiring from APS on March 22, 2017.
(b) Barbara M. Gomez is retiring from APS in July 2017.

## PART II

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

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange. At the close of business on February 17, 2017, Pinnacle West's common stock was held of record by approximately 19,581 shareholders.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE
STOCK SYMBOL: PNW

| 2016 | High | Low | Close | Dividends Per Share |
|---|---|---|---|---|
| 1st Quarter | $ 75.15 | $ 62.51 | $ 75.07 | $ 0.625 |
| 2nd Quarter | 81.08 | 70.11 | 81.06 | 0.625 |
| 3rd Quarter | 82.78 | 73.94 | 75.99 | 0.625 |
| 4th Quarter | 78.97 | 70.86 | 78.03 | 0.655 |

| 2015 | High | Low | Close | Dividends Per Share |
|---|---|---|---|---|
| 1st Quarter | $ 73.31 | $ 61.53 | $ 63.75 | $ 0.595 |
| 2nd Quarter | 64.95 | 56.01 | 56.89 | 0.595 |
| 3rd Quarter | 65.23 | 56.77 | 64.14 | 0.595 |
| 4th Quarter | 67.02 | 60.70 | 64.48 | 0.625 |

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for APS's common stock.

The chart below sets forth the dividends paid on APS's common stock for each of the four quarters for 2016 and 2015.

**Common Stock Dividends**
**(Dollars in Thousands)**

| Quarter | 2016 | 2015 |
|---|---|---|
| 1st Quarter | $ 69,400 | $ 65,800 |
| 2nd Quarter | 69,500 | 65,900 |
| 3rd Quarter | 69,500 | 65,900 |
| 4th Quarter | 72,900 | 69,300 |

The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. As of December 31, 2016, APS did not have any outstanding preferred stock.

## ITEM 6. SELECTED FINANCIAL DATA

## PINNACLE WEST CAPITAL CORPORATION – CONSOLIDATED

The selected data presented below as of and for the years ended December 31, 2016, 2015, 2014, 2013 and 2012 are derived from the Consolidated Financial Statements. The data should be read in connection with the Consolidated Financial Statements including the related notes included in Item 8 of this Form 10-K.

| | 2016 | 2015 | 2014 | 2013 | 2012 |
|---|---|---|---|---|---|
| | (dollars in thousands, except per share amounts) | | | | |
| OPERATING RESULTS | | | | | |
| Operating revenues | $ 3,498,682 | $ 3,495,443 | $ 3,491,632 | $ 3,454,628 | $ 3,301,804 |
| Income from continuing operations | $ 461,527 | $ 456,190 | $ 423,696 | $ 439,966 | $ 418,993 |
| Loss from discontinued operations – net of income taxes | — | — | — | — | (5,829) |
| Net income | 461,527 | 456,190 | 423,696 | 439,966 | 413,164 |
| Less: Net income attributable to noncontrolling interests | 19,493 | 18,933 | 26,101 | 33,892 | 31,622 |
| Net income attributable to common shareholders | $ 442,034 | $ 437,257 | $ 397,595 | $ 406,074 | $ 381,542 |
| COMMON STOCK DATA | | | | | |
| Book value per share – year-end | $ 43.14 | $ 41.30 | $ 39.50 | $ 38.07 | $ 36.20 |
| Earnings per weighted-average common share outstanding: | | | | | |
| Continuing operations attributable to common shareholders – basic | $ 3.97 | $ 3.94 | $ 3.59 | $ 3.69 | $ 3.54 |
| Net income attributable to common shareholders – basic | $ 3.97 | $ 3.94 | $ 3.59 | $ 3.69 | $ 3.48 |
| Continuing operations attributable to common shareholders – diluted | $ 3.95 | $ 3.92 | $ 3.58 | $ 3.66 | $ 3.50 |
| Net income attributable to common shareholders – diluted | $ 3.95 | $ 3.92 | $ 3.58 | $ 3.66 | $ 3.45 |
| Dividends declared per share | $ 2.56 | $ 2.44 | $ 2.33 | $ 2.23 | $ 2.67 |
| Weighted-average common shares outstanding – basic | 111,408,729 | 111,025,944 | 110,626,101 | 109,984,160 | 109,510,296 |
| Weighted-average common shares outstanding – diluted | 112,046,043 | 111,552,130 | 111,178,141 | 110,805,943 | 110,527,311 |
| BALANCE SHEET DATA | | | | | |
| Total assets | $ 16,004,253 | $ 15,028,258 | $ 14,288,890 | $ 13,486,826 | $ 13,357,123 |
| Liabilities and equity: | | | | | |
| Current liabilities | $ 1,292,946 | $ 1,442,317 | $ 1,559,143 | $ 1,618,644 | $ 1,083,542 |
| Long-term debt less current maturities | 4,021,785 | 3,462,391 | 3,006,573 | 2,774,605 | 3,176,596 |
| Deferred credits and other | 5,753,610 | 5,404,093 | 5,204,072 | 4,753,117 | 4,994,696 |
| Total liabilities | 11,068,341 | 10,308,801 | 9,769,788 | 9,146,366 | 9,254,834 |
| Total equity | 4,935,912 | 4,719,457 | 4,519,102 | 4,340,460 | 4,102,289 |
| Total liabilities and equity | $ 16,004,253 | $ 15,028,258 | $ 14,288,890 | $ 13,486,826 | $ 13,357,123 |

## SELECTED FINANCIAL DATA

## ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

| | 2016 | 2015 | 2014 | 2013 | 2012 |
|---|---|---|---|---|---|
| | | | (dollars in thousands) | | |
| OPERATING RESULTS | | | | | |
| Electric operating revenues | $ 3,489,754 | $ 3,492,357 | $ 3,488,946 | $ 3,451,251 | $ 3,293,489 |
| Fuel and purchased power costs | 1,082,625 | 1,101,298 | 1,179,829 | 1,095,709 | 994,790 |
| Other operating expenses | 1,789,149 | 1,779,075 | 1,716,325 | 1,733,677 | 1,693,170 |
| Operating income | 617,980 | 611,984 | 592,792 | 621,865 | 605,529 |
| Other income | 46,744 | 33,332 | 36,358 | 20,797 | 16,358 |
| Interest expense — net of allowance for borrowed funds | 183,090 | 176,109 | 181,830 | 183,801 | 194,777 |
| Net income | 481,634 | 469,207 | 447,320 | 458,861 | 427,110 |
| Less: Net income attributable to noncontrolling interests | 19,493 | 18,933 | 26,101 | 33,892 | 31,613 |
| Net income attributable to common shareholder | $ 462,141 | $ 450,274 | $ 421,219 | $ 424,969 | $ 395,497 |
| BALANCE SHEET DATA | | | | | |
| Total assets | $ 15,931,175 | $ 14,982,182 | $ 14,190,362 | $ 13,359,517 | $ 13,220,050 |
| Liabilities and equity: | | | | | |
| Total equity | $ 5,037,970 | $ 4,814,794 | $ 4,629,852 | $ 4,454,874 | $ 4,222,483 |
| Long-term debt less current maturities | 4,021,785 | 3,337,391 | 2,881,573 | 2,649,604 | 3,051,596 |
| Total capitalization | 9,059,755 | 8,152,185 | 7,511,425 | 7,104,478 | 7,274,079 |
| Current liabilities | 1,094,037 | 1,424,708 | 1,532,464 | 1,580,847 | 1,043,087 |
| Deferred credits and other | 5,777,383 | 5,405,289 | 5,146,473 | 4,674,192 | 4,902,884 |
| Total liabilities and equity | $ 15,931,175 | $ 14,982,182 | $ 14,190,362 | $ 13,359,517 | $ 13,220,050 |

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

## INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Consolidated Financial Statements and APS's Consolidated Financial Statements and the related Notes that appear in Item 8 of this report. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Item 1A.

## OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS currently accounts for essentially all of our revenues and earnings.

### Areas of Business Focus

***Operational Performance, Reliability and Recent Developments.***

**Nuclear.** APS operates and is a joint owner of Palo Verde. Palo Verde experienced strong performance during 2016, with the completion of two refueling outages. The fall refueling outage was completed in 28 days with the lowest collective radiation exposure dose for any pressurized water reactor outage.

**Coal and Related Environmental Matters and Transactions.** APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. On June 2, 2014, EPA proposed a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), and EPA finalized its proposal on August 3, 2015.

EPA's nationwide $CO_2$ emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, compliance with the Clean Power Plan could involve a shift in generation from coal to natural gas and renewable generation. Until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to APS. (See Note 10 for information regarding challenges to the legality of the Clean Power Plan and a court-ordered stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations.) APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

**Cholla**

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required air emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015. On January 13, 2017, EPA approved a final rule incorporating APS's compromise proposal. Once the final rule is published in the Federal Register, parties have 60 days to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict at this time whether such petitions will be filed or if they will be successful. In addition, under the terms of an executive memorandum issued on January 20, 2017, this final rule will not be published in the Federal Register until after it has been reviewed by an appointee of the President. We cannot predict when such review will occur and what may result from the additional review.

**Four Corners**

***Asset Purchase Agreement and Coal Supply Matters.*** On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS's prior retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed below. On August 8, 2016, the Arizona Supreme Court issued its opinion in the SIB matter, and the Arizona Court of Appeals has now ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction described above, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton was retained by NTEC under contract as the mine manager and operator through 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016 through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC has the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

***Lease Extension.*** APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to

2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

**Navajo Plant**

On February 13, 2017, the co-owners of the Navajo Plant voted not to pursue continued operation of the plant beyond December 2019, the expiration of the current lease term, and to pursue a new lease or lease extension with the Navajo Nation that would allow decommissioning activities to begin after December 2019 instead of later this year. Various stakeholders including regulators, tribal representatives and others interested in the continued operation of the plant intend to meet to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. We cannot predict whether any alternate solutions will be found that would be acceptable to all of the stakeholders and feasible to implement. APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($108 million as of December 31, 2016, see Note 9 for additional details) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. We cannot predict whether APS would obtain such recovery.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

**Natural Gas**. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. (See Note 3 for proposed rate recovery in our current retail rate case filing.) On September 9, 2016, Maricopa County issued a final permit decision that authorizes construction of the Ocotillo modernization project.

**Transmission and Delivery.** APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects through 2019, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service

territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for behind-the-meter technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions.

**Energy Imbalance Market.** In 2015, APS and the CAISO, the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in EIM. APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS expects that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources.

***Renewable Energy.*** The ACC approved the RES in 2006. The renewable energy requirement is 7% of retail electric sales in 2017 and increases annually until it reaches 15% in 2025. In the 2009 Settlement Agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2016. A component of the RES targets development of distributed energy systems.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes would not be made until the project was fully in service, and APS has requested cost recovery for the project in its currently pending rate case. On September 30, 2016, APS presented its preliminary findings from the residential rooftop solar program in a filing with the ACC.

On July 1, 2015, APS filed its 2016 RES Implementation Plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. The ACC has not yet ruled on the Company's 2017 RES Implementation Plan.

In September of 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent EPA regulations. The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding.

***Demand Side Management.*** In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This standard became effective on January 1, 2011.

In March 2014, the ACC approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its LFCR mechanism.

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. On April 1, 2016, APS filed an amended 2016 DSM Plan that sought minor modifications to its existing DSM Plan and requested to continue the current DSMAC and current budget of $68.9 million. On July 12, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new residential demand response or load management program that facilitates energy storage technology. On December 5, 2016, APS filed for ACC approval of a $4 million Residential Demand Response, Energy Storage and Load Management Program.

On June 1, 2016, the Company filed its 2017 DSM Implementation Plan, in which APS proposes programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and the requested budget increased to $66.6 million. The ACC has not yet ruled on the Company's 2017 DSM Plan.

***Electric Energy Efficiency.*** On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Utility Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. On July 12, 2016, the ACC ordered that ACC staff convene a workshop within 120 days to discuss a number of issues related to the Electric Energy Efficiency Standards, including the process of determining the cost effectiveness of DSM programs and the treatment of

peak demand and capacity reductions, among others. ACC staff convened the workshop on November 29, 2016 and sought public comment on potential revisions to the Electric Energy Efficiency Standards. APS cannot predict the outcome of this proceeding.

***Rate Matters.*** APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. See Note 3 for information on APS's FERC rates.

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excludes amounts that are currently collected on customer bills through adjustor mechanisms. The application requests that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have an incremental effect on average customer bills. The average annual customer bill impact of APS's request is an increase of 5.74% (the average annual bill impact for a typical APS residential customer is 7.96%). See Note 3 for details regarding the principal provisions of APS's application.

APS requested that the increase become effective July 1, 2017. On July 22, 2016, the ALJ set a procedural schedule for the rate proceeding, which supported completing the case within 12 months. The ACC staff and intervenors began filing their direct testimony in late December 2016 and additional filings of testimony are ongoing. On January 12, 2017, APS began settlement discussions with all parties. On January 13, 2017, the ALJ hearing the case before the ACC issued a procedural order delaying hearings on the case from the originally scheduled March 22, 2017 to April 24, 2017, to allow parties to participate in settlement discussions and prepare testimony on the distributed generation ("DG") rate design issues addressed in the value and cost of DG decision described below. According to the procedural order, settlement discussions are to be completed and, if applicable, any related settlement must be filed by March 17, 2017. The procedural order also extended the rate case completion date as calculated by Commission rule for an additional 33 days. APS cannot predict the outcome of this case.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand side management and renewable energy efforts and customer programs. These mechanisms are described more fully in Note 3.

As part of APS's acquisition of SCE's interest in Four Corners Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed for a rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the

Transmission Agreement was a jurisdictional contract that should have been filed with FERC. APS cannot predict the outcome of either matter.

***Net Metering.*** In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, an ALJ issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the ALJ. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC's action, effective following APS's pending rate case, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems will be replaced by a more formula-driven approach that will utilize inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the price that APS pays for utility-scale solar projects on a five year rolling average, while a forecasted avoided cost methodology is being developed. The price established by this resource comparison proxy method will be updated annually (between rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by that utility for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to the date new rates are effective based on APS's pending rate case will be grandfathered for a period of 20 years from the date of interconnection;

- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and

- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change as are all ACC policies. The determination of the initial export energy price to be paid by APS will be made in APS's currently pending rate case, which is scheduled for hearing by the ACC in April 2017. APS cannot predict the outcome of this determination.

The ACC's decision did not make any policy determinations as to any specific costs to be charged to DG solar system customers for their use of the grid. The determination of any such costs will be made in APS's future rate cases.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserts that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC's request for rehearing is required for

TASC to challenge this decision in court. To date, the ACC has taken no action on the rehearing request. The ACC's decision is expected to remain in effect during any legal challenge.

***Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB").*** In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision, and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and on August 8, 2016, the Arizona Supreme Court vacated the Court of Appeals opinion and affirmed the ACC's orders approving the water company's SIB adjustor.

***System Benefits Charge.*** The 2012 Settlement Agreement provides that once APS achieved full funding of its decommissioning obligation under the sale leaseback agreements covering Unit 2 of Palo Verde, APS was required to implement a reduced System Benefits charge effective January 1, 2016. Beginning on January 1, 2016, APS began implementing a reduced System Benefits charge. The impact on APS retail revenues from the new System Benefits charge is an overall reduction of approximately $14.6 million per year with a corresponding reduction in depreciation and amortization expense.

***Subpoena from Arizona Corporation Commissioner Robert Burns.*** On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, filed subpoenas in APS's current retail rate proceeding to APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for APS to produce all information previously requested through the subpoenas. Commissioner Burns has also scheduled a workshop in this matter for March 17, 2017. APS and Pinnacle West cannot predict the outcome of this matter.

***Financial Strength and Flexibility.*** Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities, and may readily access these facilities ensuring adequate liquidity for

each company. Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

***Other Subsidiaries.***

**Bright Canyon Energy.** On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with PG&E to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

**El Dorado.** The operations of El Dorado are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

**4CA.** See "Four Corners - Asset Purchase Agreement and Coal Supply Matters" above for information regarding 4CA.

**Key Financial Drivers**

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company's current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

***Electric Operating Revenues.*** For the years 2014 through 2016, retail electric revenues comprised approximately 94% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

***Actual and Projected Customer and Sales Growth.*** Retail customers in APS's service territory increased 1.4% for the year ended December 31, 2016 compared with the prior year. For the three years 2014 through 2016, APS's customer growth averaged 1.3% per year. We currently project annual customer growth to be 1.5-2.5% for 2017 and to average in the range of 2.0-3.0% for 2017 through 2019 based on our assessment of modestly improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, were flat for the year ended December 31, 2016 compared with the prior year. Improving economic conditions and customer

growth and an additional day of sales due to the leap year were equally offset by energy savings driven by customer conservation, energy efficiency and distributed renewable generation initiatives. For the three years 2014 through 2016, APS experienced annual increases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 0-1.0% for 2017 and increase on average in the range of 0.5-1.5% during 2017 through 2019, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to $10 million.

***Weather.*** In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

***Fuel and Purchased Power Costs.*** Fuel and purchased power costs included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

***Operations and Maintenance Expenses.*** Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors.

***Depreciation and Amortization Expenses.*** Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities. See Note 3 regarding deferral of certain costs pursuant to an ACC order.

***Property Taxes.*** Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.2% of the assessed value for 2016, 11.0% for 2015 and 10.7% for 2014. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement.)

***Income Taxes.*** Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities. The prospects for broad-based federal tax reform have increased due to the results of the 2016 elections. Any such reform may impact the Company's effective tax

rate, cash taxes paid and other financial results such as earnings per share, gross revenues and cash flows. Given the number of unknown variables and the lack of detailed legislative reform language, we are unable to predict any impacts to the Company at this time.

***Interest Expense.*** Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 6). The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

## RESULTS OF OPERATIONS

Pinnacle West's only reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

**Operating Results – 2016 compared with 2015.**

Our consolidated net income attributable to common shareholders for the year ended December 31, 2016 was $442 million, compared with $437 million for the prior year. The results reflect an increase of approximately $4 million for the regulated electricity segment primarily due to higher transmission revenues, higher retail revenues due to customer growth and changes in customer usage patterns and related pricing, partially offset by higher operations and maintenance expense primarily related to transmission, distribution and customer service costs.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | Net change |
| | (dollars in millions) | | |
| Regulated Electricity Segment: | | | |
| Operating revenues less fuel and purchased power expenses | $ 2,407 | $ 2,391 | $ 16 |
| Operations and maintenance | (906) | (868) | (38) |
| Depreciation and amortization | (485) | (494) | 9 |
| Taxes other than income taxes | (166) | (172) | 6 |
| All other income and expenses, net | 35 | 19 | 16 |
| Interest charges, net of allowance for borrowed funds used during construction | (186) | (179) | (7) |
| Income taxes | (237) | (239) | 2 |
| Less income related to noncontrolling interests (Note 18) | (19) | (19) | — |
| Regulated electricity segment income | 443 | 439 | 4 |
| All other | (1) | (2) | 1 |
| Net Income Attributable to Common Shareholders | $ 442 | $ 437 | $ 5 |

***Operating revenues less fuel and purchased power expenses.*** Regulated electricity segment operating revenues less fuel and purchased power expenses were $16 million higher for the year ended December 31, 2016 compared with the prior year. The following table summarizes the major components of this change:

| | Increase (Decrease) | | |
|---|---|---|---|
| | Operating revenues | Fuel and purchased power expenses | Net change |
| | (dollars in millions) | | |
| Lost fixed cost recovery | $ 17 | $ — | $ 17 |
| Effects of weather | 6 | 2 | 4 |
| Transmission revenues (Note 3): | | | |
| Higher transmission revenues | 27 | — | 27 |
| FERC disallowance | (12) | — | (12) |
| Higher retail revenues due to changes in customer usage patterns and related pricing | 10 | — | 10 |
| Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals | (15) | (17) | 2 |
| Palo Verde system benefits charge (offset in depreciation and amortization, see Note 3) | (14) | — | (14) |
| Lower demand side management regulatory surcharges and renewable energy regulatory surcharges and purchased power partially offset in operations and maintenance costs | (16) | (1) | (15) |
| Miscellaneous items, net | (6) | (3) | (3) |
| Total | $ (3) | $ (19) | $ 16 |

***Operations and maintenance.*** Operations and maintenance expenses increased $38 million for the year ended December 31, 2016 compared with the prior year primarily because of:

- An increase of $16 million for transmission, distribution, and customer service costs primarily related to increased maintenance costs and implementation of new systems;
- An increase of $9 million primarily for costs to support the company's positions on a solar net metering ballot initiative in Arizona and increased political participation costs;
- An increase of $8 million in fossil generation costs primarily related to $33 million in higher planned outage costs, partially offset by $25 million of lower other fossil operating costs;
- An increase of $7 million for costs related to legal, regulatory, information systems and other corporate support;
- An increase of $5 million for employee benefit costs primarily related to increased pension, medical claims and other benefit costs;
- An increase of $5 million related to higher nuclear generation costs;

- An offsetting decrease of $13 million related to costs for demand-side management, renewable energy and similar regulatory programs, which is partially offset in operating revenues and purchased power; and

- An increase of $1 million related to miscellaneous other factors.

Additionally, stock compensation costs were flat compared to the prior year as a $12 million increase in costs was offset by a one-time $12 million reduction for the adoption of new stock compensation guidance (See Notes 2 and 15);

***Depreciation and amortization.*** Depreciation and amortization expenses were $9 million lower for the year ended December 31, 2016 compared with the prior year primarily related to:

- A decrease of $20 million related to the regulatory treatment of the Palo Verde sale leaseback lease extension;

- A decrease of $14 million due to lower Palo Verde decommissioning expense recovered through the system benefits charge (offset in operating revenues); and

- An increase of $25 million due to increased plant in service.

***Taxes other than income taxes.*** Taxes other than income taxes were $6 million lower for the year ended December 31, 2016 compared with the prior year primarily due to lower assessed values resulting from a lower Arizona statutory rate, partially offset by higher property tax rates.

***All other income and expenses, net.*** All other income and expenses, net, were $16 million higher for the year ended December 31, 2016 compared with the prior year primarily due to higher allowance for equity funds used during construction and the gain on sale of a transmission line.

***Interest charges, net of allowance for borrowed funds used during construction.*** Interest charges, net of allowance for borrowed funds used during construction, increased $7 million for the year ended December 31, 2016 compared with the prior year, primarily because of higher debt balances in the current year.

**Operating Results – 2015 compared with 2014.**

Our consolidated net income attributable to common shareholders for the year ended December 31, 2015 was $437 million, compared with $398 million for the prior year. The results reflect an increase of approximately $34 million for the regulated electricity segment primarily due to the Four Corners-related rate change, lower operations and maintenance expenses, and higher retail sales due to customer growth and changes in customer usage patterns and related pricing, partially offset by higher depreciation and amortization. The all other segment's income was higher by $5 million primarily related to El Dorado's investment losses in 2014.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Net change |
| | (dollars in millions) | | |
| Regulated Electricity Segment: | | | |
| Operating revenues less fuel and purchased power expenses | $ 2,391 | $ 2,309 | $ 82 |
| Operations and maintenance | (868) | (908) | 40 |
| Depreciation and amortization | (494) | (417) | (77) |
| Taxes other than income taxes | (172) | (172) | — |
| All other income and expenses, net | 19 | 28 | (9) |
| Interest charges, net of allowance for borrowed funds used during construction | (179) | (185) | 6 |
| Income taxes | (239) | (224) | (15) |
| Less income related to noncontrolling interests (Note 18) | (19) | (26) | 7 |
| Regulated electricity segment income | 439 | 405 | 34 |
| All other | (2) | (7) | 5 |
| Net Income Attributable to Common Shareholders | $ 437 | $ 398 | $ 39 |

***Operating revenues less fuel and purchased power expenses.*** Regulated electricity segment operating revenues less fuel and purchased power expenses were $82 million higher for the year ended December 31, 2015 compared with the prior year. The following table summarizes the major components of this change:

| | Increase (Decrease) | | |
|---|---|---|---|
| | Operating revenues | Fuel and purchased power expenses | Net change |
| | (dollars in millions) | | |
| Four Corners-related rate change | $ 56 | $ — | $ 56 |
| Higher retail sales due to customer growth and changes in customer usage patterns and related pricing | 25 | 6 | 19 |
| Lost fixed cost recovery | 12 | — | 12 |
| Effects of weather | 16 | 6 | 10 |
| Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals | (69) | (68) | (1) |
| Changes in long-term wholesale contracted sales | (40) | (25) | (15) |
| Miscellaneous items, net | 3 | 2 | 1 |
| Total | $ 3 | $ (79) | $ 82 |

***Operations and maintenance.*** Operations and maintenance expenses decreased $40 million for the year ended December 31, 2015 compared with the prior year primarily because of:

- A decrease of $21 million for employee benefit costs;

- A decrease of $14 million in fossil generation costs primarily related to lower planned outage costs;

- A decrease of $13 million for costs related to corporate support;

- A decrease of $8 million related to costs for demand-side management, renewable energy and similar regulatory programs, which is partially offset in operating revenues and purchased power;

- An increase of $9 million related to higher nuclear generation costs;

- An increase of $6 million in customer service costs including costs related to a new customer information system; and

- An increase of $1 million related to other miscellaneous factors.

***Depreciation and amortization.*** Depreciation and amortization expenses were $77 million higher for the year ended December 31, 2015 compared with the prior year primarily related to:

- An increase of $34 million related to the absence of 2014 Four Corners cost deferrals and the related 2015 amortization;

- An increase of $16 million related to the Four Corners acquisition adjustment;

- An increase of $20 million due to increased plant in service;

- An increase of $10 million related to the regulatory treatment of the Palo Verde sale leaseback, which is offset in noncontrolling interests; and

- A decrease of $3 million due to other miscellaneous factors.

***All other income and expenses, net.*** All other income and expenses, net, were $9 million lower for the year ended December 31, 2015 compared with the prior year primarily due to the return on the Four Corners acquisition in 2014.

***Interest charges, net of allowance for borrowed funds used during construction.*** Interest charges, net of allowance for borrowed funds used during construction, decreased $6 million for the year ended December 31, 2015 compared with the prior year, primarily because of lower interest rates on our debt in the current year.

***Income taxes.*** Income taxes were $15 million higher for the year ended December 31, 2015 compared with the prior year primarily due to the effects of higher pretax income in the current year.

## LIQUIDITY AND CAPITAL RESOURCES

### Overview

Pinnacle West's primary cash needs are for dividends to our shareholders and principal and interest payments on our indebtedness. The level of our common stock dividends and future dividend growth will be dependent on declaration by our Board of Directors and based on a number of factors, including our financial condition, payout ratio, free cash flow and other factors.

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2016, APS's common equity ratio, as defined, was 54%. Its total shareholder equity was approximately $4.9 billion, and total capitalization was approximately $9.1 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.6 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West.

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029), which contained an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $300-$350 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years and reduces rate base for ratemaking purposes. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $98 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Condensed Consolidated Balance Sheet as of December 31, 2016.

### Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2016, 2015 and 2014 (dollars in millions):

Pinnacle West Consolidated

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Net cash flow provided by operating activities | $ 1,023 | $ 1,094 | $ 1,100 |
| Net cash flow used for investing activities | (1,252) | (1,066) | (923) |
| Net cash flow provided by (used for) financing activities | 198 | 4 | (179) |
| Net increase (decrease) in cash and cash equivalents | $ (31) | $ 32 | $ (2) |

Arizona Public Service Company

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Net cash flow provided by operating activities | $ 1,010 | $ 1,100 | $ 1,124 |
| Net cash flow used for investing activities | (1,219) | (1,060) | (922) |
| Net cash flow used for financing activities | 196 | (22) | (201) |
| Net increase (decrease) in cash and cash equivalents | $ (13) | $ 18 | $ 1 |

**Operating Cash Flows**

***2016 Compared with 2015.*** Pinnacle West's consolidated net cash provided by operating activities was $1,023 million in 2016 compared to $1,094 million in 2015. The decrease of $71 million in net cash provided is primarily due to higher operations and maintenance costs.

***2015 Compared with 2014.*** Pinnacle West's consolidated net cash provided by operating activities was $1,094 million in 2015 compared to $1,100 million in 2014, a decrease of $6 million in net cash provided. The decrease is primarily related to a $135 million income tax refund received in the first quarter of 2014, which is partially offset by a $48 million change in cash collateral posted, and other changes in working capital including increased cash receipts for the Four Corners-related rate change of $56 million.

***Retirement plans and other postretirement benefits.*** Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 116% funded as of January 1, 2016 and 115% as of January 1, 2017. Under GAAP, the qualified pension plan was 88% funded as of January 1, 2016 and January 1, 2017. See Note 7 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have made voluntary contributions to our pension plan of $100 million in 2016, $100 million in 2015 and $175 million in 2014. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2017-2019 period. With regard to our contributions to our other postretirement benefit plans, we made a contribution of approximately $1 million in each of 2016, 2015 and 2014. We expect to make contributions of less than $1 million in total for the next three years to our other postretirement benefit plans.

**Investing Cash Flows**

***2016 Compared with 2015.*** Pinnacle West's consolidated net cash used for investing activities was $1,252 million in 2016, compared to $1,066 million in 2015. The increase of $186 million in net cash used primarily related to increased capital expenditures.

***2015 Compared with 2014.*** Pinnacle West's consolidated net cash used for investing activities was $1,066 million in 2015, compared to $923 million in 2014, an increase of $143 million in net cash used primarily related to increased capital expenditures.

***Capital Expenditures.*** The following table summarizes the estimated capital expenditures for the next three years:

**Capital Expenditures**
(dollars in millions)

| | Estimated for the Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2018** | **2019** |
| APS | | | |
| Generation: | | | |
| Nuclear Fuel | $ 69 | $ 71 | $ 65 |
| Renewables | 4 | 1 | — |
| Environmental | 195 | 105 | 61 |
| New Gas Generation | 237 | 119 | 8 |
| Other Generation | 150 | 213 | 149 |
| Distribution | 402 | 406 | 480 |
| Transmission | 206 | 137 | 150 |
| Other (a) | 74 | 72 | 81 |
| Total APS | $ 1,337 | $ 1,124 | $ 994 |

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil, renewable and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. We have not included estimated costs for Cholla's compliance with EPA's regional haze rule since we have challenged the rule judicially and we have proposed a compromise strategy to EPA, which would allow us to avoid expenditures related to environmental control equipment. (See Note 10 for details regarding the status of the final rule for Cholla and a related executive memorandum.) We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest in July 2017. 4CA purchased the El Paso interest on July 6, 2016. The table above does not include capital expenditures related to 4CA's interest in Four Corners Units 4 and 5 of approximately $27 million in 2017, $15 million in 2018 and $6 million in 2019, which will be assumed by the ultimate owner of the 7% interest.

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, and new customer construction. Examples of the types of projects included in the forecast include power lines, substations, and line extensions to new residential and commercial developments.

Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

**Financing Cash Flows and Liquidity**

***2016 Compared with 2015.*** Pinnacle West's consolidated net cash provided by financing activities was $198 million in 2016, compared to $4 million in 2015, an increase of $194 million in net cash provided. The increase in net cash provided by financing activities is primarily due to a $325 million net increase in short-term borrowings and $45 million in lower long-term debt repayments partially offset by $149 million lower issuances of long-term debt through December 31, 2016 (see below).

***2015 Compared with 2014.*** Pinnacle West's consolidated net cash provided by financing activities was $4 million in 2015, compared to $179 million net cash used in 2014, an increase of $183 million in net cash provided. The increase in net cash provided by financing activities is primarily due to $237 million lower repayments of long-term debt and $111 million higher issuances of long-term debt (see below), partially offset by a $142 million net change in short-term borrowings.

***Significant Financing Activities.*** On December 21, 2016, the Pinnacle West Board of Directors declared a dividend of $0.655 per share of common stock, payable on March 1, 2017 to shareholders of record on February 1, 2017. During 2016, Pinnacle West increased its indicated annual dividend from $2.50 per share to $2.62 per share. For the year ended December 31, 2016, Pinnacle West's total dividends paid per share of common stock were $2.53 per share, which resulted in dividend payments of $274 million.

On December 27, 2016, Pinnacle West infused cash to APS of $42 million. APS used these funds to repay commercial paper borrowings.

On April 22, 2016, APS entered into a $100 million term loan facility that matures April 22, 2019. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On May 6, 2016, APS issued $350 million of 3.75% unsecured senior notes that mature on May 15, 2046. The net proceeds from the sale were used to redeem and cancel pollution control bonds (see details below), and to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On June 1, 2016, APS redeemed at par and canceled all $64 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series D and E.

On June 1, 2016, APS redeemed at par and canceled all $13 million of the Coconino County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series A.

On August 1, 2016, APS repaid at maturity APS's $250 million aggregate principal amount of 6.25% senior notes due August 1, 2016.

On September 20, 2016, APS issued $250 million of 2.55% unsecured senior notes that mature on September 15, 2026. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used in connection with the payment at maturity of our $250 million aggregate principal amount of 6.25% Notes due August 1, 2016.

On September 20, 2016, APS redeemed at par and canceled all $27 million of the Coconino County Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series B.

On December 6, 2016, APS redeemed at par and canceled all $17 million of the Coconino County Arizona Pollution Control Corporation Revenue Bonds (Arizona Public Service Company Project), Series 1998.

***Available Credit Facilities.*** Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

During the first quarter of 2016, APS increased its commercial paper program from $250 million to $500 million.

On May 13, 2016, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2019, with a new $200 million facility that matures in May 2021. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2016, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $1.7 million in commercial paper borrowings.

On May 13, 2016, APS replaced its $500 million revolving credit facility that would have matured in May 2019, with a new $500 million facility that matures in May 2021.

On August 31, 2016, PNW entered into a $75 million 364-day unsecured revolving credit facility that matures in August 2017. PNW will use the new facility to fund or otherwise support obligations related to 4CA, and borrowings under the facility will bear interest at LIBOR plus 0.80% per annum. At December 31, 2016, Pinnacle West had $40 million outstanding under the facility.

At December 31, 2016, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and the $500 million facility that matures in May 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2016, APS had $135.5 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 10 for a discussion of APS's separate outstanding letters of credit.

***Other Financing Matters.*** See Note 16 for information related to the change in our margin and collateral accounts.

**Debt Provisions**

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2016, the ratio was approximately 48% for Pinnacle West and 47% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements and term loan facilities contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

See Note 6 for further discussions of liquidity matters.

**Credit Ratings**

The ratings of securities of Pinnacle West and APS as of February 17, 2017 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

| | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|
| **Pinnacle West** | | | |
| Corporate credit rating | A3 | A- | A- |
| Commercial paper | P-2 | A-2 | F2 |
| Outlook | Stable | Stable | Stable |
| | | | |
| **APS** | | | |
| Corporate credit rating | A2 | A- | A- |
| Senior unsecured | A2 | A- | A |
| Commercial paper | P-1 | A-2 | F2 |
| Outlook | Stable | Stable | Stable |

**Off-Balance Sheet Arrangements**

See Note 18 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

**Contractual Obligations**

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2016 (dollars in millions):

| | 2017 | 2018-2019 | 2020-2021 | Thereafter | Total |
|---|---|---|---|---|---|
| Long-term debt payments, including interest: (a) | | | | | |
| APS | $ 187 | $ 1,033 | $ 523 | $ 5,248 | $ 6,991 |
| Pinnacle West | 127 | — | — | — | 127 |
| Total long-term debt payments, including interest | 314 | 1,033 | 523 | 5,248 | 7,118 |
| Short-term debt payments, including interest (b) | 177 | — | — | — | 177 |
| Fuel and purchased power commitments (c) | 617 | 1,135 | 1,033 | 7,127 | 9,912 |
| Renewable energy credits (d) | 40 | 80 | 80 | 420 | 620 |
| Purchase obligations (e) | 360 | 200 | 16 | 212 | 788 |
| Coal reclamation | 18 | 40 | 46 | 258 | 362 |
| Nuclear decommissioning funding requirements | 2 | 4 | 4 | 58 | 68 |
| Noncontrolling interests (f) | 23 | 46 | 46 | 204 | 319 |
| Operating lease payments | 12 | 20 | 13 | 60 | 105 |
| Total contractual commitments | $ 1,563 | $ 2,558 | $ 1,761 | $ 13,587 | $ 19,469 |

(a) The long-term debt matures at various dates through 2046 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2016 (see Note 6).
(b) See Note 5 - Lines of credit and short-term borrowings for further details.
(c) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 3 and 10).
(d) Contracts to purchase renewable energy credits in compliance with the RES (see Note 3).
(e) These contractual obligations include commitments for capital expenditures and other obligations.
(f) Payments to the noncontrolling interests relate to the Palo Verde Sale Leaseback (see Note 18).

This table excludes $36 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2017, 2018 and 2019 (see Note 7).

## CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"), management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

**Regulatory Accounting**

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $1,420 million of regulatory assets and $1,049 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2016.

Included in the balance of regulatory assets at December 31, 2016 is a regulatory asset of $711 million for pension benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If all or a portion of these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

See Notes 1 and 3 for more information.

**Pensions and Other Postretirement Benefit Accounting**

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2016 reported pension liability on the Consolidated Balance Sheets and our 2016 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

| | Increase (Decrease) | |
|---|---|---|
| **Actuarial Assumption (a)** | **Impact on Pension Liability** | **Impact on Pension Expense** |
| Discount rate: | | |
| Increase 1% | $ (344) | $ (12) |
| Decrease 1% | 418 | 15 |
| Expected long-term rate of return on plan assets: | | |
| Increase 1% | — | (12) |
| Decrease 1% | — | 12 |

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2016 other postretirement benefit obligation and our 2016 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

| | Increase (Decrease) | |
|---|---|---|
| **Actuarial Assumption (a)** | **Impact on Other Postretirement Benefit Obligation** | **Impact on Other Postretirement Benefit Expense** |
| Discount rate: | | |
| Increase 1% | $ (91) | $ (3) |
| Decrease 1% | 116 | 5 |
| Healthcare cost trend rate (b): | | |
| Increase 1% | 108 | 8 |
| Decrease 1% | (87) | (5) |
| Expected long-term rate of return on plan assets – pretax: | | |
| Increase 1% | — | (4) |
| Decrease 1% | — | 4 |

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.
(b) This assumes a 1% change in the initial and ultimate healthcare cost trend rate.

See Note 7 for further details about our pension and other postretirement benefit plans.

**Fair Value Measurements**

We account for derivative instruments, investments held in our nuclear decommissioning trust fund, certain cash equivalents, and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use inputs, or assumptions that market participants would use, to determine fair market value. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The significance of a particular input determines how the instrument is classified in a fair value hierarchy. The determination of fair value sometimes requires subjective and complex judgment. Our assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within a fair value hierarchy. Actual results could differ from our estimates of fair value. See Note 1 for a discussion on accounting policies and Note 13 for fair value measurement disclosures.

## OTHER ACCOUNTING MATTERS

During the fourth quarter of 2016, we early adopted a new accounting standard relating to stock-based compensation; see Notes 2 and 15 for discussion of how this standard impacted our financial statements and results of operations.

We are currently evaluating the impacts of the pending adoption of new accounting standards relating to revenue recognition, leases, financial instruments and the definition of a business. See Note 2 for information relating to these accounting matters.

## MARKET AND CREDIT RISKS

### Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund and benefit plan assets.

#### Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 13 and Note 19) and benefit plan assets. The nuclear decommissioning trust fund and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2016 and 2015. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2016 and 2015 (dollars in millions):

Pinnacle West – Consolidated

| | Short-Term Debt | | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|---|---|
| 2016 | Interest Rates | Amount | Interest Rates | Amount | Interest Rates | Amount |
| 2017 | 1.01% | $ 177 | 1.52% | $ 125 | —% | $ — |
| 2018 | — | — | 1.37% | 50 | 1.75% | 32 |
| 2019 | — | — | 1.46% | 100 | 8.75% | 500 |
| 2020 | — | — | — | — | 2.20% | 250 |
| 2021 | — | — | — | — | — | — |
| Years thereafter | — | — | 0.81% | 36 | 4.37% | 3,090 |
| Total | | $ 177 | | $ 311 | | $ 3,872 |
| Fair value | | $ 177 | | $ 311 | | $ 4,115 |

| 2015 | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|
| | Interest Rates | Amount | Interest Rates | Amount |
| 2016 | 0.01% | $ 44 | 6.15% | $ 314 |
| 2017 | 1.17% | 125 | — | — |
| 2018 | 1.02% | 50 | 1.75% | 32 |
| 2019 | — | — | 8.75% | 500 |
| 2020 | — | — | 2.20% | 250 |
| Years thereafter | 0.23% | 49 | 4.64% | 2,490 |
| Total | | $ 268 | | $ 3,586 |
| Fair value | | $ 268 | | $ 3,839 |

The tables below present contractual balances of APS's long-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2016 and 2015. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2016 and 2015 (dollars in millions):

APS — Consolidated

| 2016 | Short-Term Debt | | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|---|---|
| | Interest Rates | Amount | Interest Rates | Amount | Interest Rates | Amount |
| 2017 | 0.88% | $ 135 | —% | $ — | —% | $ — |
| 2018 | — | — | 1.37% | 50 | 1.75% | 32 |
| 2019 | — | — | 1.46% | 100 | 8.75% | 500 |
| 2020 | — | — | — | — | 2.20% | 250 |
| 2021 | — | — | — | — | — | — |
| Years thereafter | — | — | 0.81% | 36 | 4.37% | 3,090 |
| Total | | $ 135 | | $ 186 | | $ 3,872 |
| Fair value | | $ 135 | | $ 186 | | $ 4,115 |

| 2015 | Variable-Rate Long-Term Debt | | Fixed-Rate Long-Term Debt | |
|---|---|---|---|---|
| | Interest Rates | Amount | Interest Rates | Amount |
| 2016 | 0.01% | $ 44 | 6.15% | $ 314 |
| 2017 | — | — | — | — |
| 2018 | 1.02% | 50 | 1.75% | 32 |
| 2019 | — | — | 8.75% | 500 |
| 2020 | — | — | 2.20% | 250 |
| Years thereafter | 0.23% | 49 | 4.64% | 2,490 |
| Total | | $ 143 | | $ 3,586 |
| Fair value | | $ 143 | | $ 3,839 |

**Commodity Price Risk**

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

The following table shows the net pretax changes in mark-to-market of our derivative positions in 2016 and 2015 (dollars in millions):

| | 2016 | 2015 |
|---|---|---|
| Mark-to-market of net positions at beginning of year | $ (154) | $ (115) |
| Decrease (Increase) in regulatory asset | 101 | (44) |
| Recognized in OCI: | | |
| Change in mark-to-market losses for future deliveries | — | (1) |
| Mark-to-market losses realized during the period | 4 | 6 |
| Change in valuation techniques | — | — |
| Mark-to-market of net positions at end of year | $ (49) | $ (154) |

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2016 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," for more discussion of our valuation methods.

| Source of Fair Value | 2017 | 2018 | 2019 | 2020 | Total fair value |
|---|---|---|---|---|---|
| Observable prices provided by other external sources | $ 7 | $ (4) | $ (4) | $ — | $ (1) |
| Prices based on unobservable inputs | (9) | (20) | (16) | (3) | (48) |
| Total by maturity | $ (2) | $ (24) | $ (20) | $ (3) | $ (49) |

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2016 and 2015 (dollars in millions):

| | December 31, 2016 Gain (Loss) | | December 31, 2015 Gain (Loss) | |
|---|---|---|---|---|
| | Price Up 10% | Price Down 10% | Price Up 10% | Price Down 10% |
| Mark-to-market changes reported in: | | | | |
| Regulatory asset (liability) or OCI (a) | | | | |
| Electricity | $ 2 | $ (2) | $ 2 | $ (2) |
| Natural gas | 46 | (46) | 35 | (35) |
| Total | $ 48 | $ (48) | $ 37 | $ (37) |

(a) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

**Credit Risk**

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 16 for a discussion of our credit valuation adjustment policy.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market and Credit Risks" in Item 7 above for a discussion of quantitative and qualitative disclosures about market risks.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND
FINANCIAL STATEMENT SCHEDULES



See Note 12 for the selected quarterly financial data (unaudited) required to be presented in this Item.

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (PINNACLE WEST CAPITAL CORPORATION)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Pinnacle West. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2016. The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's consolidated financial statements.

February 24, 2017

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Phoenix, Arizona
February 24, 2017

**PINNACLE WEST CAPITAL CORPORATION**
**CONSOLIDATED STATEMENTS OF INCOME**
(dollars and shares in thousands, except per share amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| OPERATING REVENUES | $ 3,498,682 | $ 3,495,443 | $ 3,491,632 |
| OPERATING EXPENSES | | | |
| Fuel and purchased power | 1,075,510 | 1,101,298 | 1,179,829 |
| Operations and maintenance | 911,319 | 868,377 | 908,025 |
| Depreciation and amortization | 485,829 | 494,422 | 417,358 |
| Taxes other than income taxes | 166,499 | 171,812 | 172,295 |
| Other expenses | 3,541 | 4,932 | 2,883 |
| Total | 2,642,698 | 2,640,841 | 2,680,390 |
| OPERATING INCOME | 855,984 | 854,602 | 811,242 |
| OTHER INCOME (DEDUCTIONS) | | | |
| Allowance for equity funds used during construction (Note 1) | 42,140 | 35,215 | 30,790 |
| Other income (Note 17) | 901 | 621 | 9,608 |
| Other expense (Note 17) | (15,337) | (17,823) | (21,746) |
| Total | 27,704 | 18,013 | 18,652 |
| INTEREST EXPENSE | | | |
| Interest charges | 205,720 | 194,964 | 200,950 |
| Allowance for borrowed funds used during construction (Note 1) | (19,970) | (16,259) | (15,457) |
| Total | 185,750 | 178,705 | 185,493 |
| INCOME BEFORE INCOME TAXES | 697,938 | 693,910 | 644,401 |
| INCOME TAXES (Note 4) | 236,411 | 237,720 | 220,705 |
| NET INCOME | 461,527 | 456,190 | 423,696 |
| Less: Net income attributable to noncontrolling interests (Note 18) | 19,493 | 18,933 | 26,101 |
| NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS | $ 442,034 | $ 437,257 | $ 397,595 |
| WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC | 111,409 | 111,026 | 110,626 |
| WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED | 112,046 | 111,552 | 111,178 |
| EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING | | | |
| Net income attributable to common shareholders — basic | $ 3.97 | $ 3.94 | $ 3.59 |
| Net income attributable to common shareholders — diluted | $ 3.95 | $ 3.92 | $ 3.58 |

The accompanying notes are an integral part of the financial statements.

**PINNACLE WEST CAPITAL CORPORATION**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
(dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| NET INCOME | $ 461,527 | $ 456,190 | $ 423,696 |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX | | | |
| Derivative instruments: | | | |
| Net unrealized loss, net of tax (expense) of $(585), $(342), and $(438) (Note 16) | (538) | (957) | (810) |
| Reclassification of net realized loss, net of tax benefit of $985, $1,801 and $7,932 (Note 16) | 2,941 | 4,187 | 13,483 |
| Pension and other postretirement benefits activity, net of tax benefit (expense) of $633, $(13,302), and $1,307 (Note 7) | (1,477) | 20,163 | (2,761) |
| Total other comprehensive income | 926 | 23,393 | 9,912 |
| COMPREHENSIVE INCOME | 462,453 | 479,583 | 433,608 |
| Less: Comprehensive income attributable to noncontrolling interests | 19,493 | 18,933 | 26,101 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS | $ 442,960 | $ 460,650 | $ 407,507 |

The accompanying notes are an integral part of the financial statements.

**PINNACLE WEST CAPITAL CORPORATION**
**CONSOLIDATED BALANCE SHEETS**
(dollars in thousands)

| | December 31, | |
|---|---|---|
| | 2016 | 2015 |
| ASSETS | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | $ 8,881 | $ 39,488 |
| Customer and other receivables | 250,491 | 274,691 |
| Accrued unbilled revenues | 107,949 | 96,240 |
| Allowance for doubtful accounts | (3,037) | (3,125) |
| Materials and supplies (at average cost) | 253,979 | 234,234 |
| Fossil fuel (at average cost) | 28,608 | 45,697 |
| Income tax receivable (Note 4) | 3,751 | 589 |
| Assets from risk management activities (Note 16) | 19,694 | 15,905 |
| Deferred fuel and purchased power regulatory asset (Note 3) | 12,465 | — |
| Other regulatory assets (Note 3) | 94,410 | 149,555 |
| Other current assets | 45,028 | 37,242 |
| Total current assets | 822,219 | 890,516 |
| INVESTMENTS AND OTHER ASSETS | | |
| Assets from risk management activities (Note 16) | 1 | 12,106 |
| Nuclear decommissioning trust (Notes 13 and 19) | 779,586 | 735,196 |
| Other assets | 69,063 | 52,518 |
| Total investments and other assets | 848,650 | 799,820 |
| PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9) | | |
| Plant in service and held for future use | 17,341,888 | 16,222,232 |
| Accumulated depreciation and amortization | (5,970,100) | (5,594,094) |
| Net | 11,371,788 | 10,628,138 |
| Construction work in progress | 1,019,947 | 816,307 |
| Palo Verde sale leaseback, net of accumulated depreciation of $237,535 and $233,665 (Note 18) | 113,515 | 117,385 |
| Intangible assets, net of accumulated amortization of $603,637 and $546,038 | 90,022 | 123,975 |
| Nuclear fuel, net of accumulated amortization of $147,202 and $146,228 | 119,004 | 123,139 |
| Total property, plant and equipment | 12,714,276 | 11,808,944 |
| DEFERRED DEBITS | | |
| Regulatory assets (Notes 1, 3 and 4) | 1,313,428 | 1,214,146 |
| Assets for other postretirement benefits (Note 7) | 166,206 | 185,997 |
| Other | 139,474 | 128,835 |
| Total deferred debits | 1,619,108 | 1,528,978 |
| TOTAL ASSETS | $ 16,004,253 | $ 15,028,258 |

The accompanying notes are an integral part of the financial statements.

**PINNACLE WEST CAPITAL CORPORATION**
**CONSOLIDATED BALANCE SHEETS**
(dollars in thousands)

| | December 31, | |
|---|---|---|
| | 2016 | 2015 |
| LIABILITIES AND EQUITY | | |
| CURRENT LIABILITIES | | |
| Accounts payable | $ 264,631 | $ 297,480 |
| Accrued taxes (Note 4) | 138,964 | 138,600 |
| Accrued interest | 52,835 | 56,305 |
| Common dividends payable | 72,926 | 69,363 |
| Short-term borrowings (Note 5) | 177,200 | — |
| Current maturities of long-term debt (Note 6) | 125,000 | 357,580 |
| Customer deposits | 82,520 | 73,073 |
| Liabilities from risk management activities (Note 16) | 25,836 | 77,716 |
| Liabilities for asset retirements (Note 11) | 9,135 | 28,573 |
| Deferred fuel and purchased power regulatory liability (Note 3) | — | 9,688 |
| Other regulatory liabilities (Note 3) | 99,899 | 136,078 |
| Other current liabilities | 244,000 | 197,861 |
| Total current liabilities | 1,292,946 | 1,442,317 |
| LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6) | 4,021,785 | 3,462,391 |
| DEFERRED CREDITS AND OTHER | | |
| Deferred income taxes (Note 4) | 2,945,232 | 2,723,425 |
| Regulatory liabilities (Notes 1, 3, 4 and 7) | 948,916 | 994,152 |
| Liabilities for asset retirements (Note 11) | 615,340 | 415,003 |
| Liabilities for pension benefits (Note 7) | 509,310 | 480,998 |
| Liabilities from risk management activities (Note 16) | 47,238 | 89,973 |
| Customer advances | 88,672 | 115,609 |
| Coal mine reclamation | 221,910 | 201,984 |
| Deferred investment tax credit | 210,162 | 187,080 |
| Unrecognized tax benefits (Note 4) | 10,046 | 9,524 |
| Other | 156,784 | 186,345 |
| Total deferred credits and other | 5,753,610 | 5,404,093 |
| COMMITMENTS AND CONTINGENCIES (SEE NOTES) | | |
| EQUITY | | |
| Common stock, no par value; authorized 150,000,000 shares, 111,392,053 and 111,095,402 issued at respective dates | 2,596,030 | 2,541,668 |
| Treasury stock at cost; 55,317 shares at end of 2016 and 115,030 shares at end of 2015 | (4,133) | (5,806) |
| Total common stock | 2,591,897 | 2,535,862 |
| Retained earnings | 2,255,547 | 2,092,803 |
| Accumulated other comprehensive loss: | | |
| Pension and other postretirement benefits (Note 7) | (39,070) | (37,593) |
| Derivative instruments (Note 16) | (4,752) | (7,155) |
| Total accumulated other comprehensive loss | (43,822) | (44,748) |
| Total shareholders' equity | 4,803,622 | 4,583,917 |
| Noncontrolling interests (Note 18) | 132,290 | 135,540 |
| Total equity | 4,935,912 | 4,719,457 |
| TOTAL LIABILITIES AND EQUITY | $ 16,004,253 | $ 15,028,258 |

The accompanying notes are an integral part of the financial statements.

**PINNACLE WEST CAPITAL CORPORATION**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
(dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net Income | $ 461,527 | $ 456,190 | $ 423,696 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization including nuclear fuel | 565,011 | 571,664 | 496,487 |
| Deferred fuel and purchased power | (60,303) | 14,997 | (26,927) |
| Deferred fuel and purchased power amortization | 38,152 | 1,617 | 40,757 |
| Allowance for equity funds used during construction | (42,140) | (35,215) | (30,790) |
| Deferred income taxes | 206,870 | 236,819 | 159,023 |
| Deferred investment tax credit | 23,082 | 8,473 | 26,246 |
| Change in derivative instruments fair value | (403) | (381) | 339 |
| Stock compensation | 18,883 | 18,756 | 33,059 |
| Changes in current assets and liabilities: | | | |
| Customer and other receivables | (2,489) | (22,219) | (52,672) |
| Accrued unbilled revenues | (11,709) | 4,293 | (3,737) |
| Materials, supplies and fossil fuel | (1,491) | (23,945) | 3,724 |
| Income tax receivable | (3,162) | 2,509 | 132,419 |
| Other current assets | (23,324) | 3,145 | 4,384 |
| Accounts payable | (66,917) | (34,266) | (353) |
| Accrued taxes | 447 | (2,013) | 9,615 |
| Other current liabilities | 29,594 | 603 | 17,892 |
| Change in margin and collateral accounts — assets | 673 | (324) | (343) |
| Change in margin and collateral accounts — liabilities | 17,735 | 22,776 | (24,975) |
| Change in unrecognized tax benefits | 1,628 | (10,328) | 2,778 |
| Change in long-term regulatory liabilities | 14,682 | (20,535) | 59,618 |
| Change in other long-term assets | (60,163) | 2,426 | (56,561) |
| Change in other long-term liabilities | (82,793) | (100,715) | (114,052) |
| Net cash flow provided by operating activities | 1,023,390 | 1,094,327 | 1,099,627 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures | (1,275,472) | (1,076,087) | (910,634) |
| Contributions in aid of construction | 64,296 | 46,546 | 20,325 |
| Allowance for borrowed funds used during construction | (19,970) | (16,259) | (15,457) |
| Proceeds from nuclear decommissioning trust sales | 633,410 | 478,813 | 356,195 |
| Investment in nuclear decommissioning trust | (635,691) | (496,062) | (373,444) |
| Other | (18,651) | (3,184) | 347 |
| Net cash flow used for investing activities | (1,252,078) | (1,066,233) | (922,668) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Issuance of long-term debt | 693,151 | 842,415 | 731,126 |
| Repayment of long-term debt | (370,430) | (415,570) | (652,578) |
| Short-term borrowings and payments — net | 137,200 | (147,400) | (5,725) |
| Short-term debt borrowings under revolving credit facility | 40,000 | — | — |
| Dividends paid on common stock | (274,229) | (260,027) | (246,671) |
| Common stock equity issuance and purchases - net | (4,867) | 19,373 | 15,288 |
| Distributions to noncontrolling interests | (22,744) | (35,002) | (20,482) |
| Other | — | 1 | 161 |
| Net cash flow provided by (used for) financing activities | 198,081 | 3,790 | (178,881) |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (30,607) | 31,884 | (1,922) |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR | 39,488 | 7,604 | 9,526 |
| CASH AND CASH EQUIVALENTS AT END OF YEAR | $ 8,881 | $ 39,488 | $ 7,604 |

The accompanying notes are an integral part of the financial statements.

## PINNACLE WEST CAPITAL CORPORATION
## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands, except per share amounts)

| | Common Stock | | Treasury Stock | | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | | | | |
| Balance, December 31, 2013 | 110,280,703 | $ 2,491,558 | (98,944) | $ (4,308) | $ 1,785,273 | $ (78,053) | $ 145,990 | $ 4,340,460 |
| Net income | | — | | — | 397,595 | — | 26,101 | 423,696 |
| Other comprehensive income | | — | | — | — | 9,912 | — | 9,912 |
| Dividends on common stock ($2.33 per share) | | — | | — | (256,803) | — | — | (256,803) |
| Issuance of common stock | 369,059 | 21,412 | | — | — | — | — | 21,412 |
| Purchase of treasury stock (a) | | — | (139,746) | (7,893) | — | — | — | (7,893) |
| Reissuance of treasury stock for stock-based compensation and other | | — | 160,290 | 8,800 | — | — | — | 8,800 |
| Net capital activities by noncontrolling interests | | — | | — | — | — | (20,482) | (20,482) |
| Balance, December 31, 2014 | 110,649,762 | 2,512,970 | (78,400) | (3,401) | 1,926,065 | (68,141) | 151,609 | 4,519,102 |
| Net income | | — | | — | 437,257 | — | 18,933 | 456,190 |
| Other comprehensive income | | — | | — | — | 23,393 | — | 23,393 |
| Dividends on common stock ($2.44 per share) | | — | | — | (270,519) | — | — | (270,519) |
| Issuance of common stock | 445,640 | 28,698 | | — | — | — | — | 28,698 |
| Purchase of treasury stock (a) | | — | (154,751) | (10,136) | — | — | — | (10,136) |
| Reissuance of treasury stock for stock-based compensation and other | | — | 118,121 | 7,731 | — | — | — | 7,731 |
| Net capital activities by noncontrolling interests | | — | | — | — | — | (35,002) | (35,002) |
| Balance, December 31, 2015 | 111,095,402 | 2,541,668 | (115,030) | (5,806) | 2,092,803 | (44,748) | 135,540 | 4,719,457 |
| Net income | | — | | — | 442,034 | — | 19,493 | 461,527 |
| Other comprehensive income | | — | | — | — | 926 | — | 926 |
| Dividends on common stock ($2.56 per share) | | — | | — | (284,765) | — | — | (284,765) |
| Issuance of common stock | 296,651 | 13,982 | | — | — | — | — | 13,982 |
| Purchase of treasury stock (a) | | — | (128,105) | (9,087) | — | — | — | (9,087) |
| Reissuance of treasury stock for stock-based compensation and other | | — | 187,818 | 10,760 | — | — | — | 10,760 |
| Stock compensation cumulative effect adjustments (See Note 2) | | 40,380 | | — | 5,475 | — | — | 45,855 |
| Net capital activities by noncontrolling interests | | — | | — | — | — | (22,743) | (22,743) |
| Balance, December 31, 2016 | 111,392,053 | $ 2,596,030 | (55,317) | $ (4,133) | $ 2,255,547 | $ (43,822) | $ 132,290 | $ 4,935,912 |

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

The accompanying notes are an integral part of the financial statements.

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## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (ARIZONA PUBLIC SERVICE COMPANY)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for APS. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2016. The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's financial statements.

February 24, 2017

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiary (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Arizona Public Service Company and subsidiary as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Phoenix, Arizona
February 24, 2017

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED STATEMENTS OF INCOME
## (dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| ELECTRIC OPERATING REVENUES | $ 3,489,754 | $ 3,492,357 | $ 3,488,946 |
| OPERATING EXPENSES | | | |
| Fuel and purchased power | 1,082,625 | 1,101,298 | 1,179,829 |
| Operations and maintenance | 879,108 | 853,135 | 882,442 |
| Depreciation and amortization | 484,909 | 494,298 | 417,264 |
| Income taxes (Note 4) | 259,353 | 260,143 | 245,036 |
| Taxes other than income taxes | 165,779 | 171,499 | 171,583 |
| Total | 2,871,774 | 2,880,373 | 2,896,154 |
| OPERATING INCOME | 617,980 | 611,984 | 592,792 |
| OTHER INCOME (DEDUCTIONS) | | | |
| Income taxes (Note 4) | 13,511 | 14,302 | 7,676 |
| Allowance for equity funds used during construction (Note 1) | 42,140 | 35,215 | 30,790 |
| Other income (Note 17) | 8,607 | 2,834 | 11,295 |
| Other expense (Note 17) | (17,514) | (19,019) | (13,403) |
| Total | 46,744 | 33,332 | 36,358 |
| INTEREST EXPENSE | | | |
| Interest on long-term debt | 189,828 | 180,123 | 186,323 |
| Interest on short-term borrowings | 7,983 | 7,376 | 6,796 |
| Debt discount, premium and expense | 4,760 | 4,793 | 4,168 |
| Allowance for borrowed funds used during construction (Note 1) | (19,481) | (16,183) | (15,457) |
| Total | 183,090 | 176,109 | 181,830 |
| NET INCOME | 481,634 | 469,207 | 447,320 |
| Less: Net income attributable to noncontrolling interests (Note 18) | 19,493 | 18,933 | 26,101 |
| NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER | $ 462,141 | $ 450,274 | $ 421,219 |

The accompanying notes are an integral part of the financial statements.

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
## (dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| NET INCOME | $ 481,634 | $ 469,207 | $ 447,320 |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX | | | |
| Derivative instruments: | | | |
| Net unrealized loss, net of tax (expense) of $(585), $(342), and $(438) (Note 16) | (538) | (957) | (809) |
| Reclassification of net realized loss, net of tax benefit of $985, $1,801, and $7,932 (Note 16) | 2,941 | 4,187 | 13,483 |
| Pension and other postretirement benefits activity, net of tax (expense) benefit of $293, $(11,776), and $4,655 (Note 7) | (729) | 18,006 | (7,635) |
| Total other comprehensive income | 1,674 | 21,236 | 5,039 |
| COMPREHENSIVE INCOME | 483,308 | 490,443 | 452,359 |
| Less: Comprehensive income attributable to noncontrolling interests | 19,493 | 18,933 | 26,101 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER | $ 463,815 | $ 471,510 | $ 426,258 |

The accompanying notes are an integral part of the financial statements.

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED BALANCE SHEETS
## (dollars in thousands)

| | December 31, | |
|---|---|---|
| | 2016 | 2015 |
| ASSETS | | |
| PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9) | | |
| Plant in service and held for future use | $ 17,228,787 | $ 16,218,724 |
| Accumulated depreciation and amortization | (5,881,941) | (5,590,937) |
| Net | 11,346,846 | 10,627,787 |
| Construction work in progress | 989,497 | 812,845 |
| Palo Verde sale leaseback, net of accumulated depreciation of $237,535 and $233,665 (Note 18) | 113,515 | 117,385 |
| Intangible assets, net of accumulated amortization of $603,637 and $546,038 | 89,868 | 123,820 |
| Nuclear fuel, net of accumulated amortization of $147,202 and $146,228 | 119,004 | 123,139 |
| Total property, plant and equipment | 12,658,730 | 11,804,976 |
| INVESTMENTS AND OTHER ASSETS | | |
| Nuclear decommissioning trust (Notes 13 and 19) | 779,586 | 735,196 |
| Assets from risk management activities (Note 16) | 1 | 12,106 |
| Other assets | 48,320 | 34,455 |
| Total investments and other assets | 827,907 | 781,757 |
| CURRENT ASSETS | | |
| Cash and cash equivalents | 8,840 | 22,056 |
| Customer and other receivables | 262,611 | 274,428 |
| Accrued unbilled revenues | 107,949 | 96,240 |
| Allowance for doubtful accounts | (3,037) | (3,125) |
| Materials and supplies (at average cost) | 252,777 | 234,234 |
| Fossil fuel (at average cost) | 28,608 | 45,697 |
| Income tax receivable | 11,174 | — |
| Assets from risk management activities (Note 16) | 19,694 | 15,905 |
| Deferred fuel and purchased power regulatory asset (Note 3) | 12,465 | — |
| Other regulatory assets (Note 3) | 94,410 | 149,555 |
| Other current assets | 41,849 | 35,765 |
| Total current assets | 837,340 | 870,755 |
| DEFERRED DEBITS | | |
| Regulatory assets (Notes 1, 3, and 4) | 1,313,428 | 1,214,146 |
| Assets for other postretirement benefits (Note 7) | 162,911 | 182,625 |
| Other | 130,859 | 127,923 |
| Total deferred debits | 1,607,198 | 1,524,694 |
| TOTAL ASSETS | $ 15,931,175 | $ 14,982,182 |

The accompanying notes are an integral part of the financial statements.

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED BALANCE SHEETS
## (dollars in thousands)

| | December 31, | |
|---|---|---|
| | 2016 | 2015 |
| LIABILITIES AND EQUITY | | |
| CAPITALIZATION | | |
| Common stock | $ 178,162 | $ 178,162 |
| Additional paid-in capital | 2,421,696 | 2,379,696 |
| Retained earnings | 2,331,245 | 2,148,493 |
| Accumulated other comprehensive (loss): | | |
| Pension and other postretirement benefits (Note 7) | (20,671) | (19,942) |
| Derivative instruments (Note 16) | (4,752) | (7,155) |
| Total accumulated other comprehensive loss | (25,423) | (27,097) |
| Total shareholder equity | 4,905,680 | 4,679,254 |
| Noncontrolling interests (Note 18) | 132,290 | 135,540 |
| Total equity | 5,037,970 | 4,814,794 |
| Long-term debt less current maturities (Note 6) | 4,021,785 | 3,337,391 |
| Total capitalization | 9,059,755 | 8,152,185 |
| CURRENT LIABILITIES | | |
| Short-term borrowings (Note 5) | 135,500 | — |
| Current maturities of long-term debt (Note 6) | — | 357,580 |
| Accounts payable | 259,161 | 291,574 |
| Accrued taxes (Note 4) | 130,576 | 144,488 |
| Accrued interest | 52,525 | 56,003 |
| Common dividends payable | 72,900 | 69,400 |
| Customer deposits | 82,520 | 73,073 |
| Liabilities from risk management activities (Note 16) | 25,836 | 77,716 |
| Liabilities for asset retirements (Note 11) | 8,703 | 28,573 |
| Deferred fuel and purchased power regulatory liability (Note 3) | — | 9,688 |
| Other regulatory liabilities (Note 3) | 99,899 | 136,078 |
| Other current liabilities | 226,417 | 180,535 |
| Total current liabilities | 1,094,037 | 1,424,708 |
| DEFERRED CREDITS AND OTHER | | |
| Deferred income taxes (Note 4) | 2,999,295 | 2,764,489 |
| Regulatory liabilities (Notes 1, 3, and 4) | 948,916 | 994,152 |
| Liabilities for asset retirements (Note 11) | 607,234 | 415,003 |
| Liabilities for pension benefits (Note 7) | 488,253 | 459,065 |
| Liabilities from risk management activities (Note 16) | 47,238 | 89,973 |
| Customer advances | 88,672 | 115,609 |
| Coal mine reclamation | 206,645 | 201,984 |
| Deferred investment tax credit | 210,162 | 187,080 |
| Unrecognized tax benefits (Note 4) | 37,408 | 35,251 |
| Other | 143,560 | 142,683 |
| Total deferred credits and other | 5,777,383 | 5,405,289 |
| COMMITMENTS AND CONTINGENCIES (SEE NOTES) | | |
| TOTAL LIABILITIES AND EQUITY | $ 15,931,175 | $ 14,982,182 |

The accompanying notes are an integral part of the financial statements.

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED STATEMENTS OF CASH FLOWS
## (dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $ 481,634 | $ 469,207 | $ 447,320 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization including nuclear fuel | 564,091 | 571,540 | 496,393 |
| Deferred fuel and purchased power | (60,303) | 14,997 | (26,927) |
| Deferred fuel and purchased power amortization | 38,152 | 1,617 | 40,757 |
| Allowance for equity funds used during construction | (42,140) | (35,215) | (30,790) |
| Deferred income taxes | 221,167 | 223,069 | 155,401 |
| Deferred investment tax credit | 23,082 | 8,473 | 26,246 |
| Change in derivative instruments fair value | (403) | (381) | 339 |
| Changes in current assets and liabilities: | | | |
| Customer and other receivables | (1,601) | (21,040) | (52,466) |
| Accrued unbilled revenues | (11,709) | 4,293 | (3,737) |
| Materials, supplies and fossil fuel | (1,454) | (23,945) | 3,724 |
| Income tax receivable | (14,567) | — | 135,179 |
| Other current assets | (21,640) | 4,498 | 3,766 |
| Accounts payable | (67,543) | (34,891) | (2,355) |
| Accrued taxes | (13,912) | 13,378 | 8,650 |
| Other current liabilities | 5,097 | (3,718) | 33,970 |
| Change in margin and collateral accounts — assets | 673 | (324) | (343) |
| Change in margin and collateral accounts — liabilities | 17,735 | 22,776 | (24,975) |
| Change in long-term regulatory liabilities | 14,682 | (20,535) | 59,618 |
| Change in unrecognized tax benefits | 1,628 | (10,328) | 2,778 |
| Change in other long-term assets | (45,866) | (813) | (62,739) |
| Change in other long-term liabilities | (76,855) | (82,628) | (85,642) |
| Net cash flow provided by operating activities | 1,009,948 | 1,100,030 | 1,124,167 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures | (1,248,010) | (1,072,053) | (910,084) |
| Contributions in aid of construction | 64,296 | 46,546 | 20,325 |
| Allowance for borrowed funds used during construction | (19,481) | (16,183) | (15,457) |
| Proceeds from nuclear decommissioning trust sales | 633,410 | 478,813 | 356,195 |
| Investment in nuclear decommissioning trust | (635,691) | (496,062) | (373,444) |
| Other | (13,865) | (1,093) | 347 |
| Net cash flow used for investing activities | (1,219,341) | (1,060,032) | (922,118) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Issuance of long-term debt | 693,151 | 842,415 | 606,126 |
| Repayment of long-term debt | (370,430) | (415,570) | (527,578) |
| Short-term borrowings and payments — net | 135,500 | (147,400) | (5,725) |
| Dividends paid on common stock | (281,300) | (266,900) | (253,600) |
| Equity infusion from Pinnacle West | 42,000 | — | — |
| Noncontrolling interests | (22,744) | (35,002) | (20,482) |
| Net cash flow provided by (used for) financing activities | 196,177 | (22,457) | (201,259) |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (13,216) | 17,541 | 790 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR | 22,056 | 4,515 | 3,725 |
| CASH AND CASH EQUIVALENTS AT END OF YEAR | $ 8,840 | $ 22,056 | $ 4,515 |
| Supplemental disclosure of cash flow information: | | | |
| Cash paid (received) during the year for: | | | |
| Income taxes, net of refunds | $ 26,864 | $ 14,831 | $ (86,054) |
| Interest, net of amounts capitalized | 181,809 | 167,670 | 173,436 |
| Significant non-cash investing and financing activities: | | | |
| Accrued capital expenditures | $ 114,874 | $ 83,798 | $ 44,712 |
| Dividends declared but not paid | 72,900 | 69,400 | 65,800 |

The accompanying notes are an integral part of the financial statements.

## ARIZONA PUBLIC SERVICE COMPANY
## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
## (dollars in thousands)

| | Common Stock | | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
|---|---|---|---|---|---|---|---|
| | Shares | Amount | | | | | |
| Balance, December 31, 2013 | 71,264,947 | $ 178,162 | $ 2,379,696 | $1,804,398 | $ (53,372) | $ 145,990 | $ 4,454,874 |
| Net income | | — | — | 421,219 | — | 26,101 | 447,320 |
| Other comprehensive income | | — | — | — | 5,039 | — | 5,039 |
| Dividends on common stock | | — | — | (256,900) | — | — | (256,900) |
| Other | | — | — | 1 | — | — | 1 |
| Net capital activities by noncontrolling interests | | — | — | — | — | (20,482) | (20,482) |
| Balance, December 31, 2014 | 71,264,947 | 178,162 | 2,379,696 | 1,968,718 | (48,333) | 151,609 | 4,629,852 |
| Net income | | — | — | 450,274 | — | 18,933 | 469,207 |
| Other comprehensive income | | — | — | — | 21,236 | — | 21,236 |
| Dividends on common stock | | — | — | (270,500) | — | — | (270,500) |
| Other | | — | — | 1 | — | — | 1 |
| Net capital activities by noncontrolling interests | | — | — | — | — | (35,002) | (35,002) |
| Balance, December 31, 2015 | 71,264,947 | 178,162 | 2,379,696 | 2,148,493 | (27,097) | 135,540 | 4,814,794 |
| Equity infusion from Pinnacle West | | — | 42,000 | — | — | — | 42,000 |
| Net income | | — | — | 462,141 | — | 19,493 | 481,634 |
| Other comprehensive income | | — | — | — | 1,674 | — | 1,674 |
| Dividends on common stock | | — | — | (284,800) | — | — | (284,800) |
| Stock compensation cumulative effect adjustments (See Note 2) | | — | — | 5,411 | — | — | 5,411 |
| Net capital activities by noncontrolling interests | | — | — | — | — | (22,743) | (22,743) |
| Balance, December 31, 2016 | 71,264,947 | $ 178,162 | $ 2,421,696 | $2,331,245 | $ (25,423) | $ 132,290 | $ 5,037,970 |

The accompanying notes are an integral part of the financial statements.

## 1. Summary of Significant Accounting Policies

### Description of Business and Basis of Presentation

Pinnacle West is a holding company that conducts business through its subsidiaries, APS, El Dorado, BCE and 4CA. APS, our wholly-owned subsidiary, is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for essentially all of our revenues and earnings, and is expected to continue to do so. El Dorado is an investment firm. BCE is a subsidiary that was formed in 2014 that focuses on growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE is currently pursuing transmission opportunities through a joint venture arrangement. 4CA is a subsidiary that was formed in 2016 as a result of the purchase of El Paso's 7% interest in Four Corners.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, El Dorado, BCE and 4CA. APS's consolidated financial statements include the accounts of APS and certain VIEs relating to the Palo Verde sale leaseback. Intercompany accounts and transactions between the consolidated companies have been eliminated.

We consolidate VIEs for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. In performing our primary beneficiary analysis, we consider all relevant facts and circumstances, including the design and activities of the VIE, the terms of the contracts the VIE has entered into, and which parties participated significantly in the design or redesign of the entity. We continually evaluate our primary beneficiary conclusions to determine if changes have occurred which would impact our primary beneficiary assessments. We have determined that APS is the primary beneficiary of certain VIE lessor trusts relating to the Palo Verde sale leaseback, and therefore APS consolidates these entities (see Note 18).

Our consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments, except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented.

Certain line items are presented in more detail on the Consolidated Statements of Cash Flows than was presented in the prior years. The prior year amounts were reclassified to conform to the current year presentation. These reclassifications have no impact on net cash flows provided by operating activities. The following tables show the impacts of the reclassifications of the prior years (previously reported) amounts (dollars in thousands):

| Statement of Cash Flows for the Year Ended December 31, 2015 | As previously reported | Reclassifications to conform to current year presentation | Amount reported after reclassification to conform to current year presentation |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| Stock compensation | $ — | $ 18,756 | $ 18,756 |
| Change in other long term liabilities | (81,959) | (18,756) | (100,715) |

| Statement of Cash Flows for the Year Ended December 31, 2014 | As previously reported | Reclassifications to conform to current year presentation | Amount reported after reclassification to conform to current year presentation |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| Stock compensation | $ — | $ 33,059 | $ 33,059 |
| Change in other long-term liabilities | (80,993) | (33,059) | (114,052) |

**Accounting Records and Use of Estimates**

Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

**Regulatory Accounting**

APS is regulated by the ACC and FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment and recent rate orders applicable to APS or other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

See Note 3 for additional information.

**Electric Revenues**

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and fuel and purchased power costs.

Some of our cost recovery mechanisms are alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed.

**Allowance for Doubtful Accounts**

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including accrued utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment.

**Property, Plant and Equipment**

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- allowance for funds used during construction.

Pinnacle West's property, plant and equipment included in the December 31, 2016 and 2015 consolidated balance sheets is composed of the following (dollars in thousands):

| Property, Plant and Equipment: | 2016 | 2015 |
|---|---|---|
| Generation | $ 7,874,898 | $ 7,336,902 |
| Transmission | 2,746,508 | 2,494,744 |
| Distribution | 5,738,801 | 5,543,561 |
| General plant | 981,681 | 847,025 |
| Plant in service and held for future use | 17,341,888 | 16,222,232 |
| Accumulated depreciation and amortization | (5,970,100) | (5,594,094) |
| Net | 11,371,788 | 10,628,138 |
| Construction work in progress | 1,019,947 | 816,307 |
| Palo Verde sale leaseback, net of accumulated depreciation | 113,515 | 117,385 |
| Intangible assets, net of accumulated amortization | 90,022 | 123,975 |
| Nuclear fuel, net of accumulated amortization | 119,004 | 123,139 |
| Total property, plant and equipment | $ 12,714,276 | $ 11,808,944 |

Property, plant and equipment balances and classes for APS are not materially different than Pinnacle West.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-

lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 11.

APS records a regulatory liability for the difference between the amount that has been recovered in regulated rates and the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it can recover in regulated rates the costs calculated in accordance with this accounting guidance.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2016 were as follows:

- Fossil plant — 19 years;
- Nuclear plant — 27 years;
- Other generation — 26 years;
- Transmission — 39 years;
- Distribution — 33 years; and
- General plant — 7 years.

Pursuant to an ACC order, we deferred operating costs in 2013 and 2014 related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. See Note 3 for further discussion. These costs were deferred and are now being amortized on the depreciation line of the Consolidated Statements of Income.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $422 million in 2016, $430 million in 2015, and $396 million in 2014. For the years 2014 through 2016, the depreciation rates ranged from a low of 0.30% to a high of 14.12%. The weighted-average depreciation rate was 2.66% in 2016, 2.74% in 2015, and 2.77% in 2014.

**Allowance for Funds Used During Construction**

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statements of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 7.17% for 2016, 8.02% for 2015, and 8.47% for 2014. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

**Materials and Supplies**

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered.

**Fair Value Measurements**

We account for derivative instruments, investments held in our nuclear decommissioning trust, certain cash equivalents and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Due to the short-term nature of net accounts receivable, accounts payable, and short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost (see Note 6).

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

See Note 13 for additional information about fair value measurements.

**Derivative Accounting**

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported net on the balance sheet. See Note 16 for additional information about our derivative instruments.

**Loss Contingencies and Environmental Liabilities**

Pinnacle West and APS are involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is

probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Pinnacle West and APS record a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

**Retirement Plans and Other Postretirement Benefits**

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries. We also sponsor an other postretirement benefit plan for the employees of Pinnacle West and its subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 7 for additional information on pension and other postretirement benefits.

**Nuclear Fuel**

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE suspended the fee. In accordance with a settlement agreement with the DOE in August 2014, we will now accrue a receivable for incurred claims and an offsetting regulatory liability through the settlement period ending December of 2016. See Note 10 for information on spent nuclear fuel disposal costs.

**Income Taxes**

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes. We file our federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. The income tax accounts reflect the tax and interest associated with management's estimate of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement for all known and measurable tax exposures (see Note 4).

**Cash and Cash Equivalents**

We consider all highly liquid investments with a remaining maturity of three months or less at acquisition to be cash equivalents.

The following table summarizes supplemental Pinnacle West cash flow information for each of the last three years (dollars in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Cash paid (received) during the period for: | | | |
| Income taxes, net of refunds | $ 9,956 | $ 6,550 | $ (102,154) |
| Interest, net of amounts capitalized | 184,462 | 170,209 | 177,074 |
| Significant non-cash investing and financing activities: | | | |
| Accrued capital expenditures | $ 114,855 | $ 83,798 | $ 44,712 |
| Dividends declared but not paid | 72,926 | 69,363 | 65,790 |

**Intangible Assets**

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS's software, on Pinnacle West's Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $58 million in 2016, $58 million in 2015, and $53 million in 2014. Estimated amortization expense on existing intangible assets over the next five years is $41 million in 2017, $23 million in 2018, $12 million in 2019, $4 million in 2020, and $1 million in 2021. At December 31, 2016, the weighted-average remaining amortization period for intangible assets was 6 years.

**Investments**

El Dorado accounts for its investments using either the equity method (if significant influence) or the cost method (if less than 20% ownership and no significant influence).

Our investments in the nuclear decommissioning trust fund are accounted for in accordance with guidance on accounting for certain investments in debt and equity securities. See Note 13 and Note 19 for more information on these investments.

**Business Segments**

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution. All other segment activities are insignificant.

**Preferred Stock**

At December 31, 2016, Pinnacle West had 10 million shares of serial preferred stock authorized with no par value, none of which was outstanding, and APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50 and $100 par values, none of which was outstanding.

## 2. New Accounting Standards

### ASU 2016-09, Stock Compensation: Improvements to Employee Share-Based Payment Accounting

In March 2016, new stock compensation accounting guidance was issued intended to simplify the accounting for employee share-based payments. The new guidance impacts several aspects of the accounting for share-based payments including: modifies the tax withholding threshold that triggers liability classification of an award, requires all excess income tax benefits and deficiencies arising from share-based payments to be recognized in earnings in the period they occur, simplifies the accounting for forfeitures, and clarifies certain cash flow presentation matters. Certain aspects of the standard must be adopted using a prospective approach and other aspects must be adopted using a modified retrospective approach.

During the fourth quarter of 2016, we elected to early adopt this standard, and accordingly have applied the guidance effective as of January 1, 2016. Prior to adoption of the new standard, our stock compensation awards were generally classified as liability awards and accounted for at fair value until settled because employees could withhold at more than the minimum statutory tax withholding rate. In accordance with the new guidance, certain of these stock compensation awards are now classified as equity awards and accounted for at grant date fair value. As a result of adopting the new standard, Pinnacle West recorded a cumulative effect adjustment to retained earnings of $6 million. The other provisions of the standard did not have a material impact on our consolidated financial statements. See Note 15 for additional details of the adoption impacts.

### ASU 2015-07, Fair Value Measurement: Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)

In May 2015, new accounting guidance was issued that removes the requirement to categorize certain investments valued using net asset value, as a practical expedient, within the fair value hierarchy. We retrospectively adopted this guidance during the first quarter of 2016. The adoption of this guidance modifies our fair value disclosures, but does not impact the methodology for valuing these instruments, or our financial statement results. See Note 7 and Note 13.

### ASU 2014-09, Revenue from Contracts with Customers

In May 2014, a new revenue recognition accounting standard was issued. This standard provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. Since the issuance of the new revenue standard, additional guidance was issued to clarify certain aspects of the new revenue standard, including principal versus agent considerations, identifying performance obligations, and other narrow scope improvements. The new revenue standard, and related amendments, will be effective for us on January 1, 2018. The standard may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application.

We plan on adopting this standard on January 1, 2018, and are currently evaluating the transition method and the effect on our financial statements. As part of our evaluation we continue to actively monitor certain industry issues being addressed by the American Institute of Certified Public Accountants' Revenue Recognition Working Group and the Financial Accounting Standards Board's Transition Resource Group. Conclusions reached by these groups may impact our application of the standard, specifically in regards to the treatment of contributions in aid of construction.

**ASU 2016-01, Financial Instruments: Recognition and Measurement**

In January 2016, a new accounting standard was issued relating to the recognition and measurement of financial instruments. The new guidance will require certain investments in equity securities to be measured at fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new standard is effective for us on January 1, 2018. Certain aspects of the standard may require a cumulative effect adjustment and other aspects of the standard are required to be adopted prospectively. We plan on adopting this standard on January 1, 2018, and continue to evaluate the impacts the new guidance may have on our financial statements.

**ASU 2016-02, Leases**

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard will require a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that will initially be measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. The new standard will be effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach, with various optional practical expedients provided to facilitate transition. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

**ASU 2016-13, Financial Instruments: Measurement of Credit Losses**

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard will require entities to use a current expected credit loss model to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. The new standard is effective for us on January 1, 2020 and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

**ASU 2017-01, Business Combinations: Clarifying the Definition of a Business**

In January 2017, a new accounting standard was issued that clarifies the definition of a business. This standard is intended to assist entities with evaluating whether a transaction should be accounted for as an acquisition (or disposal) of assets or a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. The new standard is effective for us on January 1, 2018 using a prospective approach. We are evaluating the impacts of adopting this new standard, and the impacts it may have on our financial statements.

## 3. Regulatory Matters

### Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excludes amounts that are currently collected on customer bills through adjustor mechanisms. The application requests that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have an incremental effect on average customer bills. The average annual customer bill impact of APS's request is an increase of 5.74% (the average annual bill impact for a typical APS residential customer is 7.96%).

The principal provisions of the application are:

- a test year ended December 31, 2015, adjusted as described below;
- an original cost rate base of $6.8 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits, as of December 31, 2015;
- the following proposed capital structure and costs of capital:

| | Capital Structure | Cost of Capital |
|---|---|---|
| Long-term debt | 44.20 % | 5.13 % |
| Common stock equity | 55.80 % | 10.50 % |
| Weighted-average cost of capital | | 8.13 % |

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a base rate for fuel and purchased power costs of $0.029882 per kWh based on estimated 2017 prices (a decrease from the current base fuel rate of $0.03207 per kWh);
- authorization to defer for potential future recovery its share of the construction costs associated with installing selective catalytic reduction equipment at Four Corners (estimated at approximately $400 million in direct costs). APS proposes that the rates established in this rate case be increased through a step mechanism beginning in 2019 to reflect these deferred costs;
- authorization to defer for potential future recovery in the Company's next general rate case the construction costs APS incurs for its Ocotillo power plant modernization project, once the project reaches commercial operation. APS estimates the direct construction costs at approximately $500 million and that the new facility will be fully in service by early 2019;
- authorization to defer until the Company's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- updates and modifications to four of APS's adjustor mechanisms - the PSA, the LFCR, the TCA and the Environmental Improvement Surcharge ("EIS");

- a number of proposed rate design changes for residential customers, including:
  - change the on-peak time of use period from 12 p.m. - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
  - reduce the difference in the on- and off-peak energy price and lower all energy charges;
  - offer four rate plan options, three of which have demand charges and a fourth that is available to non-partial requirements customers using less than 600 kWh on average per month; and
  - modify the current net metering tariff to provide for a credit at the retail rate for the portion of generation by rooftop solar customers that offsets their own load, and for a credit for excess energy delivered to the grid at an export rate.

- proposed rate design changes for commercial customers, including an aggregation rider that allows certain large customers to qualify for a reduced rate, an extra-high load factor rate schedule for certain customers, and an economic development rate offering for new loads meeting certain criteria.

The Company requested that the increase become effective July 1, 2017. On July 22, 2016, the ALJ set a procedural schedule for the rate proceeding, which supported completing the case within 12 months.

The ACC staff and intervenors began filing their direct testimony in late December 2016 and additional filings of testimony are ongoing. On January 12, 2017, APS began settlement discussions with all parties. On January 13, 2017, the ALJ hearing the case before the ACC issued a procedural order delaying hearings on the case from the originally scheduled March 22, 2017 to April 24, 2017, to allow parties to participate in settlement discussions and prepare testimony on the distributed generation rate design issues addressed in the value and cost of DG decision. According to the procedural order, settlement discussions are to be completed and, if applicable, any related settlement must be filed by March 17, 2017. The procedural order also extended the rate case completion date as calculated by Commission rule for an additional 33 days. APS cannot predict the outcome of this case.

**Prior Rate Case Filing**

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into the 2012 Settlement Agreement detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

***Settlement Agreement***

The 2012 Settlement Agreement provides for a zero net change in base rates, consisting of: (1) a non-fuel base rate increase of $116.3 million; (2) a fuel-related base rate decrease of $153.1 million (to be implemented by a change in the Base Fuel Rate from $0.03757 to $0.03207 per kWh); and (3) the transfer of cost recovery for certain renewable energy projects from the RES surcharge to base rates in an estimated amount of $36.8 million.

Other key provisions of the 2012 Settlement Agreement include the following:

- An authorized return on common equity of 10.0%;
- A capital structure comprised of 46.1% debt and 53.9% common equity;

- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;
- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:
  - Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and
  - Deferral of 100% in all years if Arizona property tax rates decrease;
- A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);
- Implementation of a "Lost Fixed Cost Recovery" rate mechanism to support energy efficiency and distributed renewable generation;
- Modifications to the Environmental Improvement Surcharge to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;
- Modifications to the PSA, including the elimination of the 90/10 sharing provision;
- A limitation on the use of the RES surcharge and the DSMAC to recoup capital expenditures not required under the terms of the settlement agreement for the 2009 retail rate case (the "2009 Settlement Agreement");
- Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;
- Modification of the TCA to streamline the process for future transmission-related rate changes; and
- Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

The 2012 Settlement Agreement was approved by the ACC on May 15, 2012, with new rates effective on July 1, 2012. This accomplished a goal set by the parties to the 2009 Settlement Agreement to process subsequent rate cases within twelve months of sufficiency findings from the ACC staff, which generally occurs within 30 days after the filing of a rate case.

**Cost Recovery Mechanisms**

APS has received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

***Renewable Energy Standard.*** In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to

recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes would not be made until the project was fully in service, and APS has requested cost recovery for the project in its currently pending rate case. On September 30, 2016, APS presented its preliminary findings from the residential rooftop solar program in a filing with the ACC.

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. The ACC has not yet ruled on the Company's 2017 RES Implementation Plan.

In September of 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent regulations of the EPA. The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding.

***Demand Side Management Adjustor Charge.*** The ACC Electric Energy Efficiency Standards require APS to submit a Demand Side Management Implementation Plan ("DSM Plan") for review by and approval of the ACC. In March 2014, the ACC approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its LFCR mechanism.

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. On April 1, 2016, APS filed an amended 2016 DSM Plan that sought minor modifications to its existing DSM Plan and requested to continue the current DSMAC and current budget of $68.9 million. On July 12, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new residential demand response or load management program that facilitates energy storage technology. On December 5, 2016, APS filed for ACC approval of a $4 million Residential Demand Response, Energy Storage and Load Management Program.

On June 1, 2016, the Company filed its 2017 DSM Implementation Plan, in which APS proposes programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and the requested budget increased to $66.6 million. The ACC has not yet ruled on the Company's 2017 DSM Plan.

***Electric Energy Efficiency***. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. On July 12, 2016, the ACC ordered that ACC staff convene a workshop within 120 days to discuss a number of issues related to the Electric Energy Efficiency Standards, including the process of determining the cost effectiveness of DSM programs and the treatment of peak demand and capacity reductions, among others. ACC staff convened the workshop on November 29, 2016 and sought public comment on potential revisions to the Electric Energy Efficiency Standards. APS cannot predict the outcome of this proceeding.

***PSA Mechanism and Balance.*** The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;

- An adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;

- The PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);

- The PSA rate includes (a) a "Forward Component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "Historical Component," under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and

- The PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2016 and 2015 (dollars in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2016 | 2015 |
| Beginning balance | $ (9,688) | $ 6,926 |
| Deferred fuel and purchased power costs - current period | 60,303 | (14,997) |
| Amounts charged to customers | (38,150) | (1,617) |
| Ending balance | $ 12,465 | $ (9,688) |

The PSA rate for the PSA year beginning February 1, 2017 is $(0.001348) per kWh, as compared to $0.001678 per kWh for the prior year. This new rate is comprised of a forward component of $(0.001027) per kWh and a historical component of $(0.000321) per kWh.

***Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters.*** In July 2008, FERC approved an Open Access Transmission Tariff for APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the 2012 Settlement Agreement, however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

Effective June 1, 2015, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 in

accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2015.

Effective June 1, 2016, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $24.9 million for the twelve-month period beginning June 1, 2016 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2016.

APS's formula rate protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate protocols and may require companies to make changes to their protocols in the future. As a result, APS is evaluating how its formula rate protocols compare with more recently approved formula rate protocols and anticipates that it will make a filing to update its formula rate protocols in the first quarter of 2017.

***Lost Fixed Cost Recovery Mechanism.*** The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to distributed generation such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWh's lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. Distributed generation sales losses are determined from the metered output from the distributed generation units.

APS files for a LFCR adjustment every January. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 2, 2015, effective for the first billing cycle of March. APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase), to be effective for the first billing cycle of March 2016. The ACC approved the 2016 annual LFCR to be effective in May 2016. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, the two month delay in implementation did not have an adverse effect on APS. APS filed its 2017 LFCR adjustment on January 13, 2017. APS requested an adjustment of $63.7 million (a $17.3 million per year increase over 2016 levels), to be effective the first billing cycle of March 2017.

**Net Metering**

In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, the ALJ issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the ALJ. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC's action, effective following APS's pending rate case, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems will be replaced by a more formula-driven approach that will utilize inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the price that APS pays for utility-scale solar projects on a five year rolling average, while a forecasted avoided

cost methodology is being developed. The price established by this resource comparison proxy method will be updated annually (between rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by that utility for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to the date new rates are effective based on APS' pending rate case will be grandfathered for a period of 20 years from the date of interconnection;

- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and

- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change as are all ACC policies. The determination of the initial export energy price to be paid by APS will be made in APS's currently pending rate case, which is scheduled for hearing by the ACC in April 2017. APS cannot predict the outcome of this determination.

The ACC's decision did not make any policy determinations as to any specific costs to be charged to DG solar system customers for their use of the grid. The determination of any such costs will be made in APS's future rate cases.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserts that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC's request for rehearing is required for TASC to challenge this decision in court. To date, the ACC has taken no action on the rehearing request. The ACC's decision is expected to remain in effect during any legal challenge.

**Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB")**

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision, and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and on August 8, 2016, the Arizona Supreme Court vacated the Court of Appeals opinion and affirmed the ACC's orders approving the water company's SIB adjustor.

**System Benefits Charge**

The 2012 Settlement Agreement provided that once APS achieved full funding of its decommissioning obligation under the sale leaseback agreements covering Unit 2 of Palo Verde, APS was required to implement a reduced System Benefits charge effective January 1, 2016. Beginning on January 1, 2016, APS began implementing a reduced System Benefits charge. The impact on APS retail revenues from the new System Benefits charge is an overall reduction of approximately $14.6 million per year with a corresponding reduction in depreciation and amortization expense.

**Subpoena from Arizona Corporation Commissioner Robert Burns**

On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, filed subpoenas in APS's current retail rate proceeding to APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for APS to produce all information previously requested through the subpoenas. Commissioner Burns has also scheduled a workshop in this matter for March 17, 2017. APS and Pinnacle West cannot predict the outcome of this matter.

**Four Corners**

On December 30, 2013, APS purchased SCE's 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE's interest in Units 4 and 5 and the closure of Units 1-3 was $64 million as of December 31, 2016 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a

notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above. On August 8, 2016, the Arizona Supreme Court issued its opinion in the SIB matter, and the Arizona Court of Appeals has now ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. We cannot predict when or how this matter will be resolved.

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. APS cannot predict the outcome of either matter.

**Cholla**

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. On January 13, 2017, EPA approved a final rule incorporating APS's compromise proposal. Once the final rule is published in the Federal Register, parties have 60 days to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict at this time whether such petitions will be filed or if they will be successful. In addition, under the terms of an executive memorandum issued on January 20, 2017, this final rule will not be published in the Federal Register until after it has been reviewed by an appointee of the President. We cannot predict when such review will occur and what may result from the additional review.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and is seeking recovery of the unit's decommissioning and other retirement-related costs over the previously estimated remaining life of the plant in its current retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($116 million as of December 31, 2016), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

**Navajo Plant**

On February 13, 2017, the co-owners of the Navajo Plant voted not to pursue continued operation of the plant beyond December 2019, the expiration of the current lease term, and to pursue a new lease or lease extension with the Navajo Nation that would allow decommissioning activities to begin after December 2019 instead of later this year. Various stakeholders including regulators, tribal representatives and others interested in the continued operation of the plant intend to meet to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. We cannot predict whether any alternate solutions will be found that would be acceptable to all of the stakeholders and feasible to implement. APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($108 million as of December 31, 2016, see Note 9 for additional details) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. We cannot predict whether APS would obtain such recovery.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

## Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

| | Amortization Through | December 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|---|
| | | Current | Non-Current | Current | Non-Current |
| Pension | (a) | $ — | $ 711,059 | $ — | $ 619,223 |
| Retired power plant costs | 2033 | 9,913 | 117,591 | 9,913 | 127,518 |
| Income taxes - AFUDC equity | 2046 | 6,305 | 152,118 | 5,495 | 133,712 |
| Deferred fuel and purchased power — mark-to-market (Note 16) | 2020 | — | 42,963 | 71,852 | 69,697 |
| Four Corners cost deferral | 2024 | 6,689 | 56,894 | 6,689 | 63,582 |
| Income taxes — investment tax credit basis adjustment | 2046 | 2,120 | 54,356 | 1,766 | 48,462 |
| Lost fixed cost recovery | 2017 | 61,307 | — | 45,507 | — |
| Palo Verde VIEs (Note 18) | 2046 | — | 18,775 | — | 18,143 |
| Deferred compensation | 2036 | — | 35,595 | — | 34,751 |
| Deferred property taxes | (d) | — | 73,200 | — | 50,453 |
| Loss on reacquired debt | 2038 | 1,637 | 16,942 | 1,515 | 16,375 |
| AG-1 deferral | 2018 | — | 5,868 | — | — |
| Demand side management (b) | 2017 | 3,744 | — | — | — |
| Tax expense of Medicare subsidy | 2024 | 1,513 | 10,589 | 1,520 | 12,163 |
| Transmission vegetation management | 2016 | — | — | 4,543 | — |
| Mead-Phoenix transmission line CIAC | 2050 | 332 | 10,708 | 332 | 11,040 |
| Deferred fuel and purchased power (b) (c) | 2017 | 12,465 | — | — | — |
| Coal reclamation | 2026 | 418 | 5,182 | 418 | 6,085 |
| Other | Various | 432 | 1,588 | 5 | 2,942 |
| Total regulatory assets (e) | | $ 106,875 | $ 1,313,428 | $ 149,555 | $ 1,214,146 |

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. See Note 7 for further discussion.
(b) See “Cost Recovery Mechanisms” discussion above.
(c) Subject to a carrying charge.
(d) Per the provision of the 2012 Settlement Agreement.
(e) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in “Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters.”

The detail of regulatory liabilities is as follows (dollars in thousands):

| | Amortization Through | December 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|---|
| | | Current | Non-Current | Current | Non-Current |
| Asset retirement obligations | 2057 | $ — | $ 279,976 | $ — | $ 277,554 |
| Removal costs | (a) | 29,899 | 223,145 | 39,746 | 240,367 |
| Other postretirement benefits | (d) | 32,662 | 123,913 | 34,100 | 179,521 |
| Income taxes — deferred investment tax credit | 2046 | 4,368 | 108,827 | 3,604 | 97,175 |
| Income taxes - change in rates | 2045 | 1,771 | 70,898 | 1,113 | 72,454 |
| Spent nuclear fuel | 2047 | — | 71,726 | 3,051 | 67,437 |
| Renewable energy standard (b) | 2017 | 26,809 | — | 43,773 | 4,365 |
| Demand side management (b) | 2019 | — | 20,472 | 6,079 | 19,115 |
| Sundance maintenance | 2030 | — | 15,287 | — | 13,678 |
| Deferred fuel and purchased power (b) (c) | 2016 | — | — | 9,688 | — |
| Deferred gains on utility property | 2018 | 2,063 | 8,895 | 2,062 | 6,001 |
| Four Corners coal reclamation | 2031 | — | 18,248 | — | 8,920 |
| Other | Various | 2,327 | 7,529 | 2,550 | 7,565 |
| Total regulatory liabilities | | $ 99,899 | $ 948,916 | $ 145,766 | $ 994,152 |

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal (see Note 11).
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 7.

## 4. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, investment tax credit basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to deferred taxes resulting from investment tax credits ("ITC") and the change in income tax rates.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the statement of income.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 18). As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS Consolidated Statements of Income.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Total unrecognized tax benefits, January 1 | $ 34,447 | $ 44,775 | $ 41,997 | $ 34,447 | $ 44,775 | $ 41,997 |
| Additions for tax positions of the current year | 2,695 | 2,175 | 4,309 | 2,695 | 2,175 | 4,309 |
| Additions for tax positions of prior years | 886 | — | 751 | 886 | — | 751 |
| Reductions for tax positions of prior years for: | | | | | | |
| Changes in judgment | (1,953) | (10,244) | (2,282) | (1,953) | (10,244) | (2,282) |
| Settlements with taxing authorities | — | — | — | — | — | — |
| Lapses of applicable statute of limitations | — | (2,259) | — | — | (2,259) | — |
| Total unrecognized tax benefits, December 31 | $ 36,075 | $ 34,447 | $ 44,775 | $ 36,075 | $ 34,447 | $ 44,775 |

Included in the balances of unrecognized tax benefits are the following tax positions that, if recognized, would decrease our effective tax rate (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Tax positions, that if recognized, would decrease our effective tax rate | $ 11,313 | $ 9,523 | $ 11,207 | $ 11,313 | $ 9,523 | $ 11,207 |

As of the balance sheet date, the tax year ended December 31, 2013 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2012.

We reflect interest and penalties, if any, on unrecognized tax benefits in the Pinnacle West Consolidated and APS Consolidated Statements of Income as income tax expense. The amount of interest expense or benefit recognized related to unrecognized tax benefits are as follows (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Unrecognized tax benefit interest expense/ (benefit) recognized | $ 529 | $ (161) | $ 752 | $ 529 | $ (161) | $ 752 |

Following are the total amount of accrued liabilities for interest recognized related to unrecognized benefits that could reverse and decrease our effective tax rate to the extent matters are settled favorably (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Unrecognized tax benefit interest accrued | $ 1,333 | $ 804 | $ 965 | $ 1,333 | $ 804 | $ 965 |

Additionally, as of December 31, 2016, we have recognized less than $1 million of interest expense to be paid on the underpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

The components of income tax expense are as follows (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | Year Ended December 31, | | |
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Current: | | | | | | |
| Federal | $ 8,630 | $ (12,335) | $ 25,054 | $ 711 | $ 6,485 | $ 40,115 |
| State | 1,259 | 4,763 | 10,382 | 4,276 | 7,813 | 15,598 |
| Total current | 9,889 | (7,572) | 35,436 | 4,987 | 14,298 | 55,713 |
| Deferred: | | | | | | |
| Federal | 201,743 | 221,505 | 167,365 | 215,178 | 208,326 | 165,027 |
| State | 24,779 | 23,787 | 17,904 | 25,677 | 23,217 | 16,620 |
| Total deferred | 226,522 | 245,292 | 185,269 | 240,855 | 231,543 | 181,647 |
| Income tax expense | $ 236,411 | $ 237,720 | $ 220,705 | $ 245,842 | $ 245,841 | $ 237,360 |

On the APS Consolidated Statements of Income, federal and state income taxes are allocated between operating income and other income.

The following chart compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

| | Pinnacle West Consolidated | | | APS Consolidated | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | Year Ended December 31, | | |
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Federal income tax expense at 35% statutory rate | $ 244,278 | $ 242,869 | $ 225,540 | $ 254,617 | $ 250,267 | $ 239,638 |
| Increases (reductions) in tax expense resulting from: | | | | | | |
| State income tax net of federal income tax benefit | 16,311 | 18,265 | 18,149 | 18,750 | 20,433 | 21,148 |
| Credits and favorable adjustments related to prior years resolved in current year | — | (2,169) | — | — | (1,892) | — |
| Medicare Subsidy Part-D | 844 | 837 | 830 | 844 | 837 | 830 |
| Allowance for equity funds used during construction (see Note 1) | (11,724) | (9,711) | (8,523) | (11,724) | (9,711) | (8,523) |
| Palo Verde VIE noncontrolling interest (see Note 18) | (6,823) | (6,626) | (9,135) | (6,823) | (6,626) | (9,135) |
| Investment tax credit amortization | (5,887) | (5,527) | (4,928) | (5,887) | (5,527) | (4,928) |
| Other | (588) | (218) | (1,228) | (3,935) | (1,940) | (1,670) |
| Income tax expense | $ 236,411 | $ 237,720 | $ 220,705 | $ 245,842 | $ 245,841 | $ 237,360 |

On February 17, 2011, Arizona enacted legislation (H.B. 2001) that included a four-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in Arizona. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2016, APS has recorded a regulatory liability of $74 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

On April 4, 2013, New Mexico enacted legislation (H.B. 641) that included a five-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West

has revised the tax rate applicable to reversing temporary items in New Mexico. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2016, APS has recorded a regulatory liability of $2 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

The components of the net deferred income tax liability were as follows (dollars in thousands):

| | Pinnacle West Consolidated | | APS Consolidated | |
|---|---|---|---|---|
| | December 31, | | December 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| DEFERRED TAX ASSETS | | | | |
| Risk management activities | $ 26,614 | $ 70,498 | $ 26,614 | $ 70,498 |
| Regulatory liabilities: | | | | |
| Asset retirement obligation and removal costs | 200,140 | 216,765 | 200,140 | 216,765 |
| Unamortized investment tax credits | 113,195 | 100,779 | 113,195 | 100,779 |
| Other postretirement benefits | 60,375 | 83,034 | 60,375 | 83,034 |
| Other | 63,311 | 60,707 | 63,311 | 60,707 |
| Pension liabilities | 204,436 | 191,028 | 194,981 | 181,787 |
| Renewable energy incentives | 56,379 | 60,956 | 56,379 | 60,956 |
| Credit and loss carryforwards | 75,944 | 59,557 | 1,645 | — |
| Other | 158,421 | 149,033 | 187,453 | 176,016 |
| Total deferred tax assets | 958,815 | 992,357 | 904,093 | 950,542 |
| DEFERRED TAX LIABILITIES | | | | |
| Plant-related | (3,297,989) | (3,116,752) | (3,297,989) | (3,116,752) |
| Risk management activities | (7,594) | (10,626) | (7,594) | (10,626) |
| Other postretirement assets | (63,477) | (71,737) | (62,819) | (70,986) |
| Regulatory assets: | | | | |
| Allowance for equity funds used during construction | (61,088) | (54,110) | (61,088) | (54,110) |
| Deferred fuel and purchased power — mark-to-market | (21,396) | (55,020) | (21,396) | (55,020) |
| Pension benefits | (274,184) | (240,692) | (274,184) | (240,692) |
| Retired power plant costs (see Note 3) | (49,166) | (53,420) | (49,166) | (53,420) |
| Other | (123,987) | (108,441) | (123,987) | (108,441) |
| Other | (5,166) | (4,984) | (5,165) | (4,984) |
| Total deferred tax liabilities | (3,904,047) | (3,715,782) | (3,903,388) | (3,715,031) |
| Deferred income taxes — net | $ (2,945,232) | $ (2,723,425) | $ (2,999,295) | $ (2,764,489) |

As of December 31, 2016, the deferred tax assets for credit and loss carryforwards relate primarily to federal general business credits of approximately $98 million, which first begin to expire in 2031, and other federal and state loss carryforwards of $5 million, which first begin to expire in 2019. The credit and loss carryforwards amount above has been reduced by $27 million of unrecognized tax benefits.

## 5. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2016 and 2015 (dollars in thousands):

| | December 31, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | Pinnacle West | APS | Total | Pinnacle West | APS | Total |
| Commitments under Credit Facilities | $ 275,000 | $1,000,000 | $1,275,000 | $ 200,000 | $1,000,000 | $ 1,200,000 |
| Outstanding Commercial Paper and Revolving Credit Facility Borrowings | (41,700) | (135,500) | (177,200) | — | — | — |
| Amount of Credit Facilities Available | $ 233,300 | $ 864,500 | $1,097,800 | $ 200,000 | $1,000,000 | $ 1,200,000 |
| Weighted-Average Commitment Fees | 0.125% | 0.100% | | 0.125% | 0.100% | |

***Pinnacle West***

On May 13, 2016, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2019, with a new $200 million facility that matures in May 2021. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2016, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $1.7 million commercial paper borrowings.

On August 31, 2016, PNW entered into a $75 million 364-day unsecured revolving credit facility that matures in August 2017. PNW will use the new facility to fund or otherwise support obligations related to 4CA, and borrowings under the facility will bear interest at LIBOR plus 0.80% per annum. At December 31, 2016, Pinnacle West had $40 million outstanding under the facility.

***APS***

During the first quarter of 2016, APS increased its commercial paper program from $250 million to $500 million.

On May 13, 2016, APS replaced its $500 million revolving credit facility that would have matured in May 2019, with a new $500 million facility that matures in May 2021.

At December 31, 2016, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and the $500 million facility that matures in May 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2016, APS had $135.5 million of commercial paper outstanding and no outstanding borrowings or letters of credit

under its revolving credit facilities. See "Financial Assurances" in Note 10 for a discussion of APS's other outstanding letters of credit.

**Debt Provisions**

On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of 7% of APS's capitalization, and $500 million (which is required to be used for costs relating to purchases of natural gas and power). This financing order is set to expire on December 31, 2017. See Note 6 for additional long-term debt provisions.

## 6. Long-Term Debt and Liquidity Matters

All of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2016 and 2015 (dollars in thousands):

| | Maturity Dates (a) | Interest Rates | December 31, 2016 | December 31, 2015 |
|---|---|---|---|---|
| **APS** | | | | |
| Pollution control bonds: | | | | |
| Variable | 2029 | (b) | $ 35,975 | $ 92,405 |
| Fixed | 2024-2029 | 1.75%-4.70% | 147,150 | 211,150 |
| Total pollution control bonds | | | 183,125 | 303,555 |
| Senior unsecured notes | 2019-2046 | 2.20%-8.75% | 3,725,000 | 3,375,000 |
| Term loans | 2018-2019 | (c) | 150,000 | 50,000 |
| Unamortized discount | | | (11,816) | (10,374) |
| Unamortized premium | | | 4,506 | 4,686 |
| Unamortized debt issuance cost | | | (29,030) | (27,896) |
| Total APS long-term debt | | | 4,021,785 | 3,694,971 |
| Less current maturities | | | — | 357,580 |
| Total APS long-term debt less current maturities | | | 4,021,785 | 3,337,391 |
| **Pinnacle West** | | | | |
| Term loan | 2017 | (d) | 125,000 | 125,000 |
| Less current maturities | | | 125,000 | — |
| Total PNW long-term debt less current maturities | | | — | 125,000 |
| **TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES** | | | $ 4,021,785 | $ 3,462,391 |

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 0.81% at December 31, 2016 and 0.01%-0.24% at December 31, 2015.
(c) The weighted-average interest rate was 1.427% at December 31, 2016, and 1.024% at December 31, 2015.
(d) The interest rate was 1.520% at December 31, 2016 and 1.174% at December 31, 2015.

The following table shows principal payments due on Pinnacle West's and APS's total long-term debt (dollars in thousands):

| Year | Consolidated Pinnacle West | Consolidated APS |
|---|---|---|
| 2017 | $ 125,000 | $ — |
| 2018 | 82,000 | 82,000 |
| 2019 | 600,000 | 600,000 |
| 2020 | 250,000 | 250,000 |
| 2021 | — | — |
| Thereafter | 3,126,125 | 3,126,125 |
| Total | $ 4,183,125 | $ 4,058,125 |

## Debt Fair Value

Our long-term debt fair value estimates are based on quoted market prices for the same or similar issues, and are classified within Level 2 of the fair value hierarchy. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

| | As of December 31, 2016 | | As of December 31, 2015 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Pinnacle West | $ 125,000 | $ 125,000 | $ 125,000 | $ 125,000 |
| APS | 4,021,785 | 4,300,789 | 3,694,971 | 3,981,367 |
| Total | $ 4,146,785 | $ 4,425,789 | $ 3,819,971 | $ 4,106,367 |

## Credit Facilities and Debt Issuances

### *APS*

On April 22, 2016, APS entered into a $100 million term loan facility that matures April 22, 2019. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On May 6, 2016, APS issued $350 million of 3.75% unsecured senior notes that mature on May 15, 2046. The net proceeds from the sale were used to redeem and cancel pollution control bonds (see details below), and to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On June 1, 2016, APS redeemed at par and canceled all $64 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series D and E.

On June 1, 2016, APS redeemed at par and canceled all $13 million of the Coconino County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series A.

On August 1, 2016, APS repaid at maturity APS's $250 million aggregate principal amount of 6.25% senior notes due August 1, 2016.

On September 20, 2016, APS issued $250 million of 2.55% unsecured senior notes that mature on September 15, 2026. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used in connection with the payment at maturity of our $250 million aggregate principal amount of 6.25% Notes due August 1, 2016.

On September 20, 2016, APS redeemed at par and canceled all $27 million of the Coconino County Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Navajo Project), 2009 Series B.

On December 6, 2016, APS redeemed at par and canceled all $17 million of the Coconino County Arizona Pollution Control Corporation Revenue Bonds (Arizona Public Service Company Project), Series 1998.

See “Lines of Credit and Short-Term Borrowings” in Note 5 and “Financial Assurances” in Note 10 for discussion of APS’s separate outstanding letters of credit.

**Debt Provisions**

Pinnacle West’s and APS’s debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2016, the ratio was approximately 48% for Pinnacle West and 47% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of “cross-default” provisions below.

Neither Pinnacle West’s nor APS’s financing agreements contain “rating triggers” that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West’s loan agreements contain “cross-default” provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS’s bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2016, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.9 billion, and total capitalization was approximately $9.1 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.6 billion, assuming APS’s total capitalization remains the same. APS was in compliance with this common equity ratio requirement as of December 31, 2016.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017. See Note 5 for additional short-term debt provisions.

## 7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. We calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors other postretirement benefit plans (Pinnacle West Capital Corporation Group Life and Medical Plan and Pinnacle West Capital Corporation Post-65 Retiree Health Reimbursement Arrangement) for the employees of Pinnacle West and its subsidiaries. These plans provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan, which required an interim remeasurement of the benefit obligation for the plan. Effective January 1, 2015, those eligible retirees and dependents over age 65 and on Medicare can choose to be enrolled in a Health Reimbursement Arrangement (HRA). The Company is providing a subsidy allowing post-65 retirees to purchase a Medicare supplement plan on a private exchange network. The remeasurement of the benefit obligation included updating the assumptions. The remeasurement reduced net periodic benefit costs in 2014 by $10 million ($5 million of which reduced expense). The remeasurement also resulted in a decrease in Pinnacle West's other postretirement benefit obligation of $316 million, which was offset by the related regulatory asset and accumulated other comprehensive income.

Because of the plan changes, the Company is currently in the process of seeking IRS approval to move up to $140 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to move into a new account to pay for active union employee medical costs. As of December 31, 2016, such methodology would result in an amount of approximately $140 million being transferred to the new account.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 13 for further discussion of how fair values are determined. Due to subjective and complex judgments, which

may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. In its 2009 retail rate case settlement, APS received approval to defer a portion of pension and other postretirement benefit cost increases incurred in 2011 and 2012. We deferred pension and other postretirement benefit costs of approximately $14 million in 2012 and $11 million in 2011. Pursuant to an ACC regulatory order, we began amortizing the regulatory asset over three years beginning in July 2012. We amortized approximately $5 million in 2015, $8 million in 2014, $8 million in 2013 and $4 million in 2012.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction, billed to electric plant participants or charged to the regulatory asset or liability) (dollars in thousands):

| | Pension | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Service cost-benefits earned during the period | $ 53,792 | $ 59,627 | $ 53,080 | $ 14,993 | $ 16,827 | $ 18,139 |
| Interest cost on benefit obligation | 131,647 | 123,983 | 129,194 | 29,721 | 28,102 | 41,243 |
| Expected return on plan assets | (173,906) | (179,231) | (158,998) | (36,495) | (36,855) | (46,400) |
| Amortization of: | | | | | | |
| Prior service cost (credit) | 527 | 594 | 869 | (37,883) | (37,968) | (9,626) |
| Net actuarial loss | 40,717 | 31,056 | 10,963 | 4,589 | 4,881 | 1,175 |
| Net periodic benefit cost | $ 52,777 | $ 36,029 | $ 35,108 | $ (25,075) | $ (25,013) | $ 4,531 |
| Portion of cost charged to expense | $ 26,172 | $ 20,036 | $ 21,985 | $ (12,435) | $ (10,391) | $ 6,000 |

The following table shows the plans' changes in the benefit obligations and funded status for the years 2016 and 2015 (dollars in thousands):

| | Pension | | Other Benefits | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| **Change in Benefit Obligation** | | | | |
| Benefit obligation at January 1 | $ 3,033,803 | $ 3,078,648 | $ 647,020 | $ 682,335 |
| Service cost | 53,792 | 59,627 | 14,993 | 16,827 |
| Interest cost | 131,647 | 123,983 | 29,721 | 28,102 |
| Benefit payments | (142,247) | (137,115) | (26,231) | (24,988) |
| Actuarial (gain) loss | 127,467 | (91,340) | 50,942 | (55,256) |
| Benefit obligation at December 31 | 3,204,462 | 3,033,803 | 716,445 | 647,020 |
| **Change in Plan Assets** | | | | |
| Fair value of plan assets at January 1 | 2,542,774 | 2,615,404 | 833,017 | 834,625 |
| Actual return on plan assets | 166,408 | (44,690) | 63,463 | (2,399) |
| Employer contributions | 100,000 | 100,000 | 819 | 791 |
| Benefit payments | (133,825) | (127,940) | (14,648) | — |
| Fair value of plan assets at December 31 | 2,675,357 | 2,542,774 | 882,651 | 833,017 |
| **Funded Status at December 31** | $ (529,105) | $ (491,029) | $ 166,206 | $ 185,997 |

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans with an accumulated obligation in excess of plan assets as of December 31, 2016 and 2015 (dollars in thousands):

| | 2016 | 2015 |
|---|---|---|
| Projected benefit obligation | $ 3,204,462 | $ 3,033,803 |
| Accumulated benefit obligation | 3,049,406 | 2,873,467 |
| Fair value of plan assets | 2,675,357 | 2,542,774 |

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2016 and 2015 (dollars in thousands):

| | Pension | | Other Benefits | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Noncurrent asset | $ — | $ — | $ 166,206 | $ 185,997 |
| Current liability | (19,795) | (10,031) | — | — |
| Noncurrent liability | (509,310) | (480,998) | — | — |
| Net amount recognized | $ (529,105) | $ (491,029) | $ 166,206 | $ 185,997 |

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2016 and 2015 (dollars in thousands):

| | Pension | | Other Benefits | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Net actuarial loss | $ 773,750 | $ 679,501 | $ 146,509 | $ 127,124 |
| Prior service cost (credit) | 81 | 609 | (303,417) | (341,301) |
| APS's portion recorded as a regulatory (asset) liability | (711,059) | (619,223) | 156,575 | 213,621 |
| Income tax expense (benefit) | (24,202) | (23,663) | 833 | 925 |
| Accumulated other comprehensive loss | $ 38,570 | $ 37,224 | $ 500 | $ 369 |

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets and liabilities into net periodic benefit cost in 2017 (dollars in thousands):

| | Pension | Other Benefits |
|---|---|---|
| Net actuarial loss | $ 46,971 | $ 5,181 |
| Prior service cost (credit) | 81 | (37,842) |
| Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2017 | $ 47,052 | $ (32,661) |

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

| | Benefit Obligations As of December 31, | | Benefit Costs For the Years Ended December 31, | | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 | 2014 | |
| | | | | | January - September | October - December |
| Discount rate – pension | 4.08% | 4.37% | 4.37% | 4.02% | 4.88% | 4.88% |
| Discount rate – other benefits | 4.17% | 4.52% | 4.52% | 4.14% | 5.10% | 4.41% |
| Rate of compensation increase | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Expected long-term return on plan assets - pension | N/A | N/A | 6.90% | 6.90% | 6.90% | 6.90% |
| Expected long-term return on plan assets - other benefits | N/A | N/A | 4.45% | 4.45% | 6.80% | 4.25% |
| Initial healthcare cost trend rate (pre-65 participants) | 7.00% | 7.00% | 7.00% | 7.00% | 7.50% | 7.50% |
| Initial healthcare cost trend rate (post-65 participants) | 5.00% | 5.00% | 5.00% | 5.00% | 7.50% | 5.00% |
| Ultimate healthcare cost trend rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Number of years to ultimate trend rate (pre-65 participants) | 4 | 4 | 4 | 4 | 4 | 4 |
| Number of years to ultimate trend rate (post-65 participants) | 0 | 0 | 0 | 0 | 4 | 0 |

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. For 2017, we are assuming a 6.55% long-term rate of return for pension assets and 6.37% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final reports on its recommended mortality basis ("RP-2014 Mortality Tables Report" and "Mortality Improvement Scale MP-2014 Report"). At December 31, 2014, we updated our mortality assumptions using the recommended basis with modifications to better reflect our plan experience and additional data regarding mortality trends. The updated mortality assumptions resulted in a $67 million increase in Pinnacle West's pension and other postretirement obligations, which was offset by the related regulatory asset, regulatory liability and accumulated other comprehensive income.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs. A one percentage point change in the assumed initial and ultimate healthcare cost trend rates would have the following effects (dollars in thousands):

| | 1% Increase | 1% Decrease |
|---|---|---|
| Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants | $ 8,430 | $ (5,455) |
| Effect on service and interest cost components of net periodic other postretirement benefit costs | 8,440 | (6,527) |
| Effect on the accumulated other postretirement benefit obligation | 108,046 | (86,651) |

**Plan Assets**

The Board of Directors has delegated oversight of the pension and other postretirement benefit plans' assets to an Investment Management Committee ("Committee"). The Committee has adopted investment policy statements ("IPS") for the pension and the other postretirement benefit plans' assets. The investment strategies for these plans include external management of plan assets, and prohibition of investments in Pinnacle West securities.

The overall strategy of the pension plan's IPS is to achieve an adequate level of trust assets relative to the benefit obligations. To achieve this objective, the plan's investment policy provides for mixes of investments including long-term fixed income assets and return-generating assets. The target allocation between return-generating and long-term fixed income assets is defined in the IPS and is a function of the plan's funded status. The plan's funded status is reviewed on at least a monthly basis.

Changes in the value of long-term fixed income assets, also known as liability-hedging assets, are intended to offset changes in the benefit obligations due to changes in interest rates. Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury and other government agencies, U.S Treasury Futures Contracts, and fixed income debt securities issued by corporations. Long-term fixed income assets may also include interest rate swaps, and other instruments.

Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments include investments in real estate, private equity and various other strategies. The plan may also hold investments in return-generating assets by holding securities in partnerships, common and collective trusts and mutual funds.

Based on the IPS, and given the pension plan's funded status at year-end 2016, the long-term fixed income assets had a target allocation of 58% with a permissible range of 55% to 61% and the return-generating assets had a target allocation of 42% with a permissible range of 39% to 45%. The return-generating assets have additional target allocations, as a percent of total plan assets, of 22% equities in U.S. and other developed markets, 6% equities in emerging markets, and 14% in alternative investments. The pension plan IPS does not provide for a specific mix of long-term fixed income assets, but does expect the average credit quality of such assets to be investment grade. As of December 31, 2016, long-term fixed income assets represented 57% of total pension plan assets, and return-generating assets represented 43% of total pension plan assets.

As of December 31, 2016, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. Some of these asset allocation target mixes vary with the plan's funded status. As of December 31, 2016, investment in fixed income assets represented 51% of the other postretirement benefit plan total assets, and non-fixed income assets represented 49% of the other postretirement benefit plan's assets.

See Note 13 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income, U.S Treasury Futures Contracts, and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades, and are classified as Level 1. U.S Treasury Future Contracts are valued using the quoted active market prices from the exchange

on which they trade, and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices, and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity and credit quality. These instruments are classified as Level 2.

Mutual funds, partnerships, and common and collective trusts are valued utilizing a net asset value (NAV) concept or its equivalent. Mutual funds, classified as Level 1, are valued using a NAV that is observable and based on the active market in which the fund trades.

Common and collective trusts, are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives (such as tracking the performance of the S&P 500 Index). The trust's shares are offered to a limited group of investors, and are not traded in an active market. Investments in common and collective trusts are valued using NAV, as a practical expedient and accordingly are not classified in the fair value hierarchy. The NAV for trusts investing in exchange traded equities is derived from the quoted active market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2016, the plans were able to transact in the common and collective trusts at NAV.

Investments in partnerships are also valued using the concept of NAV, as a practical expedient and accordingly are not classified in the fair value hierarchy. The NAV for these investments is derived from the value of the partnerships' underlying assets. The plan's partnerships holdings relate to investments in high-yield fixed income instruments and assets of privately held portfolio companies. Certain partnerships also include funding commitments that may require the plan to contribute up to $75 million to these partnerships; as of December 31, 2016, approximately $54 million of these commitments have been funded.

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2016, by asset category, are as follows (dollars in thousands):

| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Other (a) | Balance at December 31, 2016 |
|---|---|---|---|---|
| **Pension Plan:** | | | | |
| Cash and cash equivalents | $ 13,995 | $ — | $ — | $ 13,995 |
| Fixed income securities: | | | | |
| Corporate | — | 1,210,453 | — | 1,210,453 |
| U.S. Treasury | 112,583 | — | — | 112,583 |
| Other (b) | — | 102,170 | — | 102,170 |
| Common stock equities (c) | 235,109 | — | — | 235,109 |
| Mutual funds (d) | 251,506 | — | — | 251,506 |
| Common and collective trusts: | | | | |
| Equities | — | — | 266,840 | 266,840 |
| Real estate | — | — | 161,449 | 161,449 |
| Partnerships | — | — | 208,915 | 208,915 |
| Short-term investments and other (e) | — | — | 112,337 | 112,337 |
| Total | $ 613,193 | $ 1,312,623 | $ 749,541 | $ 2,675,357 |
| **Other Benefits:** | | | | |
| Cash and cash equivalents | $ 304 | $ — | $ — | $ 304 |
| Fixed income securities: | | | | |
| Corporate | — | 268,193 | — | 268,193 |
| U.S. Treasury | 145,255 | — | — | 145,255 |
| Other (b) | — | 34,506 | — | 34,506 |
| Common stock equities (c) | 243,741 | — | — | 243,741 |
| Mutual funds (d) | 67,418 | — | — | 67,418 |
| Common and collective trusts: | | | | |
| Equities | — | — | 95,814 | 95,814 |
| Real estate | — | — | 14,509 | 14,509 |
| Partnerships | — | — | 3,060 | 3,060 |
| Short-term investments and other (e) | — | — | 9,851 | 9,851 |
| Total | $ 456,718 | $ 302,699 | $ 123,234 | $ 882,651 |

(a) These investments primarily represent assets valued using net asset value as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities.
(c) This category primarily consists of US common stock equities.
(d) These funds invest in US and international common stock equities.
(e) This category includes plan receivables and payables.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2015, by asset category, are as follows (dollars in thousands):

| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Other (a) | Balance at December 31, 2015 |
|---|---|---|---|---|
| **Pension Plan:** | | | | |
| Cash and cash equivalents | $ 1,893 | $ — | $ — | $ 1,893 |
| Fixed Income Securities: | | | | |
| Corporate | — | 1,108,736 | — | 1,108,736 |
| U.S. Treasury | 274,778 | — | — | 274,778 |
| Other (b) | — | 113,008 | — | 113,008 |
| Common stock equities (c) | 247,701 | — | — | 247,701 |
| Mutual funds - International equities | 116,307 | — | — | 116,307 |
| Common and collective trusts: | | | | |
| Equities | — | — | 315,989 | 315,989 |
| Real Estate | — | — | 150,359 | 150,359 |
| Partnerships | — | — | 169,937 | 169,937 |
| Short-term investments and other (d) | — | — | 44,066 | 44,066 |
| Total | $ 640,679 | $ 1,221,744 | $ 680,351 | $ 2,542,774 |
| **Other Benefits:** | | | | |
| Cash and cash equivalents | $ 240 | $ — | $ — | $ 240 |
| Fixed Income Securities: | | | | |
| Corporate | — | 217,026 | — | 217,026 |
| U.S. Treasury | 131,435 | — | — | 131,435 |
| Other (b) | — | 31,106 | — | 31,106 |
| Common stock equities (c) | 265,583 | — | — | 265,583 |
| Mutual funds - International equities | 52,568 | — | — | 52,568 |
| Common and collective trusts: | | | | |
| Equities | — | — | 110,055 | 110,055 |
| Real Estate | — | — | 13,512 | 13,512 |
| Short-term investments and other (d) | — | — | 11,492 | 11,492 |
| Total | $ 449,826 | $ 248,132 | $ 135,059 | $ 833,017 |

(a) These investments primarily represent assets valued using net asset value as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities.
(c) This category primarily consists of US common stock equities.
(d) This category includes plan receivables and payables.

## Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $100 million in 2016, $100 million in 2015, and $175 million in 2014. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2017-2019 period. With regard to contributions to our other postretirement benefit plans, we made a contribution of

approximately $1 million in each of 2016, 2015 and 2014. We expect to make contributions of less than $1 million in total for the next three years to our other postretirement benefit plans. APS funds its share of the contributions. APS's share of the pension plan contribution was approximately $100 million in 2016, $100 million in 2015 and $175 million in 2014. APS's share of the contributions to the other postretirement benefit plan was approximately $1 million in 2016, 2015 and 2014.

**Estimated Future Benefit Payments**

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

| Year | Pension | Other Benefits |
|---|---|---|
| 2017 | $ 172,859 | $ 31,126 |
| 2018 | 173,232 | 33,795 |
| 2019 | 182,944 | 36,195 |
| 2020 | 191,037 | 37,998 |
| 2021 | 196,292 | 39,368 |
| Years 2022-2026 | 1,049,149 | 201,944 |

Electric plant participants contribute to the above amounts in accordance with their respective participation agreements.

**Employee Savings Plan Benefits**

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2016, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own future contributions. Pinnacle West recorded expenses for this plan of approximately $10 million for 2016, $9 million for 2015, and $9 million for 2014.

## 8. Leases

We lease certain vehicles, land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates. See Note 2 for a discussion of the new lease accounting standard.

Total lease expense recognized in the Consolidated Statements of Income was $16 million in 2016, $17 million in 2015, and $18 million in 2014. APS's lease expense was $15 million in 2016, $14 million in 2015, and $15 million in 2014.

Estimated future minimum lease payments for Pinnacle West's and APS's operating leases, excluding purchased power agreements, are approximately as follows (dollars in thousands):

| Year | Pinnacle West Consolidated | APS |
|---|---|---|
| 2017 | $ 12,330 | $ 11,919 |
| 2018 | 10,987 | 10,690 |
| 2019 | 9,019 | 8,767 |
| 2020 | 7,688 | 7,439 |
| 2021 | 5,266 | 5,020 |
| Thereafter | 59,647 | 57,207 |
| Total future lease commitments | $ 104,937 | $ 101,042 |

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 18 for a discussion of VIEs.

## 9. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our Consolidated Statements of Income. We are also responsible for providing our own financing. Our share of operating expenses and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2016 (dollars in thousands):

| | Percent Owned | | Plant in Service | Accumulated Depreciation | Construction Work in Progress | |
|---|---|---|---|---|---|---|
| Generating facilities: | | | | | | |
| Palo Verde Units 1 and 3 | 29.1% | | $1,770,324 | $1,080,072 | $ 17,615 | |
| Palo Verde Unit 2 (a) | 16.8% | | 581,572 | 360,757 | 9,717 | |
| Palo Verde Common | 28.0% | (b) | 672,799 | 242,649 | 62,479 | |
| Palo Verde Sale Leaseback | | (a) | 351,050 | 237,535 | — | |
| Four Corners Generating Station | 63.0% | | 934,837 | 578,924 | 248,072 | |
| Navajo Generating Station Units 1, 2 and 3 | 14.0% | | 279,629 | 176,931 | 5,761 | |
| Cholla common facilities (c) | 63.3% | (b) | 159,707 | 58,276 | 806 | (d) |
| Transmission facilities: | | | | | | |
| ANPP 500kV System | 33.6% | (b) | 127,970 | 38,610 | 2,291 | |
| Navajo Southern System | 22.5% | (b) | 62,135 | 20,491 | 334 | |
| Palo Verde — Yuma 500kV System | 19.0% | (b) | 13,699 | 5,368 | 408 | |
| Four Corners Switchyards | 51.3% | (b) | 39,850 | 10,474 | 1,044 | |
| Phoenix — Mead System | 17.1% | (b) | 39,330 | 13,725 | 85 | |
| Palo Verde — Rudd 500kV System | 50.0% | (b) | 91,904 | 19,818 | 227 | |
| Morgan — Pinnacle Peak System | 65.2% | (b) | 140,374 | 13,557 | — | |
| Round Valley System | 50.0% | (b) | 515 | 127 | — | |
| Palo Verde — Morgan System | 85.8% | (b) | 125,908 | 1,326 | 28,949 | |
| Hassayampa — North Gila System | 80.0% | (b) | 142,541 | 3,231 | — | |
| Cholla 500kV Switchyard | 85.7% | (b) | 5,078 | 1,201 | — | |
| Saguaro 500kV Switchyard | 75.0% | (b) | 20,456 | 12,426 | 2 | |

(a) See Note 18.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.
(d) Due to the closure of Cholla Unit 2 in 2015, all new Cholla common facilities construction is owned by APS at 50.5%

4CA is a subsidiary that was formed in 2016 as a result of the purchase of El Paso's 7% interest in Four Corners. At December 31, 2016, 4CA had plant in service of $110 million, accumulated depreciation of $79 million and construction work in progress of $30 million.

## 10. Commitments and Contingencies

### Palo Verde Nuclear Generating Station

#### Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the Court of Federal Claims. The lawsuit sought to recover damages incurred due to DOE's breach of the Standard Contract for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which has been extended to December 31, 2019.

APS has submitted two claims pursuant to the terms of the August 18, 2014 settlement agreement, for two separate time periods during July 1, 2011 through June 30, 2015. The DOE has approved and paid $53.9 million for these claims (APS's share is $15.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE on October 31, 2016, and approved on February 1, 2017, in the amount of $11.3 million (APS's share is $3.3 million). Payment for the claim is expected in the second quarter of 2017.

#### Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $13.4 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million (on January 1, 2017 this coverage was increased to $450 million), which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.1 billion (on January 1, 2017 this balance was decreased to $13.0 billion) of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to a maximum annual premium of $18.9 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $111.1 million, with a maximum annual retrospective premium of approximately $16.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited

("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $23.8 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $64 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

**Fuel and Purchased Power Commitments and Purchase Obligations**

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2017 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $977 million in 2017; $737 million in 2018; $598 million in 2019; $525 million in 2020; $524 million in 2021; and $7.3 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter |
| Coal take-or-pay commitments (a) | $ 195,428 | $ 189,588 | $ 193,818 | $ 198,160 | $ 202,619 | $ 2,068,355 |

(a) Total take-or-pay commitments are approximately $3.0 billion. The total net present value of these commitments is approximately $2.1 billion.

APS may spend more to meet its actual fuel requirements than the minimum purchase obligations in our coal take-or-pay contracts. The following table summarizes actual amounts purchased under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Total purchases | $ 160,066 | $ 211,327 | $ 236,773 |

**Renewable Energy Credits**

APS has entered into contracts to purchase renewable energy credits to comply with the RES. APS estimates the contract requirements to be approximately $40 million in 2017; $40 million in 2018; $40 million in 2019; $40 million in 2020; $40 million in 2021; and $420 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

**Coal Mine Reclamation Obligations**

APS and 4CA must reimburse certain coal providers for amounts incurred for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $207 million at December 31, 2016 and $202 million at December 31, 2015. 4CA recorded an obligation for the coal mine final reclamation of approximately $15 million at December 31, 2016. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $17 million in 2017; $18 million in 2018; $19 million in 2019; $21 million in 2020; $22 million in 2021; and $241 million thereafter. 4CA expects to make payments for the final mine reclamation as follows: $1 million in 2017; $1 million in 2018; $1 million in 2019; $1 million in 2020; $2 million in 2021; and $17 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

**Superfund-Related Matters**

Superfund establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, OU3 in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater RI/FS work plan. The OU3 working group parties have agreed to a schedule with EPA that calls for the submission of a revised draft RI/FS by June 2017. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, RID filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID contractors filed ancillary lawsuits for recovery of costs against APS and the other defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

**Southwest Power Outage**

On September 8, 2011 at approximately 3:30 PM, a 500 kV transmission line running between the Hassayampa and North Gila substations in southwestern Arizona tripped out of service due to a fault that

occurred at a switchyard operated by APS. Approximately ten minutes after the transmission line went off-line, generation and transmission resources for the Yuma area were lost, resulting in approximately 69,700 APS customers losing service.

On September 6, 2013, a purported consumer class action complaint was filed in Federal District Court in San Diego, California, naming APS and Pinnacle West as defendants and seeking damages for loss of perishable inventory and sales as a result of interruption of electrical service. APS and Pinnacle West filed a motion to dismiss, which the court granted on December 9, 2013. On January 13, 2014, the plaintiffs appealed the lower court's decision. On March 2, 2016, the United States Court of Appeals for the Ninth Circuit unanimously affirmed the District Court's decision. The plaintiffs filed a Petition for Rehearing En Banc, which was denied on April 11, 2016.

**Environmental Matters**

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

***Regional Haze Rules.*** APS has received the final rulemaking imposing new requirements on Four Corners and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants. EPA recently approved a proposed rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the recent Cholla rule approval.

*Four Corners.* Based on EPA's final standards, APS estimates that its 63% share of the cost of required controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

*Navajo Plant.* APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process. See "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

*Cholla.* APS believes that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly,

on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy. Pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015.

On October 16, 2015, ADEQ issued a revised operating permit for Cholla, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. On June 30, 2016, EPA issued a proposed rule approving a revision to the Arizona SIP that incorporates APS's compromise approach for compliance with the Regional Haze program. EPA signed the final rule approving the Agency's proposal on January 13, 2017. Once the final rule is published in the Federal Register, parties have 60 days to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict at this time whether such petitions will be filed or if they will be successful. In addition, under the terms of an executive memorandum issued on January 20, 2017, this final rule will not be published in the Federal Register until after it has been reviewed by an appointee of the President. We cannot predict when such review will occur and what may result from the additional review.

***Mercury and Air Toxic Standards ("MATS").*** In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla. No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million, the majority of which has already been incurred. Litigation concerning the rules, including supplemental analyses EPA has prepared in support of the MATS regulation, is ongoing. These proceedings do not materially impact APS. Regardless of the results from further judicial or administrative proceedings concerning the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

***Coal Combustion Waste.*** On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will

continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

On December 16, 2016, President Obama signed the WIIN Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds. Because EPA has yet to undertake rulemaking proceedings to implement the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects the CCR provisions of the WIIN Act will have on APS's management of CCR.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million. APS is currently evaluating compliance alternatives for Cholla and estimates that its share of incremental costs to comply with the CCR rule for this plant is in the range of $5 million to $40 million based upon which compliance alternatives are ultimately selected. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million, the majority of which has already been incurred. Additionally, the CCR rule requires ongoing groundwater monitoring. Depending upon the results of such monitoring at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions, the costs of which we are unable to reasonably estimate at this time.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA's CCR regulations, within the next 3 years EPA is required to complete a rulemaking proceeding concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA's CCR rules. EPA is not required to take final action approving the inclusion of boron, but EPA must propose and consider its inclusion. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time, though, APS cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

***Clean Power Plan.*** On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed EGUs. EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet $CO_2$ performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in $CO_2$ emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard

that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, this timing will be impacted by the court-imposed stay described below.

Prior to the court-imposed stay described below, ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, was working to develop a compliance plan for submittal to EPA. Since the imposition of the stay, ADEQ is continuing to assess alternatives while completing outreach and soliciting feedback from stakeholders. In addition to these ongoing state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such a delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of

allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output or potential plant closures, as alternatives to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains ongoing, and additional information or considerations may arise that change our expectations.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

**Federal Agency Environmental Lawsuit Related to Four Corners**

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

**New Mexico Tax Matter**

On May 23, 2013, the New Mexico Taxation and Revenue Department ("NMTRD") issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). APS's share of the Assessment is approximately $12 million. For procedural reasons, on behalf of the Four Corners co-owners, including APS, the coal supplier made a partial payment of the Assessment in the amount of $0.8 million and immediately filed a refund claim with respect to that partial payment in August 2013. The NMTRD denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed a complaint with the New Mexico District Court contesting both the validity of the Assessment and the refund claim denial. On June 30, 2015, the court ruled that the Assessment was not valid and further ruled that APS and the other Four Corners co-owners receive a refund of all of the contested amounts previously paid under the applicable tax statute. The NMTRD filed an appeal of the decision on August 31, 2015.

On March 16, 2016, APS and the coal supplier entered into a final settlement agreement with the NMTRD with respect to the Assessment. Pursuant to the final settlement agreement, the NMTRD agreed to release the Assessment, dismiss its filed appeal, and release its rights to any other surtax claims with respect to the coal supply agreement. APS and the other Four Corners co-owners agreed to forgo refund rights with respect to all of the contested amounts previously paid under the applicable tax statute, as well as pay $1 million. APS's share of this settlement payment, together with its share of the partial payment described above, is approximately $0.8 million.

**Peabody Bankruptcy**

On April 13, 2016, Peabody Energy Corporation and certain affiliated entities filed a petition for relief under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Missouri. Under a Coal Supply Agreement, dated December 21, 2005, Peabody supplied coal to APS and PacifiCorp (collectively, the "Buyers") for use at the Cholla power plant in Arizona. APS believes that the Coal Supply Agreement terminated automatically on April 13, 2016 as a result of Peabody's bankruptcy filing. The Buyers filed a motion requesting that the Bankruptcy Court enter an order determining that the Buyers are authorized to enforce the termination provisions in the Coal Supply Agreement.

On May 13, 2016, Peabody filed a complaint against the Buyers in the bankruptcy court in which Peabody alleged that the Buyers breached the Agreement. On January 27, 2017, the bankruptcy court approved a settlement between the parties, and on February 6, 2017 the parties executed an amendment to the Coal Supply Agreement that allows for continuation of the agreement with modified terms and conditions acceptable to the parties.

**Financial Assurances**

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain commodity contract collateral obligations and other transactions. As of December 31, 2016, standby letters of credit totaled $35 million and will expire in 2017. As of December 31, 2016, surety bonds expiring through 2019 totaled $53 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. 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. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at December 31, 2016. Effective July 6, 2016, Pinnacle West has issued two parental guarantees for 4CA relating to payment obligations arising from 4CA's acquisition of El Paso's 7% interest in Four Corners, and pursuant to the Four Corners participation agreement payment obligations arising from 4CA's ownership interest in Four Corners.

## 11. Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation assets.

The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such transmission and distribution assets. Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites.

In 2016, APS recognized an ARO for the Ocotillo steam units as a condition of the air permit (issued in 2016) to allow the construction and operation of five new turbine units. This resulted in an increase to the ARO in the amount of $10 million. In addition, 4CA acquired El Paso's share of Four Corners Units 4 & 5 and the associated ARO. This resulted in an increase to the ARO in the amount of $9 million. In addition, Four Corners spent $16 million in actual decommissioning costs. Finally, in 2016, APS received a new decommissioning study for the Palo Verde Nuclear Generating Station. This resulted in an increase to the ARO in the amount of $151 million, an increase in plant in service of $131 million, and a reduction of the regulatory liability of $20 million.

In 2015, a revision to the estimated cash flows for the decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the ARO in the amount of $24 million. Also in 2015, Four Corners spent $32 million in actual decommissioning costs. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 10 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million. Finally, in 2015 there was a revision in estimated cash flows for the Cholla decommissioning, which resulted in a decrease of the ARO in the amount of $3 million.

The following table shows the change in our asset retirement obligations for 2016 and 2015 (dollars in thousands):

| | 2016 | 2015 |
|---|---|---|
| Asset retirement obligations at the beginning of year | $ 443,576 | $ 390,750 |
| Changes attributable to: | | |
| Accretion expense | 26,656 | 25,163 |
| Settlements | (15,732) | (32,048) |
| Estimated cash flow revisions | 151,046 | 17,556 |
| Newly incurred or acquired obligations | 18,929 | 42,155 |
| Asset retirement obligations at the end of year | $ 624,475 | $ 443,576 |

Decommissioning activities for Four Corners Units 1-3 began in January 2014. Thus, $9 million of the total ARO of $624 million at December 31, 2016, is classified as a current liability on the balance sheet. At December 31, 2015, $29 million of the total ARO of $444 million was classified as a current liability on the balance sheet.

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

## 12. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2016 and 2015 is provided in the tables below (dollars in thousands, except per share amounts). Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

| | 2016 Quarter Ended | | | | 2016 |
|---|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, | Total |
| Operating revenues | $ 677,167 | $ 915,394 | $ 1,166,922 | $ 739,199 | $ 3,498,682 |
| Operations and maintenance | 243,195 | 242,279 | 217,568 | 208,277 | 911,319 |
| Operating income | 50,162 | 231,748 | 451,258 | 122,816 | 855,984 |
| Income taxes | 1,914 | 65,742 | 141,446 | 27,309 | 236,411 |
| Net income | 9,326 | 126,182 | 267,900 | 58,119 | 461,527 |
| Net income attributable to common shareholders | 4,453 | 121,308 | 263,027 | 53,246 | 442,034 |
| | | | | | |
| **Earnings Per Share:** | | | | | |
| Net income attributable to common shareholders — Basic | $ 0.04 | $ 1.09 | $ 2.36 | $ 0.48 | $ 3.97 |
| Net income attributable to common shareholders — Diluted | 0.04 | 1.08 | 2.35 | 0.47 | 3.95 |

| | 2015 Quarter Ended | | | | 2015 |
|---|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, | Total |
| Operating revenues | $ 671,219 | $ 890,648 | $ 1,199,146 | $ 734,430 | $ 3,495,443 |
| Operations and maintenance | 214,944 | 210,965 | 220,449 | 222,019 | 868,377 |
| Operating income | 67,684 | 231,973 | 445,111 | 109,834 | 854,602 |
| Income taxes | 7,947 | 67,371 | 139,555 | 22,847 | 237,720 |
| Net income | 20,727 | 127,507 | 261,978 | 45,978 | 456,190 |
| Net income attributable to common shareholders | 16,122 | 122,902 | 257,116 | 41,117 | 437,257 |
| | | | | | |
| **Earnings Per Share:** | | | | | |
| Net income attributable to common shareholders — Basic | $ 0.15 | $ 1.11 | $ 2.32 | $ 0.37 | $ 3.94 |
| Net income attributable to common shareholders — Diluted | 0.14 | 1.10 | 2.30 | 0.37 | 3.92 |

**Selected Quarterly Financial Data (Unaudited) - APS**

APS's quarterly financial information for 2016 and 2015 is as follows (dollars in thousands):

| | 2016 Quarter Ended, | | | | 2016 |
|---|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, | Total |
| Operating revenues | $ 676,632 | $ 909,757 | $ 1,166,359 | $ 737,006 | $ 3,489,754 |
| Operations and maintenance | 238,711 | 233,712 | 209,366 | 197,319 | 879,108 |
| Operating income | 48,930 | 165,684 | 307,601 | 95,765 | 617,980 |
| Net income attributable to common shareholder | 7,253 | 127,188 | 269,220 | 58,480 | 462,141 |

| | 2015 Quarter Ended, | | | | 2015 |
|---|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, | Total |
| Operating revenues | $ 670,668 | $ 889,723 | $ 1,198,380 | $ 733,586 | $ 3,492,357 |
| Operations and maintenance | 209,947 | 208,031 | 216,011 | 219,146 | 853,135 |
| Operating income | 61,333 | 162,704 | 301,238 | 86,709 | 611,984 |
| Net income attributable to common shareholder | 19,868 | 125,362 | 261,187 | 43,857 | 450,274 |

## 13. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes exchange traded equities, exchange traded derivative instruments, exchange traded mutual funds, cash equivalents, and investments in U.S. Treasury securities.

Level 2 — Utilizes quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable (such as yield curves). This category includes non-exchange traded contracts such as forwards, options, swaps and certain investments in fixed income securities.

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs

may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value ("NAV"), as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, they are not traded on an exchange. During the first quarter of 2016 we retrospectively adopted new accounting guidance that requires certain instruments valued using NAV to no longer be classified within the fair value hierarchy. As such, certain instruments valued using NAV are included in our fair value disclosures and tables in a separate column; however, these investments are not classified within any of the fair value hierarchy levels. Prior to the adoption of this guidance these instruments were typically reported within Level 2 or Level 3. The adoption of this guidance changes our fair value disclosures, but does not impact the methodology for valuing these instruments, or our financial statement results.

**Recurring Fair Value Measurements**

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust, plan assets held in our retirement and other benefit plans and coal reclamation trust investments. See Note 7 for the fair value discussion of plan assets held in our retirement and other benefit plans.

***Cash Equivalents***

Cash equivalents represent short-term investments with original maturities of three months or less in exchange traded money market funds that are valued using quoted prices in active markets.

***Coal Reclamation Trust Investments***

The coal reclamation trust holds cash equivalent investments in money market funds that are valued using quoted prices in active markets, and are reported within Level 1.

***Risk Management Activities — Derivative Instruments***

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

Option contracts are primarily valued using a Black-Scholes option valuation model, which utilizes both observable and unobservable inputs such as broker quotes, interest rates and price volatilities.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions and the use of option valuation models with significant unobservable inputs.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

***Investments Held in our Nuclear Decommissioning Trust***

The nuclear decommissioning trust invests in fixed income securities and equity securities. Equity securities are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

Cash equivalents reported within Level 1 represent investments held in a short-term investment exchange-traded mutual fund, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper.

Fixed income securities issued by the U.S. Treasury held directly by the nuclear decommissioning trust are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 19 for additional discussion about our nuclear decommissioning trust.

***Fair Value Tables***

The following table presents the fair value at December 31, 2016 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (a) (Level 3) | Other | | Balance at December 31, 2016 |
|---|---|---|---|---|---|---|
| Assets | | | | | | |
| Coal reclamation trust - cash equivalents (b) | $ 14,521 | $ — | $ — | $ — | | $ 14,521 |
| Risk management activities — derivative instruments: | | | | | | |
| Commodity contracts | — | 43,722 | 11,076 | (35,103) | (c) | 19,695 |
| Nuclear decommissioning trust: | | | | | | |
| U.S. commingled equity funds | — | — | — | 353,261 | (d) | 353,261 |
| Fixed income securities: | | | | | | |
| Cash and cash equivalent funds | — | — | — | 795 | (e) | 795 |
| U.S. Treasury | 95,441 | — | — | — | | 95,441 |
| Corporate debt | — | 111,623 | — | — | | 111,623 |
| Mortgage-backed securities | — | 115,337 | — | — | | 115,337 |
| Municipal bonds | — | 80,997 | — | — | | 80,997 |
| Other | — | 22,132 | — | — | | 22,132 |
| Subtotal nuclear decommissioning trust | 95,441 | 330,089 | — | 354,056 | | 779,586 |
| Total | $ 109,962 | $ 373,811 | $ 11,076 | $ 318,953 | | $ 813,802 |
| Liabilities | | | | | | |
| Risk management activities — derivative instruments: | | | | | | |
| Commodity contracts | $ — | $ (45,641) | $ (58,482) | $ 31,049 | (c) | $ (73,074) |

(a) Primarily consists of long-dated electricity contracts.
(b) Represents investments restricted for coal mine reclamation funding related to Four Corners. These assets are included in the Other Assets line item, reported under the Investments and Other Assets section of our Consolidated Balance Sheets.
(c) Represents counterparty netting, margin and collateral. See Note 16.
(d) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(e) Represents nuclear decommissioning trust net pending securities sales and purchases.

The following table presents the fair value at December 31, 2015 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (a) (Level 3) | Other | | Balance at December 31, 2015 |
|---|---|---|---|---|---|---|
| Assets | | | | | | |
| Risk management activities — derivative instruments: | | | | | | |
| Commodity contracts | $ — | $ 22,992 | $ 30,364 | $ (25,345) | (b) | $ 28,011 |
| Nuclear decommissioning trust: | | | | | | |
| U.S. commingled equity funds | — | — | — | 314,957 | (c) | 314,957 |
| Fixed income securities: | | | | | | |
| Cash and cash equivalent funds | 12,260 | — | — | (335) | (d) | 11,925 |
| U.S. Treasury | 117,245 | — | — | — | | 117,245 |
| Corporate debt | — | 96,243 | — | — | | 96,243 |
| Mortgage-backed securities | — | 99,065 | — | — | | 99,065 |
| Municipal bonds | — | 72,206 | — | — | | 72,206 |
| Other | — | 23,555 | — | — | | 23,555 |
| Subtotal nuclear decommissioning trust | 129,505 | 291,069 | — | 314,622 | | 735,196 |
| Total | $ 129,505 | $ 314,061 | $ 30,364 | $ 289,277 | | $ 763,207 |
| Liabilities | | | | | | |
| Risk management activities — derivative instruments: | | | | | | |
| Commodity contracts | $ — | $ (144,044) | $ (63,343) | $ 39,698 | (b) | $ (167,689) |

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(d) Represents nuclear decommissioning trust net pending securities sales and purchases.

**Fair Value Measurements Classified as Level 3**

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote and option model inputs. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 3).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Our option contracts classified as Level 3 primarily relate to purchase heat rate options. The remaining option contract expired on October 1, 2016. The significant unobservable inputs at December 31, 2015 for these instruments include electricity prices, and volatilities. If electricity prices and electricity price volatilities increase, we would expect the fair value of these options to increase, and if these valuation inputs decrease, we would expect the fair value of these options to decrease. If natural gas prices and natural gas price volatilities increase, we would expect the fair value of these options to decrease, and if these inputs decrease, we would expect the fair value of the options to increase. The commodity prices and volatilities do not always move in corresponding directions. The options' fair values are impacted by the net changes of these various inputs.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2016 and December 31, 2015:

| | December 31, 2016 Fair Value (thousands) | | | | | |
|---|---|---|---|---|---|---|
| Commodity Contracts | Assets | Liabilities | Valuation Technique | Significant Unobservable Input | Range | Weighted-Average |
| Electricity: | | | | | | |
| Forward Contracts (a) | $ 10,648 | $ 32,042 | Discounted cash flows | Electricity forward price (per MWh) | $16.43 - $41.07 | $ 29.86 |
| Natural Gas: | | | | | | |
| Forward Contracts (a) | 428 | 26,440 | Discounted cash flows | Natural gas forward price (per MMBtu) | $2.32 - $3.60 | $ 2.81 |
| Total | $ 11,076 | $ 58,482 | | | | |

(a) Includes swaps and physical and financial contracts.

| Commodity Contracts | December 31, 2015 Fair Value (thousands) Assets | Liabilities | Valuation Technique | Significant Unobservable Input | Range | Weighted-Average |
|---|---|---|---|---|---|---|
| Electricity: | | | | | | |
| Forward Contracts (a) | $ 24,543 | $ 54,679 | Discounted cash flows | Electricity forward price (per MWh) | $15.92 - $40.73 | $ 26.86 |
| Option Contracts (b) | — | 5,628 | Option model | Electricity forward price (per MWh) | $23.87 - $44.13 | $ 33.91 |
| | | | | Electricity price volatilities | 40% - 59% | 52% |
| | | | | Natural gas price volatilities | 32% - 40% | 35% |
| Natural Gas: | | | | | | |
| Forward Contracts (a) | 5,821 | 3,036 | Discounted cash flows | Natural gas forward price (per MMBtu) | $2.18 - $3.14 | $ 2.61 |
| Total | $ 30,364 | $ 63,343 | | | | |

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2016 and 2015 (dollars in thousands):

| Commodity Contracts | Year Ended December 31, 2016 | 2015 |
|---|---|---|
| Net derivative balance at beginning of period | $ (32,979) | $ (41,386) |
| Total net gains (losses) realized/unrealized: | | |
| Included in earnings | — | — |
| Included in OCI | 88 | (452) |
| Deferred as a regulatory asset or liability | (37,543) | (4,009) |
| Settlements | 15,146 | 14,809 |
| Transfers into Level 3 from Level 2 | 1,900 | (6,256) |
| Transfers from Level 3 into Level 2 | 5,982 | 4,315 |
| Net derivative balance at end of period | $ (47,406) | $ (32,979) |
| Net unrealized gains included in earnings related to instruments still held at end of period | $ — | $ — |

Amounts included in earnings are recorded in either operating revenues or fuel and purchased power depending on the nature of the underlying contract.

Transfers reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

**Financial Instruments Not Carried at Fair Value**

The carrying value of our net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our short-term borrowings are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values.

## 14. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for continuing operations attributable to common shareholders for the years ended December 31, 2016, 2015 and 2014 (in thousands, except per share amounts):

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Net income attributable to common shareholders | $ 442,034 | $ 437,257 | $ 397,595 |
| Weighted average common shares outstanding — basic | 111,409 | 111,026 | 110,626 |
| Net effect of dilutive securities: | | | |
| Contingently issuable performance shares and restricted stock units | 637 | 526 | 552 |
| Weighted average common shares outstanding — diluted | 112,046 | 111,552 | 111,178 |
| Earnings per weighted-average common share outstanding | | | |
| Net income attributable to common shareholders - basic | $ 3.97 | $ 3.94 | $ 3.59 |
| Net Income attributable to common shareholders - diluted | $ 3.95 | $ 3.92 | $ 3.58 |

## 15. Stock-Based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key-employees, and non-officer members of the Board of Directors. Awards granted under the 2012 Long-Term Incentive Plan ("2012 Plan") may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2012 Plan authorizes up to 4.6 million common shares to be available for grant. As of December 31, 2016, 2.5 million common shares were available for issuance under the 2012 Plan. During 2016, 2015, and 2014, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"), and no new awards may be granted under the 2007 Plan.

**Stock-Based Compensation Expense and Activity**

During the fourth quarter of 2016, we adopted new stock-based compensation accounting guidance prescribed by ASU 2016-09, see Note 2. Prior to the adoption of this guidance we had certain awards that were accounted for as liability awards due to the ability of the employee to withhold taxes beyond the minimum statutory tax withholding rate. Under the new standard, the tax withholding terms of our awards no longer trigger liability treatment. Accordingly, effective, January 1, 2016 certain awards that were previously classified as liability awards are now accounted for as equity awards. The impacts of this accounting change relating to prior years have been applied using a modified retrospective approach, resulting in a $6 million cumulative-effect adjustment, net of income tax expense of $3 million, to increase Retained Earnings as of January 1, 2016. The impacts of this accounting change relating to the current year, resulted in a pre-tax $12 million adjustment to decrease operations and maintenance expense that was recognized during the fourth quarter of 2016. Due to this transition approach, the following discussion reflects this change in the 2016 expense and activity; however, expense and activities relating to 2015 and 2014 reflect the historical treatment. The new standard also requires excess income tax benefits and deficiencies arising from stock based compensation to now be recognized in the period incurred, simplifies accounting for forfeitures, and clarifies certain cash flow presentation matters. These other provisions of the standard did not have a material impact on our consolidated financial statements.

Compensation cost included in net income for stock-based compensation plans was $19 million in 2016, $19 million in 2015, and $33 million in 2014. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $10 million in 2016, $7 million in 2015, and $13 million in 2014.

As of December 31, 2016, there were approximately $13 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. We expect to recognize these costs over a weighted-average period of 2 years.

The total fair value of shares vested was $22 million in 2016, $21 million in 2015 and $22 million in 2014.

The following table is a summary of awards granted and the weighted-average grant date fair value for the three years ended 2016, 2015 and 2014.

| | Restricted Stock Units, Stock Grants, and Stock Units (a) | | | Performance Shares (b) | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Units granted | 141,811 | 152,651 | 179,291 | 166,666 | 151,430 | 166,244 |
| Weighted-average grant date fair value | $ 67.34 | $ 64.12 | $ 54.89 | $ 66.60 | $ 64.97 | $ 54.86 |

(a) Units granted includes awards that will be cash settled of 43,952 in 2016, 45,104 in 2015, and 49,018 in 2014.

(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2016 and changes during the year.

| | Restricted Stock Units, Stock Grants, and Stock Units | | Performance Shares | |
|---|---|---|---|---|
| | Shares | Weighted-Average Grant Date Fair Value | Shares (b) | Weighted-Average Grant Date Fair Value |
| Nonvested at January 1, 2016 | 428,287 | $ 56.69 | 305,832 | $ 58.86 |
| Granted | 141,811 | 67.34 | 166,666 | 66.60 |
| Change in performance factor | — | — | 15,573 | 54.09 |
| Vested | (230,881) | 55.07 | (171,303) | 54.09 |
| Forfeited (c) | (3,958) | 62.86 | (4,044) | 62.34 |
| Nonvested at December 31, 2016 | 335,259 (a) | 62.04 | 312,724 | 65.32 |
| Vested Awards Outstanding at December 31, 2016 | 174,201 | | 171,303 | |

(a) Includes 112,554 of awards that will be cash settled.

(b) The nonvested performance shares are reflected at target payout level. The performance metric component increase or decrease in the number of shares from the target level to the estimated actual payout level is included in the increase for performance factor amounts in the year the award vests.

(c) We account for forfeitures as they occur.

Share-based liabilities paid relating to restricted stock units were $3 million, $10 million and $9 million in 2016, 2015 and 2014, respectively. This includes cash used to settle restricted stock units of $3 million for each of the years 2016, 2015 and 2014. Restricted stock units that are cash settled are classified as liability awards. Share-based liabilities paid relating to performance shares were $16 million in 2015 and $12 million in 2014. In 2016, performance shares were classified as equity awards.

**Restricted Stock Units, Stock Grants, and Stock Units**

Restricted stock units are granted to officers and key employees. Restricted stock units typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights equal to the dividends they would have received had they directly owned the stock. Interest on dividend rights compounds quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

In December 2012, the Company granted a retention award of 50,617 performance-linked restricted stock units to the Chairman of the Board and Chief Executive Officer of Pinnacle West. This award vested on December 31, 2016, because he remained employed with the Company through that date. The Board can increase the number of awards that vest, up to an additional 33,745 restricted stock units, payable in stock, if certain performance requirements are met.

Compensation cost for restricted stock unit awards is based on the fair value of the award, with the fair value being the market price of our stock on the measurement date. Restricted stock unit awards that will be settled in cash are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date. Restricted stock unit awards that will be settled in shares are accounted for as equity awards, with compensation cost calculated using the Company's closing stock price on the date of grant. Compensation cost is recognized over the requisite service period based on the fair value of the award.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. Each stock unit is convertible to one share of stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment, plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, or 50% in cash and 50% in stock.

**Performance Share Awards**

Performance share awards are granted to officers and key employees. The awards contain two separate performance criteria that affect the number of shares that may be received if after the end of a 3-year performance period the performance criteria are met. For the first criteria, the number of shares that will vest is based upon six non-financial separate performance metrics (i.e., the metric component). The other criteria is based upon Pinnacle West's total shareholder return (TSR) in relation to the TSR of other companies in a specified utility index (i.e., the TSR component). The exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved the employee is not entitled to the dividends on those shares.

Performance share awards are accounted for as equity awards, with compensation cost based on the fair value of the award on grant date. Compensation cost relating to the metric component of the award is based on the Company's closing stock price on the date of grant, with compensation cost recognized over the requisite service period based on the number of shares expected to vest. Management evaluates the probability of meeting the metric component at each balance sheet date. If the metric component criteria are not ultimately achieved, no compensation cost is recognized relating to the metric component, and any previously recognized compensation cost is reversed. Compensation cost relating to the TSR component of the award is determined using a Monte Carlo simulation valuation model, with compensation cost recognized ratably over the requisite service period, regardless of the number of shares that actually vest.

## 16. Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. Derivative instruments that meet certain hedge accounting

criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. While we believe the economic hedges mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 13 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of OCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As cash flow hedge accounting has been discontinued for the significant majority of our contracts, after May 31, 2012, effectiveness testing is no longer being performed for these contracts.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2016, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

| Commodity | Quantity | |
|---|---|---|
| Power | 1,314 | GWh |
| Gas | 194 | Billion cubic feet |

## Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the years ended December 31, 2016, 2015 and 2014 (dollars in thousands):

| Commodity Contracts | Financial Statement Location | Year Ended December 31, 2016 | 2015 | 2014 |
|---|---|---|---|---|
| Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion) | OCI — derivative instruments | $ 47 | $ (615) | $ (372) |
| Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a) | Fuel and purchased power (b) | (3,926) | (5,988) | (21,415) |

(a) During the years ended December 31, 2016, 2015, and 2014, we had no losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $3 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the years ended December 31, 2016, 2015 and 2014 (dollars in thousands):

| Commodity Contracts | Financial Statement Location | Year Ended December 31, 2016 | 2015 | 2014 |
|---|---|---|---|---|
| Net Gain Recognized in Income | Operating revenues | $ 771 | $ 574 | $ 324 |
| Net Gain (Loss) Recognized in Income | Fuel and purchased power (a) | 25,711 | (108,973) | (66,367) |
| Total | | $ 26,482 | $ (108,399) | $ (66,043) |

(a) Amounts are before the effect of PSA deferrals.

## Derivative Instruments in the Consolidated Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Consolidated Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our 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, trade receivables and trade 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 tables presented below.

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Consolidated Balance Sheets as of December 31, 2016 and December 31, 2015, include gross liabilities of $2 million and $3 million, respectively, of derivative instruments designated as hedging instruments.

The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting as of December 31, 2016 and 2015. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Consolidated Balance Sheets.

| As of December 31, 2016: (dollars in thousands) | Gross Recognized Derivatives (a) | Amounts Offset (b) | Net Recognized Derivatives | Other (c) | Amount Reported on Balance Sheet |
|---|---|---|---|---|---|
| Current assets | $ 48,094 | $ (28,400) | $ 19,694 | $ — | $ 19,694 |
| Investments and other assets | 6,704 | (6,703) | 1 | — | 1 |
| Total assets | 54,798 | (35,103) | 19,695 | — | 19,695 |
| Current liabilities | (50,182) | 28,400 | (21,782) | (4,054) | (25,836) |
| Deferred credits and other | (53,941) | 6,703 | (47,238) | — | (47,238) |
| Total liabilities | (104,123) | 35,103 | (69,020) | (4,054) | (73,074) |
| Total | $ (49,325) | $ — | $ (49,325) | $ (4,054) | $ (53,379) |

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.

(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.

(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $4,054.

| As of December 31, 2015: (dollars in thousands) | Gross Recognized Derivatives (a) | Amounts Offset (b) | Net Recognized Derivatives | Other (c) | Amount Reported on Balance Sheet |
|---|---|---|---|---|---|
| Current assets | $ 37,396 | $ (22,163) | $ 15,233 | $ 672 | $ 15,905 |
| Investments and other assets | 15,960 | (3,854) | 12,106 | — | 12,106 |
| Total assets | 53,356 | (26,017) | 27,339 | 672 | 28,011 |
| | | | | | |
| Current liabilities | (113,560) | 40,223 | (73,337) | (4,379) | (77,716) |
| Deferred credits and other | (93,827) | 3,854 | (89,973) | — | (89,973) |
| Total liabilities | (207,387) | 44,077 | (163,310) | (4,379) | (167,689) |
| Total | $ (154,031) | $ 18,060 | $ (135,971) | $ (3,707) | $ (139,678) |

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $18,060.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $4,379, and cash margin provided to counterparties of $672.

**Credit Risk and Credit Related Contingent Features**

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of December 31, 2016, we have no counterparties with positive exposures of greater than 10% of risk management assets. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at December 31, 2016 (dollars in thousands):

| | December 31, 2016 |
|---|---|
| Aggregate fair value of derivative instruments in a net liability position | $ 104,123 |
| Cash collateral posted | — |
| Additional cash collateral in the event credit-risk related contingent features were fully triggered (a) | 23,914 |

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $144 million if our debt credit ratings were to fall below investment grade.

## 17. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for 2016, 2015 and 2014 (dollars in thousands):

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Other income: | | | |
| Interest income | $ 884 | $ 493 | $ 1,010 |
| Debt return on the purchase of Four Corners units 4 & 5 | — | — | 8,386 |
| Miscellaneous | 17 | 128 | 212 |
| Total other income | $ 901 | $ 621 | $ 9,608 |
| Other expense: | | | |
| Non-operating costs | $ (9,235) | $ (11,292) | $ (9,657) |
| Investment losses — net | (1,747) | (2,080) | (9,426) |
| Miscellaneous | (4,355) | (4,451) | (2,663) |
| Total other expense | $ (15,337) | $ (17,823) | $ (21,746) |

### Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2016, 2015 and 2014 (dollars in thousands):

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Other income: | | | |
| Interest income | $ 261 | $ 163 | $ 689 |
| Debt return on the purchase of Four Corners units 4 & 5 | — | — | 8,386 |
| Gain on disposition of property | 5,745 | 716 | 1,197 |
| Miscellaneous | 2,601 | 1,955 | 1,023 |
| Total other income | $ 8,607 | $ 2,834 | $ 11,295 |
| Other expense: | | | |
| Non-operating costs (a) | $ (11,034) | $ (11,648) | $ (10,397) |
| Loss on disposition of property | (1,246) | (2,219) | (615) |
| Miscellaneous | (5,234) | (5,152) | (2,391) |
| Total other expense | $ (17,514) | $ (19,019) | $ (13,403) |

(a) As defined by FERC, includes non-operating utility income and expense (items excluded from utility rate recovery).

## 18. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. APS will retain the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually for the period 2017 through 2023, and about $16 million annually for the period 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

The leases' terms give APS the ability to utilize the assets for a significant portion of the assets' economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. Predominantly due to the lease terms, APS has been deemed the primary beneficiary of these VIEs and therefore consolidates the VIEs.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for 2016, 2015 and 2014 of $19 million, $19 million and $26 million, respectively, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Consolidated Balance Sheets at December 31, 2016 and December 31, 2015 include the following amounts relating to the VIEs (dollars in thousands):

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation | $ 113,515 | $ 117,385 |
| Equity-Noncontrolling interests | 132,290 | 135,540 |

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our consolidated financial statements.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $291 million beginning in 2017, and up to $456 million over the lease extension term.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

## 19. Nuclear Decommissioning Trusts

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Consolidated Balance Sheets. See Note 13 for a discussion of how fair value is determined and the classification of the nuclear decommissioning trust investments within the fair value hierarchy. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have deferred realized and unrealized gains and losses (including other-than-temporary impairments on investment securities) in other regulatory liabilities. The following table includes the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust fund assets at December 31, 2016 and December 31, 2015 (dollars in thousands):

| | Fair Value | Total Unrealized Gains | Total Unrealized Losses |
|---|---|---|---|
| December 31, 2016 | | | |
| Equity securities | $ 353,261 | $ 188,091 | $ — |
| Fixed income securities | 425,530 | 9,820 | (4,962) |
| Net receivables (a) | 795 | — | — |
| Total | $ 779,586 | $ 197,911 | $ (4,962) |

| | Fair Value | Total Unrealized Gains | Total Unrealized Losses |
|---|---|---|---|
| December 31, 2015 | | | |
| Equity securities | $ 314,957 | $ 157,098 | $ (115) |
| Fixed income securities | 420,574 | 11,955 | (2,645) |
| Net payables (a) | (335) | — | — |
| Total | $ 735,196 | $ 169,053 | $ (2,760) |

(a) Net receivables/(payables) relate to pending purchases and sales of securities.

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Realized gains | $ 11,213 | $ 5,189 | $ 4,725 |
| Realized losses | (10,106) | (6,225) | (4,525) |
| Proceeds from the sale of securities (a) | 633,410 | 478,813 | 356,195 |

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2016 is as follows (dollars in thousands):

| | Fair Value |
|---|---|
| Less than one year | $ 13,063 |
| 1 year – 5 years | 119,292 |
| 5 years – 10 years | 105,612 |
| Greater than 10 years | 187,563 |
| Total | $ 425,530 |

## 20. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2016 and 2015 (dollars in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2016 | 2015 |
| **Balance at beginning of period** | $ (44,748) | $ (68,141) |
| **Derivative Instruments** | | |
| OCI (loss) before reclassifications | (538) | (957) |
| Amounts reclassified from accumulated other comprehensive loss (a) | 2,941 | 4,187 |
| Net current period OCI (loss) | 2,403 | 3,230 |
| **Pension and Other Postretirement Benefits** | | |
| OCI (loss) before reclassifications | (4,509) | 16,980 |
| Amounts reclassified from accumulated other comprehensive loss (b) | 3,032 | 3,183 |
| Net current period OCI (loss) | (1,477) | 20,163 |
| **Balance at end of period** | $ (43,822) | $ (44,748) |

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

**Changes in Accumulated Other Comprehensive Loss - APS**

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2016 and 2015 (dollars in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2016 | 2015 |
| **Balance at beginning of period** | $ (27,097) | $ (48,333) |
| **Derivative Instruments** | | |
| OCI (loss) before reclassifications | (538) | (957) |
| Amounts reclassified from accumulated other comprehensive loss (a) | 2,941 | 4,187 |
| Net current period OCI (loss) | 2,403 | 3,230 |
| **Pension and Other Postretirement Benefits** | | |
| OCI (loss) before reclassifications | (3,821) | 14,726 |
| Amounts reclassified from accumulated other comprehensive loss (b) | 3,092 | 3,280 |
| Net current period OCI (loss) | (729) | 18,006 |
| **Balance at end of period** | $ (25,423) | $ (27,097) |

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

**PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT**
**CONDENSED STATEMENTS OF COMPREHENSIVE INCOME**
(dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Operating revenues | $ 370 | $ 550 | $ 642 |
| Operating expenses | 26,424 | 12,733 | 23,507 |
| Operating loss | (26,054) | (12,183) | (22,865) |
| Other | | | |
| Equity in earnings of subsidiaries | 462,027 | 446,508 | 411,528 |
| Other expense | (1,771) | (3,302) | (3,276) |
| Total | 460,256 | 443,206 | 408,252 |
| Interest expense | 3,151 | 2,672 | 3,663 |
| Income before income taxes | 431,051 | 428,351 | 381,724 |
| Income tax benefit | (10,983) | (8,906) | (15,871) |
| Net income attributable to common shareholders | 442,034 | 437,257 | 397,595 |
| Other comprehensive income — attributable to common shareholders | 926 | 23,393 | 9,912 |
| Total comprehensive income — attributable to common shareholders | $ 442,960 | $ 460,650 | $ 407,507 |

See Combined Notes to Consolidated Financial Statements.

**PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT**
**CONDENSED BALANCE SHEETS**
(dollars in thousands)

| | December 31, | |
|---|---|---|
| | 2016 | 2015 |
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $ 41 | $ 17,432 |
| Accounts receivable | 81,751 | 93,093 |
| Income tax receivable | — | 14,895 |
| Other current assets | 340 | 197 |
| Total current assets | 82,132 | 125,617 |
| Investments and other assets | | |
| Investments in subsidiaries | 5,084,035 | 4,815,236 |
| Deferred income taxes | 53,805 | 41,065 |
| Other assets | 38,500 | 43,422 |
| Total investments and other assets | 5,176,340 | 4,899,723 |
| Total Assets | $ 5,258,472 | $ 5,025,340 |
| LIABILITIES AND EQUITY | | |
| Current liabilities | | |
| Accounts payable | $ 5,421 | $ 5,901 |
| Accrued taxes | 12,050 | 6,904 |
| Common dividends payable | 72,926 | 69,363 |
| Short-term borrowings | 41,700 | — |
| Current maturities of long-term debt | 125,000 | — |
| Other current liabilities | 31,182 | 33,120 |
| Total current liabilities | 288,279 | 115,288 |
| | | |
| Long-term debt less current maturities | — | 125,000 |
| | | |
| Pension liabilities | 21,057 | 21,933 |
| Other | 13,224 | 43,662 |
| Total deferred credits and other | 34,281 | 65,595 |
| Common stock equity | | |
| Common stock | 2,591,897 | 2,535,862 |
| Accumulated other comprehensive loss | (43,822) | (44,748) |
| Retained earnings | 2,255,547 | 2,092,803 |
| Total Pinnacle West Shareholders' equity | 4,803,622 | 4,583,917 |
| Noncontrolling interests | 132,290 | 135,540 |
| Total Equity | 4,935,912 | 4,719,457 |
| Total Liabilities and Equity | $ 5,258,472 | $ 5,025,340 |

See Combined Notes to Consolidated Financial Statements.

## PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
## SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
## CONDENSED STATEMENTS OF CASH FLOWS
(dollars in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Cash flows from operating activities | | | |
| Net income | $ 442,034 | $ 437,257 | $ 397,595 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Equity in earnings of subsidiaries — net | (462,027) | (446,508) | (411,528) |
| Depreciation and amortization | 85 | 92 | 94 |
| Deferred income taxes | (12,402) | 12,967 | 4,406 |
| Accounts receivable | 15,823 | 11,336 | (22,945) |
| Accounts payable | 10,402 | 637 | 2,017 |
| Accrued taxes and income tax receivables — net | 20,041 | (12,882) | (1,795) |
| Dividends received from subsidiaries | 239,300 | 266,900 | 253,600 |
| Other | 5,514 | (6,995) | 18,432 |
| Net cash flow provided by operating activities | 258,770 | 262,804 | 239,876 |
| Cash flows from investing activities | | | |
| Construction work in progress | (18,457) | (3,462) | — |
| Investments in subsidiaries | (19,242) | (3,491) | (10,236) |
| Repayments of loans from subsidiaries | 1,026 | 157 | 322 |
| Advances of loans to subsidiaries | (2,092) | (1,010) | (1,450) |
| Net cash flow used for investing activities | (38,765) | (7,806) | (11,364) |
| Cash flows from financing activities | | | |
| Issuance of long-term debt | — | — | 125,000 |
| Short-term debt borrowings under revolving credit facility | 40,000 | — | — |
| Commercial Paper - net | 1,700 | — | — |
| Dividends paid on common stock | (274,229) | (260,027) | (246,671) |
| Repayment of long-term debt | — | — | (125,000) |
| Common stock equity issuance - net of purchases | (4,867) | 19,373 | 15,288 |
| Other | — | — | 161 |
| Net cash flow used for financing activities | (237,396) | (240,654) | (231,222) |
| Net increase (decrease) in cash and cash equivalents | (17,391) | 14,344 | (2,710) |
| Cash and cash equivalents at beginning of year | 17,432 | 3,088 | 5,798 |
| Cash and cash equivalents at end of year | $ 41 | $ 17,432 | $ 3,088 |

See Combined Notes to Consolidated Financial Statements.

## PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
## NOTES TO FINANCIAL STATEMENTS OF HOLDING COMPANY

The Combined Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Pinnacle West Capital Corporation Holding Company Financial Statements.

The Pinnacle West Capital Corporation Holding Company Financial Statements have been prepared to present the financial position, results of operations and cash flows of the Pinnacle West Capital Corporation on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

**PINNACLE WEST CAPITAL CORPORATION**
**SCHEDULE II — RESERVE FOR UNCOLLECTIBLES**
(dollars in thousands)

| Column A | Column B | Column C | | Column D | Column E |
|---|---|---|---|---|---|
| | | Additions | | | |
| Description | Balance at beginning of period | Charged to cost and expenses | Charged to other accounts | Deductions | Balance at end of period |
| Reserve for uncollectibles: | | | | | |
| 2016 | $ 3,125 | $ 4,025 | $ — | $ 4,113 | $ 3,037 |
| 2015 | 3,094 | 4,073 | — | 4,042 | 3,125 |
| 2014 | 3,203 | 3,942 | — | 4,051 | 3,094 |

## ARIZONA PUBLIC SERVICE COMPANY
## SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

| Column A | Column B | Column C | | Column D | Column E |
|---|---|---|---|---|---|
| | | Additions | | | |
| Description | Balance at beginning of period | Charged to cost and expenses | Charged to other accounts | Deductions | Balance at end of period |
| Reserve for uncollectibles: | | | | | |
| 2016 | $ 3,125 | $ 4,025 | $ — | $ 4,113 | $ 3,037 |
| 2015 | 3,094 | 4,073 | — | 4,042 | 3,125 |
| 2014 | 3,203 | 3,942 | — | 4,051 | 3,094 |

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

None.

## ITEM 9A. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934 (the "Exchange Act") (15 U.S.C. 78a *et seq*.) is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of December 31, 2016. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of APS's disclosure controls and procedures as of December 31, 2016. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Management's Annual Reports on Internal Control Over Financial Reporting

Reference is made to "Management's Report on Internal Control over Financial Reporting (Pinnacle West Capital Corporation)" in Item 8 of this report and "Management's Report on Internal Control over Financial Reporting (Arizona Public Service Company)" in Item 8 of this report.

(c) Attestation Reports of the Registered Public Accounting Firm

Reference is made to "Report of Independent Registered Public Accounting Firm" in Item 8 of this report and "Report of Independent Registered Public Accounting Firm" in Item 8 of this report on the internal control over financial reporting of Pinnacle West and APS, respectively.

(d) Changes In Internal Control Over Financial Reporting

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended December 31, 2016 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF PINNACLE WEST

Reference is hereby made to “Information About Our Board and Corporate Governance,” “Proposal 1 — Election of Directors” and to “Section 16(a) Beneficial Ownership Reporting Compliance” in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 17, 2017 (the “2017 Proxy Statement”) and to the “Executive Officers of Pinnacle West” section in Part I of this report.

Pinnacle West has adopted a Code of Ethics for Financial Executives that applies to financial executives including Pinnacle West’s Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller, Treasurer, and General Counsel, the President and Chief Operating Officer of APS and other persons designated as financial executives by the Chair of the Audit Committee. The Code of Ethics for Financial Executives is posted on Pinnacle West’s website (*www.pinnaclewest.com)*. Pinnacle West intends to satisfy the requirements under Item 5.05 of Form 8-K regarding disclosure of amendments to, or waivers from, provisions of the Code of Ethics for Financial Executives by posting such information on Pinnacle West’s website.

## ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to “Directors’ Compensation,” “Report of the Human Resources Committee,” “Executive Compensation,” and “Human Resources Committee Interlocks and Insider Participation” in the 2017 Proxy Statement.

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

Reference is hereby made to “Ownership of Pinnacle West Stock” and "Equity Compensation Plan Table" in the 2017 Proxy Statement.

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

Reference is hereby made to “Information About Our Board and Corporate Governance” and “Related Party Transactions” in the 2017 Proxy Statement.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

**Pinnacle West**

Reference is hereby made to "Accounting and Auditing Matters — Audit Fees and — Pre-Approval Policies" in the 2017 Proxy Statement.

**APS**

The following fees were paid to APS's independent registered public accountants, Deloitte & Touche LLP, for the last two fiscal years:

| Type of Service | 2015 | 2016 |
|---|---|---|
| Audit Fees (1) | $ 2,014,747 | $ 2,137,925 |
| Audit-Related Fees (2) | 233,555 | 283,070 |
| All Other Fees (3) | 10,000 | — |

(1) The aggregate fees billed for services rendered for the audit of annual financial statements and for review of financial statements included in Reports on Form 10-Q.

(2) The aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not included in Audit Fees reported above, which primarily consist of fees for employee benefit plan audits performed in 2016 and 2015.

(3) The aggregate fees billed for advice relating to the development of a statement of work for the Company's system integrator for its new Customer Information System in 2015.

Pinnacle West's Audit Committee pre-approves each audit service and non-audit service to be provided by APS's registered public accounting firm. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve audit and non-audit services to be performed by the independent public accountants if the services are not expected to cost more than $50,000. The Chair must report any pre-approval decisions to the Audit Committee at its next scheduled meeting. All of the services performed by Deloitte & Touche LLP for APS in 2016 were pre-approved by the Audit Committee or the Chair of the Audit Committee consistent with the pre-approval policy.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

### Financial Statements and Financial Statement Schedules

See the Index to Financial Statements and Financial Statement Schedule in Part II, Item 8.

### Exhibits Filed

The documents listed below are being filed or have previously been filed on behalf of Pinnacle West or APS and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: a | Date Filed |
|---|---|---|---|---|
| 3.1 | Pinnacle West | Articles of Incorporation, restated as of May 21, 2008 | 3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962 | 8/7/2008 |
| 3.2 | Pinnacle West | Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010 | 3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962 | 8/3/2010 |
| 3.3 | APS | Articles of Incorporation, restated as of May 25, 1988 | 4.2 to APS's Form 18 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473 | 9/29/1993 |
| 3.3.1 | APS | Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012 | 3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 5/22/2012 |
| 3.4 | APS | Arizona Public Service Company Bylaws, amended as of December 16, 2008 | 3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File No. 1-4473 | 2/20/2009 |
| 4.1 | Pinnacle West | Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value | 4.1 to Pinnacle West June 28, 2011 Form 8-K Report, File No. 1-8962 | 6/28/2011 |
| 4.2 | Pinnacle West APS | Indenture dated as of January 1, 1995 among APS and The Bank of New York Mellon, as Trustee | 4.6 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473 | 1/11/1995 |
| 4.2a | Pinnacle West APS | First Supplemental Indenture dated as of January 1, 1995 | 4.4 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473 | 1/11/1995 |
| 4.3 | Pinnacle West APS | Indenture dated as of November 15, 1996 between APS and The Bank of New York, as Trustee | 4.5 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333- 15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473 | 11/22/1996 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: a | Date Filed |
|---|---|---|---|---|
| 4.3a | Pinnacle West<br>APS | First Supplemental Indenture dated as of November 15, 1996 | 4.6 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473 | 11/22/1996 |
| 4.3b | Pinnacle West<br>APS | Second Supplemental Indenture dated as of April 1, 1997 | 4.10 to APS's Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report, File No. 1-4473 | 4/9/1997 |
| 4.3c | Pinnacle West<br>APS | Third Supplemental Indenture dated as of November 1, 2002 | 10.2 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962 | 5/15/2003 |
| 4.4 | Pinnacle West | Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities | 4.1 to Pinnacle West's Registration Statement No. 333-52476 | 12/21/2000 |
| 4.5 | Pinnacle West | Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Subordinated Unsecured Debt Securities | 4.2 to Pinnacle West's Registration Statement No. 333-52476 | 12/21/2000 |
| 4.6 | Pinnacle West<br>APS | Indenture dated as of January 15, 1998 between APS and The Bank of New York Mellon Trust Company N.A. (successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank), as Trustee | 4.10 to APS's Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report, File No. 1-4473 | 1/16/1998 |
| 4.6a | Pinnacle West<br>APS | Seventh Supplemental Indenture dated as of May 1, 2003 | 4.1 to APS's Registration Statement No. 333-90824 by means of May 7, 2003 Form 8-K Report, File No. 1-4473 | 5/9/2003 |
| 4.6b | Pinnacle West<br>APS | Eighth Supplemental Indenture dated as of June 15, 2004 | 4.1 to APS's Registration Statement No. 333-106772 by means of June 24, 2004 Form 8-K Report, File No. 1-4473 | 6/28/2004 |
| 4.6c | Pinnacle West<br>APS | Ninth Supplemental Indenture dated as of August 15, 2005 | 4.1 to APS's Registration Statements Nos. 333-106772 and 333-121512 by means of August 17, 2005 Form 8-K Report, File No. 1-4473 | 8/22/2005 |
| 4.6d | APS | Tenth Supplemental Indenture dated as of August 1, 2006 | 4.1 to APS's July 31, 2006 Form 8-K Report, File No. 1-4473 | 8/3/2006 |
| 4.6e | Pinnacle West<br>APS | Eleventh Supplemental Indenture dated as of February 26, 2009 | 4.6e to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 4.6f | Pinnacle West<br>APS | Twelfth Supplemental Indenture dated as of August 25, 2011 | 4.6f to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 4.6g | Pinnacle West<br>APS | Thirteenth Supplemental Indenture dated as of January 13, 2012 | 4.6g to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 4.6h | Pinnacle West<br>APS | Fourteenth Supplemental Indenture dated as of January 10, 2014 | 4.6h to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: a | Date Filed |
|---|---|---|---|---|
| 4.6i | Pinnacle West<br>APS | Fifteenth Supplemental Indenture dated as of June 18, 2014 | 4.6i to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 4.6j | Pinnacle West<br>APS | Sixteenth Supplemental Indenture dated as of January 12, 2015 | 4.6j to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 4.6k | Pinnacle West<br>APS | Seventeenth Supplemental Indenture dated as of May 19, 2015 | 4.1 to Pinnacle West/APS May 14, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 5/19/2015 |
| 4.6l | Pinnacle West<br>APS | Eighteenth Supplemental Indenture dated as of November 6, 2015 | 4.1 to Pinnacle West/APS November 3, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 11/6/2015 |
| 4.6m | Pinnacle West<br>APS | Nineteenth Supplemental Indenture dated as of May 6, 2016 | 4.1 to Pinnacle West/APS May 3, 2016 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 5/6/2016 |
| 4.6n | Pinnacle West<br>APS | Twentieth Supplemental Indenture dated as of September 20, 2016 | 4.1 to Pinnacle West/APS September 15, 2016 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 9/20/2016 |
| 4.7 | Pinnacle West | Second Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of June 23, 2004 | 4.4 to Pinnacle West's June 23, 2004 Form 8-K Report, File No. 1-8962 | 8/9/2004 |
| 4.7a | Pinnacle West | Third Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of November 25, 2008 | 4.1 to Pinnacle West's Form S-3 Registration Statement No. 333-155641, File No. 1-8962 | 11/25/2008 |
| 4.8 | Pinnacle West | Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets | 4.1 to Pinnacle West's 1987 Form 10-K Report, File No. 1-8962 | 3/30/1988 |
| 4.8a | Pinnacle West<br>APS | Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS's total assets | 4.1 to APS's 1993 Form 10-K Report, File No. 1-4473 | 3/30/1994 |
| 10.1.1 | Pinnacle West<br>APS | Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee | 10.2 to APS's September 30, 1991 Form 10-Q Report, File No. 1-4473 | 11/14/1991 |
| 10.1.1a | Pinnacle West<br>APS | Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994 | 10.1 to APS's 1994 Form 10-K Report, File No. 1-4473 | 3/30/1995 |
| 10.1.1b | Pinnacle West<br>APS | Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994 | 10.2 to APS's 1994 Form 10-K Report, File No. 1-4473 | 3/30/1995 |
| 10.1.1c | Pinnacle West<br>APS | Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991 | 10.4 to APS's 1996 Form 10-K Report , File No. 1-4473 | 3/28/1997 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: a | Date Filed |
|---|---|---|---|---|
| 10.1.1d | Pinnacle West<br>APS | Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991 | 10.6 to APS's 1996 Form 10-K Report, File No. 1-4473 | 3/28/1997 |
| 10.1.1e | Pinnacle West<br>APS | Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002 | 10.2 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962 | 5/15/2002 |
| 10.1.1f | Pinnacle West<br>APS | Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002 | 10.4 to Pinnacle West's March 2002 Form 10-Q Report, File No. 1-8962 | 5/15/2002 |
| 10.1.1g | Pinnacle West<br>APS | Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 19, 2003 | 10.3 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962 | 3/15/2004 |
| 10.1.1h | Pinnacle West<br>APS | Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 19, 2003 | 10.5 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962 | 3/15/2004 |
| 10.1.1i | Pinnacle West<br>APS | Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of May 1, 2007 | 10.1 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/9/2007 |
| 10.1.1j | Pinnacle West<br>APS | Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of May 1, 2007 | 10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 104473 | 5/9/2007 |
| 10.1.2 | Pinnacle West<br>APS | Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2 | 10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962 | 3/26/1992 |
| 10.1.2a | Pinnacle West<br>APS | First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992 | 10.2 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 10.1.2b | Pinnacle West<br>APS | Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994 | 10.3 to APS's 1994 Form 10-K Report, File No. 1-4473 | 3/30/1995 |
| 10.1.2c | Pinnacle West<br>APS | Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 20, 1996 | 10.1 to APS's June 30, 1996 Form 10-Q Report, File No. 1-4473 | 8/9/1996 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 10.1.2d | Pinnacle West<br>APS | Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of December 16, 1996 | APS 10.5 to APS's 1996 Form 10-K Report, File No. 1-4473 | 3/28/1997 |
| 10.1.2e | Pinnacle West<br>APS | Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000 | 10.1 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962 | 5/15/2002 |
| 10.1.2f | Pinnacle West<br>APS | Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002 | 10.3 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962 | 5/15/2002 |
| 10.1.2g | Pinnacle West<br>APS | Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of December 19, 2003 | 10.4 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962 | 3/15/2004 |
| 10.1.2h | Pinnacle West<br>APS | Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of April 1, 2007 | 10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962 | 2/27/2008 |
| 10.2.1[b] | Pinnacle West<br>APS | Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively | 10.4 to APS's 1988 Form 10-K Report, File No. 1-4473 | 3/8/1989 |
| 10.2.1a[b] | Pinnacle West<br>APS | Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993 | 10.3A to APS's 1993 Form 10-K Report, File No. 1-4473 | 3/30/1994 |
| 10.2.1b[b] | Pinnacle West<br>APS | Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993 | 10.2 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473 | 11/10/1994 |
| 10.2.1c[b] | Pinnacle West<br>APS | Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997 | 10.3A to APS's 1996 Form 10-K Report, File No. 1-4473 | 3/28/1997 |
| 10.2.1d[b] | Pinnacle West<br>APS | Sixth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 2001 | 10.8A to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962 | 3/14/2001 |
| 10.2.2[b] | Pinnacle West<br>APS | Arizona Public Service Company Directors' Deferred Compensation Plan, as restated, effective January 1, 1986 | 10.1 to APS's June 30, 1986 Form 10-Q Report, File No. 1-4473 | 8/13/1986 |
| 10.2.2a[b] | Pinnacle West<br>APS | Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993 | 10.2A to APS's 1993 Form 10-K Report, File No. 1-4473 | 3/30/1994 |
| 10.2.2b[b] | Pinnacle West<br>APS | Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993 | 10.1 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473 | 11/10/1994 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 10.2.2c[b] | Pinnacle West APS | Fourth Amendment to the Arizona Public Service Company Directors Deferred Compensation Plan, effective as of January 1, 1999 | 10.8A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962 | 3/30/2000 |
| 10.2.3[b] | Pinnacle West APS | Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996 | 10.14A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962 | 3/30/2000 |
| 10.2.3a[b] | Pinnacle West APS | First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans | 10.15A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962 | 3/30/2000 |
| 10.2.4[b] | Pinnacle West APS | Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996 | 10.10A to APS's 1995 Form 10-K Report, File No. 1-4473 | 3/29/1996 |
| 10.2.4a[b] | Pinnacle West APS | First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan | 10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962 | 3/30/2000 |
| 10.2.4b[b] | Pinnacle West APS | Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan | 10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962 | 3/30/2000 |
| 10.2.4c[b] | Pinnacle West APS | Third Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective as of January 1, 2002 | 10.3 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962 | 5/15/2003 |
| 10.2.4d[b] | Pinnacle West APS | Fourth Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective January 1, 2003 | 10.64 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/13/2006 |
| 10.2.5[b] | Pinnacle West APS | Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates (as amended and restated effective January 1, 2016) | 10.2.5 to Pinnacle West/APS 2015 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/19/2016 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 10.3.1[b] | Pinnacle West<br>APS | Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, amended and restated as of January 1, 2003 | 10.7A to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962 | 3/15/2004 |
| 10.3.1a[b] | Pinnacle West<br>APS | Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 18, 2003 | 10.48b to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/13/2006 |
| 10.3.2[b] | Pinnacle West<br>APS | Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016) | 10.3.2 to Pinnacle West/APS 2015 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/19/2016 |
| 10.3.2a[b] | Pinnacle West<br>APS | First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016) | | |
| 10.4.1[b] | APS | Letter Agreement dated December 20, 2006 between APS and Randall K. Edington | 10.78 to Pinnacle West/APS 2006 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/28/2007 |
| 10.4.2[b] | APS | Letter Agreement dated July 22, 2008 between APS and Randall K. Edington | 10.3 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-4473 | 8/7/2008 |
| 10.4.3[b] | Pinnacle West<br>APS | Letter Agreement dated June 17, 2008 between Pinnacle West/APS and James R. Hatfield | 10.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 8/7/2008 |
| 10.4.4[b] | APS | Supplemental Agreement dated December 26, 2008 between APS and Randall K. Edington | 10.4.10 to Pinnacle West/APS 2008 Form 10-K Report, File No. 1-4473 | 2/20/2009 |
| 10.4.5[b] | APS | Description of 2010 Palo Verde Specific Compensation Opportunity for Randall K. Edington | 10.4.13 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/19/2010 |
| 10.4.6[b] | Pinnacle West | Letter Agreement dated May 21, 2009, between Pinnacle West and David P. Falck | 10.4 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File No. 1-8962 | 5/6/2010 |
| 10.4.7[b] | APS | Supplemental Agreement dated June 19, 2012 between APS and Randall K. Edington | 10.1 to Pinnacle West/APS June 30, 2012 Form 10-Q Report File Nos. 1-8962 and 1-4473 | 8/2/2012 |
| 10.4.8[b] | APS | Description of 2016 Palo Verde Specific Compensation Opportunity for Randall K. Edington | Pinnacle West/APS December 15, 2015 Form 8-K Report, File No. 1-4473 | 12/21/2015 |
| 10.4.9[b] | APS | Supplemental Agreement dated December 14, 2014 between APS and Randall K. Edington | 10.4.9 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 10.5.1[bd] | Pinnacle West<br>APS | Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries | 10.77 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/13/2006 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 10.5.1a[bd] | Pinnacle West APS | Form of Amended and Restated Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries | 10.4 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 11/6/2007 |
| 10.5.2[bd] | Pinnacle West APS | Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries | 10.3 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 11/6/2007 |
| 10.5.3[bd] | Pinnacle West APS | Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries | 10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/19/2010 |
| 10.5.4[bd] | Pinnacle West APS | Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries | 10.5.4 to Pinnacle West/APS 2012 Form 10-K, File Nos. 1-8962 and 1-4473 | 2/22/2013 |
| 10.6.1[b] | Pinnacle West | Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders, File No. 1-8962 | 4/20/2007 |
| 10.6.1a[b] | Pinnacle West | First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report, File No. 1-8962 | 4/20/2007 |
| 10.6.1b[bd] | Pinnacle West APS | Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/5/2009 |
| 10.6.1c[bd] | Pinnacle West | Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962 | 8/3/2010 |
| 10.6.1d[bd] | Pinnacle West | Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962 | 8/3/2010 |
| 10.6.1e[bd] | Pinnacle West | Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.4 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962 | 4/29/2011 |
| 10.6.1f[bd] | Pinnacle West | Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan | 10.5 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962 | 4/29/2011 |
| 10.6.1g[bd] | Pinnacle West | Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (Supplemental 2010 Award) | 10.6 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962 | 4/29/2011 |
| 10.6.2[b] | Pinnacle West | Description of Annual Stock Grants to Non-Employee Directors | 10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962 | 11/6/2007 |
| 10.6.3[b] | Pinnacle West | Description of Annual Stock Grants to Non-Employee Directors | 10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962 | 8/7/2008 |

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| 10.6.4[bd] | Pinnacle West<br>APS | Summary of 2017 CEO Variable Incentive Plan and Officer Variable Incentive Plan | | |
| 10.6.5 | Pinnacle West | Description of Restricted Stock Unit Grant to Donald E. Brandt | Pinnacle West/APS December 24, 2012 Form 8-K Report, File No. 1-8962 | 12/26/2012 |
| 10.6.6[b] | Pinnacle West<br>APS | Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | Appendix A to the Proxy Statement for Pinnacle West's 2012 Annual Meeting of Shareholders, File No. 1-8962 | 3/29/2012 |
| 10.6.6a[bd] | Pinnacle West | Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | 10.1 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/3/2012 |
| 10.6.6b[bd] | Pinnacle West | Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | 10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/3/2012 |
| 10.6.6c[bd] | Pinnacle West | Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | 10.6.8c to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/21/2014 |
| 10.6.6d[bd] | Pinnacle West | Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | 10.6.8d to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/21/2014 |
| 10.6.6e[bd] | Pinnacle West | Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | 10.6.6e to Pinnacle West/APS 2015 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/19/2016 |
| 10.6.6f[bd] | Pinnacle West | Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | | |
| 10.6.6g[bd] | Pinnacle West | Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan | | |
| 10.6.6h[bd] | Pinnacle West | Master Amendment to Performance Share Agreements | 10.3 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/3/2012 |
| 10.6.6i[bd] | Pinnacle West | Master Amendment to Restricted Stock Unit Agreements | 10.4 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/3/2012 |
| 10.7.1 | Pinnacle West<br>APS | Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant | 5.01 to APS's Form S-7 Registration Statement, File No. 2-59644 | 9/1/1977 |
| 10.7.1a | Pinnacle West<br>APS | Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant | 5.02 to APS's Form S-7 Registration Statement, File No. 2-59644 | 9/1/1977 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: a | Date Filed |
|---|---|---|---|---|
| 10.7.1b | Pinnacle West APS | Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985 | 10.36 to Pinnacle West's Registration Statement on Form 8-B Report, File No. 1-8962 | 7/25/1985 |
| 10.7.1c | Pinnacle West APS | Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011 | 10.1 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 4/29/2011 |
| 10.7.1d | Pinnacle West APS | Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011 | 10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 4/29/2011 |
| 10.7.2 | Pinnacle West APS | Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site | 5.04 to APS's Form S-7 Registration Statement, File No. 2-59644 | 9/1/1977 |
| 10.7.2a | Pinnacle West APS | Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Site dated April 25, 1985 | 10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962 | 7/25/1985 |
| 10.7.3 | Pinnacle West APS | Application and Grant of APS rights-of-way and easements, Four Corners Site | 5.05 to APS's Form S-7 Registration Statement, File No. 2-59644 | 9/1/1977 |
| 10.7.3a | Pinnacle West APS | Application and Amendment No. 1 to Grant of APS rights-of-way and easements, Four Corners Site dated April 25, 1985 | 10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962 | 7/25/1985 |
| 10.7.4a | Pinnacle West APS | Four Corners Project Co-Tenancy Agreement Amendment No. 6 | 10.7 to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962 | 3/14/2001 |
| 10.7.4b | Pinnacle West APS | Four Corners Project Co-Tenancy Agreement Amendment No. 7, dated December 30, 2013, among APS, El Paso Electric Company, Public Service Company of New Mexico, SRP, SCE, and Tucson Electric Power Company | 10.3 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/2/2014 |
| 10.8.1 | Pinnacle West APS | Indenture of Lease, Navajo Units 1, 2, and 3 | 5(g) to APS's Form S-7 Registration Statement, File No. 2-36505 | 3/23/1970 |
| 10.8.2 | Pinnacle West APS | Application of Grant of rights-of-way and easements, Navajo Plant | 5(h) to APS Form S-7 Registration Statement, File No. 2-36505 | 3/23/1970 |
| 10.8.3 | Pinnacle West APS | Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant | 5(l) to APS's Form S-7 Registration Statement, File No. 2-394442 | 3/16/1971 |
| 10.8.4 | Pinnacle West APS | Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976, Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998 | 10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/13/2006 |

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|---|---|---|---|---|
| 10.8.5 | Pinnacle West APS | Navajo Project Participation Agreement dated as of September 30, 1969, and Amendment and Supplement No. 1 dated as of January 16, 1970, and Coordinating Committee Agreement No. 1 dated as of September 30, 1971 | 10.108 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/13/2006 |
| 10.9.1 | Pinnacle West APS | ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto | 10. 1 to APS's 1988 Form 10-K Report, File No. 1-4473 | 3/8/1989 |
| 10.9.1a | Pinnacle West APS | Amendment No. 13, dated as of April 22, 1991, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 10.1 to APS's March 31, 1991 Form 10-Q Report, File No. 1-4473 | 5/15/1991 |
| 10.9.1b | Pinnacle West APS | Amendment No. 14 to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 99.1 to Pinnacle West's June 30, 2000 Form 10-Q Report, File No. 1-8962 | 8/14/2000 |
| 10.9.1c | Pinnacle West APS | Amendment No. 15, dated November 29, 2010, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 10.9.1c to Pinnacle West/APS 2010 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/18/2011 |
| 10.9.1d | Pinnacle West APS | Amendment No. 16, dated April 28, 2014, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles | 10.2 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/2/2014 |
| 10.10.1 | Pinnacle West APS | Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991 | 10.1 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473 | 8/8/1991 |

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| 10.10.2 | Pinnacle West<br>APS | Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991 | 10.2 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473 | 8/8/1991 |
| 10.10.2a | Pinnacle West<br>APS | Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS | 10.3 to APS's 1995 Form 10-K Report, File No. 1-4473 | 3/29/1996 |
| 10.10.3 | Pinnacle West<br>APS | Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995 | 10.4 to APS's 1995 Form 10-K Report, File No. 1-4473 | 3/29/1996 |
| 10.10.4 | Pinnacle West<br>APS | Contract among PacifiCorp, APS and DOE Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995 | 10.5 to APS's 1995 Form 10-K Report, File No. 1-4473 | 3/29/1996 |
| 10.10.5 | Pinnacle West<br>APS | Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994 | 10.6 to APS's 1995 Form 10-K Report, File No. 1-4473 | 3/29/1996 |
| 10.11.1 | Pinnacle West | Term Loan Agreement dated as of December 31, 2014 among Pinnacle West, as Borrower, JPMorgan Chase Bank, N.A., as Agent, U.S. Bank Association, as Syndication Agent, TD Bank, N.A., The Bank of Nova Scotia and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and such institutions compromising the lenders party thereto | 10.11.2 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/20/2015 |
| 10.11.2 | Pinnacle West | Five-Year Credit Agreement dated as of May 13, 2016, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto | 10.1 to Pinnacle West/APS June 30, 2016 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 8/2/2016 |
| 10.11.3 | Pinnacle West | 364-day Credit Agreement dated as of August 31, 2016, among Pinnacle West, as Borrower, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Agent and Issuing Bank, and the lenders and other parties thereto | 10.1 to Pinnacle West/APS September 30, 2016 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 11/3/2016 |
| 10.11.4 | Pinnacle West<br>APS | Five-Year Credit Agreement dated as of September 2, 2015 among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto | 10.1 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 10/30/2015 |

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| 10.11.5 | Pinnacle West APS | Term Loan Agreement dated as of June 26, 2015 among APS, as Borrower, Toronto Dominion (Texas) LLC, as Agent, Citibank, N.A., as Syndication Agent, and such institutions compromising the lenders party thereto | 10.1 to Pinnacle West/APS June 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 7/30/2015 |
| 10.11.6 | Pinnacle West APS | Term Loan Agreement dated as of April 22, 2016 among APS, as Borrower, Toronto Dominion (Texas) LLC, as Agent and such institutions compromising the lenders party thereto | 10.1 to Pinnacle West/APS March 31, 2016 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 4/29/2016 |
| 10.11.7 | Pinnacle West APS | Five-Year Credit Agreement dated as of May 13, 2016, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto | 10.2 to Pinnacle West/APS June 30, 2016 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 8/2/2016 |
| 10.12.1[c] | Pinnacle West APS | Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee | 4.3 to APS's Form 18 Registration Statement, File No. 33-9480 | 10/24/1986 |
| 10.12.1a[c] | Pinnacle West APS | Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee | 10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473 | 12/4/1986 |
| 10.12.1b[c] | Pinnacle West APS | Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee | 10.3 to APS's 1988 Form 10-K Report, File No. 1-4473 | 3/8/1989 |
| 10.12.1c[c] | Pinnacle West APS | Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee | 10.3 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |

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| 10.12.1d[c] | Pinnacle West<br>APS | Amendment No. 4, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Emerson Finance LLC, as Lessor, and APS, as Lessee | 10.2 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 10/30/2015 |
| 10.12.1e[c] | Pinnacle West<br>APS | Amendment No. 3, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Security Pacific Capital Leasing Corporation, as Lessor, and APS, as Lessee | 10.3 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 10/30/2015 |
| 10.12.2 | Pinnacle West<br>APS | Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee | 10.1 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473 | 1/20/1987 |
| 10.12.2a | Pinnacle West<br>APS | Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee | 4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473 | 8/24/1987 |
| 10.12.2b | Pinnacle West<br>APS | Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee | 10.4 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 10.12.2c | Pinnacle West<br>APS | Amendment No. 3, dated July 10, 2014, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to the First National Bank of Boston, as Lessor, and APS, as Lessee | 10.2 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 7/31/2014 |

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| 10.13.1 | Pinnacle West APS | Agreement between Pinnacle West Energy Corporation and APS for Transportation and Treatment of Effluent by and between Pinnacle West Energy Corporation and APS dated as of the 10th day of April, 2001 | 10.102 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/16/2005 |
| 10.13.2 | Pinnacle West APS | Agreement for the Transfer and Use of Wastewater and Effluent by and between APS, SRP and PWE dated June 1, 2001 | 10.103 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/16/2005 |
| 10.13.3 | Pinnacle West APS | Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP | 10.104 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/16/2005 |
| 10.13.4 | Pinnacle West APS | Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP | 10.105 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 3/16/2005 |
| 10.13.5 | Pinnacle West APS | Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and SRP | 10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 5/6/2010 |
| 10.14.1 | Pinnacle West APS | Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP | 10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386 | 3/13/1985 |
| 10.15.1 | Pinnacle West APS | Territorial Agreement between APS and SRP | 10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473 | 5/15/1998 |
| 10.15.2 | Pinnacle West APS | Power Coordination Agreement between APS and SRP | 10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473 | 5/15/1998 |
| 10.15.3 | Pinnacle West APS | Memorandum of Agreement between APS and SRP | 10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473 | 5/15/1998 |
| 10.15.3a | Pinnacle West APS | Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998 | 10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473 | 6/26/1998 |
| 10.16 | Pinnacle West APS | Purchase and Sale Agreement dated November 8, 2010 by and between SCE and APS | 10.1 to Pinnacle West/APS November 8, 2010 Form 8-K Report, File Nos. 1-8962 and 1-4473 | 11/8/2010 |
| 10.17 | Pinnacle West APS | Proposed Settlement Agreement dated January 6, 2012 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 73183) | 10.17 to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473 | 2/24/2012 |
| 12.1 | Pinnacle West | Ratio of Earnings to Fixed Charges | | |
| 12.2 | APS | Ratio of Earnings to Fixed Charges | | |
| 12.3 | Pinnacle West | Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements | | |
| 21.1 | Pinnacle West | Subsidiaries of Pinnacle West | | |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 23.1 | Pinnacle West | Consent of Deloitte & Touche LLP | | |
| 23.2 | APS | Consent of Deloitte & Touche LLP | | |
| 31.1 | Pinnacle West | Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended | | |
| 31.2 | Pinnacle West | Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended | | |
| 31.3 | APS | Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended | | |
| 31.4 | APS | Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended | | |
| 32.1[e] | Pinnacle West | Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | | |
| 32.2[e] | APS | Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | | |
| 99.1 | Pinnacle West<br>APS | Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee | 4.2 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.1a | Pinnacle West<br>APS | Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee | 4.3 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.2[c] | Pinnacle West<br>APS | Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein | 28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473 | 11/9/1992 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 99.2a[c] | Pinnacle West<br>APS | Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein | 10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473 | 12/4/1986 |
| 99.2b[c] | Pinnacle West<br>APS | Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein | 28.4 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.3[c] | Pinnacle West<br>APS | Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.5 to APS's Form 18 Registration Statement, File No. 33-9480 | 10/24/1986 |
| 99.3a[c] | Pinnacle West<br>APS | Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473 | 12/4/1986 |
| 99.3b[c] | Pinnacle West<br>APS | Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee | 4.4 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.4[c] | Pinnacle West<br>APS | Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.3 to APS's Form 18 Registration Statement, File No. 33-9480 | 10/24/1986 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 99.4a[c] | Pinnacle West APS | Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. l on December 3, 1986 Form 8, File No. 1-4473 | 12/4/1986 |
| 99.4b[c] | Pinnacle West APS | Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.6 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.5 | Pinnacle West APS | Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein | 28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473 | 11/9/1992 |
| 99.5a | Pinnacle West APS | Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein | 28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473 | 8/10/1987 |
| 99.5b | Pinnacle West APS | Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein | 28.5 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.6 | Pinnacle West APS | Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 10.2 to APS's November 18, 1986 Form 10-K Report, File No. 1-4473 | 1/20/1987 |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 99.6a | Pinnacle West<br>APS | Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee | 4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473 | 8/24/1987 |
| 99.6b | Pinnacle West<br>APS | Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee | 4.5 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.7 | Pinnacle West<br>APS | Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 10.5 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473 | 1/20/1987 |
| 99.7a | Pinnacle West<br>APS | Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee | 28.7 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.8[c] | Pinnacle West<br>APS | Indemnity Agreement dated as of March 17, 1993 by APS | 28.3 to APS's 1992 Form 10-K Report, File No. 1-4473 | 3/30/1993 |
| 99.9 | Pinnacle West<br>APS | Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank | 28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473 | 8/10/1987 |
| 99.10 | Pinnacle West<br>APS | ACC Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules | 10.2 to APS's September 30, 1999 Form 10-Q Report, File No. 1-4473 | 11/15/1999 |
| 99.11 | Pinnacle West | Purchase Agreement by and among Pinnacle West Energy Corporation and GenWest, L.L.C. and Nevada Power Company, dated June 21, 2005 | 99.5 to Pinnacle West/APS June 30, 2005 Form 10-Q Report, File Nos. 1-8962 and 1-4473 | 8/9/2005 |
| 101.INS | Pinnacle West<br>APS | XBRL Instance Document | | |
| 101.SCH | Pinnacle West<br>APS | XBRL Taxonomy Extension Schema Document | | |
| 101.CAL | Pinnacle West<br>APS | XBRL Taxonomy Extension Calculation Linkbase Document | | |

| Exhibit No. | Registrant(s) | Description | Previously Filed as Exhibit: [a] | Date Filed |
|---|---|---|---|---|
| 101.LAB | Pinnacle West<br>APS | XBRL Taxonomy Extension Label Linkbase Document | | |
| 101.PRE | Pinnacle West<br>APS | XBRL Taxonomy Extension Presentation Linkbase Document | | |
| 101.DEF | Pinnacle West<br>APS | XBRL Taxonomy Definition Linkbase Document | | |

[a]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[b]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

[e]Furnished herewith as an Exhibit.

## SIGNATURES

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

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: February 24, 2017

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

## Power of Attorney

We, the undersigned directors and executive officers of Pinnacle West Capital Corporation, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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

| Signature | Title | Date |
|---|---|---|
| /s/ Donald E. Brandt<br>(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer) | Principal Executive Officer and Director | February 24, 2017 |
| /s/ James R. Hatfield<br>(James R. Hatfield, Executive Vice President and Chief Financial Officer) | Principal Financial Officer | February 24, 2017 |
| /s/ Denise R. Danner<br>(Denise R. Danner, Vice President, Controller and Chief Accounting Officer) | Principal Accounting Officer | February 24, 2017 |

| | | |
|---|---|---|
| /s/ Denis A. Cortese<br>(Denis A. Cortese, M.D.) | Director | February 24, 2017 |
| /s/ Richard P. Fox<br>(Richard P. Fox) | Director | February 24, 2017 |
| /s/ Michael L. Gallagher<br>(Michael L. Gallagher) | Director | February 24, 2017 |
| /s/ Roy A. Herberger, Jr.<br>(Roy A. Herberger, Jr., Ph.D.) | Director | February 24, 2017 |
| /s/ Dale E. Klein<br>(Dale E. Klein, Ph.D.) | Director | February 24, 2017 |
| /s/ Humberto S. Lopez<br>(Humberto S. Lopez) | Director | February 24, 2017 |
| /s/ Kathryn L. Munro<br>(Kathryn L. Munro) | Director | February 24, 2017 |
| /s/ Bruce J. Nordstrom<br>(Bruce J. Nordstrom) | Director | February 24, 2017 |
| /s/ Paula J. Sims<br>(Paula J. Sims) | Director | February 24, 2017 |
| /s/ David P. Wagener<br>(David P. Wagener) | Director | February 24, 2017 |

## SIGNATURES

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

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: February 24, 2017

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

## Power of Attorney

We, the undersigned directors and executive officers of Arizona Public Service Company, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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

| Signature | Title | Date |
|---|---|---|
| /s/ Donald E. Brandt<br>(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer) | Principal Executive Officer and Director | February 24, 2017 |
| /s/ James R. Hatfield<br>(James R. Hatfield, Executive Vice President and Chief Financial Officer) | Principal Financial Officer | February 24, 2017 |
| /s/ Denise R. Danner<br>(Denise R. Danner, Vice President, Controller and Chief Accounting Officer) | Principal Accounting Officer | February 24, 2017 |

| | | |
|---|---|---|
| /s/ Denis A. Cortese<br>(Denis A. Cortese, M.D.) | Director | February 24, 2017 |
| /s/ Richard P. Fox<br>(Richard P. Fox) | Director | February 24, 2017 |
| /s/ Michael L. Gallagher<br>(Michael L. Gallagher) | Director | February 24, 2017 |
| /s/ Roy A. Herberger, Jr.<br>(Roy A. Herberger, Jr., Ph.D.) | Director | February 24, 2017 |
| /s/ Dale E. Klein<br>(Dale E. Klein, Ph.D.) | Director | February 24, 2017 |
| /s/ Humberto S. Lopez<br>(Humberto S. Lopez) | Director | February 24, 2017 |
| /s/ Kathryn L. Munro<br>(Kathryn L. Munro) | Director | February 24, 2017 |
| /s/ Bruce J. Nordstrom<br>(Bruce J. Nordstrom) | Director | February 24, 2017 |
| /s/ Paula J. Sims<br>(Paula J. Sims) | Director | February 24, 2017 |
| /s/ David P. Wagener<br>(David P. Wagener) | Director | February 24, 2017 |

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PINNACLE WEST
CAPITAL CORPORATION