NEW APPLICATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

LEA MÁRQUEZ PETERSON, Chairwoman
SANDRA D. KENNEDY
JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR AN ORDER OR ORDERS AUTHORIZING IT TO ISSUE, INCUR, AND AMEND EVIDENCES OF LONG-TERM INDEBTEDNESS AS DEFINED HEREIN AND SHORT-TERM INDEBTEDNESS, TO EXECUTE NEW SECURITY INSTRUMENTS TO SECURE ANY SUCH INDEBTEDNESS, AND FOR DECLARATORY ORDER CONCERNING VARIABLE INTEREST ENTITIES.	DOCKET NO. E-01345A-22-_________ **APPLICATION**

I. INTRODUCTION

Pursuant to Arizona Revised Statutes ("A.R.S.") §§ 40-285, 40-301 and 40-302, and Arizona Corporation Commission ("Commission") Decision No. 77853 (December 17, 2020 (the "2020 Order"), Arizona Public Service Company ("APS" or "Company") files this Application seeking one or more orders which, together, will authorize the Company to: (1) increase its current authorization of Continuing Long-Term Debt (as defined herein) from $7.5 billion up to $8.0 billion, including the ability to

ACC - Docket Control - Received 4/6/2022 5:07 PM
ACC - Docket Control - Docketed 4/7/2022 8:43 AM

redeem, refinance, refund, renew, reissue, roll-over, repay, re-price, and re-borrow from time-to-time such Continuing Long-Term Debt, and establish and amend the terms and provisions of Continuing Long-Term Debt; (2) continue its authorization of Continuing Short-Term Debt (as defined herein) granted in the 2020 Order, including the ability to redeem, refinance, refund, renew, reissue, roll-over, repay, re-price, and re-borrow from time-to-time such Continuing Short-Term Debt, and establish and amend the terms and provisions of Continuing Short-Term Debt from time-to-time; and (3) determine the form of security, if any, for the Continuing Long-Term Debt and the Continuing Short-Term Debt, execute and deliver one or more Security Instruments (as defined herein) in connection with the Continuing Long-Term Debt and the Continuing Short-Term Debt, and establish and amend the terms and provisions of any such Security Instruments from time-to-time.

APS further requests a declaratory order reconfirming that all impacts of the consolidation with APS for Generally Accepted Accounting Principles ("GAAP") purposes of the Palo Verde Sale Leaseback Lessor Trusts as Variable Interest Entities ("VIEs") are to be excluded for the purposes of calculating the Common Equity Test and Debt Service Coverage ratio ("DSC") (both defined in the 2020 Order). VIEs should also be excluded from calculating Continuing Long-Term Debt and Continuing Short-Term Debt balances outstanding.

Similarly, APS asks that any order or orders issued in this proceeding preserve the findings and authorizations contained in Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986). These two decisions pertain to Palo Verde Unit 2 sale and leaseback transactions. Pursuant to the 2020 Order, these lease obligations are also excluded from the calculation of Continuing Long-Term Debt and both the Common Equity Test and the DSC.

In addition, APS asks that the provisions of the 2020 Order addressing the meaning of long-term indebtedness clarify that long-term indebtedness includes solely obligations that represent repayment obligations for borrowed money (i.e., traditional debt) and excludes all purchased power agreements ("PPAs") that constitute financing leases. APS believes this exclusion is consistent with the intended scope of the statutes cited above, which were enacted and last amended in 1978 (*see* Ariz. Laws 1978, Ch. 201, § 697)—decades before anything other than borrowed money was required to be presented on a balance sheet alongside debt under GAAP (modified regarding finance lease accounting in 2019). Such clarification is, thus, necessary due to these recent lease accounting rule changes.

As an alternative to this request for clarification as to PPAs and long-term indebtedness, APS proposes that only the net liability associated with any PPA that constitutes a financing lease count toward the $8.0 billion Continuing Long-Term Debt authorization sought in this application. Unlike debt for traditionally-borrowed money, PPAs that constitute financing leases are accompanied by a right to use property, which would be represented by a lease asset on APS's balance sheet. The value of this asset largely offsets the financing lease liability associated with PPAs. As such, for PPAs that constitute financing leases, the net liability—the value of the lease liability minus the lease asset—represents the true impact on APS's balance sheet and, hence, overall financial condition. Given these unique attributes, if PPAs that constitute financing leases are to be counted towards APS's limit on Continuing Long-Term Debt, only the net lease liability should be considered. Failing this alternative approach (and in lieu of the clarification sought regarding the exclusion of PPAs that constitute finance leases from the definition of Continuing Long-Term Debt), APS would need—as part of this Application—to request an increase of its Continuing Long-Term Debt authorization up to $10.5 billion instead of a more modest increase of only $500 million up to $8.0 billion.

Finally, APS's ability to incur additional amounts of Continuing Long-Term Debt has for many years been subject to meeting two financial tests at the time of issuance – a Common Equity (Ratio) Test and a DSC Test. Both tests are defined and discussed in the 2020 Order. APS requests that these tests remain unchanged.

APS requests issuance of the order or orders sought by this Application by December 31, 2022, so that APS will have certainty as to the scope of its financing authority. APS also requests that the order or orders sought by this Application become effective immediately upon the issuance thereof.

II. SUPPORTING STATEMENTS

In support of this Application, the Company respectfully states as follows:

1. APS is a corporation duly organized and existing under the laws of the State of Arizona. The Company's principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004, and its post office address is P.O. Box 53999, Phoenix, Arizona 85072-3999.

2. The Company is a public service corporation principally engaged in providing electric service in the State of Arizona.

3. The Company is a wholly-owned subsidiary of Pinnacle West Capital Corporation ("PNW").

4. The Company is authorized to file this Application with the Commission pursuant to A.R.S. § 10-302.

5. The attorneys for the Company in this proceeding are Melissa M. Krueger and Jeffrey S. Allmon.

6. This Application is supported by the Declaration of Andrew Cooper, Vice President and Treasurer of the Company, which is attached hereto as Exhibit A.

A. Debt Financing Needs and Issues

7. The 2020 Order allows the Company, among other things, to (i) issue, sell, and incur the Continuing Long-Term Debt (defined as long-term indebtedness, including current maturities, outstanding on the effective date of the 2020 Order or thereafter issued or incurred pursuant to the 2020 Order) so long as the total Continuing Long-Term Debt does not exceed $7.5 billion for any period of more than thirty (30) days; (ii) issue, sell, and incur Continuing Short-Term Debt (defined as all short-term indebtedness outstanding on the effective date of the 2020 Order or thereafter issued or incurred

pursuant to the 2020 Order) so long as the total Continuing Short-Term Debt does not exceed the sum of: (a) seven percent (7%) of the Company's capitalization and (b) $500 million; (iii) redeem, refinance, refund, renew, reissue, roll-over, repay, and re-borrow from time-to-time such Continuing Long-Term Debt and Continuing Short-Term Debt; (iv) establish and amend the terms and provisions of the Continuing Long-Term Debt and Continuing Short-Term Debt; (v) determine the form of security, if any, for the Continuing Long-Term Debt and Continuing Short-Term Debt, execute and deliver any necessary Security Instruments (defined as any mortgage and deed of trust or similar instrument that establishes a lien on (a) all or substantially all of the Company's property, including after-acquired property, as security for all or any part of the Company's indebtedness, or (b) separate properties or groups of properties of the Company to secure particular issues or groups of issues of indebtedness), and establish and amend the terms and provisions of the Security Instruments, as may be deemed appropriate by the Company (except that APS may not enter into derivative financial instruments for purposes of managing interest rate risk and exposure and may not issue other types of financial derivative securities as part of the Continuing Long-Term Debt or Continuing Short-Term Debt authorized herein); and (vi) pay all related expenses. A copy of the 2020 Order is attached to this Application as Exhibit B.

8. In this Application, the Company seeks Commission authorization to increase its current Continuing Long-Term Debt authorization by $500 million to $8.0 billion (subject to the clarification APS seeks as to the definition of Continuing Long-Term Debt) and maintain the Continuing Short-Term Debt limitations as set forth in the 2020 Order. The Declaration describes the Company's reasons for its request to increase the Continuing Long-Term Debt financing authority and retention of the Company's existing Continuing Short-Term Debt authority. *See* discussion of "APS's Long-Term Financing Needs" in the Declaration attached as Exhibit A.

9. The Company requests that such authorization permit any redemptions, refinancing, refunding, renewal, reissuance, roll-over, repayment, re-pricing and/or re-

borrowing of any such Continuing Long-Term Debt, the incurrence or issuance of any additional Continuing Long-Term Debt and the establishment, amendment, or revision of any terms or provisions of or relating to any Continuing Long-Term Debt as long as the total amount of Continuing Long-Term Debt at any one time outstanding does not exceed $8.0 billion for any period of more than thirty (30) days (again, subject to the clarification APS seeks as to the definition of Continuing Long-Term Debt). Such authorization will allow the Company to maintain the flexibility necessary to refund and/or incur or issue Continuing Long-Term Debt as market conditions allow. At no time, however, will the Company be able to exceed the proposed Continuing Long-Term Debt limitation for any period of more than thirty (30) days without further Commission authorization. The authorization sought in this paragraph would supersede and replace the Continuing Long-Term Debt limitation authorized by the 2020 Order.

1. The Definition of Continuing Long-Term Debt in the 2020 Order Should be Clarified to only Cover Traditionally Borrowed Money.

10. In 2019 the new GAAP lease accounting standard, ASC 842, became effective, and resulted in changes in the treatment and presentation of lease obligations. ASC 842 requires both operating and finance lease obligations to be reflected on the balance sheet but does not require the lease obligations to be classified as debt instruments under GAAP. This is because lease obligations are distinct from traditional debt obligations for borrowed money. This distinction results from a drive to achieve more consistent balance sheet disclosure across accounting standards but does not change the underlying nature of PPAs that constitute finance leases as being distinct from and unlike obligations associated with borrowed money.

11. Consistent with the GAAP presentation, APS requests the order or orders issued in this proceeding clarify that long-term indebtedness for purposes of the overall cap of $8.0 billion for Continuing Long-Term Debt (as requested herein), the cap on Continuing Short-Term Debt, the computation of the DSC and Common Equity Test and of A.R.S. §§ 40-301, *et seq.*, excludes all PPAs that constitute finance leases. With this

clarification of the definition of Continuing Long-Term Debt, APS requires only a modest increase in Commission authorization for the Company's long-term indebtedness of up to an $8.0 billion limit. Such distinct treatment is consistent with Commission authority under A.R.S. §§ 40-301, *et seq.*, which only references the issuance of "stocks and stock certificates, bonds, notes and *other evidences of indebtedness*." *See, e.g.*, A.R.S. § 40-302 (emphasis added) (characterizing Commission authority over public service corporation financing). These statutes were enacted and last amended decades ago (i.e., in 1978)—long before GAAP standards were modified in 2019 to change the balance sheet presentation of lease obligations—and, hence, could not have contemplated a scope that extends beyond traditional indebtedness to cover finance leases. *See* Ariz. Laws 1978, Ch. 201, § 697. As such, given that GAAP does not require lease and other service obligations, such as PPAs, to be classified as debt, the exclusion of PPAs that otherwise constitute financing leases from the definition of Continuing Long-Term Debt is entirely appropriate.

12. PPAs, in particular, are also distinct from traditional debt and "other evidences of indebtedness" in so far as the Commission is able to oversee the costs of purchased power through the Company's Power Supply Adjustment mechanism. This oversight mechanism is wholly appropriate for PPAs where APS takes on these obligations solely out of need to address customer load growth. Unlike debt for traditionally borrowed money—for which APS can access capital to finance the purchase of plant additions to rate base—PPAs provide for only the purchase of energy, capacity, energy storage, and other critical electricity service resources needed to serve customers.

13. Moreover, PPAs are accounted for much differently than debt for traditionally borrowed money. Whereas traditional debt represent unsecured obligations of APS not associated with any specific asset, the liabilities associated with PPAs that constitute financing leases are largely offset on the Company's balance sheet by leased assets (i.e., the right to use leased property). This offsetting effect means that the impact

of PPA obligations that otherwise constitute financing leases is effectively neutral with respect to APS's overall financial condition.

14. In these additional respects, PPAs and other service agreements are unlike and distinct from debt for traditionally borrowed money covered by A.R.S. §§ 40-301, *et seq*. *See* A.R.S. § 40-302(A) (describing the Commission's authority to issue financing orders for public service corporations and the purposes for which such authority may be used but providing that "except as otherwise permitted in the order, such purposes are *not, wholly or in part, reasonably chargeable to operative expenses or to income*") (emphasis added).

15. In the alternative, if the Commission would like to maintain the current definition of Continuing Long-Term Debt from the 2020 Order, APS requests that the Commission only count the *net* liability associated with PPAs that constitute financing leases toward the Company's limit on long-term indebtedness. As described above, this treatment is reasonable given the unique attributes associated with how PPA financing leases are presented on APS's balance sheet. In this respect, PPAs that constitute financing leases provide APS with a right to use property. This right is presented as a leased asset, which largely offsets the liabilities associated with a given PPA that constitute a financing lease. Because the effect on APS's balance sheet, and hence the Company's overall financial condition, is effectively neutral with PPAs that constitute financing leases, considering only the net liability associated with such obligations is a reasonable approach to evaluating how financing lease PPAs impact APS's Continuing Long-Term Debt authority. As such, this net liability—i.e., the PPA financing lease liability minus the lease asset—should be the only portion of PPAs, which otherwise constitute financing leases, that should count toward APS's limit on Continuing Long-Term Debt.

16. Failing this alternative approach (in lieu of the clarification sought regarding the exclusion of PPA finance leases from the definition of Continuing Long-Term Debt), APS would need—as part of this Application—to request an increase of its Continuing

Long-Term Debt authorization up to $10.5 billion instead of a modest increase of only up to $8.0 billion.

2. Other Considerations for this Application.

17. Consistent with the 2020 Order, the Company also requests a declaratory order that confirms that all impacts of the consolidation with APS for accounting purposes of VIEs are to be excluded for the purposes of calculating the Common Equity Test and DSC and any Continuing Long-Term Debt and Continuing Short-Term Debt balances outstanding. Although beginning in 2010, GAAP required these entities to be consolidated with APS for financial reporting purposes, APS has no debt or equity interest in the VIEs and does not exercise any manner of control over them.

18. The present formula for determining DSC per the 2020 Order states that DSC is calculated by dividing the sum of Operating Income plus Depreciation and Amortization plus Income Taxes by total interest expense. As part of this Application, APS requests that this test remain unchanged.

19. The Company requests that the authorizations sought in this Application be permitted to go into effect on the effective date of the order or orders issued in this proceeding and remain effective unless or until APS files a new financing application. In such instance, the authorizations sought herein would remain in effect pending Commission disposition of any such future financing application.

20. The Company requests that all other ordering language, provisions, obligations, and requirements of the 2020 Order continue to apply to APS, without any modification in substance except as expressly requested herein, be included in the order or orders sought by this Application.

B. Purposes

21. Although described in more detail in the attached Declaration, the Company proposes that in general the net proceeds from its issuance of Continuing Long-Term Debt and Continuing Short-Term Debt will be applied, directly or indirectly, to augment the funds available from all sources to finance its construction, resource acquisition and

maintenance programs, to redeem or retire outstanding securities, to repay or refund other outstanding long-term or short-term debt, and to meet certain of the Company's working capital and other cash requirements.

C. General

17. The relief requested herein regarding the proposed issuance or incurrence of the Continuing Long-Term Debt and the Continuing Short-Term Debt, the establishment and amendment of any terms and provisions of any such indebtedness, the execution and delivery of any Security Instruments, and the establishment and amendment of any terms and provisions of any Security Instruments, all as contemplated herein, are for lawful purposes, are within the Company's corporate powers, are compatible with the public interest, with sound financial practices, and with the proper performance by the Company of service as a public service corporation and will not impair its ability to perform that service. The foregoing, all as contemplated herein, are reasonably necessary or appropriate for such purposes and that such purposes are not, wholly or in part, reasonably chargeable to the Company's operating expenses or to income, except as expressly contemplated by this Application.

18. The Company requests that notice of the filing of this Application be given as directed by the Commission in conformity with A.R.S. § 40-302.

19. The Company requests that the order or orders sought by this Application become effective immediately upon the issuance thereof.

20. The most current public financial statements of the Company and PNW, which are included in their most recent combined Annual Report on Form 10-K filed with the Securities Exchange Commission, are attached to this Application as Exhibit C.

* * * * * *

WHEREFORE, the Company asks that the Commission cause notice of the filing of this Application to be given as requested above; hold such a hearing or hearings as the Commission deems necessary at a time or times to be specified; make any inquiry or investigation as the Commission may deem of assistance in this matter; make any findings required by A.R.S. §§ 40-285, 40-301, and 40-302, as applicable, relative to the issuance and incurrence of Continuing Long-Term Debt and Continuing Short-Term Debt, the execution and delivery of any Security Instruments, the establishment and amendment of any terms and provisions of any Continuing Long-Term Debt or Continuing Short-Term Debt or any such Security Instruments issued in accordance therewith; establish that, so long as APS has filed a timely request for subsequent financing authority, any authorization provided as a result of this Application shall not expire and shall remain in effect until the Commission issues an order as to any subsequent application for additional financing authority; and thereafter make one or more immediately effective orders which, together:

(i) increase the Continuing Long-Term Debt limit from \$7.5 billion to \$8.0 billion and confirm the existing limitations on Continuing Short-Term Debt;

(ii) confirm that impacts of consolidation of VIEs are to be excluded from the Common Equity Test and DSC calculations as well as the calculation of Continuing Long-Term Debt and Continuing Short-Term Debt balances outstanding;

(iii) confirm that long-term indebtedness for purposes of the overall cap of \$8.0 billion for Continuing Long-Term Debt, the cap on Continuing Short-Term Debt, the computation of the DSC and Common Equity Test, and of A.R.S. §§ 40-301, *et seq.*, excludes all PPAs that constitute finance leases;

(iv) confirm that authorizations sought in this Application will be effective as of the effective date of order or orders sought by this Application;

(v) confirm the continued validity of Decision Nos. 55120 and 55320; and

(vi) confirm that all ordering language, provisions, obligations, and requirements of the 2020 Order not modified by the clauses above or as otherwise described herein will be included in the order or orders sought by this Application.

Dated at Phoenix, Arizona this 6th day of April 2022.

PINNACLE WEST CAPITAL CORPORATION

By: /s/ Jeffrey S. Allmon
Jeffrey S. Allmon
Melissa M. Krueger
Attorneys for Arizona Public Service Company

ORIGINAL electronically filed
this 6th day of April 2022 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

EXHIBITS

Exhibit A	Declaration of Andrew Cooper, the Vice President and Treasurer of Arizona Public Service Company.
Exhibit B	Arizona Corporation Commission Order in Decision No. 77853 (December 17, 2020).
Exhibit C	Pinnacle West Capital Corporation and Arizona Public Service Company Annual Report on Form 10-K for the year ended December 31, 2021.

Exhibit A

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

LEA MÁRQUEZ PETERSON, Chairwoman
SANDRA D. KENNEDY
JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR AN ORDER OR ORDERS AUTHORIZING IT TO ISSUE, INCUR, AND AMEND EVIDENCES OF LONG-TERM INDEBTEDNESS AS DEFINED HEREIN AND SHORT-TERM INDEBTEDNESS, TO EXECUTE NEW SECURITY INSTRUMENTS TO SECURE ANY SUCH INDEBTEDNESS, AND FOR DECLARATORY ORDER CONCERNING VARIABLE INTEREST ENTITIES.	DOCKET NO. E-01345A-22-____ **DECLARATION OF ANDREW COOPER**

STATE OF ARIZONA)
) ss.
County of Maricopa)

I, Andrew Cooper, upon my oath, do swear and attest as follows:

General

1. My name is Andrew Cooper. I am Vice President and Treasurer of Arizona Public Service Company ("APS" or "Company"). In my capacity as the Treasurer of the Company, I am responsible for the treasury, financing and investment functions at APS.

2. The assertions of fact contained within the Application of the Company, to which this Declaration is attached, are true and correct to the best of my knowledge and belief.

3. The purpose of this Declaration is to testify, from my personal experience and involvement as the Treasurer, regarding the rationale behind the requests contained in the Application.

Specific Background Facts

4. Arizona Corporation Commission ("Commission") Decision No. 77853 (December 17, 2020) (the "2020 Order"), allows the Company to have outstanding at any time long-term indebtedness (including current maturities) in an aggregate principal amount of up to $7.5 billion. By its terms, the 2020 Order excludes the impact of the Palo Verde Unit 2 sale/leaseback transactions, which were separately approved by the Commission in Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986). The 2020 Order permits the Company to issue, redeem or refinance and establish and amend the terms of its long-term debt, as long as total outstanding long-term debt does not exceed $7.5 billion during any period of more than thirty days. The fact that the long-term debt limit can actually be exceeded for a period of thirty days or less enables APS to continue its ability to conservatively refinance in advance of an upcoming maturity or planned redemption if APS is at or near the total limitation.

5. The modest increase in cap for Continuing Long-Term Debt requested in the Application would enable APS to continue to efficiently and reliably access external capital needed to refinance maturing indebtedness and fund capital investment over the next several years. These capital requirements include continued investment in energy infrastructure to maintain performance and reliability standards. Capital requirements also include the Company's ability to meet the future needs of our customers and serve the increasing load from Arizona's economic growth, as well as ensuring on-going investments needed to maintain the existing APS generation fleet. Thus, the requested financing order is compatible with sound financial policy and the public interest.

6. Arizona Revised Statutes § 40-302(D) allows the Company to issue short-term debt in an amount not to exceed 7% of its capitalization without Commission approval. However, A.R.S. § 40-302(D) restricts the refunding or roll-over of any such notes. The 2020 Order allows the Company to refund or roll-over any such short-term debt (the Continuing Short-Term Debt as defined in the Application) as long as the total short-term debt does not exceed the sum of (a) 7% of the Company's capitalization and

(b) $500 million. APS seeks no change to the 2020 Order authorization relative to Continuing Short-Term Debt.

7. The Company is asking the Commission to increase the limit on Continuing Long-Term Debt (as defined in the Application and further described below) to $8.0 billion.

Benefits of Financial Flexibility

8. The concept of an overall dollar limit on the amount of long-term debt outstanding, as contained in the 2020 Order, provides financial flexibility that allows APS to access the capital markets when timely, limit exposure to distress and disruptions in the capital markets, and avoid over-reliance on short-term borrowing and liquidity resources. This flexibility occurs in a number of areas, and a few examples are listed here. First, there is the ability to time the financing around SEC disclosure filings and cash flow requirements. Capital markets can be volatile and uncertain, and having the ability to quickly enter the markets to issue new debt can yield better financing pricing and terms. In this respect, financing flexibility benefits our customers and reduces risk. Second, there is the ability to size various debt issuances at a more optimal level. For example, over the last 40 or so years (the time during which APS has been bound by an overall dollar debt limit rather than only having authority for a specific issuance of debt), APS could enter the market as frequently as necessary as long as the Company stayed within the limit. For this reason, the Company could size debt issuances in amounts appropriate for its capital structure and avoid size-related interest rate premiums. Third, there is the ability to obtain competitive terms available at the time. Because the Company was given the ability to negotiate the terms deemed appropriate, it could adapt to changing market conditions and get competitive terms available at the time of the financing.

9. The importance of this financial flexibility is underscored by the more volatile financial markets corporate borrowers now encounter, after the relative market stability of the decade following the recovery from the 2008 financial crisis. As the Federal Reserve now contemplates interest rate hikes in the face of accelerating inflation

and capital markets respond to geopolitical issues in Europe, market access must be carefully monitored and timed to take advantage of windows that will ensure full access to needed funds and low cost of funding. Volatile markets are a particular challenge for companies like APS, where credit rating downgrades by all three credit rating agencies after the outcome of the 2019 Rate Case and determinations by the agencies to maintain a "negative" outlook on APS's credit put additional pressure on market pricing and capacity for APS debt.

10. The 2020 Order granted APS authorization to enter into a new mortgage or other security agreements, and the Company asks that this same authorization be continued. Such authorization included the ability of APS to pledge or mortgage APS assets as security for its debt. While the Company does not currently have a mortgage agreement in place, there may come a time when characteristics of the capital markets indicate it is advantageous for APS to enter into a new mortgage or other security agreements and once again issue secured debt.

11. As described earlier, and as further illustrated later in this Declaration and in Appendix A, the continued financing authority requested in the Application would enable APS to continue to manage its financing requirements and capital structure despite changing financial needs and market conditions. Thus, the requested financing order is compatible with sound financial policy and the public interest.

12. The Company has continuously complied with each of the terms and conditions of the 2020 Order and is in compliance with such Order as of the date of this Application.

APS's Long-Term Debt Financing Needs

13. In light of the continuing and growing need of the Company to invest in utility infrastructure and generation resources to serve our customers, and the resulting projected future financing needed to fund the Company's capital expenditures, maintenance program, debt maturities and other cash requirements, the Company requests Commission authorization to increase the long-term debt limitation to $8.0

billion. *See* Appendix A to my Declaration for details on the $8.0 billion of long-term debt authority requested. Absent this continuing limit, APS's ability to fund these requirements and access the capital markets in a timely manner and to take advantage of favorable market conditions and limit risk will be severely impacted. APS would be required to request Commission authorization for each debt issuance once the current limit is met and would need to seek authorization well in advance of each issuance to ensure the authorization was in place at the time the funding was required. In addition to hampering the Company's ability to reliably and timely access the capital markets, which could unnecessarily increase the Company's cost of capital, this would be administratively inefficient for both the Commission and the Company.

14. Appendix A illustrates and supports the Company's request for the $8.0 billion overall limit for outstanding long-term indebtedness, effectively incorporating a total estimate of future external financing required after giving effect to internally generated cash and the infusion of common equity capital into APS by its parent company, Pinnacle West Capital Corporation. The schedule provides long-term debt balances at the beginning and end of each year for a four-year period beginning at the end of 2021, based on a forecast assuming reasonable growth in the Company's cash flows. The Company's operating cash flows are shown ("Cash from Operations") along with use of those cash flows to make capital investments, support dividends, and repay short-term indebtedness. The net result of these sources and uses of cash is negative, thus implying a need for external debt financing. This reliance on external financing has increased in part due to the pressure on Cash from Operations caused by the outcome of the 2019 APS Rate Case. These external financing requirements are addressed with long-term financing of the type requested in the instant Application. Based on these assumptions, total outstanding long-term debt exceeds the $7.5 billion current limit by the end of 2025. The request for an $8.0 billion limit is sized incrementally higher – by approximately $400 million – than the forecasted long-term debt balance at the end of 2025 reflected in Appendix A to account conservatively for contingencies. This ensures

that the Company can respond to changes in global macroeconomic conditions, capital market volatility, inflationary pressures, and unanticipated liquidity needs.

15. However, as further detailed in the Application and illustrated in Appendix A, the Company requests that Continuing Long-Term Debt be defined as excluding purchased power agreements ("PPAs") that constitute finance leases. Certain PPAs that APS anticipates entering into over the forecast period to meet the reliability needs of our growing customer base (in particular, PPAs for energy storage services) are expected to be classified as finance leases. These finance leases are distinct from traditional money borrowed by APS; they are not classified as Long-Term Debt under Generally Accepted Accounting Principles and, unlike debt obligations, are matched with a specific associated offsetting lease asset on APS's balance sheet representing the right to use of an asset. As Appendix A shows, inclusion of these anticipated finance leases is expected to cause APS to exceed the current $7.5 billion limit on Continuing Long-Term Debt in 2023. As a consequence, APS would require a Continuing Long-Term Debt cap of $10.5 billion over the forecast period instead of only the modest increase of $8.0 billion under the definition of Continuing Long-Term Debt requested in the Application.

Summary

The financing flexibility provided in previous Commission orders has served the Company's customers well by allowing the Company to access often volatile capital markets in a timely and efficient manner, thereby enhancing the Company's ability to finance its capital needs, enabling APS to appropriately fund its debt maturity requirements, and prudently manage the Company's financing costs and the cost of capital reflected in customer rates. APS faces significant capital expenditures that will necessitate additional long-term financing. The Company is seeking a new financing order that authorizes the higher Continuing Long-Term Debt limit (as defined in the Application) and continues the authorization of the issuance of Continuing Short-Term Debt to meet these needs. This new financing order would allow APS to continue to meet growing financing needs in an efficient and cost-effective manner that benefits APS's customers.

Dated this 6th day of April 2022.

I declare under penalty of perjury that the foregoing is true and correct. Signed on the 6th day of April 2022.

Andrew Cooper

Andrew Cooper

Appendix A

Projected APS Outstanding Long-Term Debt

($MM)	2021A	2022E	2023E	2024E	2025E
Excluding Finance Leases:					
Long-term debt at beginning of year		[redacted]			
Cash from operations					
Capital expenditures					
Dividends					
Free cash flow					
Repayment of short-term debt					
Equity infusion from PNW					
Long-term debt at end of year	6,316	[redacted]			7,615
Including Finance Leases:					
Long-term debt at beginning of year		[redacted]			
Cash from operations					
Capital expenditures					
Dividends					
Free cash flow					
Repayment of short-term debt					
Equity infusion from PNW					
Forecasted Finance Leases					
Long-term debt at end of year	6,316	[redacted]			10,050

Exhibit B

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

ROBERT "BOB" BURNS – Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR AN ORDER OR ORDERS AUTHORIZING IT TO ISSUE, INCUR, AND AMEND EVIDENCES OF LONG-TERM INDEBTEDNESS AND SHORT-TERM INDEBTEDNESS, TO EXECUTE NEW SECURITY INSTRUMENTS TO SECURE ANY SUCH INDEBTEDNESS, AND FOR A DECLARATORY ORDER CONCERNING VARIABLE INTEREST ENTITIES.	DOCKET NO. E-01345A-20-0063 DECISION NO. 77853 **ORDER**

Arizona Corporation Commission
DOCKETED
DEC 17 2020
DOCKETED BY

Open Meeting
December 8 and 9, 2020
Phoenix, Arizona

BY THE COMMISSION:

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Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

FINDINGS OF FACT

APS Generally

1. Arizona Public Service Company ("APS") is a wholly owned subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). Both APS and Pinnacle West are Arizona corporations with their principal places of business in Phoenix, Arizona.

2. APS is a public service corporation primarily engaged in providing electric service to more than 1 million customers in Arizona. APS provides either retail or wholesale electric service throughout most of Arizona, with the major exceptions of the Tucson metropolitan area and approximately one-half of the Phoenix metropolitan area. APS also generates, sells, and delivers electricity to wholesale customers in the western United States.

3. APS's current financing authority was granted in Decision No. 76973 (November 27,

2018).

Procedural History

4. On March 27, 2020, APS filed with the Commission an Application requesting an Order or Orders authorizing it to issue, incur, and amend evidences of long-term indebtedness and short-term indebtedness and to execute new security instruments to secure any such indebtedness, and for a declaratory order concerning certain variable interest entities ("Financing Application").

5. On August 14, 2020, APS filed a Certification of Publication for Financing Application, showing that notice of the Financing Application had been published in the *Arizona Republic,* a newspaper of statewide circulation, on July 29 and August 2, 2020. APS also stated that it had, on July 29, 2020, posted the same public notice at the bottom of the homepage of APS's website and would leave it posted there until the Commission issues a decision on the Financing Application. The public notice provided by APS met the Commission's standards for provision of public notice on financing applications.

6. On September 8, 2020, Staff filed its Staff Report, providing recommendations for the resolution of the Financing Application.

7. On September 18, 2020, APS filed Comments to Staff's Report, generally supporting Staff's recommendations, but requesting several modifications.

8. Staff did not file a response to APS's Comments.

Background—Recent Prior Financing Decisions

Decision No. 73659 (February 6, 2013) ("2013 Order")

9. In the 2013 Order,[1] the Commission defined Continuing Long-Term Debt and Continuing Short-Term Debt, authorized an increase in APS's debt limits for short-term and long-term debt, granted new authority for APS to enter into debt instruments designed to manage its interest rate risk and exposure, renewed authorizations and conditions adopted for APS in Decision No. 69947 (October 30, 2007),[2] and imposed additional conditions. Specifically, the Commission ordered the following:

[1] The 2013 Order was issued in Docket No. E-01345A-11-0423.

[2] Decision No. 69947 authorized APS to have long-term debt of up to \$4.2 billion and short-term debt of up to 7 percent of its total capital plus \$500 million.

(a) That Continuing Long-Term Debt meant all long-term indebtedness (including current maturities) outstanding on the effective date of the 2013 Order or thereafter issued or incurred pursuant to the 2013 Order, not to exceed \$5.1 billion for any period of more than 30 days; [OP 1][3]

(b) That Continuing Short-Term Debt meant all short-term indebtedness outstanding on the date of the 2013 Order or thereafter issued or incurred pursuant to the 2013 Order (excluding current maturities of long-term debt), not to exceed 7 percent of APS's capitalization plus up to an additional \$500 million; [OP 3]

(c) That APS was authorized:

(i) To issue, sell, and incur the Continuing Long-Term Debt and the Continuing Short-Term Debt; to redeem, refinance, refund, renew, reissue, roll-over, repay, re-price, and re-borrow from time to time the Continuing Long-Term Debt and Continuing Short-Term Debt; and to establish and amend the terms and provisions of long-term and short-term indebtedness from time to time;

(ii) To determine the form of security (subject to the limitations in the 2013 Order), if any, for the Continuing Long-Term Debt and the Continuing Short-Term Debt; to execute and deliver the Security Instruments; and to establish and amend the terms and provisions of the Security Instruments, as may be deemed appropriate by APS in connection with the Continuing Long-Term Debt and the Continuing Short-Term Debt; and

(iii) To pay all related expenses, all as contemplated in its Application filed in the docket for the 2013 Order; [OP 1]

(d) That all impacts of the consolidation with APS for accounting purposes of the Palo Verde Unit II Sale/Leaseback Lessor Trusts as Variable Interest Entities ("VIEs"), required by

[3] The ordering paragraph of the 2013 Order in which each listed provision is contained is identified in brackets following the provision, with "OP" meaning ordering paragraph and a numeral indicating which ordering paragraph.

U.S. Generally Accepted Accounting Practices ("GAAP"),[4] were to be excluded for the purpose of calculating any dollar limits placed on the authorizations for Continuing Long-Term Debt and Continuing Short-Term Debt granted in the 2013 Order; [OP 2]

(e) That APS was authorized to issue short-term debt at any time and from time to time, subject to the restrictions for Continuing Short-Term Debt, and that the amount of the short-term debt issued in excess of 7 percent of APS's capitalization was to be used solely for costs relating to natural gas or power purchases; [OP 3]

(f) That before issuance or incurrence of short-term debt in excess of 7 percent of APS's capitalization, APS was required to have a Commission-authorized adjustor mechanism for recovery of natural gas or power purchases and, if the adjustor mechanism were terminated, the authorization for the additional $500 million of short-term debt would terminate 12 months thereafter; [OP 4]

(g) That if all or a portion of the authorized short-term debt relating to natural gas and power purchases became classified as long-term debt because the amount remained outstanding for more than 12 months, the debt would continue to be counted as Continuing Short-Term Debt and would not be counted against the limit for Continuing Long-Term Debt; [OP 5]

(h) That APS was authorized, for the purpose of managing interest rate risk and exposure, to enter into derivative financial instruments that convert floating cost long-term securities to long-term fixed securities, and to execute and issue forward-starting swaps based on LIBOR[5] or U.S. Treasuries and U.S. Treasury rate-locks for the purpose of hedging changes in interest rates up to 18 months in advance of planned issuances of fixed-rate taxable long-term debt having final maturity of five years or longer, subject to the following restrictions:

(i) APS was prohibited from entering into any derivative financial instrument that effectively converted fixed cost long-term debt to floating/variable cost debt;

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[4] According to APS, beginning in 2010, GAAP required the VIEs to be consolidated with APS for financial reporting purposes, although APS has no debt or equity interest in the VIEs and does not exercise any control over the VIEs. The Palo Verde Unit 2 Sale/Leaseback was authorized by Commission Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986).

[5] "LIBOR" means London Interbank Offered Rate.

(ii) APS was prohibited from using derivative financial instruments for speculative purposes; and

(iii) APS's issuance of a derivative security other than as specifically authorized in the 2013 Order constituted grounds for summary revocation of the general authorization to issue long-term indebtedness granted in the 2013 Order; [OP 6]

(i) That prior to initiation of trading activity in financial derivative securities or similar contracts to manage interest rate risk and exposure, APS was required to file with the Commission's Docket Control, as a compliance item in the 2013 Order docket, confirmation that APS had established an appropriate management policy and system of internal controls, formally approved by APS's Board of Directors, designed to govern such trading within the organization; [OP 7]

(j) That ratemaking treatment of any gains or losses associated with pre-issuance interest rate hedging transactions was not determined in the 2013 Order; [OP 8]

(k) That immediately subsequent to issuance of any Continuing Long-Term Debt, APS was required:

(i) To have a minimum common equity ratio of 42 percent, with the ratio calculated as common equity divided by the sum of the common equity, preferred stock, and APS's long-term debt (including current maturities of long-term debt), using the most recent audited financial statements available prior to the date of calculation, adjusted to give effect to the issuance of any new indebtedness (including the proposed indebtedness for which the calculation was being made), and excluding all impacts of the consolidation with APS for accounting purposes of the VIEs ("Common Equity Test"); [OP 9(a)]

(ii) To have a debt service coverage ratio ("DSC") equal to or greater than 2.0, with the DSC calculated as the sum of operating income, depreciation and amortization, and income tax, divided by interest on short-term and long-term debt, using the most recent audited financial statements, adjusted to reflect the interest impact of changes to outstanding debt to the date of calculation (calculated as the annualized interest at the actual interest rate on any new debt issued after the 12-month period covered by the applicable audited financial statements and remaining outstanding on the date of calculation); including, for purposes of this calculation, the annualized interest at the expected interest rate on the new long-term debt to be issued or incurred and for which the DSC calculation was being made; and excluding all impacts of the consolidation with APS for accounting purposes of the VIEs; [OP 9(b)]

(iii) Not to have variable interest long-term debt exceeding an aggregate limit of $750 million, with any floating cost security effectively converted to a fixed cost security by issuance of a financial derivative instrument or any other means (as authorized in the 2013 Order) deemed a fixed cost security for purposes of calculating the limit; [OP 9(c)] and

(iv) Not to have entered into any agreement/contract for any financial derivative security or similar instrument other than as authorized in the 2013 Order; [OP 9(d)]

(l) That changes in GAAP or in the interpretation of GAAP (collectively "GAAP Changes") were to be treated as follows: any contract or other legally binding arrangement ("Obligation") to which APS was or became a party was not to be considered indebtedness for purposes of the 2013 Order, including the Continuing Long-Term Debt limit, the Continuing Short-Term Debt limit, the Common Equity Test, and the DSC, until further Commission action, if:

(i) The Obligation was not considered indebtedness under GAAP as of the date APS became a party to the Obligation; [OP 10(a)]

(ii) GAAP Changes subsequently occurred that resulted in the Obligation being considered indebtedness for purposes of GAAP; [OP 10(b)]

(iii) APS notified the Commission of the GAAP Changes that resulted in the Obligation's being classified as indebtedness for GAAP purposes, within 30 days after APS filed its Quarterly Report on Form 10-Q or its Annual Report on Form 10-K with the Securities and Exchange Commission ("SEC") following the end of the fiscal quarter in which the GAAP Change occurred (the "Notification Period"); [OP 10(c)] and

(iv) Within the Notification Period, APS filed an application with the Commission specifically requesting a decision regarding whether such reclassified Obligation should be included in, or excluded from, the Continuing Long-Term Debt limit, the Continuing Short-Term Debt limit, the Common Equity Test, and the DSC calculation; [OP 10(d)]

(m) That except for Commission Decision No. 55120 (July 24, 1986) and Decision No. 55320 (December 5, 1986), which remained in full force and effect, the authorizations provided in the 2013 Order for APS to incur short-term and long-term debt obligations replaced and terminated all existing authorizations for APS to incur short-term and long-term debt; [OP 11]

(n) That unless APS filed an application with the Commission prior to January 1, 2017, seeking to continue or expand the authorizations granted in the 2013 Order (which application would extend the authorizations approved in the 2013 Order until further order of the Commission), the authorizations granted in the 2013 Order would expire on December 31, 2017; [OP 12]

(o) That on each occasion when APS entered into a new long-term debt agreement, unless the new long-term debt agreement had a principal value of less than $5 million within a calendar year (a) for any individual agreement or transaction or (b) in the aggregate for similar agreements or transactions with a single entity, APS was required:

(i) To file with Docket Control, as a compliance item in the 2013 Order docket, within 90 days of the completion of the transaction, a description of the transaction and a demonstration that the rates and terms were consistent with those generally available to comparable entities at the time; and

(ii) To provide the Commission's Utilities Division Director a copy of the relevant agreements; [OP 13]

(p) That if APS entered into a new mortgage and deed of trust, APS was required to file documentation thereof with Docket Control, as a compliance item, within 60 days of entering into the mortgage or deed of trust; [OP 14]

(q) That APS was authorized to sign and deliver documents and to engage in acts as were reasonably necessary to effectuate the authorizations granted in the 2013 Order; [OP 15]

(r) That APS was authorized to issue Continuing Long-Term Debt and Continuing Short-Term Debt for the purposes of augmenting the funds available from all sources to finance APS's construction, resource acquisition, and maintenance programs; to redeem or retire outstanding securities; to repay or refund other outstanding long-term or short-term debt; and to use Continuing Short-Term Debt to meet certain of APS's working capital and other cash requirements, and that those purposes (other than those relating to the issuance or incurrence of Continuing Short-Term Debt) were not, wholly or in part, reasonably chargeable to operating expense or to income; [OP 16]

(s) That APS was required to use the proceeds from debt incurred pursuant to the 2013 Order only for the purposes set forth in the 2013 Order; [OP 17] and

(t) That approval of the financing as set forth in the 2013 Order did not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates. [OP 18]

Decision No. 76973 (November 27, 2018) ("2018 Order")

10. In the Application and Amended Application that led to the 2018 Order,[6] APS requested:

(a) Continuation of its authority for Continuing Long-Term Debt, but with a higher cap of $5.9 billion;

(b) Continuation of its authority for Continuing Short-Term Debt;

[6] The 2018 Order was issued in Docket No. E-01345A-16-0472.

(c) Authorization to determine the form of security, if any for its Continuing Long-Term Debt and Continuing Short-Term Debt, and to execute and deliver the Security Instruments and to establish and amend the terms and provisions of any such Security Instruments;[7]

(d) Confirmation that the impacts of consolidation with APS for GAAP purposes of the Palo Verde Sale/Leaseback Lessor Trusts as VIEs were to be excluded when calculating the Common Equity Test, DSC, and outstanding balances of Continuing Long-Term and Continuing Short-Term Debt;

(e) Because of new Financial Accounting Standards Board ("FASB") lease accounting guidance, codified as ASC 842, which APS was to implement effective January 1, 2019, authorization to include only the following in Continuing Long-Term Debt:

> solely those obligations that (i) truly represent repayment obligations for borrowed money (i.e., traditional "debt"), and/or (ii) would have been reflected on the Company's balance sheet as a capital lease in periods prior to the adoption of [ASC 842] both for purposes of the overall cap of $5.9 billion for Continuing Long-Term Debt or the cap on Continuing Short-Term Debt and the computation of the DSC and [Common Equity Test].[8]

(f) That all other ordering language, provisions, obligations, and requirements of the 2013 Order be adopted without substantive modification, with the exception of:

(i) OP 6, relating to managing interest rate risk and the use of derivatives for such purpose;

(ii) OP 7, related to filing a risk management policy and system of controls related to the use of derivatives;

(iii) OP 8, related to ratemaking treatment for derivatives-related transactions;

(iv) A portion of OP 9(c), which, for the purpose of calculating the aggregate limit of $750 million for variable interest long-term debt, deemed as a

[7] APS defined "Security Instruments" to mean:

> any mortgage and deed of trust or similar instrument that establishes a lien on (a) all or substantially all of the Company's property, including after-acquired property, as security for all or any part of the Company's indebtedness, or (b) separate properties or groups of properties of the Company to secure particular issues or groups of issues of indebtedness.

2018 Order at 10 n5.

[8] 2018 order at 14 (quoting Amended Application at 3-4).

fixed cost security any floating cost security effectively converted to a fixed cost security by issuance of a financial derivative instrument or any other means; and

(v) OP 9(d), which prohibited APS from entering into any agreement/contract for any financial derivative security or similar instrument other than as authorized in the 2013 Order; and

(g) That the authorizations granted in the 2018 Order terminate on December 31 of the fifth calendar year after the effective date of the 2018 Order, unless APS were to file a new financing application before that date, which would extend the authorizations during the pendency of the new financing application.

11. In the 2018 order, the Commission approved the relief requested by APS in its Application and Amended Application but also ordered that APS may not enter into derivative financial instruments for purposes of managing interest rate risk and exposure and may not issue other types of financial derivative securities as part of the Continuing Long-Term Debt or Continuing Short-Term Debt authorized in the 2018 Order.

The Financing Application

12. In the Financing Application, APS requests that the Commission, by December 31, 2020, issue one or more Orders, with immediate effective dates, to:

(a) Increase and extend APS's authorization for Continuing Long-Term Debt (as defined in the Financing Application) from $5.9 billion to $7.5 billion, while maintaining APS's abilities to modify the debt as granted in the 2018 Order;

(b) Extend APS's authorization for Continuing Short-Term Debt (as defined in the Financing Application), while maintaining APS's abilities to modify the debt as granted in the 2018 Order;

(c) Authorize APS to determine the form of security, if any, for the Continuing Long-Term Debt and the Continuing Short-Term Debt; to execute and deliver Security Instruments (as defined in the Financing Application) in connection with the Continuing Long-Term Debt and the

Continuing Short-Term Debt; and to establish and amend the terms and provisions of any such Security Instruments from time to time;

(d) Reconfirm that all impacts of the consolidation with APS for GAAP purposes of the Palo Verde Sale/Leaseback Lessor Trusts as VIEs are to be excluded for the purposes of calculating the outstanding balances of Continuing Long-Term Debt and Continuing Short-Term Debt and calculating the Common Equity Test and DSC;

(e) Preserve the findings and authorizations in Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986) pertaining to Palo Verde Unit II sale and leaseback transactions, which lease obligations were, per the 2018 Order, excluded from the calculation of the Common Equity Test and the DSC;

(f) Clarify the provisions of the 2018 Order addressing the meaning of Long-Term Indebtedness so that it includes solely obligations that represent repayment obligations for borrowed money (i.e., traditional debt) and excludes all lease and other long-term service obligations, such as purchased power agreements;

(g) Modify the method for calculating DSC to exclude income taxes, which APS asserts will reverse the result of 2018 changes in how APS presents its income statement that inadvertently make it easier to obtain a DSC of 2.0 or greater; and

(h) Lift the $150 million annual cap on equity infusions into APS from Pinnacle West, which was imposed by Decision No. 58063 (November 3, 1992), so that APS can preserve a balanced capital structure and can access the long-term debt market on reasonable terms.

13. The Financing Application includes the Declaration of James R. Hatfield, APS's Executive Vice President, Chief Administrative Officer, and Treasurer. Mr. Hatfield asserts that the increased cap for Continuing Long-Term Debt would allow APS, over the next few years, to access external capital necessary to fund significant capital investment and to refinance maturing indebtedness. Mr. Hatfield states that the requested financing authority is compatible with sound financial policy and the public interest because APS will use the capital to continue investments in energy delivery infrastructure to maintain performance and reliability standards and meet future customer needs, to comply with new environmental regulations, to invest in generation, and to meet

other cash requirements. Mr. Hatfield asserts that allowing APS the flexibility of an increased cap on Continuing Long-Term Debt will continue to enable APS to access capital markets when timely, to limit its exposure to capital market disruptions, and to avoid over-reliance on short-term debt and liquidity resources. According to Mr. Hatfield, this flexibility gives APS the ability to time its financings around SEC disclosure filings and cash flow requirements, to enter the markets quickly to issue new debt when better financing pricing and terms are available, to size its debt issuances at an optimal level for its needs and avoid size-related interest rate premiums, and to negotiate and obtain competitive terms. Mr. Hatfield asserts that without the increased cap on Continuing Long-Term Debt, APS will need to request Commission authorization for each debt issuance that causes APS's long-term debt balance to exceed $5.9 billion, well in advance of the issuance, to ensure authorization is granted before the funding is needed. According to Mr. Hatfield, this would be administratively inefficient for the Commission and APS, would hamper APS's ability to access capital markets in a reliable and timely fashion, and could increase APS's cost of capital.

14. Mr. Hatfield states that although APS does not currently have a mortgage agreement in place, APS may at some point determine it advantageous to enter into a new mortgage or other security agreement and issue secured debt.

15. Mr. Hatfield further states that APS has continuously complied with the terms and conditions of the 2018 Order and is currently in compliance with the 2018 Order.

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16. Appendix A to Mr. Hatfield's Declaration shows that APS's capital expenditures are projected to exceed its cash from operations beginning in 2021, that its free cash flow is projected to be negative in at least 2020 through 2022, that dividends will nonetheless be paid in 2020 through 2022 (with annual increases), and that Pinnacle West will make equity infusions (lower than APS's projected dividend payments) in 2021 and 2022.[9] Appendix A projects the following outstanding end-of-year Continuing Long-Term Debt for APS, in billions:

2019	2020	2021	2022	2023	2024
$5.226	$5.576	$6.076	$6.526	$6.926	$7.461

17. The Financing Application also includes Pinnacle West and APS's consolidated Form 10-K Annual Report filed with the SEC for the year ended December 31, 2019 ("Annual Report"). The Annual Report shows that at the end of 2019, APS had operating income of $686.98 million, net income of $584.76 million, total capitalization of $10.83 billion, total equity of $5.99 billion, long-term debt less current maturities of $4.83 billion, current maturities of long-term debt of $350 million, and total current liabilities of $1.49 billion. Additionally the Annual Report shows that APS had net cash flow provided by operating activities of approximately $1.01 billion and an increase in cash and cash equivalents from approximately $5.71 million at the beginning of 2019 to approximately $10.17 million at the end of 2019. The Annual Report further reports a cost of capital of 4.10 percent for APS's long-term debt and of 10.15 percent for APS's common stock equity. The Annual Report shows that APS intends to increase its annual capital expenditures from $1.33 billion in 2020 to $1.65 billion in 2021 and approximately $1.73 billion in 2022, primarily due to increases in expenditures for renewables and energy storage systems. APS states that 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. The Annual Report also states that as of December 31, 2017, APS no longer has derivative instruments that are designated as cash flow hedging instruments.

[9] See Appendix A. No projections beyond long-term debt balances at the beginning and end of the year were provided for 2023 and 2024.

18. APS requests that the authorizations sought in the Financing Application be permitted to go into effect on the effective date of the Order or Orders issued in this docket and to remain in effect unless or until APS files a new financing application, in which case the authorizations would remain in effect until the Commission resolves the future financing application.

19. APS further requests that the Order or Orders issued in this Docket include all other ordering language, provisions, obligations, and requirements of the 2018 Order, without any substantive modification except as expressly requested by APS in the Financing Application.

Staff Report & Recommendations

20. APS is in good standing with the Commission's Corporations Division.

21. The Commission's Consumer Services database shows that from January 1, 2017, through August 17, 2020, a total of 2,414 complaints were filed about APS, with 1,825 of those received in 2017 and 2018 and the remaining 589 received in 2019 and 2020. Additionally, the Consumer Services database shows that as of August 17, 2020, APS had a total of 38 pending complaints—16 from 2019 and 22 from 2020—while all other complaints against it have been resolved and closed.

22. Based on a review of APS's application, estimated capital expenditures for 2020 through 2022, responses to Staff data requests, and other relevant information, Staff's engineer determined that APS's service reliability data is consistent with that of other utilities,[10] and that APS's estimated capital expenditures for the years 2020 through 2022 appear to be reasonable and consistent with APS's proposed infrastructure projects. Staff made no "used and useful" determination and reached no conclusions for future rate base or ratemaking purposes concerning the proposed infrastructure projects.

23. Based on APS's 2019 SEC Form 10-K, Staff calculated APS's DSC as 6.29, its common equity ratio as 53.65%, and its short-term debt ratio at 3.23%. Staff calculated that if APS were to borrow the full requested limit of $7.5 billion for Continuing Long-Term Debt, and Pinnacle West were

[10] Staff noted that APS's System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in recent years have reached or exceeded the targets recommended by Staff in APS's last rate case, Docket No. E-01345A-16-0036, but indicated that the issue would be addressed in APS's current rate case, Docket No. E-01345A-19-0236.

to make an additional equity infusion of $350 million in 2021, APS's DSC would be 4.12 and its common equity ratio would be 43.32%, both of which exceed the minimum requirements imposed by the 2018 Order.

24. Staff opposes APS's request to exclude income tax from the calculation of DSC. Staff asserts that DSC is calculated by dividing the sum of operating income, depreciation and amortization, and income taxes by total interest expense. In spite of APS's assertion that income taxes should be excluded from the DSC calculation because the 2018 Tax Cuts and Jobs Act inadvertently made it easier for utilities to meet DSC requirements when income taxes are retained in the DSC calculation, Staff is not persuaded that the DSC calculation should be modified. According to Staff, it is still appropriate to include income taxes in the DSC calculation because doing so does not adversely impact APS's DSC in this docket and also preserves the integrity of DSC calculations in evaluating debt financing for other utilities.

25. Staff agrees that it is appropriate to lift the annual cap on equity infusions so that Pinnacle West may continue to infuse equity into APS and APS is able to meet its operational and financial requirements and to fulfill its responsibilities as a public service corporation. Staff asserts, however, that APS must be required to continue meeting the Common Equity Test imposed by the 2018 Order and to demonstrate through a compliance filing that it would meet the Common Equity Test even if Pinnacle West's annual equity infusions exceed $350 million.

26. Staff recommends that the Commission do the following:

(a) Increase the cap for APS's Continuing Long-Term Debt financing to an aggregate amount not to exceed $7.5 billion for any period more than 30 days, under the terms and conditions defined in the 2018 Order;

(b) Continue the authorization for APS's Continuing Short-Term Debt, in an amount not to exceed seven percent of APS's capitalization plus up to an additional $500 million, under the terms and conditions defined in the 2018 Order;

(c) Continue the authorization for APS to redeem, refinance, refund, renew, reissue, roll-over, repay, and re-borrow from time to time its authorized Continuing Long-Term Debt and Continuing Short-Term Debt as defined in the 2018 Order;

(d) Reauthorize APS's Continuing Long-Term Debt and Continuing Short-Term Debt levels through December 31, 2023;

(e) Confirm that for accounting purposes the impact associated with the Palo Verde Sale/Leaseback Lessor Trusts as VIEs are to be excluded for the purpose of calculating the Common Equity Test, the DSC, and any dollar limits placed on authorizations for Long-Term Debt and Short-Term Debt;

(f) Deny APS's proposal to exclude income taxes from the calculation of its DSC;

(g) Approve APS's proposal to remove the $150 million annual cap on equity infusion by Pinnacle West, while requiring APS, if its annual equity infusions exceed $350 million, to demonstrate in a compliance filing that such equity infusions pass the Common Equity Test imposed by the 2018 Order; and

(h) Provide that the orders granted in this proceeding shall become effective immediately upon the issuance of a Decision herein, and shall remain in effect through December 31, 2023, unless superseded by another Commission order on a new APS financing application.

27. Staff did not make an express recommendation concerning APS's request to revise the definition of long-term debt for purposes of calculating Continuing Long-Term Debt and calculating the Common Equity Test and DSC, although Staff did include in its recommendations that APS's Continuing Long-Term Debt authority should be increased "under the terms and conditions defined in the 2018 Order." Because the 2018 Order does not include the language change requested by APS, Staff's recommendation is consistent with denial of APS's requested change to the definition of long-term debt.

28. On September 18, 2020, APS filed Comments to the Staff Report. In its Comments, APS supported most of Staff's recommendations but made several additional requests:

(a) APS requests inclusion of the following language in the Decision in this docket, as the same type of language was included in the 2018 Order and in prior APS financing decisions: "The financing authorization recommended by Staff should remain in effect until further order of the Commission if APS files an application to continue or amend the authorization no later than December 31, 2022."

(b) APS requests that the language from the 2018 Order preserving the provisions of Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986) and excluding the Palo Verde Sale/Leaseback VIEs from both the definition of Continuing Long-Term Debt and the calculation of the Common Equity Test and DSC be included in the Decision in this docket, as it has been in prior APS financing decisions since 1986.

(c) APS requests that the definition of long-term debt for purposes of calculating the Continuing Long-Term Debt limit, the Common Equity Test, and DSC be limited to traditional debt, meaning "borrowed money," and exclude all lease obligations and other long-term service obligations such as purchased power agreements ("PPAs"), which APS asserts would be consistent with the Commission's treatment of the Palo Verde Sale/Leaseback transactions, the Commission's exclusion of non-traditional liabilities from the calculation of Tucson Electric Power Company's ("TEP's") debt limit in Decision No. 75414 (January 19, 2016), and the original meaning of A.R.S. §§ 40-301 and 40-302. APS asserts that this will remove a disincentive for third-party ownership PPAs, which the Commission has repeatedly encouraged APS to consider as a compliment to its owned generation.

(d) APS requests that the Decision in this docket use the ordering language, provisions, obligations, and requirements of the 2018 Order as they apply to APS, except as APS has expressly requested modifications to the language in the Financing Application.

The Applicable Statutes

29. A.R.S. § 40-285 prohibits a public service corporation, such as APS, from selling, leasing, assigning, mortgaging, or otherwise disposing of or encumbering all or any part of its line, plant, or system necessary or useful in the performance of its duties to the public without obtaining prior approval through a Commission order.

30. A.R.S. §§ 40-301 and 40-302 provide that a public service corporation may issue stocks and stock certificates, bonds, notes, and other evidences of indebtedness payable at periods of more than 12 months after the date of issuance only after obtaining prior approval through a Commission order that authorizes the issuance and states the amount of the issuance, the purposes to which the issue or proceeds are to be applied, and that the issue is reasonably necessary or appropriate for the purposes

specified in the order and that, except as otherwise permitted in the order, such purposes are not, wholly or in part, reasonably chargeable to operative expenses or to income. Additionally, A.R.S. § 40-301 provides:

> The commission shall not make any order or supplemental order granting any application as provided by this article unless it finds that such issue is for lawful purposes which are within the corporate powers of the applicant, are compatible with the public interest, with sound financial practices, and with the proper performance by the applicant of service as a public service corporation and will not impair its ability to perform that service.

31. A.R.S. § 40-302(B) provides that the Commission may grant or refuse permission for the issue of evidences of indebtedness, may grant permission for a lesser amount, and may attach to its permission conditions the Commission deems reasonable and necessary.

32. A.R.S. § 40-302(D) authorizes a public service corporation, without Commission consent, to issue notes payable at periods of not more than 12 months after date of issuance, provided that they are for proper purposes, are not in violation of law, and do not exceed seven percent of total capitalization if the public service corporation's operating revenues exceed $250,000. The statute further provides that such a note may not be refunded by the issuance of stocks, stock certificates, bonds, notes, or any other evidence of indebtedness without Commission consent.

Referenced Decisions

33. In Decision No. 58063 (November 3, 1992), the Commission lifted a stay on the Affiliated Interest Rules that had been adopted in 14 A.A.C. 2, Article 8 ("Rules") through Decision No. 56844 (March 14, 1990). Little more than a month after adopting the Rules, the Commission issued Decision No. 56890 (April 26, 1990), staying the decision that adopted the Rules because of anticipated litigation. In Decision No. 58063, the Commission lifted the stay in phases, with additional provisos. For A.A.C. R14-2-803, the Commission lifted the stay but required that for situations requiring prior notification under A.A.C. R14-2-803(A), the stay should be lifted only for specific situations, among them the following:

> [A] public utility holding company either increases or decreases its financial interest in an affiliate or utility in an amount in excess of the following "exempt amounts", [sic] which vary depending on the public utility holding

company's and any affiliate's pre-existing utility assets in all jurisdictions including Arizona:

TOTAL UTILITY ASSETS	EXEMPT AMOUNT
A. $0 - $1 Billion	$5 Million
B. Over $1 Billion to $3 Billion	$25 Million
C. Over $3 Billion to $6 Billion	$50 Million
D. Over $6 Billion to $10 Billion	$100 Million
E. Over $10 Billion	$150 Million

The "exempt amounts" are to be measured on a cumulative basis over the calendar year in which the transactions will be made.[11]

34. In Decision No. 75414 (January 19, 2016), the Commission approved TEP's request to have calculation of its long-term indebtedness, for purposes of the Commission-imposed cap on aggregate outstanding long-term indebtedness, exclude existing capital lease obligations and indebtedness arising under TEP's credit and reimbursement agreements.[12] This exclusion was consistent with TEP's prior financing authorization granted in Decision No. 73658 (February 6, 2013).

Discussion & Resolution

35. Decision No. 58063 did not establish a cap of $150 million on the annual equity infusions into APS that Pinnacle West can make. Rather, Decision No. 58063 established that as long as Pinnacle West does not exceed $150 million in annual equity infusions, there is no requirement for a Notice of Intent to be filed under A.A.C. R14-2-803(A) or for Pinnacle West and APS to receive Commission approval for a "reorganization"[13] under A.A.C. R14-2-803.[14]

36. Staff supports allowing APS to receive more than $150 million in aggregate annual equity infusions from Pinnacle West. Staff did not, however, recommend that Decision No. 58063 be modified under A.R.S. § 40-252 or that APS be excluded from application of Decision No. 58063 or A.A.C. R14-2-803. Because APS currently is not prohibited from receiving more than $150 million in

[11] Decision No. 58063 at 6-7.

[12] Decision No. 75414 at 13-14.

[13] A.A.C. R14-2-801 defines "reorganize" or "reorganization" to mean "acquisition or divestiture of a financial interest in an affiliate or a utility, or reconfiguration of an existing affiliate or utility's position in the corporate structure or the merger or consolidation of an affiliate or a utility."

[14] A.A.C. R14-2-803 requires a utility or affiliate intending to reorganize an existing public utility holding company to notify the Commission at least 120 days before the reorganization and provides for Commission approval or rejection of the reorganization. A.A.C. R14-2-803(C) provides that "the Commission may reject the proposal if it determines that it would impair the financial status of the public utility, otherwise prevent it from attracting capital at fair and reasonable terms, or impair the ability of the public utility to provide safe, reasonable and adequate service."

aggregate annual equity infusions from Pinnacle West, and neither APS nor Staff has suggested that Decision No. 58063 be modified under A.R.S. § 40-252 or that APS be excluded from application of Decision No. 58063 or A.A.C. R14-2-803, the Commission does not need to and will not make any changes in response to APS's request for the "cap" to be lifted.

37. Per the 2018 Order, "Continuing Long-Term Debt" and "long-term indebtedness" have the following meanings:

> Continuing Long-Term Debt [means] all long-term indebtedness (including current maturities) outstanding on the effective date of [the 2018 Order] or hereafter issued or incurred pursuant to [the 2018 Order], . . . with long-term indebtedness including solely (1) obligations that truly represent repayment obligations for borrowed money (i.e., traditional "debt"), and (2) any obligations that in periods prior to the adoption of ASC 842 would have been reflected on [APS's] balance sheet as capital leases both for purposes of the overall cap of $5.9 billion for Continuing Long-Term Debt or the cap on Continuing Short-Term Debt and the computation of the [DSC] ratio and common equity ratio.[15]

38. In the Financing Application, APS requests that the definitions of "Continuing Long-Term Debt" and "long-term indebtedness" include only item (1) above, "obligations that truly represent repayment obligations for borrowed money (i.e., traditional 'debt')." APS cited Decision No. 75414 and the original meanings of A.R.S. §§ 40-301 and 40-302 to support its request.

39. APS did not provide any documentation or other information to support its assertions concerning the original meanings of A.R.S. §§ 40-301 and 40-302.

40. Decision No. 75414 concerning TEP was issued prior to the February 2016 issuance of ASC 842 that resulted in changes concerning accounting for leases. Decision No. 75414 thus does not support APS's current request to have the definition of its long-term indebtedness diverge from that in the 2018 Order, which was adopted at APS's request.

41. Staff has not supported APS's requested modified definition, and APS has not justified its request to diverge from the definitions included in the 2018 Order. Thus, APS's requested modification to the definition of "long-term indebtedness" as included in the 2018 Order will not be adopted. If APS requires additional long-term debt authorization as a result of the definition of long-

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[15] 2018 Order at 19.

term indebtedness adopted herein, APS may file another financing application seeking such authorization.

42. Staff's recommendations set forth in Findings of Fact No. 26(a) through (f) are just and reasonable and in the public interest and should be adopted.

43. Based on the record in this matter, we find that the financings proposed by APS, as described in Findings of Fact Nos. 12, 18, 19, and 28, with the modifications described in Findings of Fact Nos. 36 and 41 and subject to the Staff recommendations listed in Findings of Fact No. 42, are for lawful purposes which are within the corporate powers of APS, are compatible with the public interest, with sound financial practices, and with the proper performance by APS of service as a public service corporation, and will not impair APS's ability to perform that service. Additionally, we find that these financings are reasonably necessary and appropriate for the purposes described by APS in its Financing Application and that such purposes are not, wholly or in part, reasonably chargeable to APS's operating expenses or to income.

44. The financing authorizations granted herein are just and reasonable and in the public interest and should be approved.

CONCLUSIONS OF LAW

1. APS is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. Title 40.

2. The Commission has jurisdiction over APS and over the subject matter of the Financing Application.

3. Notice of the Financing Application was provided in accordance with the law.

4. The financings approved herein are for lawful purposes which are within the corporate powers of APS, are compatible with the public interest, with sound financial practices, and with the proper performance by APS of service as a public service corporation, and will not impair APS's ability to perform that service.

5. The financings approved herein are reasonably necessary and appropriate for the purposes described by APS in the Financing Application, and such purposes are not, wholly or in part, reasonably chargeable to APS's operating expenses or to income.

6. Approval of the financings set forth herein does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates.

7. The approvals granted by the Commission herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that Arizona Public Service Company is hereby authorized to issue, sell, and incur at any time and from time to time Continuing Long-Term Debt in an aggregate amount not to exceed $7.5 billion for any period of more than 30 days, with Continuing Long-Term Debt meaning all long-term indebtedness (including current maturities) outstanding on the effective date of this Decision or hereafter issued or incurred pursuant to this Decision, and with long-term indebtedness including solely (1) obligations that truly represent repayment obligations for borrowed money (i.e., traditional "debt"), and (2) any obligations that in periods prior to the adoption of ASC 842 would have been reflected on Arizona Public Service Company's balance sheet as capital leases, both for purposes of the overall cap of $7.5 billion for Continuing Long-Term Debt or the cap on Continuing Short-Term Debt and the computation of the debt service coverage ratio and common equity ratio.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby authorized to issue, sell, and incur at any time and from time to time Continuing Short-Term Debt in an aggregate amount not to exceed 7 percent of Arizona Public Service Company's capitalization plus up to an additional $500 million, with Continuing Short-Term Debt meaning all short-term indebtedness outstanding on the date of this Decision or hereafter issued or incurred pursuant to this Decision (excluding current maturities of long-term debt).

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby authorized (1) to redeem, refinance, refund, renew, reissue, roll-over, repay, re-price, and re-borrow from time to time such Continuing Long-Term Debt and Continuing Short-Term Debt and to establish and amend the terms and provisions of long-term and short-term indebtedness from time to time; (2) to determine the form of security, if any, for the Continuing Long-Term Debt and the Continuing Short-Term Debt, to execute and deliver the security instruments, and to establish and amend the terms and provisions of the security instruments, as may be deemed appropriate by Arizona Public Service Company in connection with the Continuing Long-Term Debt and the Continuing Short-Term Debt, except that Arizona Public Service Company may not enter into derivative financial instruments for purposes of managing interest rate risk and exposure and may not issue other types of financial derivative securities as part of the Continuing Long-Term Debt or Continuing Short-Term Debt authorized herein; and (3) to pay all related expenses as contemplated in the Financing Application.

IT IS FURTHER ORDERED that Arizona Public Service Company may use the amount of Continuing Short-Term Debt issued in excess of 7 percent of Arizona Public Service Company's capitalization solely for costs relating to natural gas or power purchases.

IT IS FURTHER ORDERED that before issuing or incurring short-term debt in excess of 7 percent of Arizona Public Service Company's capitalization, Arizona Public Service Company must have a Commission-authorized adjustor mechanism for recovery of natural gas or power purchases, and if such mechanism is terminated, the authorization for the additional $500 million of short-term debt shall terminate 12 months thereafter.

IT IS FURTHER ORDERED that if all or a portion of the authorized short-term debt relating to natural gas and power purchases becomes classified as long-term debt because the amount remains outstanding for more than 12 months, such debt shall continue to be counted as Continuing Short-Term Debt and shall not be counted against the limit for Continuing Long-Term Debt.

IT IS FURTHER ORDERED that all impacts of the consolidation with Arizona Public Service Company, for accounting and financial reporting purposes, of the Palo Verde Unit II Sale/Leaseback Lessor Trusts as Variable Interest Entities are excluded for the purposes of calculating any dollar limits placed on the authorizations for Continuing Long-Term Debt and Continuing Short-Term Debt granted herein; calculating Arizona Public Service Company's common equity ratio as described in section (1) of the next Ordering Paragraph; and calculating Arizona Public Service Company's debt service coverage ratio as described in section (2) of the next Ordering Paragraph.

IT IS FURTHER ORDERED that immediately after issuance of any Continuing Long-Term Debt, Arizona Public Service Company shall:

1. Have a common equity ratio of at least 42 percent, with the ratio calculated as common equity divided by the sum of common equity, preferred stock, and long-term debt (including current maturities of long-term debt), using the most recent audited financial statements available prior to the date of calculation, adjusted to give effect to the issuance of any new indebtedness (including the proposed indebtedness for which the common equity ratio calculation is being made);
2. Have a debt service coverage ratio equal to or greater than 2.0, with the ratio calculated as the sum of operating income, depreciation and amortization, and income tax, divided by interest on short-term and long-term debt, using the most recent audited financial statements available prior to the date of calculation, adjusted to reflect the interest impact of changes to outstanding debt up to the date of calculation (calculated as the annualized interest at the actual interest rate on any new debt issued after the 12-month period covered by the applicable audited financial statements and remaining outstanding on the date of calculation), and including the annualized interest at the expected interest rate on the new long-term debt to be issued or incurred and for which the debt service coverage ratio calculation is being made; and
3. Not have variable interest long-term debt exceeding an aggregate limit of $750 million.

IT IS FURTHER ORDERED that in the event of a change in United States Generally Accepted Accounting Principles or in the interpretation of GAAP (either considered a "GAAP Change"), any contract or other legally binding arrangement to which Arizona Public Service Company is or becomes a party ("Obligation") shall not, without further Commission action, be considered indebtedness for purposes of this Decision (including when calculating Continuing Long-Term Debt, Continuing Short-Term Debt, common equity ratio, and debt service coverage ratio) provided that:

1. The Obligation was not considered indebtedness under GAAP as of the date Arizona Public Service Company became a party to the Obligation;
2. A GAAP Change subsequently occurred that resulted in the Obligation being considered indebtedness for purposes of GAAP; and
3. Within 30 days after Arizona Public Service Company files its Quarterly Report (Form

10-Q) or its Annual Report (Form 10-K) with the Securities and Exchange Commission, following the end of the fiscal quarter in which the GAAP Change occurred:

a. Arizona Public Service Company notifies the Commission of the GAAP Change, and

b. Arizona Public Service Company files an application with the Commission specifically requesting a decision regarding whether the Obligation should be included or excluded when calculating Arizona Public Service Company's Continuing Long-Term Debt, Continuing Short-Term Debt, common equity ratio, and debt service coverage ratio.

IT IS FURTHER ORDERED that with the exceptions of Commission Decision Nos. 55120 (July 24, 1986) and 55320 (December 5, 1986) (pertaining to the consolidation with Arizona Public Service Company, for accounting and financial reporting purposes, of the Palo Verde Unit II Sale/Leaseback Lessor Trusts as Variable Interest Entities), the authorizations in this Decision for Arizona Public Service Company to issue short-term and long-term debt obligations shall replace all existing authorizations for the incurrence of short-term and long-term debt obligations, and all such existing authorizations shall terminate upon the effective date of this Decision.

IT IS FURTHER ORDERED that the authorizations granted herein shall expire on December 31, 2023, unless Arizona Public Service Company files an application with the Commission prior to January 1, 2023, seeking to continue or expand such authorizations, in which event the authorizations granted herein shall continue until further order of the Commission.

IT IS FURTHER ORDERED that on each occasion when Arizona Public Service Company enters into a new long-term debt agreement, unless the new long-term debt agreement has a principal value of less than $5 million within a calendar year (a) for any individual agreement or transaction or (b) in the aggregate for similar agreements or transactions with a single entity, Arizona Public Service Company shall, within 90 days of the completion of the transaction:

1. File with the Commission's Docket Control, as a compliance item in this docket, a description of the transaction and a demonstration that the rates and terms are consistent with those generally available to comparable entities at the time; and

2. Provide the Commission's Utilities Division Director a copy of the relevant agreements.

IT IS FURTHER ORDERED that if Arizona Public Service Company enters into a new mortgage and/or deed of trust, Arizona Public Service Company shall, within 60 days of entering into the mortgage and/or deed of trust, file documentation thereof with Docket Control, as a compliance filing in this docket.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby authorized to sign and deliver such documents and to engage in such acts as are reasonably necessary to effectuate the authorizations granted herein.

IT IS FURTHER ORDERED that Arizona Public Service Company may use the proceeds from the Continuing Long-Term Debt and Continuing Short-Term Debt authorized herein only for the following purposes: to augment the funds available from all sources to finance Arizona Public Service Company's construction, resource acquisition, and maintenance programs; to redeem or retire outstanding securities; to repay or refund other outstanding long-term or short-term debt; and, as to Continuing Short-Term Debt only, to meet certain of Arizona Public Service Company's working capital and other cash requirements.

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IT IS FURTHER ORDERED that authorization of the financings set forth herein does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN BURNS	COMMISSIONER DUNN	COMMISSIONER KENNEDY

COMMISSIONER OLSON	COMMISSIONER MARQUEZ PETERSON

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 17 day of December 2020.

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________
SNH/(gb)

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-20-0063

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Exhibit C

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, 2021

OR

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

For the transition period from to

Commission File Number	Exact Name of Each Registrant as specified in its charter; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (an Arizona corporation) 400 North Fifth Street, P O Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	**ARIZONA PUBLIC SERVICE COMPANY** (an Arizona corporation) 400 North Fifth Street, P O Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0011170

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

	Title Of Each Class	Trading Symbol	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	PNW	New York Stock Exchange

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 each 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth company See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐						

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒	Smaller reporting company	☐
Emerging growth company	☐						

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U S C 7262(b)) by the registered public accounting firm that prepared or issued its audit report ☒

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act)

PINNACLE WEST CAPITAL CORPORATION	Yes	☐	No	☒
ARIZONA PUBLIC SERVICE COMPANY	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	$	9,024,891,205	as of June 30, 2021
ARIZONA PUBLIC SERVICE COMPANY	$	0	as of June 30, 2021

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

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of February 17, 2022:	112,931,929
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2 50 par value, outstanding as of February 17, 2022:	71,264,947

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 18, 2022 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.

TABLE OF CONTENTS

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 subsidiary of the Company
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
CAISO	California Independent System Operator
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
COVID-19	Coronavirus
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
DSM	Demand side management
EES	Energy Efficiency Standard
EGU	Electric generating unit
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
GHG	Greenhouse gas
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
Palo Verde	Palo Verde Generating Station or PVGS
Pinnacle West	Pinnacle West Capital Corporation (any use of the words "Company," "we," and "our" refer to Pinnacle West)
PPA	Power Purchase Agreement
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
TEAM	Tax expense adjustor mechanism
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," "anticipate," "goal," "seek," "strategy," "likely," "should," "will," "could," 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" of this report, these factors include, but are not limited to:

- the potential effects of the continued COVID-19 pandemic, including, but not limited to, demand for energy, economic growth, our employees and contractors, vaccine mandates, supply chain, expenses, capital markets, capital projects, operations and maintenance activities, uncollectable accounts, liquidity, cash flows or other unpredictable events;
- 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 (including large increases in ambient temperatures), the general economy or social conditions, customer, and sales growth (or decline), the effects of energy conservation measures and distributed generation ("DG"), and technological advancements;
- the potential effects of climate change on our electric system, including as a result of weather extremes such as prolonged drought and high temperature variations in the area where APS conducts its business;
- 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 or interpretations of existing legislation or regulations, including those relating to environmental requirements, regulatory and energy 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 through our rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- the ability of APS to achieve its clean energy goals (including a goal by 2050 of 100% clean, carbon-free electricity) and, if these goals are achieved, the impact of such achievement on APS, its customers, and its business, financial condition, and results of operations;
- 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 direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, or other catastrophic events, such as fires, explosions, pandemic health events or similar occurrences;
- 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 GHG 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 landowners 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, and in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" 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.

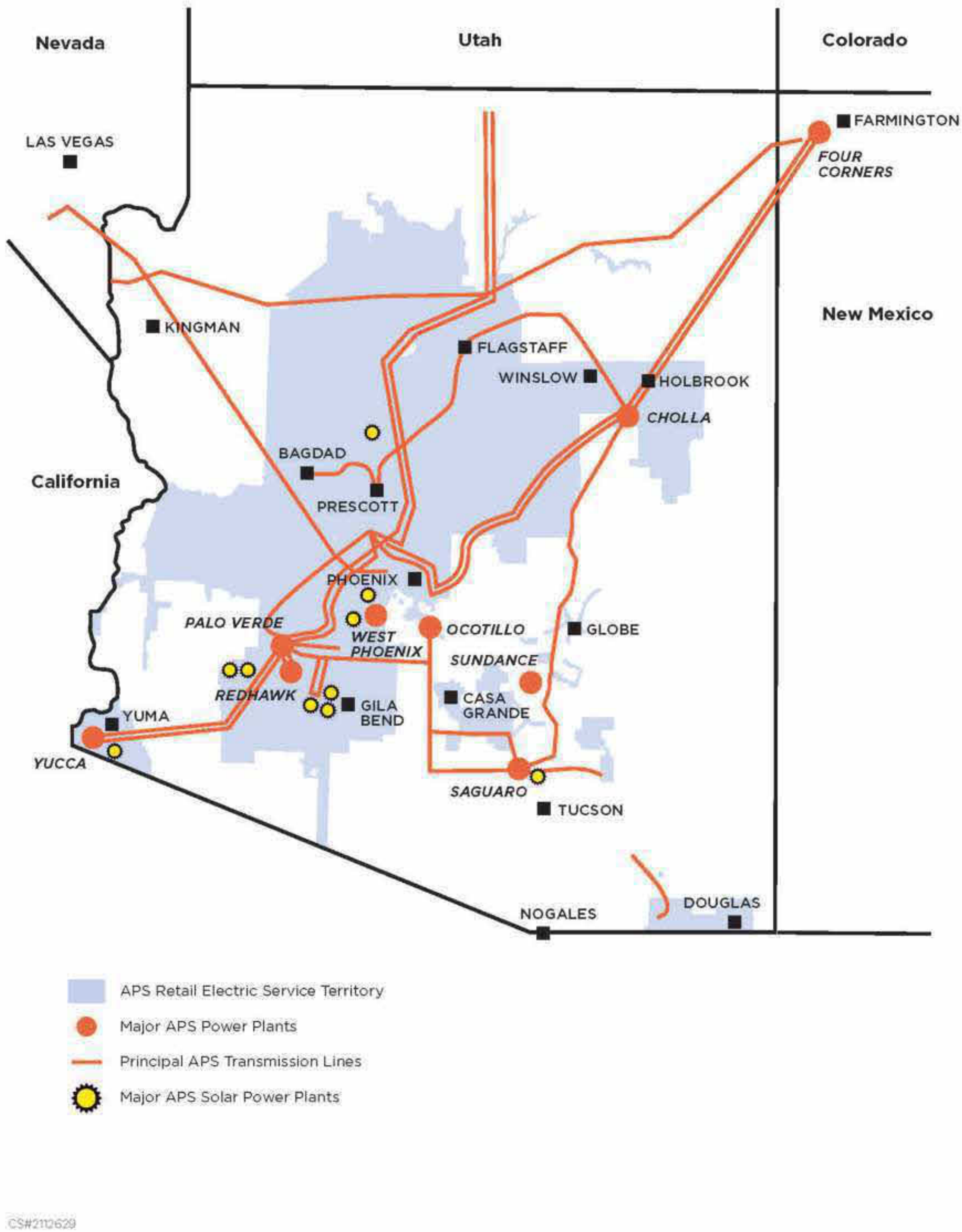
Pinnacle West's other subsidiaries are El Dorado, BCE and 4CA. Additional information related to these subsidiaries is provided later in this report.

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

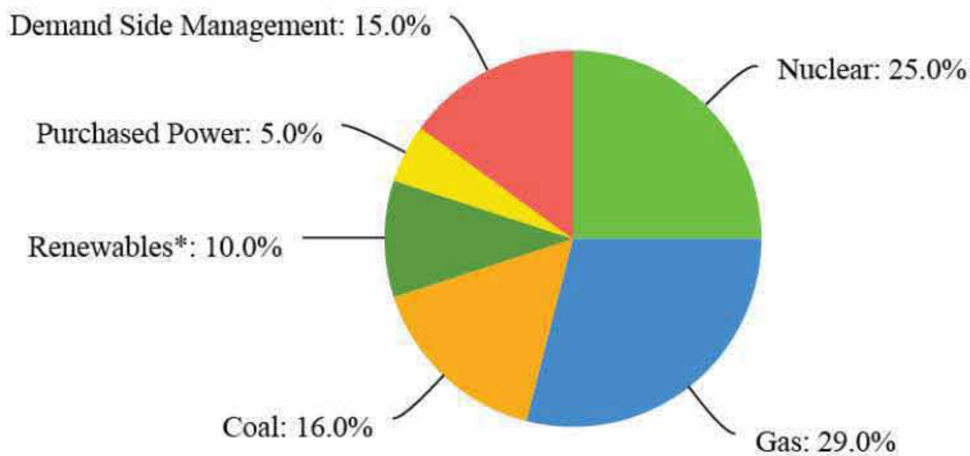
APS currently provides electric service to approximately 1.3 million customers. We own or lease 6,323 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2021, no single purchaser or user of energy accounted for more than 1.8% 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 2021 were as follows:



*Renewables include energy from wind, solar, geothermal, biomass, DG, and solar PPAs.

The share of APS's energy supply being derived from clean resources is 50%, which includes energy from nuclear, renewables and DSM. BCE also has acquired minority ownership positions in two wind farms that achieved commercial operation in 2020. Both wind farms deliver power under long-term PPAs. See "Business of Other Subsidiaries — Bright Canyon Energy" below for information regarding BCE's investments.

Clean Energy Focus Initiatives

In response to climate change, the entire electric utility industry, as well as the global economy, is in the midst of a profound transition to clean energy and a new low-carbon economy. APS has undertaken a number of initiatives to reduce carbon, including renewable energy procurement and development, and 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" below for details of these plans and initiatives. APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass. In addition, in January 2020, APS announced its

Clean Energy Commitment, a three-pronged approach aimed at ultimately eliminating carbon-emitting resources from its electric generation resource portfolio.

APS's clean energy goals consist of three parts:

- a 2050 goal to provide 100% clean, carbon-free electricity;
- a 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- a commitment to end APS's use of coal-fired generation by 2031.

Among other strategies, APS intends to achieve these goals through various methods such as relying on Palo Verde, the nation's largest producer of carbon-free energy; increasing clean energy resources, including renewables; developing energy storage; ceasing the use of coal-generated electricity; managing demand with a modern interactive grid; promoting customer technology and energy efficiency; and optimizing regional resources. Management takes into consideration climate change and other environmental risks in its strategy development, business planning, and enterprise risk management processes. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information about APS's Clean Energy Commitment.

Over this same period of time, APS also intends to harden its infrastructure in order to improve climate resiliency, which involves system and operational improvements aimed at reducing the impact of extreme weather events and other climate-related disruptions upon APS's operations. Among other resiliency strategies, APS anticipates increasing investments in a modern and more flexible electricity grid with advanced distribution technologies. APS plans to continue its comprehensive forest management programs aimed at reducing wildfires, as those risks become compounded by shorter, drier winters and longer, hotter summers as a result of climate change.

APS prepares an annual inventory of GHG emissions from its operations. For APS's operations involving fossil-fuel electricity generation and electricity transmission and distribution, APS's annual GHG inventory is reported to EPA under the EPA GHG Reporting Program. APS also voluntarily tracks the full scope of APS's GHG emissions arising from all APS operations. In addition to reporting to the EPA, we publicly report Scope 1, 2 and 3 GHG emissions. This data is then communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com/corporate-responsibility*). 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.

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.

Nuclear

Palo Verde 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 originally resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amendment relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. 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 participant owners of Palo Verde 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 through 2028 and 86% through 2029; 100% of Palo Verde's requirements for conversion services through 2026 and 30% through 2030; 100% of Palo Verde's requirements for enrichment services through 2026 and 76% for 2027; and 100% of Palo Verde's requirements for fuel fabrication through 2027 for Unit 2 and Unit 1 and 2028 for Unit 3.

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. 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 legal proceedings followed challenging DOE's withdrawal of its Yucca Mountain construction authorization application and the NRC's cessation of its review of the Yucca Mountain construction authorization application, which were consolidated into one matter at the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit"). Following the D.C. Circuit's August 2013 order, the NRC issued two volumes of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. Publication of these volumes do not signal whether or when the NRC might authorize construction of the repository. APS is directly involved in legal proceedings related to the 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 Palo Verde participants, filed a lawsuit against the DOE in the United States Court of Federal Claims ("Court of Federal Claims") for damages incurred due to the 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 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 the 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 NWPA. On August 18, 2014, APS and the DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by the DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014, settlement agreement, for seven separate time periods during July 1, 2011, through June 30, 2020. The DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 4. On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). In February 2022, the DOE approved this claim.

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 NRC's evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the Waste Confidence Decision update for further action consistent with National Environmental Policy Act. 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. 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 Generating Station — Nuclear Insurance" in Note 11 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 two oil-only power plants: Fairview, located in the town of Douglas, Arizona and Yucca GT-4 in Yuma, 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 3,573 MW. A portion of the gas for these plants is financially hedged up to three years in advance of purchasing and that position is converted to a physical gas purchase one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2027. Fuel oil is acquired under short-term purchases delivered by truck directly to the power plants.

Ocotillo was originally a 330 MW 4-unit gas plant located in Tempe. In early 2014, APS announced a project to modernize the plant, which involved retiring two older 110 MW steam units, adding five 102 MW combustion turbines, and maintaining two existing 55 MW combustion turbines. In total, this increased the capacity of the site by 290 MW to 620 MW. See Note 4 for rate recovery as part of the ACC final written Opinion and Order issued reflecting its decision in APS's general retail rate case (the

"2017 Rate Case Decision") and the 2019 Retail Rate Case Filing. The Ocotillo modernization project was completed in 2019.

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. APS has a total entitlement from Four Corners of 970 MW. Additionally, 4CA, a wholly-owned subsidiary of Pinnacle West, owned 7% of Units 4 and 5 from July 2016 through July 2018 following its acquisition of El Paso's interest in these units described below. As part of APS's Clean Energy Commitment, APS has committed to cease using coal-fired generation as part of its portfolio of electricity generating resources, including Four Corners, by 2031.

NTEC, a company formed by the Navajo Nation to own the mine that serves Four Corners and develop other energy projects, is the coal supplier for Four Corners. 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 of 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.

On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. NTEC assumed 4CA's reclamation and decommissioning obligations associated with the 7% interest. The sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

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.

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 operated that unit for PacifiCorp. 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 approved 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. Following the closure of Unit 2, APS has a total entitlement from Cholla of 381 MW. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

APS purchases all of Cholla's coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a coal transportation contract that runs through 2024.

Navajo Plant — The Navajo Plant was a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operated the plant and APS owned a 14% interest in Units 1, 2 and 3. APS had a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government.

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant would remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, which allowed for decommissioning activities to begin after the plant ceased operations in November 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant. See Note 4 for details related to the resulting regulatory asset 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.

See Note 11 for information regarding APS's coal mine reclamation obligations related to these coal-fired plants.

Solar Facilities

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

APS owns and operates more than thirty 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 systems 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, was 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. The pilot program is now complete and as part of the 2017 Rate Case Decision, the participants have been transferred to the Solar Partner Program described below. Additionally, APS owns

13 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 costs for this program have been included in APS's rate base as part of the 2017 Rate Case Decision.

In the 2017 Rate Case Decision, the ACC also approved the "APS Solar Communities" program. APS Solar Communities (formerly AZ Sun II) is a three-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems on low to moderate income residential homes, non-profit entities, Title I schools, and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. Currently, APS has installed 11 MW of DG systems under the APS Solar Communities program. In the 2019 Rate Case decision, the ACC authorized APS to spend $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the decision.

Energy Storage

APS deploys a number of advanced technologies on its system, including energy storage. Energy storage provides capacity, improves power quality, can be utilized for system regulation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage also aids in integrating renewable generation by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to meet customer reliability requirements, increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid.

In 2018, APS issued a request for proposal ("RFP") for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are expected to be in service during the summer of 2022. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS's AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2022 with respect to 100 MW and in 2023 with respect to 50 MW.

As a result of its December 2020 RFPs, as of February 2022, APS has executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs totaling 275 MW solar plus storage resource. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021. The remaining project was filed in February 2022 for ACC approval and is pending ACC review. Service under the agreements is expected to begin in 2023 and 2024.

APS currently plans to install more than 900 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of December 31, 2021. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
APS Owned: Energy Storage	—	201
PPAs - Energy Storage	—	510
Residential Energy Storage	12(a)	3
Total Energy Storage Portfolio	**12**	**714**

(a) This includes 11.7 MW of APS customer-owned batteries and 0.3 MW of APS-owned residential batteries.

<u>Purchased Power Contracts</u>

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. In addition, APS has also entered into several PPAs for energy storage. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for details on our energy storage PPAs.

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of December 31, 2021, 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, 2022	45
Demand Response Agreement (b)	Summer seasons through 2025	75
Tolling Agreement	Summer seasons from Summer 2020 through Summer 2025	565
Tolling Agreement	June 1 through September 30, 2020-2026	570
Renewable Energy (c)	Various	736
Tolling Agreement	May 1 through October 31, 2021-2027	463
Energy Storage	Various	510

(a) Up to 45 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) The capacity under this agreement is 75 MW for years 2022 through 2025.
(c) 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 2021 peak one-hour demand on its electric system was recorded on June 18, 2021, at 7,580 MW, compared to the 2020 peak of 7,660 MW recorded on July 30, 2020. APS's reserve margin at the time of the 2021 peak demand, calculated using system load serving capacity, was 15%. For 2022, due to expiring purchased power contracts, APS is procuring market resources to maintain its minimum 15% planning reserve criteria.

Future Resources and Resource Plan

ACC rules require utilities to develop 15-year Integrated Resource Plans ("IRP") which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases.

See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Clean Energy Focus Initiatives" and "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for information regarding future plans for energy storage. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning —

Generation Facilities — Coal-Fueled Generating Facilities" above for information regarding plans for Cholla, Four Corners and the Navajo Plant.

Energy Imbalance Market

In 2016, APS began to participate in the Western Energy Imbalance Market ("EIM"), a voluntary, real-time optimization market operated by the CAISO. The EIM allows for rebalancing supply and demand in 15-minute blocks and dispatching generation every five minutes, instead of the traditional one-hour blocks. APS continues to expect that its participation in EIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources. APS is in discussions with the EIM operator, CAISO, and other EIM participants about the feasibility of creating a voluntary day-ahead market to achieve more cost savings and use the region's renewable resources more efficiently.

Energy Modernization Plan

On July 30, 2020, the ACC Staff issued final draft energy rules, which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. On November 13, 2020, the ACC approved a final draft energy rules package which required additional procedural steps in the rulemaking process. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments to the final energy rules. The adopted rules require 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. See Note 4 for additional information related to these energy rules.

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 12% of retail electric sales in 2022 and increases annually until it reaches 15% in 2025.

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 12% in 2022. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan. On July 1, 2021, APS filed its 2022 RES Implementation Plan and amended it on December 9, 2021. The following table summarizes the RES requirement standard and its timing:

	2022	2025
RES (inclusive of distributed energy) as a % of retail electric sales	12%	15%
Percent of RES to be supplied from distributed energy resources	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 2,758 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 2,218 MW are currently in operation and 540 MW are under contract for development or are under construction. Renewable resources in operation include 247 MW of facilities owned by APS, 736 MW of long-term purchased power agreements, and an estimated 1,235 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 as of December 31, 2021. 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**		**33**	
Total APS Owned				**247**	**—**
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**	
CO Bar Solar A	**Coconino County, AZ**	**2023**	**18**		**80**
CO Bar Solar B	**Coconino County, AZ**	**2023**	**18**		**80**
Mesquite Solar 5	**Tonopah, AZ**	**2023**	**20**		**60**
Wind:					
Aragonne Mesa	**Santa Rosa, NM**	**2022**	**20**	**200**	
High Lonesome	**Mountainair, NM**	**2009**	**30**	**100**	
Perrin Ranch Wind	**Williams, AZ**	**2012**	**25**	**99**	
Chevelon Butte	**Winslow, AZ**	**2023**	**20**		**238**
Geothermal:					
Salton Sea	**Imperial County, CA**	**2006**	**23**	**10**	
Biomass:					
Snowflake	**Snowflake, AZ**	**2008**	**15**	**14**	
Biogas:					
NW Regional Landfill	**Surprise, AZ**	**2012**	**20**	**3**	
Total Purchased Power Agreements				**736**	**458**
Distributed Energy					
Solar (b)					
Third-party Owned	**AZ**	**Various**		**1,202**	**82**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	
Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**1,235**	**82**
Total Renewable Portfolio				**2,218**	**540**

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

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

In September 2019, APS issued an RFP that requested up to 250 MW of wind resources to be in service as soon as possible, but no later than 2022. As a result of this RFP, APS executed a 200 MW PPA for a wind resource that went into service in January 2022. In December 2020, APS issued two additional RFPs: (i) a battery storage RFP for projects to be located at two AZ Sun sites; and (ii) an all source RFP that solicited resources to meet our clean energy needs and capacity to maintain system reliability, and that was later amended to include a request for 150 MW of solar resources to be developed on APS property and owned by APS (collectively, the "December 2020 RFPs"). As a result of the all source RFP, APS executed a PPA in October 2021 for a 238 MW wind resource to be in service by June 2023, and also executed an engineering, procurement, and construction contract in November 2021 for a 150 MW solar resource to be owned by APS and in service in early 2023. APS continues to negotiate contracts for additional resources to be in service in 2024 in connection with the all source RFP. Once it secures those important resources and closes out the December 2020 RFPs, APS intends to issue its next all source RFP to address resource needs for 2025 and beyond.

Demand Side Management

On January 1, 2011, Arizona regulators adopted an EES of 22% cumulative annual energy savings by 2020 to increase energy efficiency and other DSM programs encouraging customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. APS achieved the 22% EES in 2021. See Note 4 for information regarding energy efficiency, other DSM obligations and the Energy Modernization Plan.

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. See Note 4 for information regarding ACC's regulation of APS's retail electric rates.

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 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.

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020 ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. At the same time, the Arizona legislature is considering a bill that would nullify, if approved, a 20-year-old electric deregulation law that has been in place since

1998. The bill has several procedural steps in the legislative process before becoming law. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. See Note 4 for information regarding APS's transmission rates. During 2021, approximately 7.6% 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 natural gas. The majority of these activities are undertaken to mitigate risk in APS's portfolio.

Transmission and Delivery

APS continues to work closely with customers, stakeholders, and regulators to identify and plan for transmission needs that support new customers, system reliability, access to markets and clean energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this report includes new APS transmission projects, along with other transmission costs for upgrades and replacements, including those for data center and semi-conductor manufacturing development. 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 new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain delivery functions.

Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent successful attempts by Congress to pass legislation that would regulate GHG emissions, and it is unclear at this time whether legislation regulating or limiting utility-sector GHG emissions under consideration in the 117th Congress will become law. 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, without limitation, 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 regulating GHGs, 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 analysis for new major sources and major modifications to existing plants.

On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. On October 29, 2021, the U.S. Supreme Court announced that it was accepting judicial review of the January D.C. Circuit decision vacating the ACE regulations. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings or ongoing litigation related to the scope of EPA's authority under the Clean Air Act to regulate carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standards ("NAAQS") 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.

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. Final regulations imposing BART requirements have now been imposed on each APS coal-fired power plant. Four Corners was required to install new pollution controls to comply with BART, while similar pollution control installation requirements were not necessary for Cholla.

Cholla. In early 2017, EPA approved a final rule containing a revision to Arizona's State Implementation Plan ("SIP") for Cholla that implemented BART requirements for this facility, which did not require the installation of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset.

Four Corners. Based on EPA's final standards, APS's 63% share of the cost of required BART controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. See Note 4 for information regarding the related rate recovery. 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 purchased the interest from 4CA on July 3, 2018. See "Four Corners — 4CA Matter" in Note 11 for a discussion of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

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 RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing 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 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. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.
- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.
- Based on an August 21, 2018, D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments by April 11, 2021 at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.
- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020 final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020, and is currently pending. This application will be subject to public comment and, potentially, judicial review. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and we anticipate receiving a proposed decision with respect to the Cholla facility in 2022.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

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 $27 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations, or cash flows.

Effluent Limitation Guidelines. On September 30, 2015, EPA finalized revised effluent limitation guidelines ("ELG") 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.

On August 11, 2017, EPA announced that it would be initiating rulemaking proceedings to potentially revise the September 2015 ELGs. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the ELGs for these waste-streams would be required from November 1, 2018, until November 1, 2020. At this time, APS's National Pollutant Discharge Elimination System ("NPDES") discharge permit for Four Corners contains a December 31, 2023, compliance deadline for achieving "zero discharge" of bottom ash transport waters. Nonetheless, on October 13, 2020, EPA published a final rule relaxing these "zero discharge" limitations for bottom ash handling water and allowing for approximately 10% of such wastewater to be discharged (on a volumetric, 30-day rolling average basis) under limited power plant operating scenarios. At this time, APS is pursuing a modification to the Four Corners NPDES discharge permit in order to implement the most recent ELG rulemaking. We cannot at this time predict the outcome of this permit modification proceeding, including any public commenting or permit appeal procedures. The Cholla facility does not require NPDES permitting.

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone NAAQS at a level of 70 parts per billion ("ppb"). Further, on December 23, 2020, EPA issued a final regulation retaining the current primary NAAQS for ozone, following a required scientific review process. With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA was expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. While EPA took action designating attainment and unclassifiable areas on November 6, 2017, the Agency's final action designating non-attainment areas was not issued until April 30, 2018. At that time, EPA designated the geographic areas containing Yuma and

Phoenix, Arizona as in non-attainment with the 2015 70 ppb ozone NAAQS. The vast majority of APS's natural gas-fired EGUs are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APS's fossil-fuel fired EGU fleet is located were designated as in attainment. We anticipate that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will be in place between 2023 and 2024. 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 ("CERCLA" or "Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, 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 ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the first or second quarter of 2022. APS estimates that its cost related to this investigation and study is approximately $3 million. APS anticipates 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 environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party 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.

Four Corners National Pollutant Discharge Elimination System Permit

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA's 2015 revised ELGs for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018, to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. The EAB thereafter dismissed the environmental group appeal on February 12, 2019. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. As of November 11, 2021, the parties to this lawsuit, including APS, reached a tentative agreement to settle this matter. Review of this agreement, including public commenting, is currently pending with the EPA. Notwithstanding this tentative agreement, we cannot predict the outcome of these appeal proceedings, including further settlement discussions, and, if settlement efforts fail and the appeal is eventually successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

Water Supply

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its operating 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. 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 adjudication. 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, including a number of gas-fired power plants located within Maricopa and Pinal Counties. 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.

At this time, the lower court proceedings in the Gila River adjudication are in the process of determining the specific hydro-geologic testing protocols for determining which groundwater wells located outside of the subflow zone of the Gila River should be subject to the adjudication court's jurisdiction. A hearing to determine this jurisdictional test question was held in March 2018 in front of a special master, and a draft decision based on the evidence heard during that hearing was issued on May 17, 2018. The decision of the special master, which was finalized on November 14, 2018, but which is subject to further review by the trial court judge, accepts the proposed hydro-geologic testing protocols supported by APS and other industrial users of groundwater. A final decision by the trial court judge in this matter remains pending. Further proceedings have been initiated to determine the specific hydro-geologic testing protocols for subflow depletion determinations. The determinations made in this final stage of the proceedings may ultimately govern the adjudication of rights for parties, such as APS, that rely on groundwater extraction to support their industrial operations. APS cannot predict the outcome of these proceedings.

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. No trial or pretrial proceedings have been scheduled for adjudication of APS's water right claims. The adjudication court is currently conducting a trial of federal reserved water right claims asserted by the Hopi Tribe and by the United States as trustee for the Tribe. In addition, the adjudication court has established a schedule for consideration of separate federal reserved water right claims asserted by the Navajo Nation and by the United States as trustee for the Nation. There is no established timeframe within which the adjudication court is expected to issue a final determination of water rights for the Hopi Tribe and the Navajo Nation, and any such final determination is likely to occur multiple years in the future.

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.

Human Capital

The Company seeks to attract the best employees, to retain those employees and to create a safe, inclusive, and productive work environment for all employees. We believe the strength of our employees is one of the significant contributors to our Company's success. Human capital measures and objectives that the Company focuses on in retaining its talent and managing its business include the safety of our employees, career development, diversity, equity and inclusion, succession planning, hiring, voluntary turnover, compensation, benefits, employee experience and engagement.

COVID-19

The health, well-being and safety of our employees, customers and communities is our top priority. In March 2020, we began operating under our long-standing pandemic and business continuity plans to address COVID-19. We had regular COVID-19 planning sessions to address the safety, operational and business risks associated with the pandemic. By the middle of March 2020, we successfully transitioned all of our employees to remote work unless they were essential workers that needed to remain onsite. We identified business-critical positions in our operations and support organizations, with backup personnel ready to assist if an issue arose. Additionally, efforts to ensure the health and safety of our employees resulted in bifurcated control rooms, thus reducing the number of employees in mission-critical locations. We also established COVID-19 safety protocols, social distancing practices and offered virtual options whenever possible. The Company also took rapid action to implement an all Company COVID-19 hotline, a focused COVID-19 team, and procured on-site COVID-19 testing at key facilities early in the pandemic. Through this testing, case management and contact tracing, the Company has been able to significantly limit COVID-19 transmission in the workplace. As a result of these efforts, we were able to maintain the continuity of the essential services that we provide to our customers, while also managing the spread of the virus and promoting the health, physical and mental well-being, and safety of our employees.

Employee Safety

Our work and our decisions are anchored in safety – safety is the foundation of everything we do, and employee safety is our paramount responsibility as an employer. We develop safety practices and programs that ensure employees have safe and secure workplaces that allow them to perform at the highest levels. Our comprehensive safety programs and our focus on human and organizational performance and injury case management contribute significantly to our strong safety performance. As we continue to improve our safety performance, our ultimate goal remains serious injury reduction. Our employees are expected to do the right thing and are empowered to speak up when there are better or safer ways of doing business, including stopping work to reassess or improve safety. Safety committees operate in organizations throughout the Company, providing opportunities for employees to positively impact their local safety cultures and performance.

Diversity, Equity, and Inclusion

Diversity, equity, and inclusion are core cultural principles, and we recognize that diversity of demographics, backgrounds and cultural perspective is a key driver for our success. Our Executive Diversity & Inclusion Council leads this commitment with an emphasis on diversity among employees, in the workplace and through our community involvement, as well as an increased focus on attracting and retaining diverse talent. This focus extends to individual business units in the Company, which report on the diversity of their teams during management review meetings to build awareness and address gaps of workforce diversity.

Our efforts to support and empower employees include a commitment to full inclusion. In 2019, we signed the UNITY Pledge in support of full inclusion and equality in employment, housing, and public accommodations for all Arizonans, including gay and transgender people. The UNITY Pledge reinforces our commitment to fostering an environment that recognizes our employees' unique needs and celebrates the value of diverse perspectives. The Company sponsors ten employee network groups that are intended to create a sense of inclusion and belonging for employees. In 2020, we conducted company-wide executive listening sessions to provide our employees with the opportunity to share their inclusion experiences with our officers.

We continue to focus on hiring diverse employees as well as hiring employees from our veteran community. During 2021, 44% of external hires were ethnically or racially diverse, 37% were female and 10% were veterans. Additionally, as of December 31, 2021, 33% of our employees are ethnically or racially diverse, 25% are female and 16% are veterans. Also, as of December 31, 2021, 40% of the Company's officers are female. In 2021, APS received the 2021 Inclusive Workplace Award, a joint award presented by the Diversity Leadership Alliance and the Arizona Society of Human Resources Management. The award recognizes APS as an Arizona corporation that leads by example, creating an inclusive environment in which employees can be their genuine, authentic selves and partners on community outreach efforts and support.

Succession Planning

Through a strong focus on succession planning, we ensure that our Company is prepared to fill executive and other key leadership roles with capable, experienced employees. We continually revisit and revise succession plans to make certain that qualified individuals are in place to move into critical positions. We have strategically selected successors for our management team to lead our Company into the future with strong and sustainable performance. In addition, we assure that each business unit of the Company has talent management strategies and development plans to meet its future leadership needs. Effective succession planning helps us identify employees with leadership potential and also allows us to evaluate any gaps in education, skills and experience that need to be addressed to prepare those employees to move into leadership roles. At management review meetings, officers and directors review how business units are addressing succession planning, leadership opportunities and retirement projections.

Talent Strategy and Development

We place significant focus on attracting and developing a skilled workforce. To attract and retain top talent, we provide formal professional development programs through blended learning education and leadership training. Our employees have access to a wide variety of training and development opportunities, including leadership academies, rotational programs, mentoring programs, industry certifications and loaned executive programs. In 2021, we graduated 84 employees from our leadership academies. Additionally, our Learning and Development organization was recognized as a top training organization, earnings an APEX Award from Training Magazine.

Talent pipelines help sustain our skilled workforce needs. Pipeline strategies include our apprentice and rotational programs. Additionally, our recruiters target specific colleges and programs of study that we have identified as talent pipelines. In 2021, we hosted 67 summer interns with a diversity rate of 68%.

Total Rewards Strategy

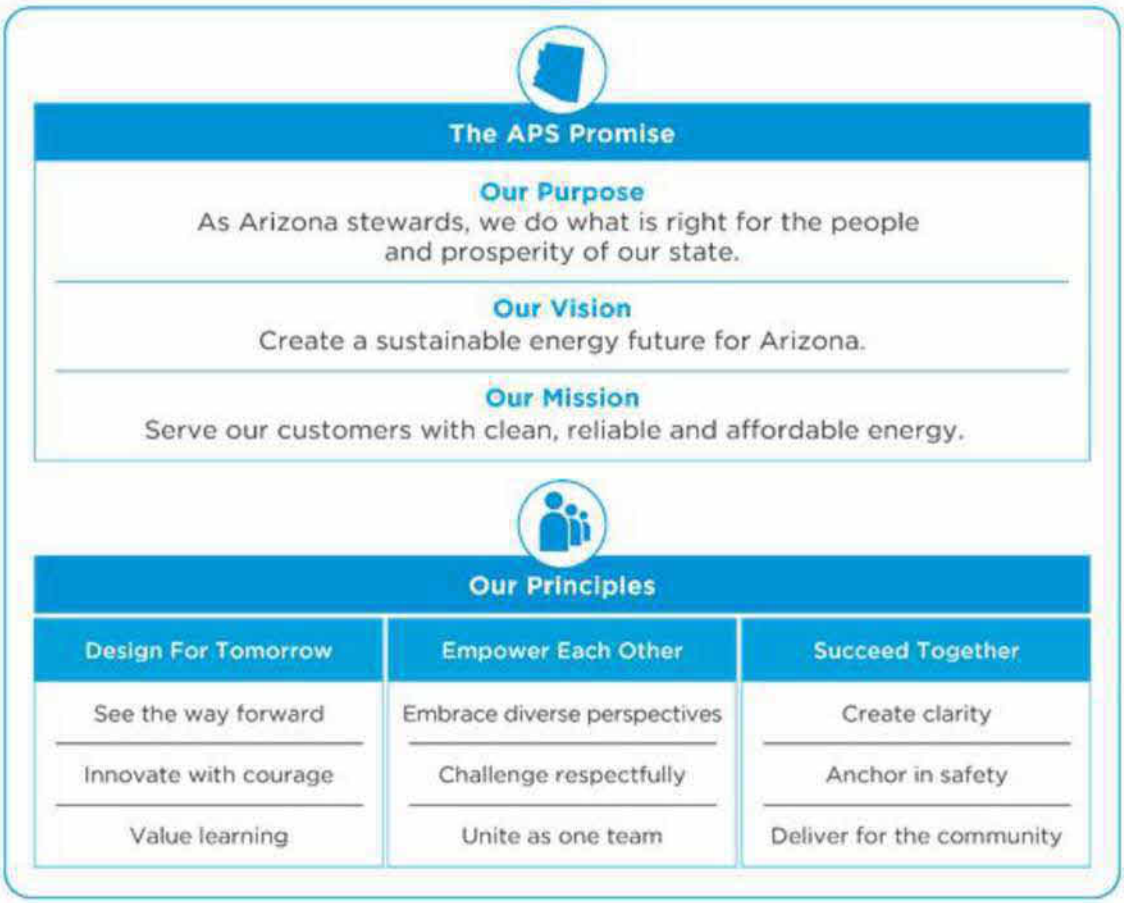
In addition to our talent strategy, we place significant focus on our Total Rewards strategy for attracting, developing, and rewarding our highly skilled workforce. Our employees are important to the success and future of our organization and our customers' experiences. At the Company, our pay and benefits, along with retirement, recognition, time off, career development and well-being, make up our Total Rewards program. It is an important part of the employee experience at the Company and supports personal well-being and professional satisfaction. We are committed to providing programs that matter to our employees throughout various life and career phases.

Employee Engagement

An annual employee experience survey and focused quarterly pulse-surveys, enable us to gather employee feedback, identify opportunities for improvement and compare our performance to other companies. Through the surveys, we track our Employee Experience Index, a set of seven questions that encompass key elements of a positive employee experience, including recognition, career development possibilities and pride in the organization. Based on survey results, business units and individual managers are encouraged to take meaningful actions to improve the employee experience. In response to past surveys, we have launched enterprise-wide initiatives focused on improving communication between employees and management as well as removing obstacles that prevent job success. Other initiatives driven by the survey have given employees more access to leadership and improved meeting efficiency. Our cross-functional Employee Engagement Council focuses on improving employee recognition across the organization. We work to ensure that a positive work environment is maintained for all employees. Through an outreach initiative, we obtain feedback from new hires regarding their employee experience. In 2019, we integrated our employee experience surveys with onboarding surveys and exit interviews. Bringing together these elements allows us to get a more complete picture of the experience of our employees, from the time they join the Company until they decide to leave.

Company Culture

In 2020, the Company launched the APS Promise, anchoring our commitment to our customers, community, and each other. The Promise explains our purpose, our vision and mission and the principles and behaviors that will empower us to achieve our strategic goals. It represents the opportunity to build on our cultural strengths and develop new behaviors to enable our future success.



BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company's core expertise in the electric energy industry. In 2014, BCE formed 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 electric transmission opportunities within the 11 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. As of December 31, 2021, BCE had total assets of approximately $27 million.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek wind farm in Missouri ("Clear Creek") and the 250 MW Nobles 2 wind farm in Minnesota ("Nobles 2"). Clear

Creek achieved commercial operation in May 2020 and Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado

El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and 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. El Dorado committed to a $25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of December 31, 2021, El Dorado has contributed approximately $10 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a $25 million investment in invisionAZ Fund, which is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona. The investment will be made by El Dorado as investments are selected by the invisionAZ Fund.

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, 2021
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	91
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	5,776
BCE	400 East Van Buren Street Phoenix, AZ 85004	2014	5
El Dorado	400 East Van Buren Street Phoenix, AZ 85004	1983	—
4CA	400 East Van Buren Street Phoenix, AZ 85004	2016	—
Total			5,872

The APS number includes employees at jointly-owned generating facilities (approximately 2,158 employees) for which APS serves as the generating facility manager. Approximately 1,229 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW"). In March 2020, the Company concluded negotiations with the IBEW and approved a three-year extension of the contract set to expire on April 1, 2020. Under the extension, union members received wage increases for 2020, 2021 and 2022; there were no other changes. The current contract expires on April 1, 2023.

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. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers, such as the Company, that file electronically with the SEC. The address of that website is www.sec.gov. 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 and 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 and adjustor recovery mechanisms. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings, adjustor recovery 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. Additionally, given that APS is subject to oversight by several regulatory agencies, a resolution by one may not foreclose potential actions by others for similar or related matters, such as the resolution of an Arizona Attorney General matter. See Note 11.

The ACC must also approve APS's issuance of equity and debt 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, including the infusion of equity into APS. 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 negative operational and financial impacts depends in part upon compliance with federal, state and local laws, judicial decisions, statutes, regulations and ACC requirements, which may be revised from time to time by legislative or other action, 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 (approximately $1.2 million 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.

Changes in laws or regulations that govern APS, new interpretations of law and regulations, or the imposition of new or revised laws or regulations could have an adverse impact on the manner in which we operate our business and our results of operations. In particular, new or revised laws or interpretations of existing laws or regulations may impact or call into question the ACC's permissive regulatory authority, which may result in uncertainty as to jurisdictional authority within our state, and uncertainty as to whether ACC decisions will be binding or challenged by other agencies or bodies asserting jurisdiction. In November 2021, the Arizona Court of Appeals issued an opinion that called into question the ACC-approved limitation of liability provision found in the APS Service Schedules. While APS is currently seeking review of the decision at the Arizona Supreme Court, the Court of Appeals decision—if undisturbed—could have an adverse impact on APS's future, potential litigation exposure. We are unable to predict the impact on our business and operating results from any pending or future regulatory or legislative rulemaking.

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 generating 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 generating 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 GHGs, water quality, discharges of wastewater and waste 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.

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. To the extent the rule requires the closure or modification of these CCR units, modification, or changes to the manner of closure of such units, or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal. In addition, the rule may also require corrective action to address releases from CCR disposal units or the presence of CCR constituents within groundwater near CCR disposal units above certain regulatory thresholds.

Ozone National Ambient Air Quality Standards. In 2015, EPA finalized revisions to the NAAQS for ozone, which set new, more stringent standards on emissions of nitrogen oxide, a precursor to ozone, in an effort 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, or other clean energy rules or initiatives, the economics or feasibility 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 CO_2, 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 CO_2 emissions from existing power plants, the CPP. The implementation of this rule within the jurisdictions where APS operates would have resulted in a shift in generation from coal to more natural gas and renewable generation. Because of a view that the federal Clean Air Act did not permit such an expansive use of administrative authority over utility generation resources, in 2019 regulations were issued that repealed the CPP and replaced it with a far narrower set of regulations focused solely on coal-fired power plant efficiency improvements. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new regulations governing carbon emissions from existing power plants consistent with the court's ruling. That decision endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP, and the current administration has expressed its intent to assert such authority through new carbon emission regulations governing existing power plants.

Depending on the outcome of future carbon emission rulemakings under the Clean Air Act targeting new and existing power plants, the utility industry may become subject to more stringent and expansive regulations. To the extent that these regulations focus on generation shifting as a means of compliance with federal emission performance standards, the electric utility industry may be forced to incur substantial costs necessary to achieve compliance. In addition, we anticipate that such regulations will be challenged in federal court prior to their implementation. Depending on the outcome of such judicial review, 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 United States' 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 may represent a greater challenge. As part of conducting its business, APS recognizes that the southwestern United States is particularly susceptible to the risks posed by climate change, which over time is projected to exacerbate high temperature extremes and prolong drought in the area where APS conducts its business.

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 its 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. Differences in the co-owners' willingness or ability to continue their participation could lead to eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets. See Note 4 for a discussion of the Navajo Plant and Cholla retirement and the related risks associated with APS's continued recovery of its remaining investment in the plant.

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. This is in large part due to a 2004 Arizona Court of Appeals decision that found critical components of the ACC's rules to be violative of the Arizona Constitution. The ruling also voided the operating authority of all the competitive providers previously authorized by the ACC. 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.

In November 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. At the same time, the Arizona legislature is considering a bill that would nullify, if approved, a 20-year-old electric deregulation law that has been in place since 1998. The bill has several procedural steps in the legislative process before becoming law.

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 regulations could be enacted by any of these governmental authorities, which could affect the Company's tax positions. The prospects for federal tax reform have increased due to the results of the 2020 Federal 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 or cash flows.

Apart from the impact upon electricity demand, weather conditions related to prolonged high temperatures or extreme heat events present operational challenges. In the southwestern United States, where APS conducts its business, the effects of climate change are projected to increase the overall average temperature, lead to more extreme temperature events, and exacerbate prolonged drought conditions leading to the declining availability of water resources. Extreme heat events and rising temperatures are projected to reduce the generation capacity of thermal-power plants and decrease the efficiency of the transmission grid. These operational risks related to rising temperatures and extreme heat events could affect APS's financial condition, results of operations or 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. In addition, the decrease in snowpack can also lead to reduced water supplies in the areas where APS relies upon non-renewable water resources to supply cooling and process water for electricity generation. Prolonged and extreme drought conditions can also affect APS's long-term ability to access the water resources necessary for thermal electricity generation operations. Reductions in the availability of water for power plant cooling could negatively impact APS's financial condition, results of operations or cash flows.

Effects of Energy Conservation Measures and Distributed Energy Resources. The ACC enacted rules regarding energy efficiency that mandated 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 revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the LFCR is designed 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 is 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 2.2% for the year ended December 31, 2021, compared with the prior-year period. For the three years through 2021, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2022, and the average annual growth will be in the range of 1.5% to 2.5% through 2024 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, for the year ended December 31, 2021, compared with the prior-year period increased 4.2%, which reflects a correction to 2020 commercial and industrial sales volumes of 111 GWh. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were residential sales being stronger than anticipated due to continued work-from-home policies, a strong improvement in sales to commercial and industrial customers, and the ramp-up of new data center customers. Though the total expected impact of COVID-19 on future sales is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales.

For the three years through 2021, annual retail electricity sales growth averaged 1.7%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.5% to 2.5% for 2022 and average annual growth will be in the range of 3.5% to 4.5% through 2024, including the effects of customer conservation, energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of new, large manufacturing facilities, which are expected to contribute to average annual growth in the range of 1.0% to 2.0% through 2024. This projected sales growth range also includes our estimated contributions of several large data centers, but not all, and we will continue to estimate contributions and evaluate sales guidance as these customers develop more usage history. These estimates could be further impacted by slower than expected growth of the Arizona economy, slower than expected ramp-up of the new data centers, larger manufacturing facilities not coming to Arizona as expected, a shift away from remote work, slower than expected commercial and industrial expansions, or acceleration of the expected effects of customer conservation, energy efficiency and distributed renewable generation initiatives.

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, ramp-up of data centers, impacts of energy efficiency programs and growth in DG, and responses to retail price changes. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 million.

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 could 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 impact of wildfires could negatively affect APS's results of operations.

Wildfires have the potential to affect the communities that APS serves and APS's vast network of electric transmission and distribution lines and facilities. The potential likelihood of wildfires has increased due to many of the same weather impacts existing in Arizona as those that led to the catastrophic wildfires in Northern California. While we proactively take steps to mitigate wildfire risk in the areas of our electrical assets, wildfire risk is always present due to APS's expansive service territory. APS could be held liable for damages incurred as a result of wildfires if it was determined that they were caused by or enhanced due to APS's negligence. The Arizona liability standard is different from that of California, which generally imposes liability for resulting damages without regard to fault. Any damage caused to our assets, loss of service to our customers, or liability imposed as a result of wildfires could negatively impact APS's financial condition, results of operations or cash flows.

The inability to successfully develop, acquire or operate 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 current and future generation portfolio. The current regulatory standards, laws, and regulations 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 carbon emissions, renewables development and energy efficiency measures. The development of any generation facility is also subject to many risks, including those related to financing, siting, permitting, new and evolving technology, and the construction of sufficient transmission capacity to support these facilities. 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, construction, and operation 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, construct, and operate fossil fuel infrastructure projects in the future.

In January 2020, APS announced its goal to provide 100% clean, carbon-free electricity by 2050 with an intermediate 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy. APS's ability to successfully execute its clean energy commitment is dependent upon a number of external factors, some of which include supportive national and state energy policies, a supportive regulatory environment, sales and customer growth, the development, deployment and advancement of clean energy technologies and continued access to capital markets.

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 the operation of 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. Climate change is also projected to exacerbate prolonged drought conditions. 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 that could adversely affect our business and financial condition.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the regular course of our business, we handle a range of sensitive security, customer, and business systems information. There appears to be an increasing level of activity, sophistication, and maturity of threat actors, in particular nation state actors, that seek to exploit potential vulnerabilities in the electric utility industry and wish to disrupt the U.S. bulk power system, our information technology systems, generation (including our Palo Verde nuclear facility), transmission and distribution facilities, and other infrastructure facilities and systems and physical assets. We have been and could be the target of attacks, and the aforementioned systems are critical areas of cyber protection for us.

We rely extensively on IT systems, networks, and services, including internet sites, data hosting and processing facilities, and other hardware, software and technical applications and platforms. Some of these systems are managed, hosted, provided, or used for third parties to assist in conducting our business. Malicious actors may attack vendors to disrupt the services these vendors provide to us or to use those vendors as a cyber conduit to attack us. As more third parties are involved in the operation of our business, there is a risk the confidentiality, integrity, privacy, or security of data held by, or accessible to, third parties may be compromised.

If a significant cybersecurity event or breach were to occur, we may not be able to fulfill critical business functions and we could (i) experience property damage, disruptions to our business, theft of or unauthorized access to customer, employee, financial or system operation information or other information; (ii) experience loss of revenue or incur significant costs for repair, remediation and breach notification, and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. If such disruptions or breaches are not detected quickly, their effects could be compounded or could delay our response or the effectiveness of our response and ability to limit our exposure to potential liability. These types of events could also require significant management attention and resources and could have a material adverse impact on our financial condition, results of operations or cash flows.

We develop and maintain systems and processes aimed at detecting and preventing information and cybersecurity incidents which require significant investment, maintenance, and ongoing monitoring and updating as technologies and regulatory requirements change. These systems and processes may be insufficient to mitigate the possibility of cybersecurity incidents, malicious social engineering, fraudulent or other malicious activities, and human error or malfeasance in the safeguarding of our data.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer information 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 NRC also has issued regulations and standards related to the protection of critical digital assets at commercial nuclear power plants. The increasing promulgation of NERC and NRC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards. Experiencing a cybersecurity incident could cause us to be non-compliant with applicable laws and regulations, such as those promulgated by NERC and the NRC, privacy laws, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings and regulatory fines or penalties.

The risk of these system-related events and security breaches occurring continues to intensify. 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. To date, we do not believe we have experienced a material breach or disruption to our network or information systems or our service operations. We may not be able to anticipate and prevent all cyberattacks or information security breaches, and our ongoing investments in security resources, talent, and business practices may not be effective against all threat actors. As such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks from being successful in the future.

We maintain 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 is subject to a number of exclusions and may not cover the total loss or damage caused by a breach. Coverage for cybersecurity events continues to evolve as the industry matures. In the future, adequate insurance may not be available at rates that we believe are reasonable, and the costs of responding to and recovering from a cyber incident may not be covered by insurance or recoverable in rates.

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.

Four Corners 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 that could adversely affect our business and financial condition.

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 APS's 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. APS may be required under federal law to pay up to $120.1 million (but not more than $17.9 million per year) of liabilities arising out of a nuclear incident not only at Palo Verde, but at any other nuclear power plant in the United States. In addition, APS is subject to retrospective premium adjustments under its nuclear property insurance policies with Nuclear Electric Insurance Limited ("NEIL") for approximately $22.4 million if NEIL's losses in any policy year exceed accumulated funds and if the retrospective premium assessment is declared by NEIL's Board of Directors. Although APS has 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.

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, including carbon-free nuclear generation, and increase the complexity of managing APS's information technology and power system operations, which could adversely affect APS's business.

Customer-sited alternative energy technologies present challenges to APS's operations due to misalignment with APS's existing operational needs. When these resources lack "dispatchability" and other elements of utility-side control, they are considered "unmanaged" resources. The cumulative effect of such unmanaged resources results in added complexity for APS's system management.

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, including energy storage 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 our 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 many companies in the electric utility industry, our workforce is maturing, with approximately 30% of employees eligible to retire by the end of 2026. Although we have undertaken efforts to recruit, train and develop new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees. Additionally, any regulatory changes requiring us to enforce a COVID-19 vaccine mandate could impact the availability of, and our ability to attract and retain, sufficient qualified employees. These or other employee workforce factors could negatively impact our business, financial condition, or results of operations.

COVID-19 could negatively affect our business.

COVID-19 is a continually developing situation around the globe that has led to economic disruption and volatility in the financial markets. The continued spread of COVID-19 and efforts to contain the virus and mitigate its public health effects, including but not limited to a vaccine mandate, could decrease demand for energy, lower economic growth, impact our employees and contractors, cause disruptions in our supply chain, increase certain costs, further increase volatility in the capital markets (and result in increases in the cost of capital or an inability to access the capital markets or draw on available credit facilities), delay the completion of capital or other construction projects and other operations and maintenance activities, delay payments or increase uncollectable accounts, impact our ability to hire or retain qualified employees, or cause other unpredictable events, each of which could adversely affect our business, results of operations, cash flows or financial condition.

As a result of the COVID-19 pandemic, from March 2020 through April 2021, APS experienced higher electric residential sales and lower electric commercial and industrial sales and the cumulative impact on weather normalized retail electricity sales usage was a net increase as compared to 2019. APS also experienced an increase in bad debt expense associated with the COVID-19 pandemic that resulted in a negative impact to its 2021 operating results. In mid-March 2020, we drew on our revolving credit facilities as a result of the commercial paper markets failing to function normally due to COVID-19, but we were subsequently able to utilize the commercial paper market in April 2020 and we have paid down the revolving credit facilities completely. We are also experiencing increased operations and maintenance expenses due to the need for personal protective equipment and other health and safety-related costs related to COVID-19.

Despite our efforts to manage the impacts, the degree to which the COVID-19 pandemic and related actions ultimately impact our business, financial position, results of operations and cash flows will depend on factors beyond our control including the duration, spread and severity of the outbreak, the actions taken to contain COVID-19 and mitigate its public health effects, including but not limited to a vaccine mandate, the impact on the U.S. and global economies and demand for energy, and how quickly and to what extent normal economic and operating conditions resume.

FINANCIAL RISKS

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 adversely impact our financial results. We could 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, new rules or regulations and other economic, social, and political factors could decrease the value of our benefit plan assets, nuclear decommissioning trust funds and other special use funds or increase the valuation of our related obligations, resulting in significant additional funding requirements. We are also 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 our pension trust and 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 and related regulations. 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 and other postretirement benefit expense and all of the currently estimated nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner could have a material negative impact on our financial condition, results of operations or cash flows.

Pending or future federal or state legislative or regulatory activity or court proceedings could increase costs of providing medical insurance for our employees and retirees. Any potential changes and resulting cost impacts cannot be determined with certainty at this time.

Our cash flow depends on the performance of APS and its ability to make distributions.

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 its subsidiaries will be effectively senior in right of payment to its own 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 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 over-the-counter ("OTC") 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 natural gas. 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 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.

GENERAL RISKS

Proposals to change policy in Arizona or other states made through ballot initiatives or referenda may increase the Company's cost of operations or impact its business plans.

In Arizona and other states, a person or organization may file a ballot initiative or referendum with the Arizona Secretary of State or other applicable state agency and, if a sufficient number of verifiable signatures are presented, the initiative or referendum may be placed on the ballot for the public to vote on the matter. Ballot initiatives and referenda may relate to any matter, including policy and regulation related to the electric industry, and may change statutes or the state constitution in ways that could impact Arizona utility customers, the Arizona economy, and the Company. Some ballot initiatives and referenda are drafted in an unclear manner and their potential industry and economic impact can be subject to varied and conflicting interpretations. We may oppose certain initiatives or referenda (including those that could result in negative impacts to our customers, the state, or the Company) via the electoral process, litigation, traditional legislative mechanisms, agency rulemaking or otherwise, which could result in significant costs to the Company. The passage of certain initiatives or referenda could result in laws and regulations that impact our business plans and have a material adverse impact on our financial condition, results of operations or cash flows.

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 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

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 revisions to 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, changes to the internal policies of our lenders, 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, fiscal policy, financial regulation, rating agency treatment 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 increase the cost and/or reduce the amount of 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.

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 beneficially owns 10% or more of our outstanding voting power, or any of our affiliates or associates who beneficially owned 10% or more of our outstanding voting power at any time during the prior three years) 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 and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise;
- 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;
- restrictions that limit the rights of our shareholders to call a special meeting of shareholders; and
- restrictions regarding the rights of our shareholders to nominate directors or to submit proposals to be considered at shareholder meetings.

While these provisions may 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 2021 fiscal year and that remain unresolved.

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned generating facilities as of December 31, 2021 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	2		Coal	Base Load	387
Total Steam					1,357
Combined Cycle:					
Redhawk (e)	2		Gas	Load Following	1,088
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,975
Combustion Turbine:					
Ocotillo (d)	7		Gas	Peaking	620
Saguaro	3		Gas	Peaking	189
Douglas/Fairview	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					1,598
Solar:					
Cotton Center (f)	1		Solar	As Available	17
Hyder I (f)	1		Solar	As Available	16
Paloma (f)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend (f)	1		Solar	As Available	32
Hyder II (f)	1		Solar	As Available	14
Foothills (f)	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star (f)	1		Solar	As Available	10
Red Rock	1		Solar	As Available	40
APS Owned Distributed Energy			Solar	As Available	33
Multiple facilities			Solar	As Available	4
Total Solar					247
Total Capacity					6,323

(a) 100% unless otherwise noted.
(b) APS's 29.1% ownership in Palo Verde includes leased interests and is the largest capacity interest of all the participants. 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, SCE, El Paso, Public Service Company of New Mexico, Southern California Public Power Authority, and Los Angeles Department of Water & Power.
(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and NTEC (7%). The plant is operated by APS.
(d) Ocotillo Steam Units 1 and 2 were retired on January 10, 2019. Units 3 through 7 all went into service on or prior to May 30, 2019, which increased generation capacity by 510 MW.
(e) Redhawk generation capacity increased by 104 MW following the Advanced Gas Path upgrade installed on both units.
(f) APS is under contract and currently plans to add battery storage at these AZ Sun sites. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for details related to these and other energy storage agreements.

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, and subsequently sold the interest to NTEC on July 3, 2018. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal-Fueled Generating Facilities — Four Corners" in Item 1 and "Four Corners — 4CA Matter" in Note 11 for additional information about 4CA's interest in Four Corners.

Transmission and Distribution Facilities

Current Facilities. APS's transmission facilities consist of approximately 5,814 pole miles of overhead lines and approximately 74 miles of underground lines, 5,743 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,258 miles of overhead lines and approximately 22,821 miles of underground primary cable (19,778 when excluding abandoned conductor), all of which are located in Arizona. APS also owns and maintains 475 substations, including both transmission and distribution yards. 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, 2021:

	Percent Owned (Weighted-Average)
Morgan — Pinnacle Peak System	64.7 %
Palo Verde — Rudd 500kV System	50.0 %
Round Valley System	50.0 %
ANPP 500kV System	33.5 %
Navajo Southern System	26.8 %
Four Corners Switchyards	60.1 %
Palo Verde — Yuma 500kV System	25.8 %
Phoenix — Mead System	17.1 %
Palo Verde — Morgan System	87.8 %
Hassayampa — North Gila System	80.0 %
Cholla 500kV Switchyard	85.7 %
Saguaro 500kV Switchyard	60.0 %
Kyrene — Knox System	50.0 %

Expansion. Each year APS prepares and files with the ACC a Ten-Year Transmission Plan. In APS's 2022 plan, APS projects it will develop 81 miles of new transmission lines over the next 10 years. The 2022 Ten-Year Plan includes a new 35-mile 500kV line from the Jojoba substation to the Rudd substation. The purpose of this project is to bring in a new source to the west and southwest parts of the Phoenix metropolitan area which is experiencing rapid economic development. In addition, this new source will provide customers in the area greater access to a diverse mix of resources from around the region.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities.

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 Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations.

APS, on behalf of the Four Corners participants, negotiated amendments to the Four Corners facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal-Fueled Generating Facilities — Four Corners" in Item 1 for additional information about the Four Corners right-of-way and lease matters.

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 4 for ACC and FERC-related matters.

See Note 11 for information regarding environmental matters, Superfund–related matters and other disputes.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors, or in certain cases also by the Human Resources Committee, at any time. The executive officers, their ages at February 25, 2022, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Jeffrey B. Guldner	56	Chairman of the Board, Chief Executive Officer and President of Pinnacle West	2019-Present
		Chairman of the Board, Chief Executive Officer and President of APS	2021-Present
		Chairman of the Board and Chief Executive Officer of APS	2020-2021
		President of APS	2018-2020
		Executive Vice President, Public Policy of Pinnacle West	2017-2019
		Executive Vice President, Public Policy of APS	2017-2018
		General Counsel of Pinnacle West and APS	2017-2018
		Senior Vice President, Public Policy of APS	2014-2017
Elizabeth A. Blankenship	50	Vice President, Controller and Chief Accounting Officer of Pinnacle West and APS	2019-Present
		General Manager, Accounting Operations of APS	2019-2019
		Director, Accounting Operations of APS	2014-2019
Andrew D. Cooper	43	Vice President and Treasurer of Pinnacle West and APS	2020-Present
		Director, Corporate Finance of Consolidated Edison Company of New York, Inc.	2017-2020
Donna M. Easterly	57	Senior Vice President, Human Resources of APS	2020-Present
		Vice President, Human Resources and Ethics of APS	2017-2020
		Vice President, Chief Procurement Officer of APS	2014-2017
Theodore N. Geisler	43	Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2020-Present
		Vice President and Chief Information Officer of APS	2018-2020
		General Manager, Transmission and Distribution Operations and Maintenance of APS	2017-2018
		Director, Investor Relations of Pinnacle West	2016-2017
Maria L. Lacal	61	Executive Vice President and Chief Nuclear Officer, PVGS, of APS	2020-Present
		Senior Vice President, Regulatory and Oversight, PVGS, of APS	2016-2020
Barbara D. Lockwood	55	Senior Vice President, Public Policy of APS	2020-Present
		Vice President, Regulation of APS	2015-2020
Robert E. Smith	52	Executive Vice President, General Counsel and Chief Development Officer of Pinnacle West and APS	2021- Present
		Senior Vice President and General Counsel of Pinnacle West and APS	2018-2021
Jacob Tetlow	49	Executive Vice President, Operations of APS	2021-Present
		Senior Vice President, Non-Nuclear Operations of APS	2020-2021
		Vice President, Transmission and Distributions Operations of APS	2017-2020
		General Manager, Transmission Operations and Maintenance of APS	2014-2017

PART II

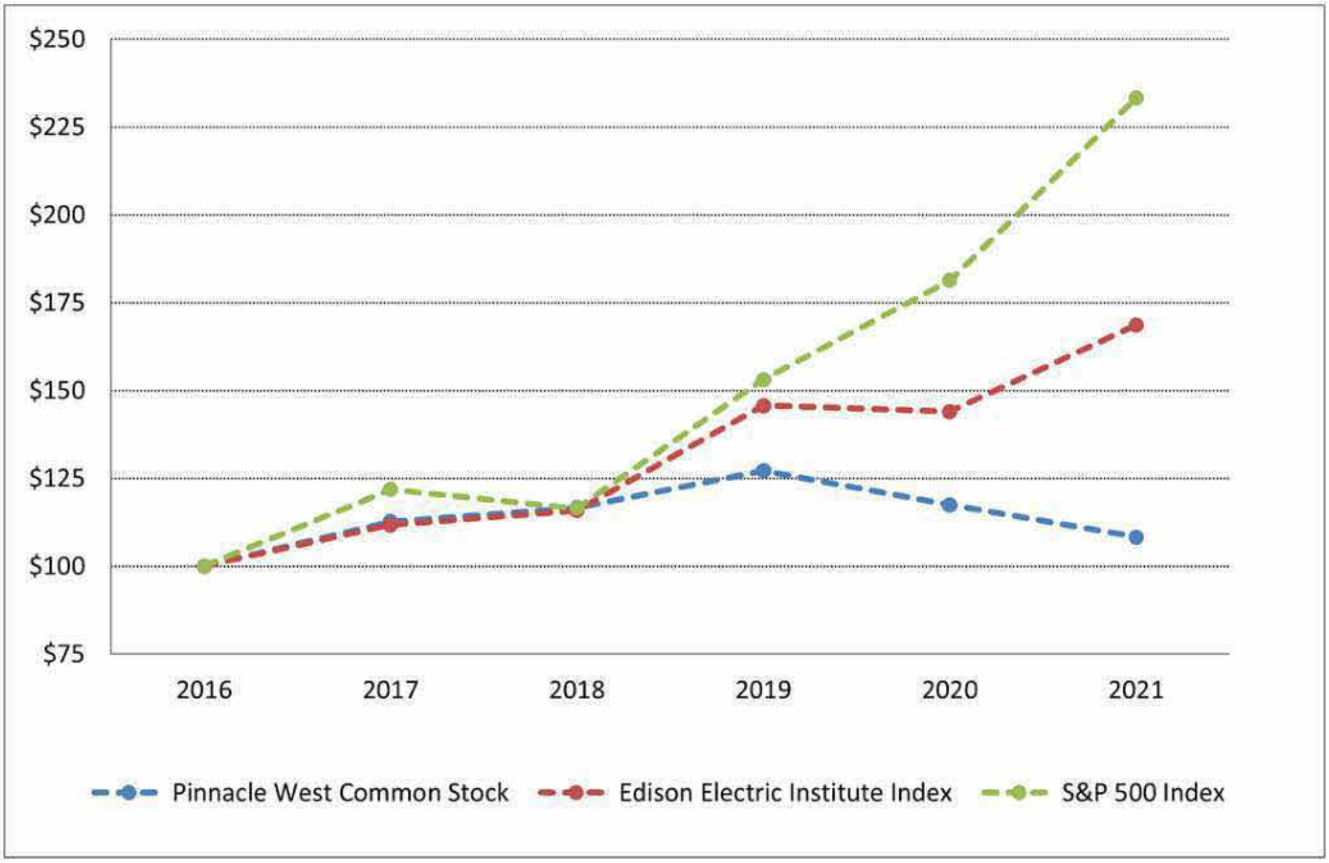
ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange under stock symbol PNW. At the close of business on February 17, 2022, Pinnacle West's common stock was held of record by approximately 15,730 shareholders.

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. At December 31, 2021, APS did not have any outstanding preferred stock.

Stock Performance Chart

This graph compares the cumulative total shareholder return on Pinnacle West's common stock during the five years ended December 31, 2021, to the cumulative total returns on the S&P 500 Index and the Edison Electric Index. The comparison assumes that $100 was invested on December 31, 2016, in Pinnacle West's common stock and in each of the indices shown and that all of the dividends were reinvested.



	Years Ended December 31,					
Company/Index	2016	2017	2018	2019	2020	2021
Pinnacle West Common Stock	$100	$113	$117	$127	$117	$108
Edison Electric Institute Index	$100	$112	$116	$146	$144	$169
S&P 500 Index	$100	$122	$116	$153	$181	$233

ITEM 6. [RESERVED]

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. This discussion provides a comparison of the 2021 results with 2020 results. A comparison of the 2020 results with 2019 results can be found in the Annual Report on Form 10-K for the fiscal year ended December 31, 2020. 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

Business Overview

Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of about $22 billion. For over 130 years, Pinnacle West and our affiliates have provided energy and energy-related products to people and businesses throughout Arizona.

Pinnacle West derives essentially all of our revenues and earnings from our principal subsidiary, APS. APS is Arizona's largest and longest-serving electric company that generates safe, affordable, and reliable electricity for approximately 1.3 million retail customers in 11 of Arizona's 15 counties. APS is also the operator and co-owner of Palo Verde — a primary source of electricity for the southwest United States and the largest nuclear power plant in the United States.

COVID-19 Pandemic

The COVID-19 pandemic continues to be an evolving situation. The Company is operating under long-standing pandemic and business continuity plans that exist to address situations including pandemics like COVID-19. We are focused on ensuring the health and safety of our employees, contractors, and the general public by helping limit the spread of this virus and ensuring continued, safe, and reliable electric service for APS customers.

We identified business-critical positions in our operations and support organizations, with backup personnel ready to assist if an issue arose. Additionally, efforts to ensure the health and safety of our employees resulted in bifurcated control rooms, thus reducing the number of employees in mission-critical locations. We also established COVID-19 safety protocols, social distancing practices and offering virtual options whenever possible. The Company also took rapid action to implement an all Company COVID-19 hotline, a focused COVID-19 team, and procured on-site COVID-19 testing at key facilities early in the pandemic. Through this testing, case management and contact tracing, the Company has been able to significantly limit COVID-19 transmission in the workplace. As a result of these efforts, we were able to maintain the continuity of the essential services that we provide to our customers, while also managing the spread of the virus and promoting the health, physical and mental well-being and safety of our employees, customers, and communities. In the summer of 2021, the Company began transitioning employees that were previously working remotely back to the workplace on a limited basis and began the reduction of our COVID-19 safety protocols and restrictions. Due to the COVID-19 variants and increased transmission rates, the Company has delayed its full transition back to the workplace and COVID-19 safety protocols and restrictions remain in place.

Essential planned work and capital investments are continuing during the pandemic with priority given to support fire mitigation and summer storm efforts, as well as heat related outages. Raw material shortages, rising inflation, COVID-19 related work force disruptions and natural disasters are putting increased pressure on the global supply chain. APS is experiencing some delays in finished materials and tight labor markets. To date, APS has not experienced labor or material supply chain shortages that have significantly impacted its ability to serve its customers' needs. However, shortages are causing minor delays, and shifting of work projects based on material availability. If APS continues to experience delays in materials, it could experience an increase in purchased power costs for summer generation needs. Such increased purchased power costs would be expected to be recoverable through the PSA. See Note 4 for additional information on the PSA. APS has measures in place to continually monitor and evaluate resource needs and supply chain adequacy but cannot predict whether there will be material supply chain shortages in the future.

The Company's operations and maintenance expenses, exclusive of bad debt expense, increased by approximately $4.3 million for the year ended December 31, 2021, primarily due to costs for personal protective equipment and other health and safety-related costs related to COVID-19. We do not expect the Company's operation and maintenance expenses to be materially impacted in 2022 by costs related to COVID-19.

While the total expected impact of COVID-19 on future sales is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales from commercial and industrial customers increased to levels in line with pre-COVID-19 sales but residential sales continued to be higher than pre-COVID-19 sales. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 million.

The Coronavirus Aid, Relief, and Economic Security (CARES) Act allows employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, which was approximately $18 million. We paid half of this cash deferral by December 31, 2021, and the remainder will be paid by December 31, 2022.

On June 30, 2020, FERC issued an order granting a waiver request related to the existing AFUDC rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 31, 2022. The order provides a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS has adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in both 2020 and 2021 but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements. See Note 1.

Due to COVID-19, APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020, until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS voluntarily began waiving late payment fees of its customers on March 13, 2020, and is continuing to waive late payment fees. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium, and the related write-offs of customer delinquent accounts. See Note 4 for additional information regarding the Summer Disconnection Moratorium. The Summer Disconnection Moratorium, the suspension of disconnections due to COVID-19 and the increased bad debt expense associated with both events resulted in a negative impact to its 2021 operating results of approximately $25 million pre-tax above the impact of disconnections on its operating results for years that did not have the Summer Disconnection Moratorium or COVID-19. APS expects that the Summer Disconnection Moratorium, the suspension of disconnections due to COVID-19 and the increased bad debt expense associated with this will continue to negatively impact its operating results for the foreseeable future in amounts similar to 2020 and 2021. The estimated impact depends on certain current assumptions, including, but not limited to, customer behaviors, population, and employment growth.

In February 2021, due to COVID-19, APS delayed the annual reset of the PSA. Rather than the increase being effective February 2021, the PSA reset was implemented with 50% of the increase effective April 2021 and the remaining 50% increase effective November 2021. See Note 4.

More detailed discussion of the impacts and future uncertainties related to the COVID-19 pandemic can be found throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations and the Combined Notes to Pinnacle West's and APS's financial statements that appear in Part II, Item 8 of this report and "Risk Factors" in Part I, Item 1A of this report.

Strategic Overview

Our strategy is to deliver shareholder value by creating a sustainable energy future for Arizona by serving our customers with clean, reliable, and affordable energy.

Clean Energy Commitment

We are committed to doing our part to make the future clean and carbon-free. As Arizona stewards, we do what is right for the people and prosperity of Arizona. Our vision is to create a sustainable energy future for Arizona through providing clean, affordable, and reliable energy. We can accomplish our visions through collaboration with customers, communities, employees, policymakers, shareholders, and other stakeholders. Our clean energy goal is based on sound science and supports continued growth and economic development while maintaining reliability and affordable prices for APS's customers.

APS's clean energy goals consist of three parts:

- A 2050 goal to provide 100% clean, carbon-free electricity;
- A 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and

- A commitment to end APS's use of coal-fired generation by 2031.

APS's ability to successfully execute its clean energy commitment is dependent upon a number of important external factors, some of which include a supportive regulatory environment, sales and customer growth, development of clean energy technologies and continued access to capital markets.

2050 Goal: 100% Clean, Carbon-Free Electricity. Achieving a fully clean, carbon-free energy mix by 2050 is our aspiration. The 2050 goal will involve new thinking and depends on improved and new technologies.

2030 Goal: 65% Clean Energy. APS has an energy mix that is already 50% clean with existing plans to add more renewables and energy storage before 2025. By building on those plans, APS intends to attain an energy mix that is 65% clean by 2030, with 45% of APS's generation portfolio coming from renewable energy. "Clean" is measured as percent of energy mix which includes all carbon-free resources like nuclear and demand-side management, and "renewable" is expressed as a percent of retail sales. This target will serve as a checkpoint for our resource planning, investment strategy, and customer affordability efforts as APS moves toward 100% clean, carbon-free energy mix by 2050.

2031 Goal: End APS's Use of Coal-Fired Generation. The commitment to end APS's use of coal-fired generation by 2031 will require APS to cease use of coal-generation at Four Corners. APS has permanently retired more than 1,000 MW of coal-fired electric generating capacity. These closures and other measures taken by APS have resulted in a total reduction of carbon emissions of 33% since 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units by 2025.

APS understands that the transition away from coal-fired power plants toward a clean energy future will pose unique economic challenges for the communities around these plants. We worked collaboratively with stakeholders and leaders of the Navajo Nation to consider the impacts of ceasing operation of APS coal-fired power plants on the communities surrounding those facilities to propose a comprehensive Coal Community Transition ("CCT") plan. The proposed framework provided substantial financial and economic development support to build new economic opportunities and addresses a transition strategy for plant employees. We are committed to continuing our long-running partnership with the Navajo Nation in other areas as well, including expanding electrification and developing tribal renewable projects. Our proposed CCT plan supported the Navajo Nation, where Four Corners is located, the communities surrounding the Cholla Power Plant and the Hopi Tribe, which is impacted by closure of the Navajo Plant. On November 2, 2021, the ACC approved an amended 2019 Rate Case ROO that will require (i) equal payments over a three-year period that total $10 million to the Navajo Nation, (ii) a $1 million one-time payment to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (iii) a $500,000 one-time payment to the Navajo County communities within 60 days of the 2019 Rate Case decision, (iv) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (v) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. The payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant. All ordered payments and expenditures would be recoverable through rates. See Note 4 for a discussion of the CCT plan.

In June 2021, APS and the owners of Four Corners entered into agreements to operate Four Corners seasonally beginning in fall 2023, subject to the necessary governmental approvals and conditions associated with changes in plant ownership. Under seasonal operation, a single unit will remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. In addition, the other unit will be operational throughout the summer season of June through October when customer demand is the highest. APS believes that operating Four Corners seasonally will bring environmental benefits and ensure continued service reliability for its customers, especially during Arizona's hot summer months, as APS transitions to ceasing to use coal-fired generation by 2031. By moving to seasonal operations, Four Corners will become a more flexible resource that supports increasing amounts of clean energy, helping to compensate for the intermittent output of renewable resources. This change also helps ensure reliability of a critical energy source while reducing operations and maintenance costs. APS estimates that the shift to seasonal operations will reduce annual carbon emissions at Four Corners by an estimated 20-25%, as compared to current conditions.

Renewables. APS's IRP (see Note 4 for additional information) establishes the path to meeting our clean energy commitment and maintaining reliable electric service for our customers. APS intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Our IRP rapidly adds clean energy and storage resources while maintaining reliable and affordable service. Its near-term actions are focused on clean energy and positive customer outcomes and includes: (a) competitive solicitations to procure clean energy resources such as solar, wind, energy storage, and DSM resources, all of which lead to a cleaner grid; and (b) strategic, short-term wholesale market purchases from a combination of existing merchant natural gas units, neighboring utility systems and wholesale market participants that ensure operational reliability.

APS has a diverse portfolio of existing and planned renewable resources, including solar, wind, geothermal, biomass and biogas that supports our commitment to clean energy, which is already strengthened by Palo Verde, the nation's largest carbon-free, clean energy resource, that provides the foundation for reliable and affordable service for APS customers. APS's longer-term clean energy strategy includes pursuing the right mix of purchased power contracts for new facilities, procurement of new facilities to be owned by APS, and the ongoing development of distributed energy resources. This balance will ensure an appropriately diverse portfolio designed to achieve the same operational reliability and customer affordability as APS's near-term strategies. In addition, APS is actively seeking to include future facility purchase options in its PPAs that will enable investments with greater financial flexibility.

APS uses competitive "all source" requests for proposal ("RFPs") to pursue market resources that meet its system needs and offer the best value for customers. APS selects projects based on cost and commercial viability, taking into consideration timing and likelihood of successful contracting and development. Under current market conditions, APS must aggressively contract for resources that can withstand supply chain and other geopolitical pressures. Available projects are guided by IRP timelines and quantities and APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the RFP process. 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. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio" in Item 1 for details regarding APS's renewable energy resources.

In September 2019, APS issued an RFP that requested up to 250 MW of wind resources to be in service as soon as possible, but no later than 2022. As a result of this RFP, APS executed a 200 MW PPA for a wind resource that went into service in January 2022. In December 2020, APS issued two additional RFPs: (i) a battery storage RFP for projects to be located at two AZ Sun sites; and (ii) an all source RFP that solicited resources to meet our clean energy needs and capacity to maintain system reliability, and was later amended to include a request for 150 MW of solar resources to be developed on APS property and owned by APS (collectively, the "December 2020 RFPs"). As a result of the all source RFP, APS executed a PPA in October 2021 for a 238 MW wind resource to be in service by June 2023, and also executed an engineering, procurement, and construction contract in November 2021 for a 150 MW solar resource to be owned by APS and in service in early 2023. APS continues to negotiate contracts for additional resources to be in service in 2024 in connection with the all source RFP. Once it secures those important resources and closes out the December 2020 RFPs, APS intends to issue its next all source RFP to address resource needs for 2025 and beyond.

Energy Storage. APS deploys a number of advanced technologies on its system, including energy storage. Energy storage provides capacity, improves power quality, can be utilized for system regulation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage also aids in integrating renewable generation by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to meet customer reliability requirements, increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid.

In 2018, APS issued an RFP for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are expected to be in service during the summer of 2022. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS's AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2022 with respect to 100 MW and in 2023 with respect to 50 MW.

As a result of its December 2020 RFPs, as of February 2022, APS has executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs totaling 275 MW solar plus storage resource. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021. The remaining project was filed in February 2022 for ACC approval and is pending ACC review. Service under the agreements is expected to begin in 2023 and 2024.

APS currently plans to install more than 900 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of December 31, 2021. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
APS Owned: Energy Storage	—	201
PPAs - Energy Storage	—	510
Residential Energy Storage	12(a)	3
Total Energy Storage Portfolio	**12**	**714**

(a) This includes 11.7 MW of APS customer-owned batteries and 0.3 MW of APS-owned residential batteries.

Palo Verde. Palo Verde, the nation's largest carbon-free, clean energy resource, will continue to be a foundational part of APS's resource portfolio. The plant currently supplies nearly 70% of our clean energy and provides the foundation for the reliable and affordable service for APS customers. Palo Verde is not just the cornerstone of our current clean energy mix; it also is a significant provider of clean energy to the southwest United States. The plant is a critical asset to the Southwest, generating more than 32 million MWh annually – enough power for more than 4 million people. Its continued operation is important to a carbon-free and clean energy future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy.

Affordable

We believe it is APS's responsibility to deliver electric services to customers in the most cost-effective manner. Since January 2018 through November 2021, the average residential bill decreased by 4.99%, or $7.48, due to net reductions in cost recovery adjustor mechanisms.

Building upon existing cost management efforts, APS launched a customer affordability initiative in 2019. The initiative was implemented company-wide to thoughtfully and deliberately assess our business processes and organizational approaches to completing high-value work and internal efficiencies. In 2021, APS continued to drive this initiative by identifying opportunities to streamline its business processes and deliver sustainable cost savings, which resulted in the Company identifying approximately $30 million in annual incremental cost saving opportunities in 2022.

Participation in the EIM continues to be a tool for creating savings for APS's customers from the real-time, voluntary market. APS continues to expect that its participation in EIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources. APS continues to evaluate opportunities that benefit our customers and is exploring opportunities to move to a day-ahead market with the expectation of reliably achieving incrementally greater cost savings and using the region's increasing renewable resources more efficiently. As part of that effort, APS is exploring several options. APS is in discussions with the current EIM operator, the CAISO, the Western Resource Adequacy Program, the Western Markets Exploratory Group, and the Southwest Power Pool. Each of these explorations also involve other entities and are being undertaken to evaluate the feasibility and cost/benefit of creating a voluntary day-ahead market.

Reliable

While our energy mix evolves, the obligation to deliver reliable service to our customers remains. Notwithstanding the challenges presented by the COVID-19 pandemic, as well the Phoenix metropolitan experiencing the warmest June on record and its summer monsoon being the third wettest over the last 41 years, APS continued to provide reliable service to its customers in 2021.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth, and enabling more renewable energy resources. Our advanced distribution management system allows operators to locate outages, control line devices remotely and helps them coordinate more closely with field crews to safely maintain an increasingly dynamic grid. The system also integrates a new meter data management system that increases grid visibility and gives customers access to more of their energy usage data.

Wildfire safety remains a critical focus for APS and other utilities. We increased investment in fire mitigation efforts to clear defensible space around our infrastructure, build partnerships with government entities and first responders and educate customers and communities. These programs contribute to customer reliability, responsible forest management and safe communities.

The new units at our modernized Ocotillo Power Plant provide cleaner-running and more efficient units. They support reliability by responding quickly to the variability of solar generation and delivering energy in the late afternoon and early evening when solar production declines as the sun sets and customer demand peaks.

In April 2021, the CAISO sought FERC authorization for certain tariff changes intended to try to address risks associated with high heat weather events. Although APS is generally supportive of some of these changes, others would change the load, export, and wheeling priorities in a way that would unfairly benefit California entities at the expense of non-California entities. On June 25, 2021, FERC issued an order accepting the CAISO's proposed changes. On July 26, 2021, APS filed seeking a rehearing of FERC's June 25, 2021, order. On August 26, 2021, FERC issued a notice indicating that the pending requests for rehearing were denied by operation of law and providing for further consideration. The requests for rehearing will be addressed in a future FERC order. APS cannot predict the outcome of these proceedings.

APS's key elements to delivering reliable power include resource planning, sufficient reserve margins, customer partnerships to manage peak demand, fire mitigation, and operational preparedness. Seasonal readiness procedures at APS also include walkdowns to ensure good material conditions and critical control system surveys. APS also plans for the unexpected by conducting emergency operations drills and coordinating on fire and emergency management with federal, state, and local agencies.

Customer-Focused

Recognizing that creating customer value is inextricably linked to increasing shareholder value, APS's focus remains on its customers and the communities it serves. Accordingly, it is APS's goal to achieve an industry-leading, best-in-class customer experience. This multi-year objective includes incrementally improving the company's J.D. Power ("JDP") overall customer satisfaction ratings from the fourth quartile to the first quartile of its peer set comprised of large investor-owned utilities. APS's rating improved in 2021 with its fourth-quarter JDP residential overall customer satisfaction score ranked in the third quartile. APS made year-over-year improvements in power quality and reliability, billing and payment, and phone customer care.

In mid-2021, APS initiated an organization-wide customer experience strategy council designed to further drive a customer-oriented culture and improve JDP Company performance. Through this and other on-going customer-centric initiatives, APS has embraced increased empathy training for care center associates and adopted more flexible payment arrangements for customers. Numerous customer web-based enhancements also were implemented, including streamlined navigation and Spanish language transaction capabilities on aps.com; an enhanced online power outage center; and enrollment of more than 1 million customers for outage email and text notifications. Furthermore, APS launched a broad-reaching ad campaign focused on energy efficiency and financial assistance programs.

APS offers discounts to qualified limited-income customers, as well as programs to help customers stay current on their bills. Qualified customers experiencing an unplanned major expense or an unexpected reduction in income can receive up to $800 a year to cover current or past due APS bills through the Crisis Bill Assistance program. APS's Energy Support program gives qualified limited-income customers a 25% discount on their bill each month. As of December 31, 2021, customers received almost $23 million in bill assistance from various sources, with the largest amount coming from the Arizona Department of Economic Security's Emergency Rental Assistance Program. This combined funding will aid approximately 36,000 APS customers.

A customer advisory board and a consumer working group were formed in 2020, one made up of a cross-section of customers, and the other of stakeholders and advocates representing various customer interests, met several times in 2021 to keep APS apprised of customer needs, wants and perspectives. Their direct feedback helped facilitate improved analysis, education, and communication to customers about their rate plan options, rate names and related communications. As of December 1, 2021, about 54% of APS customers are on their most economical plan. The advisory board also helped inform an on-going redesign and enhancements to APS's monthly bill based on additional customer feedback, research, and industry best practices.

Developing Clean Energy Technologies

Electric Vehicles

APS is making electric vehicle charging more accessible for its customers and helping Arizona businesses, schools and governments electrify their fleets. In 2021, APS continued its expansion of its Take Charge AZ Pilot Program. As of January 2022, APS had installed approximately 400 charging ports at business customer locations with more stations expected to be added through 2022. The program provides charging equipment, installation, and maintenance to business customers, government agencies, and multifamily housing communities. In addition to the Level 2 charging stations, APS has begun construction of DC fast charging stations that will be owned and operated by APS at five locations in Arizona. This project is projected to be completed during 2022, with each location including 2-150 kilowatt and 2-350 kilowatt DC fast charging stations. Charging at these stations will be accessible through the Electrify America charging network. APS also has a goal of 450,000 light-duty electric vehicles in its service territory by 2030.

Additionally, as part of the 2020 DSM Plan, the ACC approved programs for electric vehicles, including a residential program to measure electric vehicle charging as well as a $100 rebate to home builders for new home 240V charging station garage outlets.

The ACC ordered the state's public service corporations, including APS, to develop a long-term, comprehensive Statewide Transportation Electrification Plan ("TE Plan") for Arizona. The TE Plan is intended to provide a roadmap for Transportation Electrification in Arizona, focused on realizing the associated air quality and economic development benefits for all residents in the state along with understanding the impact of electric vehicle charging on the grid. APS actively participated in developing this plan. The ACC approved the plan in December 2021. APS is currently working with stakeholders to develop a budget and implementation plan for ACC review.

Hydrogen Production

Palo Verde, in partnership with Idaho National Laboratory ("INL"), Energy Harbor Corporation ("Energy Harbor") and Xcel Energy Incorporated ("Xcel"), was chosen by the DOE's Office of Nuclear Energy to participate in a series of hydrogen production projects with the goal to improve the long-term economic competitiveness of the nuclear power industry. The multi-phase projects began in 2020 with a series of small-scale hydrogen production demonstration projects led by Energy Harbor and Xcel, as well as a technical and economic assessment performed by INL of using electricity generated at Palo Verde to produce hydrogen.

Based on the experience from Palo Verde's utility partners' small scale demonstration projects and from the Palo Verde-specific technical and economic assessment performed by INL, in April 2021, PNW Hydrogen LLC ("PNW Hydrogen"), a newly formed subsidiary of Pinnacle West, applied for DOE funding for a larger scale hydrogen production demonstration project using electricity sourced from Palo Verde. On October 7, 2021, PNW Hydrogen was notified that DOE's Office of Energy Efficiency & Renewable Energy and Office of Nuclear Energy had selected PNW Hydrogen's application for an award of $20 million in federal funding to support the hydrogen production demonstration project, subject to negotiation and execution of a definitive Cooperative Agreement funding instrument between PNW Hydrogen and DOE.

Carbon Capture

Carbon capture technologies can isolate CO_2 and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. Carbon capture technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology.

Environmental, Social, and Governance ("ESG") Practices

Pinnacle West has been integrating ESG practices into its core work for almost 30 years. As a business strategy, we seek solutions that provide "shared value," meaning solutions that address societal and environmental challenges in a way that also delivers business value. Our commitment extends beyond implementing sustainability practices; we are dedicated to working with our stakeholders to identify and address the sustainability issues that we are uniquely positioned to impact through our business. In 2020, in support of our clean energy commitment and the growing focus on ESG within our organization, we increased our efforts by dedicating a new Sustainability Department at Pinnacle West to integrating ESG best practices into the everyday work of the Company.

As a first step, the Company engaged the Electric Power Research Institute ("EPRI") and leveraged input from employees, large customers, limited-income advocates, economic development groups, environmental non-governmental organizations, leading sustainability academics and other stakeholders to identify and assess the sustainability issues that matter most. In total, 23 Priority Sustainability Issues ("PSIs") were identified and prioritized. The most critical category, Integral Shared Value, includes four issues deemed most important and most able to be impacted by our actions: clean energy, customer experience, energy access and reliability and safety and health. These Integral PSIs provide the foundation for informing our strategic direction, creating a framework for incorporating best practices and driving enterprise-wide alignment and accountability. In 2021, the Company engaged EPRI for the second phase of this work, focused on benchmarking best practices within these four Integral Shared Value PSIs. We will utilize the benchmarking information to identify opportunities for further improvement in our ESG performance.

In 2021, the Company established a Social Issues Committee Framework. The goal of the framework is to provide a process for considering emergent social issues, and for determining whether or how best to engage. The committee's responsibility is to determine, using a set of principles grounded in the APS Promise and the PSIs, whether engagement on specific emergent social issues is appropriate and, if so, how best to engage.

In 2021, the Company finalized an ESG Strategic Framework to guide our work. The framework is based upon three foundational pillars: ESG Policy Advocacy (we advocate for policy that supports our clean energy goals); Driving Performance (improving our ESG performance in the most important areas, including our PSIs); and effectively communicating and amplifying our ESG story to our various stakeholders, including investors, customers, employees and beyond. The framework will guide and shape our ESG work moving forward.

Regulatory Overview

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that was the subject of a separate proceeding, see "Four Corners SCR Cost Recovery" in Note 4. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the TEAM. The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.1 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- 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 Fuel Rate of $0.030168 per kWh;
- authorization to defer until APS'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;
- a number of proposed rate and program changes for residential customers, including:
  - a super off-peak period during the winter months for APS's time-of-use with demand rates;
  - additional $1.25 million in funding for APS's limited-income crisis bill program; and
  - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project. See Note 4 for a discussion of the 2017 Settlement Agreement; and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant. See Note 4 for details related to the resulting regulatory asset.

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) a $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism, to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) the CCT plan related to the closure or future closure of coal-fired generation facilities of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021, and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the RES adjustment mechanism. APS filed exceptions on September 13, 2021 regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $500,000 to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed with the ACC an application for rehearing of the 2019 Rate Case and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m., but did not explicitly approve the 10-months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend until September 1, 2022, the deadline to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

See Note 4 for information regarding additional regulatory matters.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 4 for additional information regarding the Four Corners SCR cost recovery.

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's strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company's core expertise in the electric energy industry. In 2014, BCE formed 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 electric transmission opportunities within the 11 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.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek and the 250 MW Nobles 2 wind farms. Clear Creek achieved commercial operation in May 2020 and Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado. El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. El Dorado committed to a $25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of December 31, 2021, El Dorado has contributed approximately $10 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a $25 million investment in invisionAZ Fund, which is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately held early stage and emerging growth technology companies and businesses primarily based in the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona.

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 2019 through 2021, retail electric revenues comprised approximately 94% of our total 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 2.2% for the year ended December 31, 2021, compared with the prior-year period. For the three years through 2021, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2022, and the average annual growth will be in the range of 1.5% to 2.5% through 2024 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, for the year ended December 31, 2021, compared with the prior-year period increased 4.2%, which reflects a correction to 2020 commercial and industrial customer sales volumes of 111 GWh ("2020 Sales Volume Correction."). The 2020 Sales Volume Correction impacted prior disclosure in our Quarterly Reports on Form 10-Q. The retail electricity sales in kWh, adjusted to exclude the effects of weather variations, for the three-month period ended March 31, 2021, the six-month period ended June 30, 2021, and the nine-month period ended Sept 30, 2021 with the 2020 Sales Volume Correction reflected would have been 0.2%, 3.1% and 3.5%, respectively. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were residential sales being stronger than anticipated due to continued work-from-home policies, a strong improvement in sales to commercial and industrial customers, and the ramp-up of new data center customers. Though the total expected impact of COVID-19 on future sales is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales.

For the three years through 2021, annual retail electricity sales growth averaged 1.7%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.5% to 2.5% for 2022, and average annual growth will be in the range of 3.5% to 4.5% through 2024, including the effects of customer conservation, energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of new, large manufacturing facilities, which are expected to contribute to average annual growth in the range of 1.0% to 2.0% through 2024. This projected sales growth range also includes our estimated contributions of several large data centers, but not all, and we will continue to estimate contributions and evaluate sales guidance as these customers develop more usage history. These estimates could be further impacted by slower than expected growth of the Arizona economy, slower than expected ramp-up of the new data centers, larger manufacturing facilities not coming to Arizona as expected, a shift away from remote work, slower than expected commercial and industrial expansions, or acceleration of the expected effects of customer conservation, energy efficiency and distributed renewable generation initiatives.

Consistent with our focus on continuously looking for improvement in our processes and procedures, we updated our weather normalization methodology in 2020 to better leverage available AMI data (smart meter data). While the prior method only used one to two months of daily usage data to estimate weather impacts, the new method utilizes a rolling four-year period of daily usage data, which improves the accuracy of estimated weather impacts on energy sales since many more data points are used for each calculation. The impact to our 2019-2021 average normalized sales growth from this change in methodology is 0.1%.

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, ramp-up of data centers, impacts of energy efficiency programs and growth in DG, and responses to retail price changes. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 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 $25 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 $15 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, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and DSM 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 “Liquidity and Capital Resources” below for information regarding the planned additions to our facilities.

Pension and Other Postretirement Non-Service Credits, Net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, 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.

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 10.7% of the assessed value for 2021, 10.8% for 2020 and 10.9% for 2019. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units and transmission and distribution facilities.

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. On December 22, 2017, the Tax Cuts and Jobs Act (the "Tax Act") was enacted and was generally effective on January 1, 2018. Changes impacting the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. See Note 5 for details of the impacts on the Company as of December 31, 2021. In APS's 2017 Rate Case Decision, the ACC approved the TEAM, which was being used to pass through the income tax effects to retail customers of the Tax Act. As part of the 2019 Rate Case (defined above), all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case. See Note 4 for details of the TEAM.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. See Note 7 for further details. 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 sales supplied under traditional cost-based rate regulation) and related activities and includes electricity generation, transmission, and distribution.

Operating Results – 2021 compared with 2020

Our consolidated net income attributable to common shareholders for the year ended December 31, 2021, was $619 million, compared with $551 million for the prior year. The results reflect an increase of approximately $69 million for the regulated electricity segment primarily due to higher revenue driven by higher customer usage and growth, lower refunds in the current year related to the Tax Act, higher transmission revenues, the one-time charge in 2020 related to the Arizona Attorney General Matter, higher pension and other postretirement non-service credits, and lower other expenses, partially offset by the effects of weather, higher depreciation and amortization expense and higher income taxes, including lower amortization of excess deferred taxes.

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

	Year Ended December 31, 2021	Year Ended December 31, 2020	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,645	$ 2,589	$ 56
Operations and maintenance	(951)	(953)	2
Depreciation and amortization	(651)	(614)	(37)
Taxes other than income taxes	(235)	(225)	(10)
Pension and other postretirement non-service credits — net	113	56	57
All other income and expenses, net	61	26	35
Interest charges, net of allowance for borrowed funds used during construction	(233)	(229)	(4)
Income taxes (Note 5)	(110)	(78)	(32)
Less income related to noncontrolling interests (Note 18)	(17)	(19)	2
Regulated electricity segment income	622	553	69
All other	(3)	(2)	(1)
Net Income Attributable to Common Shareholders	$ 619	$ 551	$ 68

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $56 million higher for the year ended December 31, 2021, 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)		
Higher retail revenue due to changes in customer usage patterns and customer growth, partially offset by the impacts of energy efficiency and distributed generation	$ 112	$ 36	$ 76
Lower refunds in the current year related to the Tax Act (Note 4)	30	—	30
Higher transmission revenues (Note 4)	26	—	26
Arizona Attorney General Matter (Note 11)	24	—	24
Higher renewable energy regulatory surcharges, offset by operations and maintenance costs	14	(5)	19
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	158	160	(2)
Effects of weather	(150)	(36)	(114)
Miscellaneous items, net	1	4	(3)
Total	$ 215	$ 159	$ 56

Operations and maintenance. Operations and maintenance expenses decreased $2 million for the year ended December 31, 2021, compared with the prior-year period primarily because of:

- A decrease of $21 million primarily related to the COVID Customer Support Fund (see Note 4), personal protective equipment and other health and safety-related costs for COVID-19 response;
- A decrease of $13 million for costs related to transmission and distribution;
- An increase of $16 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- An increase of $12 million related to employee benefits; and
- An increase of $4 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $37 million higher for the year ended December 31, 2021, compared with the prior-year period primarily due to increased plant in service of $31 million and the regulatory deferrals for the Ocotillo modernization project and the Four Corners SCR project of $6 million.

Taxes other than income taxes. Taxes other than income taxes were $10 million higher for the year ended December 31, 2021, compared with the prior-year period primarily due to higher property values.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $57 million higher for the year ended December 31, 2021, compared to the prior-year period primarily due to actual market returns exceeding estimated returns in 2020.

All other income and expenses, net. All other income and expenses, net were $35 million higher for the year ended December 31, 2021, compared to the prior-year period primarily due to the prior year CCT and APS Foundation contributions.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction were $4 million higher for the year ended December 31, 2021, compared to the prior-year period primarily due to higher debt balances in the current period, partially offset by higher allowance for borrowed funds due to increased capital expenditures.

Income taxes. Income taxes were $32 million higher for the year ended December 31, 2021, compared with the prior-year period primarily due to higher pre-tax net income and lower amortization of excess deferred taxes, partially offset by a net operating loss carryback benefit that the Company recognized during the first quarter of 2021.

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, 2021, APS's common equity ratio, as defined, was 51%. Its total shareholder equity was approximately $6.6 billion, and total capitalization was approximately $13.1 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $5.2 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 financings and equity infusions from Pinnacle West.

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, 2021, and 2020 (dollars in millions):

Pinnacle West Consolidated

	2021	2020
Net cash flow provided by operating activities	$ 860	$ 967
Net cash flow used for investing activities	(1,387)	(1,278)
Net cash flow provided by financing activities	477	361
Net increase (decrease) in cash and cash equivalents	$ (50)	$ 50

Arizona Public Service Company

	2021	2020
Net cash flow provided by operating activities	$ 865	$ 929
Net cash flow used for investing activities	(1,391)	(1,286)
Net cash flow provided by financing activities	478	404
Net increase (decrease) in cash and cash equivalents	$ (48)	$ 47

Operating Cash Flows

2021 Compared with 2020. Pinnacle West's consolidated net cash provided by operating activities was \$860 million in 2021 compared to \$967 million in 2020, a decrease of \$107 million in net cash provided primarily due to \$252 million higher fuel and purchased power costs, \$93 million higher payments for operations and maintenance costs, \$15 million higher other taxes and \$11 million higher interest payments, partially offset by \$175 million higher cash receipts from electric revenues and \$93 million other changes in working capital. The difference between APS and Pinnacle West's net cash provided by operating activities primarily relates to APS's income tax cash payments to Pinnacle West and other changes in working capital.

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. Pinnacle West also sponsors other postretirement benefit plans for the employees of Pinnacle West and its 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 estimated to be 138% funded as of January 1, 2022, and was 131% as of January 1, 2021. 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 2021, \$100 million in 2020, and \$150 million in 2019. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2022, 2023 or 2024. Regarding contributions to our other postretirement benefit plan, we did not make any contributions in 2021 or 2020 and do not expect to make any contributions in 2022, 2023 or 2024. The Company was reimbursed \$24 million in 2021, \$26 million in 2020, and \$30 million in 2019 for prior years retiree medical claims from the other postretirement benefit plan trust assets. We continually monitor financial market volatility and its impact on our retirement plans and other postretirement benefits, but we believe, our liability driven investment strategy helps to minimize the impact of market volatility on our plan's funded status. For instance, our pension plan's funded status, as measured for accounting principles generally accepted in the United States of America ("GAAP") purposes, is still above 107% funded as of December 31, 2021, and our postretirement benefit plans have a funded status, also as measured for GAAP purposes at December 31, 2021, in excess of 145%. See Note 8 for additional details.

The Coronavirus Aid, Relief, and Economic Security (CARES) Act allows employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020 that was approximately \$18 million. We paid approximately \$9 million on December 28, 2021, and will pay the second half of this cash deferral by December 31, 2022.

Investing Cash Flows

2021 Compared with 2020. Pinnacle West's consolidated net cash used for investing activities was \$1,387 million in 2021 compared to \$1,278 million in 2020, an increase of \$109 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,		
	2022	**2023**	**2024**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 110	$ 120	$ 110
Renewables and Energy Storage Systems ("ESS") (a)	230	210	450
Other Generation (b)	250	270	190
Distribution	510	530	500
Transmission	250	210	210
Other (c)	175	185	190
Total APS	$ 1,525	$ 1,525	$ 1,650

(a) APS Solar Communities program, energy storage, renewable projects, and other clean energy projects.
(b) Includes generation environmental projects.
(c) Primarily information systems and facilities projects.

The table above does not include capital expenditures related to BCE projects.

Generation capital expenditures are comprised of various additions and improvements to APS's clean resources, including nuclear plants, renewables and ESS. Generation capital expenditures also include improvements to existing fossil plants. Examples of the types of projects included in the forecast of generation capital expenditures are additions of renewables and energy storage, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers, and environmental equipment. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

2021 Compared with 2020. Pinnacle West's consolidated net cash provided by financing activities was $477 million in 2021 compared to $361 million of net cash provided in 2020, an increase of $116 million in net cash provided by financing activities primarily due to $915 million lower long-term debt repayments, partially offset by $850 million in lower issuances of long-term debt, a net increase in short-term borrowings of $69 million and higher dividend payments of $19 million.

APS's consolidated net cash provided by financing activities was $478 million in 2021 compared to $404 million in 2020, an increase of $74 million in net cash provided by financing activities primarily due to $465 million lower long-term debt repayments, offset by $653 million in lower issuances of long-term debt, a net increase in short-term borrowings of $279 million, and higher dividend payments of $19 million.

Significant Financing Activities. On December 15, 2021, the Pinnacle West Board of Directors declared a dividend of $0.85 per share of common stock, payable on March 1, 2022, to shareholders of record on February 1, 2022. During 2021, Pinnacle West increased its indicated annual dividend from $3.32 per share to $3.40 per share. For the year ended December 31, 2021, Pinnacle West's total dividends paid per share of common stock were $3.34 per share, which resulted in dividend payments of $369 million.

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. See Note 6 for more information on available credit facilities.

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 these covenants. For both Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2021, the ratio was approximately 56% for Pinnacle West and 50% 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.

On December 17, 2020, the ACC issued a financing order that, subject to specified parameters and procedures, increased APS's long-term debt limit from $5.9 billion to $7.5 billion, and authorized APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). See Note 7 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 17, 2022, 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. On October 12, 2021, Fitch Ratings downgraded the issuer ratings of the Company and APS from A- to BBB+ and the senior unsecured ratings of the Company and APS from A- and A to BBB+ and A-, respectively, with a negative outlook retained. Fitch Ratings also affirmed the commercial paper ratings of the Company and APS at F2. On November 9, 2021, S&P downgraded the issuer ratings of the Company and APS from A- to BBB+. S&P also downgraded the senior unsecured ratings of the Company and APS from BBB+ to BBB and A- to BBB+, respectively, with a negative outlook retained. Commercial paper ratings remained unchanged at A-2 for both entities. On November 17, 2021, Moody's downgraded both the issuer and senior unsecured ratings of the Company from A3 to Baa1. Concurrently, Moody's downgraded the issuer and senior unsecured ratings of APS from A2 to A3. Commercial paper for APS was downgraded from P-1 to P-2. The commercial paper ratings for the Company remain unchanged. The outlooks for both companies are negative. 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	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB	BBB+
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative
APS			
Corporate credit rating	A3	BBB+	BBB+
Senior unsecured	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative

Contractual Obligations

Pinnacle West has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Material contractual obligations and other commitments are as follows:

- Pinnacle West and APS have material long-term debt obligations that mature at various dates through 2050 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2021. See Note 7.

- Pinnacle West and APS maintain committed revolving credit facilities. See Note 6 for short-term debt details.

- Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. See Notes 4 and 11. Purchase obligations includes capital expenditures and other obligations. See Note 11. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 9.

- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 4 and 11.

- APS must reimburse certain coal providers for amounts incurred for final and contemporaneous coal mine reclamation. See Note 11.

- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 18.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with 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 amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, 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, except for pension benefits, which would be charged to OCI and result in lower future earnings. Management judgments also include assessing the impact of potential ACC or FERC Commission-ordered refunds to customers on regulatory liabilities. We had $1,712 million of regulatory assets and $2,795 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2021. See Notes 1 and 4 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit assets, liabilities 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, 2021, reported pension assets and liabilities on the Consolidated Balance Sheets and our 2021 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 Plans**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (388)	$ 5
Decrease 1%	471	15
Expected long-term rate of return on plan assets:		
Increase 1%	—	(28)
Decrease 1%	—	28

(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, 2021, other postretirement benefit obligation and our 2021 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 Plans**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (72)	$ (4)
Decrease 1%	90	5
Healthcare cost trend rate (b):		
Increase 1%	80	8
Decrease 1%	(65)	(7)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(6)
Decrease 1%	—	6

(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 8 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 trusts fund, investments held in our other special use funds, 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 of accounting policies and Note 13 for fair value measurement disclosures.

Asset Retirement Obligations

We recognize an ARO for the future decommissioning or retirement of our tangible long-lived assets for which a legal obligation exists. The ARO liability represents an estimate of the fair value of the current obligation related to decommissioning and the retirement of those assets. ARO measurements inherently involve uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the amount we recognize as an ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the asset's current license or lease term and expected decommissioning dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related assets. In addition, we accrete the ARO liability to reflect the passage of time. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. In accordance with GAAP accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal.

AROs as of December 31, 2021 are described further in Note 12.

OTHER ACCOUNTING MATTERS

In July 2021, a new accounting standard, ASU 2021-05, was issued that amends lessor's accounting treatment for certain lease transactions with variable lease payments. We adopted the standard on January 1, 2022 using a prospective approach. The adoption of this standard did not impact our financial statements. See Note 3 for additional information.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices, investments held by our nuclear decommissioning trust, other special use funds 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, other special use funds (see Note 13 and Note 19), and benefit plan assets. The nuclear decommissioning trust, other special use funds 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, 2021, and 2020. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2021, and 2020 (dollars in millions):

Pinnacle West – Consolidated

2021	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2022	0.18 %	$ 292	0.78 %	$ 150	—	$ —
2023	—	—	—	—	—	—
2024	—	—	0.85 %	150	3.35 %	250
2025	—	—	—	—	1.99 %	800
2026	—	—	—	—	2.55 %	250
Years thereafter	—	—	0.22 %	36	3.87 %	5,480
Total		$ 292		$ 336		$ 6,780
Fair value		$ 292		$ 336		$ 7,390

2020	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2021	0.40 %	$ 169	—	$ —	—	$ —
2022	—	—	—	—	—	—
2023	—	—	—	—	—	—
2024	—	—	—	—	3.35 %	250
2025	—	—	—	—	1.99 %	800
Years thereafter	—	—	0.18 %	36	3.95 %	5,280
Total		$ 169		$ 36		$ 6,330
Fair value		$ 169		$ 36		$ 7,577

The tables below present contractual balances of APS's long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2021, and 2020. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2021, and 2020 (dollars in millions):

APS — Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2021	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2022	0.18 %	$ 279	—	$ —	—	$ —
2023	—	—	—	—	—	—
2024	—	—	—	—	3.35 %	250
2025	—	—	—	—	3.15 %	300
2026	—	—	—	—	2.55 %	250
Years thereafter	—	—	0.22 %	36	3.87 %	5,480
Total		$ 279		$ 36		$ 6,280
Fair value		$ 279		$ 36		$ 6,898

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2020	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2021	—	$ —	—	$ —
2022	—	—	—	—
2023	—	—	—	—
2024	—	—	3.35 %	250
2025	—	—	3.15 %	300
Years thereafter	0.18 %	36	3.95 %	5,280
Total		$ 36		$ 5,830
Fair value		$ 36		$ 7,068

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 natural gas. 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 (dollars in millions):

	December 31, 2021	December 31, 2020
Mark-to-market of net positions at beginning of year	$ (13)	$ (71)
Increase in regulatory liability	120	57
Recognized in OCI:		
Mark-to-market losses realized during the period	—	1
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$ 107	$ (13)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2021, 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	2022	2023	2024	2025	2026	Total Fair Value
Observable prices provided by other external sources	$ 63	$ 35	$ 12	$ —	$ —	$ 110
Prices based on unobservable inputs	(3)	—	—	—	—	(3)
Total by maturity	$ 60	$ 35	$ 12	$ —	$ —	$ 107

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 (dollars in millions):

	December 31, 2021 Gain (Loss)		December 31, 2020 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ —	$ —	$ 4	$ (4)
Natural gas	50	(50)	49	(49)
Total	$ 50	$ (50)	$ 53	$ (53)

(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

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 Capital Corporation. 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, 2021. The effectiveness of our internal control over financial reporting as of December 31, 2021, 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 25, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, 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, 2021, the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, 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 an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting — Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 4 to the financial statements.

Critical Audit Matter Description

Arizona Public Service Company ("APS"), which is a wholly-owned subsidiary of the Company, is subject to rate regulation by the Arizona Corporation Commission (the "ACC"), which has jurisdiction with respect to the rates charged by public service utilities in Arizona. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant and equipment; regulatory assets and liabilities; operating revenues; fuel and purchased power; operations and maintenance expense; and depreciation expense.

The ACC's rate-making policies are premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the ACC in the future will impact the accounting for regulated operations, including decisions about the amount of allowable deferred costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the ACC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings.

We identified Regulatory Accounting, specifically the impact of rate regulation on the financial statements, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes, recent rate orders specific to APS and to other regulated entities in the same jurisdiction, and likelihood of success of legal appeals. Management judgments also include assessing the impact of potential ACC-ordered refunds to customers on regulatory liabilities. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the ACC and legal bodies, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to regulatory accounting included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs of recently completed plant and costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; and the implementation of new rates as ordered by the ACC.
- We evaluated the Company's disclosures related to regulatory accounting, specifically the impact of rate regulation on the financial statements, including the balances recorded and regulatory developments.
- We read relevant regulatory rate orders issued by the ACC for APS and other public utilities in Arizona, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the ACC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory assets and liabilities for completeness.
    - We observed the ACC open meetings for the APS 2019 Retail Rate Case. We read the ACC approved decision regarding the 2019 Retail Rate Case.
    - We obtained the Company's internally prepared memo regarding impacts of the ACC decision to rates and recorded balances.
    - We tested that new rates were implemented within the system effective December 1, 2021.

- We evaluated management's assessment of the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities based on applicable regulatory orders or precedents set by the ACC under similar circumstances. For certain regulatory assets or liabilities where management's assessment is based on precedents established by the ACC under similar circumstances and not specifically addressed in a regulatory order, we also obtained a letter from internal legal counsel regarding their assessment. We read the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact management's assessment.
- We evaluated management's assessment that the SCR plant investment is not probable of a partial disallowance and that the SCR deferred costs are probable of recovery. We read the Notice of Direct Appeal filed with the Arizona Court of Appeals and Petition for Special Action filed with the Arizona Supreme Court, reviewed the Company's internally prepared memo, and reviewed a legal letter from the Company's external counsel to assess the likelihood of recovery in future rates or of a future reduction in rates based on the ACC decision.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 25, 2022

We have served as the Company's auditor since 1932.

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

	Year Ended December 31,		
	2021	2020	2019
OPERATING REVENUES (Note 2)	$ 3,803,835	$ 3,586,982	$ 3,471,209
OPERATING EXPENSES			
Fuel and purchased power	1,152,551	993,419	1,042,237
Operations and maintenance	954,067	958,910	941,616
Depreciation and amortization	650,875	614,378	590,929
Taxes other than income taxes	234,639	224,835	218,579
Other expenses	6,393	7,288	5,888
Total	2,998,525	2,798,830	2,799,249
OPERATING INCOME	805,310	788,152	671,960
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	41,737	33,776	31,431
Pension and other postretirement non-service credits — net (Note 8)	112,541	56,341	22,989
Other income (Note 17)	45,100	56,703	50,263
Other expense (Note 17)	(25,396)	(57,776)	(17,880)
Total	173,982	89,044	86,803
INTEREST EXPENSE			
Interest charges	254,314	247,501	235,251
Allowance for borrowed funds used during construction (Note 1)	(21,052)	(18,530)	(18,528)
Total	233,262	228,971	216,723
INCOME BEFORE INCOME TAXES	746,030	648,225	542,040
INCOME TAXES (Note 5)	110,086	78,173	(15,773)
NET INCOME	635,944	570,052	557,813
Less: Net income attributable to noncontrolling interests (Note 18)	17,224	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 618,720	$ 550,559	$ 538,320
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,910	112,666	112,443
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	113,192	112,942	112,758
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 5.48	$ 4.89	$ 4.79
Net income attributable to common shareholders — diluted	$ 5.47	$ 4.87	$ 4.77

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,		
	2021	2020	2019
NET INCOME	$ 635,944	$ 570,052	$ 557,813
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized gain (loss), net of tax benefit (expense) of $(378), $662, and $0	1,077	(2,089)	—
Reclassification of net realized gain, net of tax benefit (expense) of $18, $(171), and $(375) (Note 16)	18	592	1,137
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(2,256), $1,371, and $3,452 (Note 8)	6,840	(4,203)	(10,525)
Total other comprehensive income (loss)	7,935	(5,700)	(9,388)
COMPREHENSIVE INCOME	643,879	564,352	548,425
Less: Comprehensive income attributable to noncontrolling interests	17,224	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 626,655	$ 544,859	$ 528,932

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

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

	December 31, 2021	December 31, 2020
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,969	$ 59,968
Customer and other receivables	391,923	313,576
Accrued unbilled revenues	133,980	132,197
Allowance for doubtful accounts (Note 2)	(25,354)	(19,782)
Materials and supplies (at average cost)	349,135	314,745
Fossil fuel (at average cost)	18,032	19,552
Income tax receivable (Note 5)	7,514	6,792
Assets from risk management activities (Note 16)	63,481	2,931
Deferred fuel and purchased power regulatory asset (Note 4)	388,148	175,835
Other regulatory assets (Note 4)	130,376	115,878
Other current assets	83,896	76,627
Total current assets	1,551,100	1,198,319
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	1,294,757	1,138,435
Other special use funds (Notes 13 and 19)	358,410	254,509
Assets from risk management activities (Note 16)	46,908	1,818
Other assets	97,884	91,104
Total investments and other assets	1,797,959	1,485,866
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 10)		
Plant in service and held for future use	21,688,661	20,837,885
Accumulated depreciation and amortization	(7,504,603)	(7,110,310)
Net	14,184,058	13,727,575
Construction work in progress	1,329,478	937,384
Palo Verde sale leaseback, net of accumulated depreciation of $256,884 and $253,014 (Note 18)	94,166	98,036
Intangible assets, net of accumulated amortization of $737,694 and $698,500	273,693	282,570
Nuclear fuel, net of accumulated amortization of $133,122 and $137,207	106,039	113,645
Total property, plant and equipment	15,987,434	15,159,210
DEFERRED DEBITS		
Regulatory assets (Notes 1, 4 and 5)	1,192,987	1,133,987
Operating lease right-of-use assets (Note 9)	890,057	505,064
Assets for pension and other postretirement benefits (Note 8)	545,723	502,992
Other	37,962	34,983
Total deferred debits	2,666,729	2,177,026
TOTAL ASSETS	$ 22,003,222	$ 20,020,421

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

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

	December 31, 2021	December 31, 2020
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 393,083	$ 318,585
Accrued taxes	168,645	159,551
Accrued interest	57,332	56,962
Common dividends payable	95,988	93,531
Short-term borrowings (Note 6)	292,000	169,000
Current maturities of long-term debt (Note 7)	150,000	—
Customer deposits	42,293	48,340
Liabilities from risk management activities (Note 16)	4,373	7,557
Liabilities for asset retirements (Note 12)	4,473	15,586
Operating lease liabilities (Note 9)	100,443	74,785
Regulatory liabilities (Note 4)	296,271	229,088
Other current liabilities	151,968	187,448
Total current liabilities	1,756,869	1,360,433
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 7)	6,913,735	6,314,266
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 5)	2,311,862	2,135,403
Regulatory liabilities (Notes 1, 4, 5 and 8)	2,499,213	2,450,169
Liabilities for asset retirements (Note 12)	762,909	689,497
Liabilities for pension benefits (Note 8)	152,865	166,484
Liabilities from risk management activities (Note 16)	—	11,062
Customer advances	257,151	221,032
Coal mine reclamation	174,616	170,097
Deferred investment tax credit	186,570	191,372
Unrecognized tax benefits (Note 5)	4,657	5,834
Operating lease liabilities (Note 9)	728,401	361,336
Other	232,914	190,643
Total deferred credits and other	7,311,158	6,592,929
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,014,528 and 112,760,051 issued at respective dates	2,702,743	2,677,482
Treasury stock at cost; 87,608 shares at end of 2021 and 72,006 shares at end of 2020	(6,401)	(6,289)
Total common stock	2,696,342	2,671,193
Retained earnings	3,264,719	3,025,106
Accumulated other comprehensive loss (Note 20)	(54,861)	(62,796)
Total shareholders' equity	5,906,200	5,633,503
Noncontrolling interests (Note 18)	115,260	119,290
Total equity	6,021,460	5,752,793
TOTAL LIABILITIES AND EQUITY	$ 22,003,222	$ 20,020,421

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, 2021	2020	2019
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 635,944	$ 570,052	$ 557,813
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	719,141	686,253	664,140
Deferred fuel and purchased power	(256,871)	(93,651)	(82,481)
Deferred fuel and purchased power amortization	44,557	(12,047)	49,508
Allowance for equity funds used during construction	(41,737)	(33,776)	(31,431)
Deferred income taxes	117,471	69,469	(1,479)
Deferred investment tax credit	(4,802)	(5,096)	(3,938)
Stock compensation	18,460	18,292	18,376
Changes in current assets and liabilities:			
Customer and other receivables	(72,559)	(18,191)	(12,789)
Accrued unbilled revenues	(1,783)	(4,032)	9,005
Materials, supplies and fossil fuel	(32,870)	11,623	(51,826)
Income tax receivable	(722)	14,935	(21,727)
Other current assets	(22,720)	(30,640)	(3,507)
Accounts payable	20,267	(6,059)	50,641
Accrued taxes	9,094	14,652	(9,920)
Other current liabilities	(52,086)	22,520	(84,651)
Change in margin and collateral accounts — assets	(50)	404	(247)
Change in margin and collateral accounts — liabilities	350	100	(125)
Change in unrecognized tax benefits	(568)	2,220	2,704
Change in long-term regulatory liabilities	57,549	13,017	124,221
Change in other long-term assets	(246,473)	(67,453)	(82,895)
Change in other long-term liabilities	(29,578)	(186,227)	(132,666)
Net cash provided by operating activities	860,014	966,365	956,726
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,473,475)	(1,326,584)	(1,191,447)
Contributions in aid of construction	105,654	62,503	70,693
Allowance for borrowed funds used during construction	(21,052)	(18,530)	(18,528)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,720,966	819,518	719,034
Investment in nuclear decommissioning trust and other special use funds	(1,725,480)	(822,608)	(722,181)
Other	6,458	7,883	11,452
Net cash used for investing activities	(1,386,929)	(1,277,818)	(1,130,977)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	746,999	1,596,672	1,092,188
Repayment of long-term debt	—	(915,150)	(600,000)
Short-term borrowings and (repayments) — net	142,000	73,325	54,275
Short-term debt borrowings under revolving credit facility	—	751,690	49,000
Short-term debt repayments under revolving credit facility	(19,000)	(770,690)	(65,000)
Dividends paid on common stock	(369,478)	(350,577)	(329,643)
Common stock equity issuance and purchases — net	(2,350)	(1,389)	692
Distributions to noncontrolling interests	(21,255)	(22,743)	(22,744)
Net cash provided by financing activities	476,916	361,138	178,768
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(49,999)	49,685	4,517
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	59,968	10,283	5,766
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 9,969	$ 59,968	$ 10,283

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, 2018	112,159,896	$2,634,265	(58,135)	$ (4,825)	$2,641,183	$ (47,708)	$ 125,790	$ 5,348,705
Net income		—		—	538,320	—	19,493	557,813
Other comprehensive loss		—		—	—	(9,388)	—	(9,388)
Dividends on common stock ($3.04 per share)		—		—	(341,893)	—	—	(341,893)
Issuance of common stock	380,230	25,296		—	—	—	—	25,296
Purchase of treasury stock (a)		—	(121,493)	(11,202)	—	—	—	(11,202)
Reissuance of treasury stock for stock-based compensation and other		—	76,082	6,600	—	—	—	6,600
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2019	112,540,126	2,659,561	(103,546)	(9,427)	2,837,610	(57,096)	122,540	5,553,188
Net income		—		—	550,559	—	19,493	570,052
Other comprehensive loss		—		—	—	(5,700)	—	(5,700)
Dividends on common stock ($3.23 per share)		—		—	(363,063)	—	—	(363,063)
Issuance of common stock	219,925	17,921		—	—	—	—	17,921
Purchase of treasury stock (a)		—	(81,256)	(7,181)	—	—	—	(7,181)
Reissuance of treasury stock for stock-based compensation and other		—	112,796	10,319	—	—	—	10,319
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2020	112,760,051	2,677,482	(72,006)	(6,289)	3,025,106	(62,796)	119,290	5,752,793
Net income		—		—	618,720	—	17,224	635,944
Other comprehensive income		—		—	—	7,935	—	7,935
Dividends on common stock ($3.36 per share)		—		—	(379,108)	—	—	(379,108)
Issuance of common stock	254,477	25,261		—	—	—	—	25,261
Purchase of treasury stock (a)		—	(68,892)	(4,655)	—	—	—	(4,655)
Reissuance of treasury stock for stock-based compensation and other		—	53,290	4,543	—	—	—	4,543
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		—		—	1	—	1	2
Balance, December 31, 2021	113,014,528	$2,702,743	(87,608)	$ (6,401)	$3,264,719	$ (54,861)	$ 115,260	$ 6,021,460

(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.

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 Arizona Public Service Company. 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, 2021. The effectiveness of our internal control over financial reporting as of December 31, 2021, 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 25, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiaries (the "Company") as of December 31, 2021 and 2020, 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, 2021, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, 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 an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting – Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Arizona Corporation Commission (the "ACC"), which has jurisdiction with respect to the rates charged by public service utilities in Arizona. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant and equipment; regulatory assets and liabilities; operating revenues; fuel and purchased power; operations and maintenance expense; and depreciation expense.

The ACC's rate-making policies are premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the ACC in the future will impact the accounting for regulated operations, including decisions about the amount of allowable deferred costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the ACC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings.

We identified Regulatory Accounting, specifically the impact of rate regulation on the financial statements, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes, recent rate orders specific to APS and to other regulated entities in the same jurisdiction, and likelihood of success of legal appeals. Management judgments also include assessing the impact of potential ACC-ordered refunds to customers on regulatory liabilities. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the ACC and legal bodies, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to regulatory accounting included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs of recently completed plant and costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; and the implementation of new rates as ordered by the ACC.
- We evaluated the Company's disclosures related to regulatory accounting, specifically the impact of rate regulation on the financial statements, including the balances recorded and regulatory developments.
- We read relevant regulatory rate orders issued by the ACC for APS and other public utilities in Arizona, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the ACC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory assets and liabilities for completeness.
    - We observed the ACC open meetings for the APS 2019 Retail Rate Case. We read the ACC approved decision regarding the 2019 Retail Rate Case.
    - We obtained the Company's internally prepared memo regarding impacts of the ACC decision to rates and recorded balances.
    - We tested that new rates were implemented within the system effective December 1, 2021.

- We evaluated management's assessment of the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities based on applicable regulatory orders or precedents set by the ACC under similar circumstances. For certain regulatory assets or liabilities where management's assessment is based on precedents established by the ACC under similar circumstances and not specifically addressed in a regulatory order, we also obtained a letter from internal legal counsel regarding their assessment. We read the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact management's assessment.
- We evaluated management's assessment that the SCR plant investment is not probable of a partial disallowance and that the SCR deferred costs are probable of recovery. We read the Notice of Direct Appeal filed with the Arizona Court of Appeals and Petition for Special Action filed with the Arizona Supreme Court, reviewed the Company's internally prepared memo, and reviewed a legal letter from the Company's external counsel to assess the likelihood of recovery in future rates or of a future reduction in rates based on the ACC decision.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 25, 2022

We have served as the Company's auditor since 1932.

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

	Year Ended December 31,		
	2021	2020	2019
OPERATING REVENUES (Note 2)	$ 3,803,835	$ 3,586,982	$ 3,471,209
OPERATING EXPENSES			
Fuel and purchased power	1,152,551	993,419	1,042,237
Operations and maintenance	940,588	945,181	926,716
Depreciation and amortization	650,773	614,293	590,844
Taxes other than income taxes	234,569	224,790	218,540
Other expense	6,393	7,288	5,888
Total	2,984,874	2,784,971	2,784,225
OPERATING INCOME	818,961	802,011	686,984
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	41,737	33,776	31,431
Pension and other postretirement non-service credits — net (Note 8)	112,742	57,359	24,529
Other income (Note 17)	43,053	51,755	46,884
Other expense (Note 17)	(18,897)	(53,694)	(12,990)
Total	178,635	89,196	89,854
INTEREST EXPENSE			
Interest charges	243,592	233,452	220,174
Allowance for borrowed funds used during construction (Note 1)	(21,052)	(18,530)	(18,528)
Total	222,540	214,922	201,646
INCOME BEFORE INCOME TAXES	775,056	676,285	575,192
INCOME TAXES (Note 5)	125,553	88,764	(9,572)
NET INCOME	649,503	587,521	584,764
Less: Net income attributable to noncontrolling interests (Note 18)	17,224	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 632,279	$ 568,028	$ 565,271

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,		
	2021	2020	2019
NET INCOME	$ 649,503	$ 587,521	$ 584,764
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax expense of $18, $18, and $0	(18)	(18)	—
Reclassification of net realized gain, net of tax benefit (expense) of $18, $(171), and $(375) (Note 16)	18	592	1,137
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(1,990), $1,955, and $3,136 (Note 8)	6,038	(5,970)	(9,552)
Total other comprehensive income (loss)	6,038	(5,396)	(8,415)
COMPREHENSIVE INCOME	655,541	582,125	576,349
Less: Comprehensive income attributable to noncontrolling interests	17,224	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 638,317	$ 562,632	$ 556,856

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

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

	December 31, 2021	December 31, 2020
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 10)		
Plant in service and held for future use	$ 21,685,200	$ 20,834,424
Accumulated depreciation and amortization	(7,501,317)	(7,107,058)
Net	14,183,883	13,727,366
Construction work in progress	1,327,721	937,384
Palo Verde sale leaseback, net of accumulated depreciation of $256,884 and $253,014 (Note 18)	94,166	98,036
Intangible assets, net of accumulated amortization of $736,560 and $697,366	273,537	282,415
Nuclear fuel, net of accumulated amortization of $133,122 and $137,207	106,039	113,645
Total property, plant and equipment	15,985,346	15,158,846
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	1,294,757	1,138,435
Other special use funds (Notes 13 and 19)	358,410	254,509
Assets from risk management activities (Note 16)	46,908	1,818
Other assets	42,440	44,192
Total investments and other assets	1,742,515	1,438,954
CURRENT ASSETS		
Cash and cash equivalents	9,374	57,310
Customer and other receivables	390,533	312,644
Accrued unbilled revenues	133,980	132,197
Allowance for doubtful accounts (Note 2)	(25,354)	(19,782)
Materials and supplies (at average cost)	349,135	314,745
Fossil fuel (at average cost)	18,032	19,552
Income tax receivable (Note 5)	10,756	—
Assets from risk management activities (Note 16)	63,481	2,931
Deferred fuel and purchased power regulatory asset (Note 4)	388,148	175,835
Other regulatory assets (Note 4)	130,376	115,878
Other current assets	57,729	47,593
Total current assets	1,526,190	1,158,903
DEFERRED DEBITS		
Regulatory assets (Notes 1, 4, and 5)	1,192,987	1,133,987
Operating lease right-of-use assets (Note 9)	888,207	503,475
Assets for pension and other postretirement benefits (Note 8)	537,092	495,673
Other	37,319	34,413
Total deferred debits	2,655,605	2,167,548
TOTAL ASSETS	$ 21,909,656	$ 19,924,251

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

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

	December 31, 2021	December 31, 2020
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	3,021,696	2,871,696
Retained earnings	3,470,235	3,216,955
Accumulated other comprehensive loss (Note 20)	(34,880)	(40,918)
Total shareholder equity	6,635,213	6,225,895
Noncontrolling interests (Note 18)	115,260	119,290
Total equity	6,750,473	6,345,185
Long-term debt less current maturities (Note 7)	6,266,693	5,817,945
Total capitalization	13,017,166	12,163,130
CURRENT LIABILITIES		
Short-term borrowings (Note 6)	278,700	—
Accounts payable	389,365	311,699
Accrued taxes	152,012	148,970
Accrued interest	56,622	56,322
Common dividends payable	96,000	93,500
Customer deposits	42,293	48,340
Liabilities from risk management activities (Note 16)	4,373	7,557
Liabilities for asset retirements (Note 12)	4,473	15,586
Operating lease liabilities (Note 9)	100,199	74,695
Regulatory liabilities (Note 4)	296,271	229,088
Other current liabilities	145,286	190,420
Total current liabilities	1,565,594	1,176,177
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 5)	2,331,701	2,143,673
Regulatory liabilities (Notes 1, 4, 5 and 8)	2,499,213	2,450,169
Liabilities for asset retirements (Note 12)	762,909	689,497
Liabilities for pension benefits (Note 8)	138,328	148,943
Liabilities from risk management activities (Note 16)	—	11,062
Customer advances	257,151	221,032
Coal mine reclamation	174,616	170,097
Deferred investment tax credit	186,570	191,372
Unrecognized tax benefits (Note 5)	37,423	39,410
Operating lease liabilities (Note 9)	726,572	359,653
Other	212,413	160,036
Total deferred credits and other	7,326,896	6,584,944
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 21,909,656	$ 19,924,251

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, 2021	2020	2019
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 649,503	$ 587,521	$ 584,764
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	719,039	686,168	664,055
Deferred fuel and purchased power	(256,871)	(93,651)	(82,481)
Deferred fuel and purchased power amortization	44,557	(12,047)	49,508
Allowance for equity funds used during construction	(41,737)	(33,776)	(31,431)
Deferred income taxes	128,852	36,462	48,367
Deferred investment tax credit	(4,802)	(5,096)	(3,938)
Changes in current assets and liabilities:			
Customer and other receivables	(72,101)	(28,206)	(12,075)
Accrued unbilled revenues	(1,783)	(4,032)	9,005
Materials, supplies and fossil fuel	(32,870)	11,623	(51,826)
Income tax receivable	(10,756)	7,313	(7,313)
Other current assets	(25,587)	(24,669)	(1,461)
Accounts payable	23,510	(4,503)	53,258
Accrued taxes	3,042	12,642	(40,029)
Other current liabilities	(61,647)	29,587	(82,138)
Change in margin and collateral accounts — assets	(50)	404	(247)
Change in margin and collateral accounts — liabilities	350	100	(125)
Change in unrecognized tax benefits	(568)	2,220	2,704
Change in long-term regulatory liabilities	57,549	13,017	124,221
Change in other long-term assets	(231,804)	(65,139)	(85,725)
Change in other long-term liabilities	(20,272)	(186,871)	(129,682)
Net cash provided by operating activities	865,554	929,067	1,007,411
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,471,795)	(1,326,584)	(1,191,447)
Contributions in aid of construction	105,654	62,503	70,693
Allowance for borrowed funds used during construction	(21,052)	(18,530)	(18,528)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,720,966	819,518	719,034
Investment in nuclear decommissioning trust and other special use funds	(1,725,480)	(822,608)	(722,181)
Other	273	(554)	6,336
Net cash used for investing activities	(1,391,434)	(1,286,255)	(1,136,093)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	446,999	1,099,722	1,092,188
Repayment of long-term debt	—	(465,150)	(600,000)
Short-term borrowings and (repayments) — net	278,700	—	—
Short-term debt borrowings under revolving credit facility	—	540,000	—
Short-term debt repayments under revolving credit facility	—	(540,000)	—
Dividends paid on common stock	(376,500)	(357,500)	(336,300)
Equity infusion from Pinnacle West	150,000	150,000	—
Noncontrolling interests	(21,255)	(22,743)	(22,744)
Net cash provided by financing activities	477,944	404,329	133,144
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(47,936)	47,141	4,462
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	57,310	10,169	5,707
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 9,374	$ 57,310	$ 10,169

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, 2018	71,264,947	$ 178,162	$ 2,721,696	$ 2,788,256	$ (27,107)	$ 125,790	$ 5,786,797
Net income		—	—	565,271	—	19,493	584,764
Other comprehensive loss		—	—	—	(8,415)	—	(8,415)
Dividends on common stock		—	—	(341,600)	—	—	(341,600)
Capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2019	71,264,947	178,162	2,721,696	3,011,927	(35,522)	122,540	5,998,803
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	568,028	—	19,493	587,521
Other comprehensive loss		—	—	—	(5,396)	—	(5,396)
Dividends on common stock		—	—	(363,000)	—	—	(363,000)
Capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2020	71,264,947	178,162	2,871,696	3,216,955	(40,918)	119,290	6,345,185
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	632,279	—	17,224	649,503
Other comprehensive income		—	—	—	6,038	—	6,038
Dividends on common stock		—	—	(379,000)	—	—	(379,000)
Capital activities by noncontrolling interests		—	—	—	—	(21,255)	(21,255)
Other		—	—	1	—	1	2
Balance, December 31, 2021	71,264,947	$ 178,162	$ 3,021,696	$ 3,470,235	$ (34,880)	$ 115,260	$ 6,750,473

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

COMBINED NOTES TO CONSOLIDATED 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. 4CA is a subsidiary that was formed in 2016 as a result of the purchase of El Paso's 7% interest in Four Corners. See Note 11 for more information on 4CA matters.

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 Variable Interest Entities (each a "VIE") 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 for additional information. We have determined that Pinnacle West is the primary beneficiary of a captive insurance protected cell VIE. As of December 31, 2021, the captive cell's activities are insignificant to our consolidated financial statements.

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.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Accounting

APS is regulated by the ACC and the 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 amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers.

Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, 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. Management judgments also include assessing the impact of potential Commission-ordered refunds to customers on regulatory liabilities.

See Note 4 for additional information.

Electric Revenues

Revenues primarily consist of activities that are classified as revenues from contracts with customers. Our electric revenues generally represent a single performance obligation delivered over time. We have elected to apply the practical expedient that allows us to recognize revenue based on the amount to which we have a right to invoice for services performed.

We derive electric revenues primarily from sales of electricity to our regulated retail customers. Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. 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 regulated retail 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 electricity are netted against other contracts to sell electricity. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow. We net these book-outs, which reduces both wholesale 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.

See Notes 2 and 4 for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. See Note 2.

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
- AFUDC.

Pinnacle West's property, plant and equipment included in the December 31, 2021, and 2020 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	**2021**	**2020**
Generation	$ 9,480,572	$ 9,199,012
Transmission	3,402,016	3,290,477
Distribution	7,520,016	7,107,007
General plant	1,286,057	1,241,389
Plant in service and held for future use	21,688,661	20,837,885
Accumulated depreciation and amortization	(7,504,603)	(7,110,310)
Net	14,184,058	13,727,575
Construction work in progress	1,329,478	937,384
Palo Verde sale leaseback, net of accumulated depreciation	94,166	98,036
Intangible assets, net of accumulated amortization	273,693	282,570
Nuclear fuel, net of accumulated amortization	106,039	113,645
Total property, plant and equipment	$ 15,987,434	$ 15,159,210

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 12 for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

APS records a regulatory liability for the excess that has been recovered in regulated rates over the amount calculated in accordance with guidance on accounting for AROs. APS believes it is probable it will recover in regulated rates, the costs calculated in accordance with this accounting guidance.

We record depreciation and amortization 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, 2021, were as follows:

- Steam generation — 12 years;
- Nuclear plant — 25 years;
- Other generation — 19 years;
- Transmission — 37 years;
- Distribution — 33 years; and
- General plant — 7 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $575 million in 2021, $553 million in 2020, and $522 million in 2019. For the years 2019 through 2021, the depreciation rates ranged from a low of 1.37% to a high of 12.15%. The weighted-average depreciation rate was 2.87% in 2021, 2.84% in 2020, and 2.81% in 2019.

Asset Retirement Obligations

APS has AROs for its Palo Verde nuclear facilities and certain other generation assets. The Palo Verde ARO 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 AROs 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 AROs 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 ARO 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.

See Note 12 for further information on Asset Retirement Obligations.

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 6.75% for 2021, 6.72% for 2020, and 6.98% for 2019. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed, and the property is placed in service.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On June 30, 2020, FERC issued an order granting a waiver request related to the existing AFUDC rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 21, 2022. The order provides a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS has adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in 2020 and 2021 but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements.

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 apply recurring fair value measurements to cash equivalents, derivative instruments, investments held in the nuclear decommissioning trust and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefits plans. Due to the short-term nature of 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 7 for additional information.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 natural gas. 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, in addition to a non-qualified pension plan. We also sponsor another 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 8 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

$0.001 per kWh of nuclear generation through May 2014, at which point the DOE reduced the fee to zero. In accordance with a settlement agreement with the DOE in August 2014 for interim storage, we now accrue a receivable and an offsetting regulatory liability through the settlement period ending December of 2022. See Note 11 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 and are based on currently enacted tax rates. 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 5 for additional discussion.

Cash and Cash Equivalents

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

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

	Year ended December 31,		
	2021	2020	2019
Cash paid (received) during the period for:			
Income taxes, net of refunds	$ 229	$ (3,019)	$ 12,535
Interest, net of amounts capitalized	227,584	216,951	218,664
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 167,733	$ 113,502	$ 141,297
Dividends declared but not paid	95,988	93,531	87,982

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

	Year ended December 31,		
	2021	2020	2019
Cash paid (received) during the period for:			
Income taxes, net of refunds	$ 19,783	$ 41,176	$ (15,042)
Interest, net of amounts capitalized	217,749	206,328	204,261
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 167,657	$ 113,502	$ 141,297
Dividends declared but not paid	96,000	93,500	88,000

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 $80 million in 2021, $70 million in 2020, and $66 million in 2019. Estimated amortization expense on existing intangible assets over the next five years is $75 million in 2022, $63 million in 2023, $44 million in 2024, $33 million in 2025, and $27 million in 2026. At December 31, 2021, the weighted-average remaining amortization period for intangible assets was 6 years.

Investments

El Dorado holds investments in both debt and equity securities. Investments in debt securities are generally accounted for as held-to-maturity and investments in equity securities are accounted for using either the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 20% ownership and no significant influence).

BCE holds investments in equity securities. Investments in equity securities are accounted for using either the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 20% ownership and no significant influence).

Our investments in the nuclear decommissioning trusts, coal reclamation escrow accounts and active union employee medical account, are accounted for in accordance with guidance on accounting for investments in debt and equity securities. See Notes 13 and 19 for more information on these investments.

Leases

We determine if an agreement is a lease at contract inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To control the use of an identified asset an entity must have both a right to obtain substantially all of the benefits from the use of the asset and the right to direct the use of the asset. If we determine an agreement is a lease, and we are the lessee, we recognize a right-of-use lease asset and a lease liability at the lease commencement date. Lease liabilities are recognized based on the present value of the fixed lease payments over the lease term. To present value lease liabilities we use the implicit rate in the lease if the information is readily available, otherwise we use our incremental borrowing rate determined at lease commencement. Our incremental borrowing rate is based on the rate of interest we would have to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. When measuring right-of-use assets and lease liabilities we exclude variable lease payments, other than those that depend on an index or rate or are in-substance fixed payments. For short-term leases with terms of 12 months or less, we do not recognize a right-of-use lease asset or lease liability. We recognize operating lease expense using a straight-line pattern over the periods of use.

APS enters into purchased power contracts that may contain leases. This occurs when a purchased power agreement designates a specific power plant, APS obtains substantially all of the economic benefits from the use of the plant and has the right to direct the use of the plant. Purchased power lease contracts may also include energy storage facilities. Lease costs relating to purchased power lease contracts are reported in fuel and purchased power on the Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 4. We also may enter into lease agreements related to vehicles, office space, land, and other equipment. See Note 9 for information on our lease agreements.

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, 2021, 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. Revenue

Sources of Revenue

The following table provides detail of Pinnacle West's consolidated revenue disaggregated by revenue sources (dollars in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Retail Electric Service			
Residential	$ 1,913,324	$ 1,929,178 (a)	$ 1,761,122
Non-Residential	1,586,940	1,486,098	1,509,514
Wholesale Energy Sales	187,640	93,345	121,805
Transmission Services for Others	99,285	65,859	62,460
Other Sources	16,646	12,502	16,308
Total Operating Revenues	$ 3,803,835	$ 3,586,982	$ 3,471,209

(a) Residential revenues for the year ended December 31, 2020, reflect a $24 million reduction related to the Arizona Attorney General matter. See Note 11.

Retail Electric Revenue. Pinnacle West's retail electric revenue is generated by wholly-owned regulated subsidiary APS's sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the year ended December 31, 2021, 2020 and 2019 were $3,760 million, $3,533 million. and $3,415 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the year ended December 31, 2021, 2020 and 2019, our revenues that do not qualify as revenue from contracts with customers were $44 million, $54 million and $56 million, respectively. This relates primarily to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 4 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Consolidated Balance Sheets as of December 31, 2021, and 2020.

Allowance for Doubtful Accounts

On March 13, 2020, due to the COVID-19 pandemic we voluntarily suspended disconnections of customers for nonpayment. The suspension of customer disconnections was extended from March 13, 2020, through December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and certain customers with past due balances were placed on eight-month payment arrangements. During this time, our disconnection policies were also impacted by the Summer Disconnection Moratorium. These circumstances and the on-going COVID-19 pandemic continue to impact our allowance for doubtful accounts including our write-off factor. We continue to monitor the impacts of COVID-19, our disconnection policies, summer moratorium, payment arrangements, among other considerations impacting our estimated write-off factor and allowance for doubtful accounts. See Note 1 for our accounting policies on allowance for doubtful accounts. See Note 4 for additional discussion on the COVID-19 pandemic and the Summer Disconnection Moratorium.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides a rollforward of Pinnacle West's allowance for doubtful accounts (dollars in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Allowance for doubtful accounts, balance at beginning of period	$ 19,782	$ 8,171	$ 4,069
Bad debt expense	22,251	20,633	11,819
Actual write-offs	(16,679)	(9,022)	(7,717)
Allowance for doubtful accounts, balance at end of period	$ 25,354	$ 19,782	$ 8,171

3. New Accounting Standards

ASU 2021-05, Leases: Certain Leases with Variable Lease Payments

In July 2021, a new accounting standard was issued that amends the lease accounting guidance. The amended guidance will require lessors to account for certain lease transactions, that contain variable lease payments, as operating leases. The amendments are intended to eliminate the recognition of any day-one loss associated with certain sales-type and direct-financing lease transactions. The changes do not impact lessee accounting. The standard may be adopted using either a prospective or modified retrospective approach. We adopted this standard on January 1, 2022, using a prospective approach. The adoption of this standard did not impact our financial statements.

4. Regulatory Matters

COVID-19 Pandemic

During 2020 and 2021, APS implemented several programs and initiatives to help our customers deal with the economic and other impacts of the COVID-19 pandemic, including but not limited to the following:

- *Suspension of Disconnections; Waiver of Late Payment Fees.* APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020, until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers with past due balances of $75 or greater as of that date were automatically placed on eight-month payment arrangements. APS voluntarily began waiving late payment fees of its customers on March 13, 2020 and is continuing to waive late payment fees. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts.

- *COVID-19 Emergency Relief Package.* On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption, which was different than actual consumption during the refund period.

- *COVID Customer Support Fund.* In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID Customer Support Fund"). The COVID Customer Support Fund was comprised of (i) approximately $8.8 million in funds that are not recoverable through rates, and (ii) an additional $3.6 million in bill credits for limited income customers ordered by the ACC in December 2020, of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates, with the remaining bill credits being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers with a delinquency of two or more months, providing a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

- *Deferral of PSA Rate Increase.* In February 2021, APS delayed the annual reset of the PSA, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. See below for discussion of the PSA.

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that was the subject of a separate proceeding. See "Four Corners SCR Cost Recovery" below. It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the TEAM. The proposed total annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.10 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- 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 rate of $0.030168 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- authorization to defer until APS'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;
- a number of proposed rate and program changes for residential customers, including:
  - a super off-peak period during the winter months for APS's time-of-use with demand rates;
  - additional $1.25 million in funding for APS's limited-income crisis bill program; and
  - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 MW of medium and large commercial customers;
- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant. See "Navajo Plant" below.

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) a $89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS's filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, a (i) $169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism, to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition ("CCT") plan related to the closure or future closure of coal-fired generation facilities, of which $25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in our December 31, 2021 financials.

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to $59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to $50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021 and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the RES adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

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On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m., but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. The ACC Staff has been directed to report to the ACC on the investigation in April 2022. APS cannot predict the outcome of this matter.

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2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules.

Other key provisions of the 2017 Settlement Agreement include the following:

- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as APS Solar Communities) for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low- and moderate-income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time-of-use period from noon to 7 p.m. to 3 p.m. to 8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered DG customers would be required to select a rate option that has time-of-use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027, for combined-cycle generating units), unless expressly authorized by the ACC.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"). The new rates went into effect on August 19, 2017.

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See "Rate Plan Comparison Tool and Investigation" below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case 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 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 DSM Plan.

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its IRP, and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source requests for proposals ("RFP") requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the RES residential and non-residential distributed energy requirements for 2022. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC EES requires APS to submit a Demand Side Management Implementation Plan ("DSM Plan") annually for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its LFCR mechanism. See below for discussion of the LFCR.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan sought a requested budget of $52.6 million and requested a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels but kept the overall budget at $52.6 million.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of $51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of $51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning $36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately $43 million to customers. The additional $7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Plan, which requested a budget of $63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Plan that proposed an additional performance incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Plan.

On April 20, 2021, APS filed a request to extend the June 1, 2021 deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021.

Power Supply Adjustor Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations primarily 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 or refunded 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.

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The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2021 and 2020 (dollars in thousands):

	Twelve Months Ended December 31, 2021	Twelve Months Ended December 31, 2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs — current period	256,871	93,651
Amounts refunded/(charged) to customers	(44,558)	12,047
Ending balance	$ 388,148	$ 175,835

The PSA rate for the PSA year beginning February 1, 2019, was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh, which consisted of a forward component of $(0.002086) per kWh and a historical component of $0.001630 per kWh. The 2020 PSA rate is a $0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the PSA rate increase taking effect in April 2021 and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a PSA rate of $0.003544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit, which is currently underway, to better understand the factors that contributed to the increase in fuel costs. APS cannot predict the outcome of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

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On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA. On December 29, 2020, the ACC Staff filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the prudency. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service. On December 16, 2021, the ACC approved this application but did not rule on the prudency. APS cannot predict the outcome of this matter.

Environmental Improvement Surcharge ("EIS"). The EIS permits APS to recover the capital carrying costs (rate of return, depreciation, and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022 application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it will become effective with the first billing cycle in April 2022 absent the ACC taking action.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow 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 settlement agreement entered into in 2012 regarding APS's rate case ("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. 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 with 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. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 17, 2020, APS made a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Act, as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020 filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

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Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the 12-month period beginning June 1, 2019, in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

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 DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents non-residential kWh as set forth in the 2019 Rate Case decision. 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 kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020

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LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR application filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism as a result of the 2019 Rate Case decision did not materially impact its results of operations and financial statements for the year ended December 31, 2021.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels). The ACC's final determination of APS's 2022 annual LFCR adjustment filing and related earnings test may materially impact the timing and amounts of future LFCR revenue recognition. See Note 2 for a discussion of alternative revenue program accounting treatment related to certain regulatory cost recovery mechanisms and see the Regulatory Assets and Liabilities table below. APS cannot predict the outcome or timing of the ACC's consideration and final determination of its 2022 annual LFCR adjustment filing.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 will be recorded as a part of the balancing account and will be addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit are recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021 and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS's next rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail 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 APS 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 September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- 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 general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

In accordance with the 2017 Rate Case Decision, APS filed its request for an export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021.

See "2016 Retail Rate Case Filing" above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on 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.

After various proceedings between September 2016 and March 2020, at which time Burns' appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns' position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns' motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and oral argument is scheduled for March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new EES was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

On July 16, 2020, FERC issued a final rule revising FERC's regulations implementing PURPA. The final rule went into effect on December 31, 2020.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur and customers will have four months to pay back their deposit and any remaining delinquent amounts. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. Although the rules are not yet final, APS intends to employ the calendar method for its disconnection moratorium. This is consistent with APS's existing disconnection moratorium processes since 2019.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. At the same time, the Arizona legislature is considering a bill that would nullify, if approved, a 20-year-old electric deregulation law that has been in place since 1998. The bill has several procedural steps in the legislative process before becoming law. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved 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. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs ($41.8 million as of December 31, 2021), 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. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant ($62.2 million as of December 31, 2021), in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($16.8 million as of December 31, 2021). The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

		December 31, 2021		December 31, 2020	
	Amortization Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 509,751	$ —	$ 469,953
Deferred fuel and purchased power (b) (c)	2022	388,148	—	175,835	—
Income taxes — AFUDC equity	2051	7,625	164,768	7,169	158,776
Ocotillo deferral (e)	2031	9,507	138,143	—	95,723
Retired power plant costs	2033	15,160	99,681	28,181	114,214
SCR deferral (e) (f)	2031	8,147	97,624	—	81,307
Lost fixed cost recovery (b)	2022	63,889	—	41,807	—
Deferred property taxes	2027	8,569	41,057	8,569	49,626
Deferred compensation	2036	—	33,997	—	36,195
Income taxes — investment tax credit basis adjustment	2056	1,129	23,639	1,113	24,291
Four Corners cost deferral	2024	8,077	15,998	8,077	24,075
Palo Verde VIEs (Note 18)	2046	—	21,094	—	21,255
Coal reclamation	2026	2,978	13,862	1,068	16,999
Loss on reacquired debt	2038	1,648	9,372	1,689	10,877
Mead-Phoenix transmission line — contributions in aid of construction	2050	332	9,048	332	9,380
Tax expense adjustor mechanism (b)	2031	656	5,845	6,226	—
TCA balancing account (b)	2023	170	3,663	—	—
Tax expense of Medicare subsidy	2024	1,235	2,469	1,235	3,704
Demand side management (b)	2022	919	—	—	7,268
PSA interest	2022	335	—	4,355	—
Deferred fuel and purchased power — mark-to-market (Note 16)	2024	—	—	3,341	9,244
Other	Various	—	2,976	2,716	1,100
Total regulatory assets (d)		$ 518,524	$ 1,192,987	$ 291,713	$ 1,133,987

(a) This asset represents the future recovery of pension benefit obligations and expense 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. As a result of the 2019 Rate Case Decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. See Note 8 for further discussion.

(b) See "Cost Recovery Mechanisms" discussion above.

(c) Subject to a carrying charge.

(d) 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."

(e) Balance includes amounts for future regulatory consideration and amortization period determination.

(f) See "Four Corners SCR Cost Recovery" discussion above.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The detail of regulatory liabilities is as follows (dollars in thousands):

		December 31, 2021		December 31, 2020	
	Amortization Through	Current	Non-Current	Current	Non-Current
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 40,903	$ 971,545	$ 41,330	$ 1,012,583
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	7,239	221,877	7,240	229,147
Asset retirement obligations	2057	—	614,683	—	506,049
Other postretirement benefits	(d)	37,789	337,027	37,705	349,588
Removal costs	(c)	69,476	50,104	52,844	103,008
Deferred fuel and purchased power — mark-to-market (Note 17)	2024	60,693	46,908	—	—
Income taxes — change in rates	2051	2,876	64,802	2,839	66,553
Four Corners coal reclamation	2038	2,316	53,076	5,460	49,435
Spent nuclear fuel	2027	6,701	38,581	6,768	44,221
Income taxes — deferred investment tax credit	2056	2,264	47,337	2,231	48,648
Renewable energy standard (b)	2022	38,453	187	39,442	103
FERC transmission true up (b)	2023	21,379	12,924	6,598	3,008
Property tax deferral (e)	2024	4,671	15,521	—	13,856
Sundance maintenance	2031	—	13,797	2,989	11,508
Demand side management (b)	2022	—	5,417	10,819	—
Tax expense adjustor mechanism (b) (e)	N/A	—	4,835	7,089	—
Deferred gains on utility property	2022	1,301	551	2,423	1,544
TCA balancing account (b)	2022	—	—	2,902	4,672
Active union medical trust	N/A	—	—	—	6,057
Other	Various	210	41	409	189
Total regulatory liabilities		$ 296,271	$ 2,499,213	$ 229,088	$ 2,450,169

(a) For purposes of presentation on the Statement of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as "Deferred income taxes" under Cash Flows From Operating Activities.

(b) See "Cost Recovery Mechanisms" discussion above.

(c) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.

(d) See Note 8.

(e) Balance includes amounts for future regulatory consideration and amortization period determination.

5. 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 Consolidated 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 ("ITC") basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to the change in income tax rates and deferred taxes resulting from ITCs.

The Tax Act reduced the corporate tax rate to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities as of December 31, 2017. In accordance with accounting for regulated companies, the effect of this rate reduction was substantially offset by a net regulatory liability.

Federal income tax laws require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter of 2018, the Company began amortization of FERC jurisdictional net excess deferred tax liabilities in 2018. On March 13, 2019, the ACC approved the Company's proposal to amortize non-depreciation related net excess deferred tax liabilities subject to its jurisdiction over a twelve-month period. As a result, the Company began amortization in March 2019. The Company recorded $14 million of income tax benefit related to the amortization of these non-depreciation related net excess deferred tax liabilities as of March 31, 2020, with these non-depreciation related net excess deferred tax liabilities being fully amortized as of March 31, 2020. On October 29, 2019, the ACC approved the Company's proposal to amortize depreciation related net excess deferred tax liabilities subject to its jurisdiction over a 28.5-year period with amortization to retroactively begin as of January 1, 2018. The Company recorded $31 million of income tax benefit related to amortization of these depreciation related net excess deferred tax liabilities for the periods ending December 31, 2021, and December 31, 2020. See Note 4 for more details.

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 Statements of Income.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax. 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. See Note 18 for additional details related to the Palo Verde sale leaseback VIEs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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		
	2021	2020	2019	2021	2020	2019
Total unrecognized tax benefits, January 1	$ 45,655	$ 43,435	$ 40,731	$ 45,655	$ 43,435	$ 40,731
Additions for tax positions of the current year	3,305	3,418	3,373	3,305	3,418	3,373
Additions for tax positions of prior years	1,449	1,431	1,843	1,449	1,431	1,843
Reductions for tax positions of prior years for:						
Changes in judgment	(2,659)	(1,965)	(2,078)	(2,659)	(1,965)	(2,078)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(2,664)	(664)	(434)	(2,664)	(664)	(434)
Total unrecognized tax benefits, December 31	$ 45,086	$ 45,655	$ 43,435	$ 45,086	$ 45,655	$ 43,435

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		
	2021	2020	2019	2021	2020	2019
Tax positions, that if recognized, would decrease our effective tax rate	$ 26,300	$ 25,714	$ 22,813	$ 26,300	$ 25,714	$ 22,813

As of the balance sheet date, the tax year ended December 31, 2018, 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 2017.

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		
	2021	2020	2019	2021	2020	2019
Unrecognized tax benefit interest expense/ (benefit) recognized	$ (535)	$ 266	$ 459	$ (535)	$ 266	$ 459

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		
	2021	2020	2019	2021	2020	2019
Unrecognized tax benefit interest accrued	$ 1,320	$ 1,855	$ 1,589	$ 1,320	$ 1,855	$ 1,589

Additionally, as of December 31, 2021, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2021	2020	2019	2021	2020	2019
Current:						
Federal	$ (5,041)	$ 11,869	$ (13,551)	$ 1,514	$ 57,299	$ (54,697)
State	2,458	1,932	3,195	(11)	99	695
Total current	(2,583)	13,801	(10,356)	1,503	57,398	(54,002)
Deferred:						
Federal	95,327	53,398	(14,982)	101,175	15,122	29,321
State	17,342	10,974	9,565	22,875	16,244	15,109
Total deferred	112,669	64,372	(5,417)	124,050	31,366	44,430
Income tax expense/(benefit)	$ 110,086	$ 78,173	$ (15,773)	$ 125,553	$ 88,764	$ (9,572)

The following chart compares pretax income at the 21% statutory federal income tax rate to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2021	2020	2019	2021	2020	2019
Federal income tax expense at statutory rate	$ 156,666	$ 136,127	$ 113,828	$ 162,762	$ 142,020	$ 120,790
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	22,656	19,146	18,599	23,339	20,124	19,267
State income tax credits net of federal income tax benefit	(7,015)	(8,951)	(8,519)	(5,277)	(7,213)	(6,781)
Net operating loss carryback tax benefit	(5,915)	—	—	—	—	—
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,558)	(50,543)	(124,082)	(36,558)	(50,543)	(124,082)
Allowance for equity funds used during construction (see Note 1)	(4,180)	(2,747)	(2,476)	(4,180)	(2,747)	(2,476)
Palo Verde VIE noncontrolling interest (see Note 18)	(3,617)	(4,094)	(4,094)	(3,617)	(4,094)	(4,094)
Investment tax credit amortization	(7,620)	(7,510)	(6,851)	(7,620)	(7,510)	(6,851)
Other	(4,331)	(3,255)	(2,178)	(3,296)	(1,273)	(5,345)
Income tax expense/(benefit)	$ 110,086	$ 78,173	$ (15,773)	$ 125,553	$ 88,764	$ (9,572)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of the net deferred income tax liability were as follows (dollars in thousands):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2021	2020	2021	2020
DEFERRED TAX ASSETS				
Risk management activities	$ 677	$ 4,287	$ 677	$ 4,287
Regulatory liabilities:				
Excess deferred income taxes — Tax Cuts and Jobs Act	306,915	319,091	306,915	319,091
Asset retirement obligation and removal costs	174,952	157,470	174,952	157,470
Unamortized investment tax credits	49,601	50,879	49,601	50,879
Other postretirement benefits	92,654	95,778	92,654	95,778
Other	65,815	43,551	65,815	43,551
Operating lease liabilities	204,890	107,853	204,378	107,414
Pension liabilities	42,136	45,853	37,814	40,168
Coal reclamation liabilities	43,165	42,065	43,165	42,065
Renewable energy incentives	22,646	25,355	22,646	25,355
Credit and loss carryforwards	57,077	26,460	18,902	8,034
Other	74,184	78,113	74,184	78,113
Total deferred tax assets	1,134,712	996,755	1,091,703	972,205
DEFERRED TAX LIABILITIES				
Plant-related	(2,570,613)	(2,489,899)	(2,570,613)	(2,489,899)
Risk management activities	(27,276)	(1,174)	(27,276)	(1,174)
Pension and other postretirement assets	(133,624)	(123,462)	(132,769)	(122,580)
Other special use funds	(64,610)	(42,927)	(64,610)	(42,927)
Operating lease right-of-use assets	(204,890)	(107,853)	(204,378)	(107,414)
Regulatory assets:				
Allowance for equity funds used during construction	(42,616)	(41,038)	(42,616)	(41,038)
Deferred fuel and purchased power	(96,033)	(47,673)	(96,033)	(47,673)
Pension benefits	(126,010)	(116,219)	(126,010)	(116,219)
Retired power plant costs	(28,389)	(35,214)	(28,389)	(35,214)
Other	(123,902)	(106,227)	(123,902)	(106,227)
Other	(28,611)	(20,472)	(6,808)	(5,513)
Total deferred tax liabilities	(3,446,574)	(3,132,158)	(3,423,404)	(3,115,878)
Deferred income taxes — net	$ (2,311,862)	$ (2,135,403)	$ (2,331,701)	$ (2,143,673)

As of December 31, 2021, PNW Consolidated deferred tax assets for credit and loss carryforwards relate to federal general business credits of approximately $51 million, which first begin to expire in 2036, state credit carryforwards net of federal benefit of $42 million, which first begin to expire in 2023, and Arizona net operating loss net of federal benefit of $6 million, which will expire in 2041. PNW Consolidated credit and loss carryforwards amount above has been reduced by $42 million of unrecognized tax benefits.

As of December 31, 2021, APS Consolidated deferred tax assets for credit and loss carryforwards relate to state credit carryforwards net of federal benefit of $24 million, which first begin to expire in 2024 and Arizona net operating loss net of federal benefit of $4 million, which will expire in 2041. APS

Consolidated credit and loss carryforwards amount above has been reduced by $9 million of unrecognized tax benefits.

6. 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 (dollars in thousands):

	December 31, 2021			December 31, 2020		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facilities	$ 200,000	$1,000,000	$1,200,000	$ 231,000	$ 1,000,000	$ 1,231,000
Outstanding Commercial Paper, Term Loan and Revolving Credit Facility Borrowings	(13,300)	(278,700)	(292,000)	(169,000)	—	(169,000)
Amount of Credit Facilities Available	$ 186,700	$ 721,300	$ 908,000	$ 62,000	$ 1,000,000	$ 1,062,000
Commitment Fees	0.175%	0.125%		0.125%	0.100%	

Pinnacle West

On May 5, 2020, Pinnacle West refinanced its 364-day $50 million term loan agreement with a new 364-day $31 million term loan facility that would have matured May 4, 2021. Borrowings under the facility bore interest at Eurodollar Rate plus 1.40% per annum. Pinnacle West repaid this facility on April 27, 2021.

On May 28, 2021, Pinnacle West replaced its $200 million revolving credit facility that would have matured on July 11, 2023, with a new $200 million revolving credit facility that matures on May 28, 2026. 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. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At December 31, 2021, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility and $13 million of commercial paper borrowings.

APS

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured on June 29, 2022 and July 11, 2023, respectively, with two new $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. 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 and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $279 million of outstanding commercial paper borrowings.

See "Financial Assurances" in Note 11 for a discussion of other outstanding letters of credit.

Debt Provisions

On December 17, 2020, 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 (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). See Note 7 for additional long-term debt provisions.

7. 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 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2021	December 31, 2020
APS				
Pollution control bonds:				
Variable	2029	(b)	$ 35,975	$ 35,975
Total pollution control bonds			35,975	35,975
Senior unsecured notes	2024-2050	2.20%-6.88%	6,280,000	5,830,000
Unamortized discount			(14,995)	(15,900)
Unamortized premium			13,575	14,781
Unamortized debt issuance cost			(47,862)	(46,911)
Total APS long-term debt			6,266,693	5,817,945
Less current maturities			—	—
Total APS long-term debt less current maturities			6,266,693	5,817,945
Pinnacle West				
Senior unsecured notes	2025	1.3%	500,000	500,000
Term loans	2022-2024	(c)	300,000	—
Unamortized discount			(34)	(44)
Unamortized debt issuance cost			(2,924)	(3,635)
Total Pinnacle West long-term debt			797,042	496,321
Less current maturities			150,000	—
Total Pinnacle West long-term debt less current maturities			647,042	496,321
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 6,913,735	$ 6,314,266

(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 0.22% at December 31, 2021, and 0.18% at December 31, 2020.
(c) The weighted-average interest rate was 0.81% at December 31, 2021. See additional details below.

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
2022	$ 150,000	$ —
2023	—	—
2024	400,000	250,000
2025	800,000	300,000
2026	250,000	250,000
Thereafter	5,515,975	5,515,975
Total	$ 7,115,975	$ 6,315,975

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2021		As of December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 797,042	$ 792,735	$ 496,321	$ 509,050
APS	6,266,693	6,933,619	5,817,945	7,103,791
Total	$ 7,063,735	$ 7,726,354	$ 6,314,266	$ 7,612,841

Credit Facilities and Debt Issuances

Pinnacle West

On December 21, 2021, Pinnacle West entered into a $450 million term loan facility that matures December 20, 2024. On December 21, 2021, $150 million of the proceeds were received and recognized as long-term debt on the Consolidated Balance Sheets. On January 6, 2022, the remaining $300 million of proceeds was received and recognized on that date as long-term debt on the Consolidated Balance Sheets. The proceeds were used for general corporate purposes.

On December 23, 2020, Pinnacle West entered into a $150 million term loan facility that matures June 30, 2022. The proceeds were received on January 4, 2021, and used for general corporate purposes. We recognized the term loan facility as long-term debt upon settlement on January 4, 2021. On January 6, 2022, Pinnacle West repaid this term loan facility early.

APS

On August 16, 2021, APS issued $450 million of 2.2% unsecured senior notes that mature December 15, 2031. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper, replenish cash used to fund capital expenditures, and for general corporate purposes.

On December 21, 2021, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On January 6, 2022, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

See “Lines of Credit and Short-Term Borrowings” in Note 6 and “Financial Assurances” in Note 11 for discussion of APS’s separate outstanding letters of credit.

BCE

On February 11, 2022, a special purpose subsidiary of BCE entered into a credit agreement to finance capital expenditures and related costs for a microgrid project in California under development by the subsidiary. The credit facilities consist of an approximately $33 million equity bridge loan facility, an approximately $42 million non-recourse construction to term loan facility, and an approximately $5 million letter of credit. In connection with the credit agreement, Pinnacle West has guaranteed the full amount of the equity bridge loan. On February 11, 2022, $12 million was drawn from the equity bridge loan.

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, 2021, the ratio was approximately 56% for Pinnacle West and 50% 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.

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 December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's long-term debt authorization from $5.9 billion to $7.5 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs. See Note 6 for additional short-term debt provisions.

8. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 "HRA") 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.

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.

Under the HRA, included in the other postretirement benefit plan, the Company provides a subsidy to retirees to defray the cost of a Medicare supplemental policy. Prior to 2020, we had been assuming a 4.75% escalation of these benefits; however, actual escalation has been significantly less than this assumption. Accordingly, during 2020 and for future periods, the escalation assumption was reduced to 2.00% (see weighted-average assumption table below). This escalation factor assumption change, among other factors, resulted in an increase in the over-funded status of the other postretirement benefit plan as of December 31, 2020. As a result, on January 4, 2021, we initiated the transfer of approximately $106 million of investment assets from the other postretirement benefit plan into the Active Union Employee Medical Account Trust. The Active Union Employee Medical Account is an existing trust account that holds investments restricted for paying active union employee medical costs. See Note 19. The transfer of other postretirement benefit plan investment assets into the Active Union Employee Medical Account permits access to approximately $106 million of assets for the sole purpose of paying active union employee medical benefits. This transfer of investment assets into the Active Union Employee Medical Account is consistent with the terms of a similar 2018 transaction.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and are recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. Our retail rates provide for the inclusion of annual benefit costs, which allows for recovery or return of this regulatory asset/liability. See Note 4.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 or billed to electric plant participants) (dollars in thousands):

	Pension Plans			Other Benefits Plans		
	2021	2020	2019	2021	2020	2019
Service cost-benefits earned during the period	$ 61,236	$ 56,233	$ 49,902	$ 17,796	$ 22,236	$ 18,369
Non-service costs (credits):						
Interest cost on benefit obligation	98,566	118,567	136,843	16,513	25,857	29,894
Expected return on plan assets	(202,628)	(187,443)	(171,884)	(41,444)	(40,077)	(38,412)
Amortization of:						
Prior service credit	—	—	—	(37,705)	(37,575)	(37,821)
Net actuarial (gain)/loss	15,948	34,612	42,584	(10,093)	—	—
Net periodic benefit cost/(benefit)	$ (26,878)	$ 21,969	$ 57,445	$ (54,933)	$ (29,559)	$ (27,970)
Portion of cost/(benefit) charged to expense	$ (32,743)	$ 3,386	$ 30,312	$ (38,657)	$ (20,966)	$ (19,859)

The following table shows the plans' changes in the benefit obligations and funded status (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2021	2020	2021	2020
Change in Benefit Obligation				
Benefit obligation at January 1	$ 3,902,867	$ 3,613,114	$ 624,034	$ 746,924
Service cost	61,236	56,233	17,796	22,236
Interest cost	98,566	118,567	16,513	25,857
Benefit payments	(207,928)	(191,704)	(31,280)	(31,511)
Actuarial (gain) loss	(137,917)	306,657	(35,222)	(139,472)
Benefit obligation at December 31	3,716,824	3,902,867	591,841	624,034
Change in Plan Assets				
Fair value of plan assets at January 1	3,886,544	3,318,351	961,165	837,494
Actual return on plan assets	18,169	642,373	41,432	150,076
Employer contributions	100,000	100,000	—	—
Benefit payments	(192,672)	(174,180)	(24,310)	(26,405)
Transfer to active union medical account	—	—	(105,852)	—
Fair value of plan assets at December 31	3,812,041	3,886,544	872,435	961,165
Funded Status at December 31	$ 95,217	$ (16,323)	$ 280,594	$ 337,131

The following table shows information for pension plans with an accumulated obligation in excess of plan assets (dollars in thousands):

	As of December 31,	
	2021	2020
Accumulated benefit obligation	161,086	171,672
Fair value of plan assets	—	—

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2021, and December 31, 2020, therefore the only pension plan with an accumulated benefit obligation in excess of plan assets in 2021 and 2020 is a non-qualified supplemental excess benefit retirement plan.

The following table shows information for pension plans with a projected benefit obligation in excess of plan assets (dollars in thousands):

	As of December 31, 2021	As of December 31, 2020
Projected benefit obligation	169,912	182,184
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on a projected benefit obligation basis at December 31, 2021, and December 31, 2020, therefore the only pension plan with a projected benefit obligation in excess of plan assets in 2021 and 2020 is a non-qualified supplemental excess benefit retirement plan.

The following table shows the amounts recognized on the Consolidated Balance Sheets (dollars in thousands):

	Pension Plans 2021	Pension Plans 2020	Other Benefits Plans 2021	Other Benefits Plans 2020
Noncurrent asset	$ 265,129	$ 165,861	$ 280,594	$ 337,131
Current liability	(17,047)	(15,700)	—	—
Noncurrent liability	(152,865)	(166,484)	—	—
Net amount recognized (funded status)	$ 95,217	$ (16,323)	$ 280,594	$ 337,131

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2021, and 2020 (dollars in thousands):

	Pension Plans 2021	Pension Plans 2020	Other Benefits Plans 2021	Other Benefits Plans 2020
Net actuarial loss (gain)	$ 582,895	$ 552,301	$ (262,352)	$ (237,233)
Prior service credit	—	—	(114,632)	(152,337)
APS's portion recorded as a regulatory (asset) liability	(509,751)	(469,953)	374,816	387,293
Income tax expense (benefit)	(18,081)	(20,364)	990	1,018
Accumulated other comprehensive loss (gain)	$ 55,063	$ 61,984	$ (1,178)	$ (1,259)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2021	2020	2021	2020	2019
Discount rate – pension plans	2.92 %	2.53 %	2.53 %	3.30 %	4.34 %
Discount rate – other benefits plans	2.98 %	2.63 %	2.63 %	3.42 %	4.39 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	4.00 %	4.00 %
Expected long-term return on plan assets - pension plans	N/A	N/A	5.30 %	5.75 %	6.25 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	4.90 %	4.85 %	5.40 %
Initial healthcare cost trend rate (pre-65 participants)	6.00 %	6.50 %	6.50 %	7.00 %	7.00 %
Ultimate healthcare cost trend rate (pre-65 participants)	4.75 %	4.75 %	4.75 %	4.75 %	4.75 %
Number of years to ultimate trend rate (pre-65 participants)	4	5	4	5	7
Initial and ultimate healthcare cost trend rate (post-65 participants) (a)	2.00 %	2.00 %	2.00 %	4.75 %	4.75 %
Interest crediting rate – cash balance pension plans	4.50 %	4.50 %	4.50 %	4.50 %	4.50 %

(a) See discussion above relating to this assumptions impact on benefit obligations and the January 2021 asset transfer to the Active Union Employee Medical Account.

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 2022, we are assuming a 5.00% long-term rate of return for pension assets and 5.50% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs.

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 may 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 2021, the target and actual allocation for the pension plan at December 31, 2021, are as follows:

	Target Allocation	Actual Allocation
Long-term fixed income assets	80 %	79 %
Return-generating assets	20 %	21 %
Total	100 %	100 %

The permissible range is within +/-3% of the target allocation shown in the above table, and also considers the plan's funded status.

The following table presents the additional target allocations, as a percent of total pension plan assets, for the return-generating assets:

	Target Allocation
Equities in US and other developed markets	12 %
Equities in emerging markets	4 %
Alternative investments	4 %
Total	20 %

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, 2021, 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. The following table presents the actual allocations of the investment for the other postretirement benefit plan at December 31, 2021:

	Actual Allocation
Long-term fixed income assets	63 %
Return-generating assets	37 %
Total	100 %

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 Futures 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, which includes exchange traded funds (ETFs), are classified as Level 1, and 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, and fixed income securities is derived from the 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, 2021, 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. Certain partnerships also include funding commitments that may require the plan to contribute up to $50 million to these partnerships; as of December 31, 2021, approximately $38 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2021, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 821	$ —	$ —	$ 821
Fixed income securities:				
Corporate	—	1,765,623	—	1,765,623
U.S. Treasury	1,008,211	—	—	1,008,211
Other (b)	—	165,496	—	165,496
Common stock equities (c)	209,063	—	—	209,063
Mutual funds (d)	132,656	—	—	132,656
Common and collective trusts:				
Equities	—	—	255,141	255,141
Real estate	—	—	173,197	173,197
Partnerships	—	—	15,730	15,730
Short-term investments and other (e)	—	—	86,103	86,103
Total	$ 1,350,751	$ 1,931,119	$ 530,171	$ 3,812,041
Other Benefits:				
Cash and cash equivalents	$ 121	$ —	$ —	$ 121
Fixed income securities:				
Corporate	—	244,572	—	244,572
U.S. Treasury	287,057	—	—	287,057
Other (b)	—	9,330	—	9,330
Common stock equities (c)	176,024	—	—	176,024
Mutual funds (d)	26,262	—	—	26,262
Common and collective trusts:				
Equities	—	—	96,547	96,547
Real estate	—	—	23,851	23,851
Short-term investments and other (e)	2,517	—	6,154	8,671
Total	$ 491,981	$ 253,902	$ 126,552	$ 872,435

(a) These investments primarily represent assets valued using NAV 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 and asset backed securities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in international common stock equities.
(e) This category includes plan receivables and payables.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2020, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 9,911	$ —	$ —	$ 9,911
Fixed income securities:				
Corporate	—	1,684,782	—	1,684,782
U.S. Treasury	794,571	—	—	794,571
Other (b)	—	112,224	—	112,224
Common stock equities (c)	331,058	—	—	331,058
Mutual funds (d)	262,765	—	—	262,765
Common and collective trusts:				
Equities	—	—	407,522	407,522
Real estate	—	—	191,595	191,595
Partnerships	—	—	22,420	22,420
Short-term investments and other (e)	—	—	69,696	69,696
Total	$ 1,398,305	$ 1,797,006	$ 691,233	$ 3,886,544
Other Benefits:				
Cash and cash equivalents	$ 1,909	$ —	$ —	$ 1,909
Fixed income securities:				
Corporate	—	221,488	—	221,488
U.S. Treasury	258,102	—	—	258,102
Other (b)	—	8,316	—	8,316
Common stock equities (c)	175,605	—	—	175,605
Mutual funds (d)	34,310	—	—	34,310
Common and collective trusts:				
Equities	—	—	94,674	94,674
Real estate	—	—	19,778	19,778
Short-term investments and other (e)	142,995	—	3,988	146,983
Total	$ 612,921	$ 229,804	$ 118,440	$ 961,165

(a) These investments primarily represent assets valued using NAV 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 U.S. common stock equities.
(d) These funds invest in U.S. and international common stock equities.
(e) 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 2021, $100 million in 2020, and $150 million in 2019. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2022, 2023 or 2024. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2021 or 2020 and do not expect to make any contributions in 2022, 2023 or 2024. The Company was reimbursed

$24 million in 2021, $26 million in 2020, and $30 million in 2019 for prior years retiree medical claims from the other postretirement benefit plan trust assets.

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 Plans	Other Benefits Plans
2022	$ 220,549	$ 31,244
2023	219,132	31,658
2024	221,724	31,486
2025	222,356	30,988
2026	221,709	30,780
Years 2027-2031	1,121,557	151,194

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 2021, 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 $12 million for 2021, $11 million for 2020, and $11 million for 2019.

9. Leases

We lease certain land, buildings, vehicles, equipment, and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain purchased power agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2022 through 2050. Substantially all of our leasing activities relate to APS.

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.

On May 1, 2021, APS had a new purchased power lease contract that commenced, with a lease term expiring on October 31, 2027. On December 31, 2021, APS modified an existing purchased power lease contract that had commenced in June 2020. The lease modification extends the expiration of this lease from September 30, 2025, to October 31, 2031, among other changes. These purchased power lease agreements allow APS the right to the generation capacity from certain natural-gas fueled generators during certain months of each year throughout the term of the arrangements. As APS only has rights to use the assets during certain periods of each year the leases have non-consecutive periods of use. APS does not operate or maintain these leased assets. APS controls the dispatch of these leased assets and is required to pay fixed monthly capacity payments during the periods of use. For these types of leased assets APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. These purchased power lease contracts are accounted for as operating leases. The contracts do not contain purchase options or term extension options. In addition to the fixed monthly capacity payment, APS must also pay variable charges based on the actual production volume of the asset. The variable consideration is not included in the measurement of our lease obligation.

The following table provides information related to our lease costs (dollars in thousands):

	For the Year Ended December 31,		
	2021	2020	2019
Operating Lease Cost - Purchased Power Lease Contracts	$ 105,762	$ 68,883	42,190
Operating Lease Cost - Land, Property, and Other Equipment	18,498	18,493	18,038
Total Operating Lease Cost	124,260	87,376	60,228
Variable lease cost (a)	118,969	122,331	114,015
Short-term lease cost	3,872	3,804	4,385
Total lease cost	$ 247,101	$ 213,511	$ 178,628

(a) Primarily relates to purchased power lease contracts.

Lease costs are primarily included as a component of operating expenses on our Consolidated Statements of Income. Lease costs relating to purchased power lease contracts are recorded in fuel and purchased power on the Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 4. The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable purchased power lease contracts. Payments under most renewable purchased power lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the generation source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheet.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information related to the maturity of our operating lease liabilities (dollars in thousands):

Year	December 31, 2021 Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
2022	$ 103,752	$ 13,051	$ 116,803
2023	106,151	10,758	116,909
2024	104,315	8,073	112,388
2025	106,582	6,034	112,616
2026	120,016	4,803	124,819
Thereafter	299,594	35,289	334,883
Total lease commitments	840,410	78,008	918,418
Less imputed interest	72,249	17,325	89,574
Total lease liabilities	$ 768,161	$ 60,683	$ 828,844

We recognize lease assets and liabilities upon lease commencement. At December 31, 2021, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from June 2022 through June 2024, with lease terms expiring through May 2044. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $1.3 billion over the term of the arrangements.

The following tables provide other additional information related to operating lease liabilities (dollars in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 116,661	$ 75,097	$ 69,075
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	500,582	441,653	11,262

	December 31, 2021	December 31, 2020
Weighted average remaining lease term	8 years	6 years
Weighted average discount rate (a)	2.13 %	1.69 %

(a) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

10. 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, 2021 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1 %		$1,932,629	$1,113,905	$ 28,288
Palo Verde Unit 2 (a)	16.8 %		657,102	384,193	14,084
Palo Verde Common	28.0 %	(b)	792,849	334,804	43,690
Palo Verde Sale Leaseback		(a)	351,050	256,884	—
Four Corners Generating Station	63.0 %		1,686,702	608,247	21,515
Cholla Common Facilities (c)	50.5 %		208,709	121,877	1,608
Transmission facilities:					
ANPP 500kV System	33.5 %	(b)	133,289	53,708	115
Navajo Southern System	26.8 %	(b)	89,895	35,144	1,535
Palo Verde — Yuma 500kV System	25.8 %	(b)	23,650	7,188	716
Four Corners Switchyards	60.1 %	(b)	73,133	18,637	258
Phoenix — Mead System	17.1 %	(b)	39,523	20,150	—
Palo Verde — Rudd 500kV System	50.0 %		96,376	29,426	—
Morgan — Pinnacle Peak System	64.7 %	(b)	119,814	23,575	138
Round Valley System	50.0 %		535	180	—
Palo Verde — Morgan System	87.8 %	(b)	259,180	27,995	268
Hassayampa — North Gila System	80.0 %		148,039	19,317	—
Cholla 500kV Switchyard	85.7 %		8,287	2,163	5
Saguaro 500kV Switchyard	60.0 %		21,655	13,471	—
Kyrene — Knox System	50.0 %		578	328	—

(a) See Note 18.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 (see Note 4 for additional information), and APS operated the unit for PacifiCorp. Cholla Unit 4 was retired on December 24, 2020. The common facilities at Cholla are jointly-owned.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Commitments and Contingencies

Palo Verde 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 DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007, through June 30, 2011, 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, which required DOE to pay the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. The settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019. On September 1, 2020, APS and DOE entered into an addendum to the settlement agreement allowing for the recovery of costs incurred through December 31, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014, settlement agreement, for seven separate time periods during July 1, 2011, through June 30, 2020. DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 4. On November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). In February 2022, the DOE approved this claim.

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 $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $13.1 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 $137.6 million, subject to a maximum annual premium of approximately $20.5 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 $120.1 million, with a maximum annual retrospective premium of approximately $17.9 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 $22.4 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. Additionally, at the sole discretion of the NEIL Board of Directors, APS would be liable to provide approximately $63.3 million in deposit premium within 20 days of request as assurance to satisfy any site obligation of retrospective premium assessment. 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 2022 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $1 billion in 2022; $765 million in 2023; $703 million in 2024; $686 million in 2025; $687 million in 2026; and $6.9 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. These amounts include estimated commitments relating to purchased power lease contracts. See Note 9.

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,					
	2022	2023	2024	2025	2026	Thereafter
Coal take-or-pay commitments (a)	$ 202,917	$ 201,826	$ 203,638	$ 194,192	$ 195,121	$ 925,644

(a) Total take-or-pay commitments are approximately $1.9 billion. The total net present value of these commitments is approximately $1.5 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):

	Years Ended December 31,		
	2021	2020	2019
Total purchases	$ 219,958	$ 189,817	$ 204,888

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 $32 million in 2022; $30 million in 2023; $29 million in 2024; $26 million in 2025; $22 million in 2026; and $87 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers 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 $175 million at December 31, 2021, and $170 million at December 31, 2020. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $17 million in 2022; $18 million in 2023; $19 million in 2024; $20 million in 2025; $21 million in 2026; and $48 million thereafter. These funds are held in an escrow account and will be distributed to certain coal providers under the terms of the applicable coal supply agreements. Any amendments to current coal supply agreements may change the timing of the contribution or cost of final reclamation. The annual payments to the escrow account and final distribution to certain coal providers may be subject to adjustments based on escrow earnings.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("PRPs"). PRPs may be strictly, 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 ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the first or second quarter of 2022. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates 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, the 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 environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party 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.

Arizona Attorney General Matter

APS received civil investigative demands from the Attorney General seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying $24.75 million, approximately $24 million of which was returned to customers as restitution.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2021. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately

$154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 4 for additional information regarding the Four Corners SCR cost recovery.

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 GHGs, 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 pollution control requirements on Four Corners. EPA required the plant to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plant.

Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. 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 purchased the interest from 4CA on July 3, 2018. See "Four Corners — 4CA Matter" below for a discussion of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest. In addition, EPA issued a final 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 "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset.

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. These criteria include standards governing 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 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. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

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- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.
- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.
- Based on an August 21, 2018, D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments by April 11, 2021, at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.
- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's July 29, 2020, final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020, and is currently pending. This application will be subject to public comment and, potentially, judicial review. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and we anticipate receiving a proposed decision with respect to the Cholla facility in 2022.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows.

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 $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and

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Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. Nonetheless, on October 29, 2021, the U.S. Supreme Court announced that it was accepting judicial review of the January D.C. Circuit decision vacating the ACE regulations. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings or ongoing litigation related to the scope of EPA's authority under the Clean Air Act to regulate carbon emissions from existing power plants.

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.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. As of November 11, 2021, the parties to this lawsuit, including APS, reached a tentative agreement to settle this matter. Review of this agreement, including public commenting, is currently pending with EPA. Notwithstanding this tentative agreement, we cannot predict the outcome of these appeal proceedings, including further settlement discussions, and, if settlement efforts fail and the appeal is eventually successful, whether that outcome will have a material impact on our financial position, results of operations, or cash flows.

Four Corners

4CA Matter

On July 6, 2016, 4CA purchased El Paso's 7% interest in Four Corners. NTEC purchased this 7% interest on July 3, 2018, from 4CA. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. The note is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement. As of December 31, 2021, the note has a remaining balance of approximately $9.2 million. NTEC continues to make payments in accordance with the terms of the note. Due to its short-remaining term, among other factors, there are no expected credit losses associated with the note.

In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

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 commodity contract collateral obligations and other transactions. As of December 31, 2021, standby letters of credit totaled approximately $5 million and will expire in 2022. As of December 31, 2021, surety bonds expiring through 2023 totaled approximately $14 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, 2021. In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. See "Four Corners — 4CA Matter" above for information related to this guarantee. Pinnacle West has not needed to perform under this guarantee. A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee, including expected credit losses, to be immaterial.

In connection with BCE's acquisition of minority ownership positions in the Clear Creek wind farm in Missouri and Nobles 2 wind farm in Minnesota, Pinnacle West has issued parental guarantees to guarantee the obligations of BCE subsidiaries to make required equity contributions to fund project construction (the "Equity Contribution Guarantees") and to make production tax credit funding payments to borrowers of the projects (the "PTC Guarantees"). The amounts guaranteed by Pinnacle West are reduced as payments are made under the respective guarantee agreements. The Equity Contribution Guarantees remaining as of December 31, 2021, are immaterial in amount (approximately $2 million) and the PTC Guarantees (approximately $37 million as of December 31, 2021) are currently expected to be terminated 10 years following the commercial operation date of the applicable project.

In connection with the credit agreement entered into by a special purpose subsidiary of BCE on February 11, 2022, Pinnacle West has guaranteed the full amount of the equity bridge loan under the credit facility. See Note 7 for additional details.

12. Asset Retirement Obligations

In 2021, APS revised its cost estimates for existing AROs at Cholla related to updated estimates for the closure of ponds and facilities, which resulted in an increase to the ARO of approximately $28 million. See additional details in Notes 4 and 11.

In 2020, APS revised its cost estimates for existing AROs at Cholla relating to updated estimates for the closure of ponds and facilities, and at Four Corners and the Navajo Plant relating to corrective action and water monitoring costs, which resulted in an increase to the ARO of $6 million. Also in 2020, an updated Four Corners decommissioning study was finalized for the updated closure date of 2031, which resulted in an increase to the ARO of $13 million.

The following table shows the change in our AROs (dollars in thousands):

	2021	2020
Asset retirement obligations at the beginning of year	$ 705,083	$ 657,218
Changes attributable to:		
Accretion expense	38,437	38,652
Settlements	(4,111)	(9,710)
Estimated cash flow revisions	27,973	18,923
Asset retirement obligations at the end of year	$ 767,382	$ 705,083

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 4.

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 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including 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).

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may 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 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, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 8 for fair value discussion of plan assets held in our retirement and other benefit plans.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

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.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 19 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below 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 trustees' and escrow agent's internal operating controls and valuation processes.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury 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 fixed income 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.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments 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.

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid investments are valued using active market prices.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

The following table presents the fair value at December 31, 2021, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 115,079	$ —	$ (4,690)	(a)	$ 110,389
Nuclear decommissioning trust:						
Equity securities	45,264	—	—	(27,782)	(b)	17,482
U.S. commingled equity funds	—	—	—	595,048	(c)	595,048
U.S. Treasury debt	240,745	—	—	—		240,745
Corporate debt	—	203,454	—	—		203,454
Mortgage-backed securities	—	155,574	—	—		155,574
Municipal bonds	—	72,189	—	—		72,189
Other fixed income	—	10,265	—	—		10,265
Subtotal nuclear decommissioning trust	286,009	441,482	—	567,266		1,294,757
Other special use funds:						
Equity securities	47,570	—	—	936	(b)	48,506
U.S. Treasury debt	298,170	—	—	—		298,170
Municipal bonds	—	11,734	—	—		11,734
Subtotal other special use funds	345,740	11,734	—	936		358,410
Total assets	$ 631,749	$ 568,295	$ —	$ 563,512		$ 1,763,556
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (4,740)	$ (2,738)	$ 3,105	(a)	$ (4,373)

(a) Represents counterparty netting, margin, and collateral. See Note 16.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2020, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 9,016	$ 4	$ (4,271)	(a)	$ 4,749
Nuclear decommissioning trust:						
Equity securities	29,796	—	—	(17,828)	(b)	11,968
U.S. commingled equity funds	—	—	—	610,055	(c)	610,055
U.S. Treasury debt	164,514	—	—	—		164,514
Corporate debt	—	149,509	—	—		149,509
Mortgage-backed securities	—	99,623	—	—		99,623
Municipal bonds	—	89,705	—	—		89,705
Other fixed income	—	13,061	—	—		13,061
Subtotal nuclear decommissioning trust	194,310	351,898	—	592,227		1,138,435
Other special use funds:						
Equity securities	37,337	—	—	504	(b)	37,841
U.S. Treasury debt	203,220	—	—	—		203,220
Municipal bonds	—	13,448	—	—		13,448
Subtotal other special use funds	240,557	13,448	—	504		254,509
Total assets	$ 434,867	$ 374,362	$ 4	$ 588,460		$ 1,397,693
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (20,498)	$ (1,107)	$ 2,986	(a)	$ (18,619)

(a) Represents counterparty netting, margin, and collateral. See Note 16.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

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 or other characteristics of the product. 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 4.

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.

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.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 7 for our long-term debt fair values. The NTEC note receivable related to the sale of 4CA's interest in Four Corners bears interest at 3.9% per annum and has a book value of $9 million as of December 31, 2021, as presented on the Consolidated Balance Sheets. The carrying amount is not materially different from the fair value of the note receivable and is classified within Level 3 of the fair value hierarchy. See Note 11 for more information on 4CA matters.

14. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share (in thousands, except per share amounts):

	2021	2020	2019
Net income attributable to common shareholders	$ 618,720	$ 550,559	$ 538,320
Weighted average common shares outstanding — basic	112,910	112,666	112,443
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	282	276	315
Weighted average common shares outstanding — diluted	113,192	112,942	112,758
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders — basic	$ 5.48	$ 4.89	$ 4.79
Net income attributable to common shareholders — diluted	$ 5.47	$ 4.87	$ 4.77

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 2021 Long-Term Incentive Plan ("2021 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 2021 Plan authorizes up to 1.5 million common shares to be available for grant. As of December 31, 2021, 1.2 million common shares were available for issuance under the 2021 Plan. During 2021, 2020, and 2019, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2012 to May 2021 were issued under the 2012 Long-Term Incentive Plan ("2012 Plan"), and awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"). No new awards may be granted under the 2012 or 2007 Plans.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $18 million in 2021, $18 million in 2020, and $18 million in 2019. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $3 million in 2021, $4 million in 2020, and $7 million in 2019.

As of December 31, 2021, there were approximately $11 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 2021, $22 million in 2020 and $21 million in 2019.

The following table is a summary of awards granted and the weighted-average grant date fair value for each of the last three years:

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2021	2020	2019	2021	2020	2019
Units granted	152,345	118,403	109,106	161,840	122,830	142,874
Weighted-average grant date fair value	$ 76.72	$ 71.70	$ 89.15	$ 82.42	$ 104.74	$ 92.16

(a) Units granted includes awards that will be cash settled of 51,074 in 2021, 45,646 in 2020, and 48,972 in 2019.

(b) Reflects the target payout level.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table is a summary of the status of non-vested awards as of December 31, 2021, 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, 2021	220,557	$ 77.93	260,004	$ 98.28
Granted	152,345	76.72	161,840	82.42
Vested	(115,099)	80.50	(136,070)	92.16
Forfeited (c)	(4,647)	80.11	(5,092)	95.07
Nonvested at December 31, 2021	253,156 (a)	79.37	280,682	92.16
Vested Awards Outstanding at December 31, 2021	88,706		136,070	

(a) Includes 118,538 of awards that will be cash settled.
(b) The nonvested performance shares are reflected at target payout level.
(c) We account for forfeitures as they occur.

Share-based liabilities paid relating to restricted stock units were $4 million, $6 million, and $5 million in 2021, 2020 and 2019, respectively. This includes cash used to settle restricted stock units of $3 million, $4 million, and $5 million in 2021, 2020 and 2019, respectively. Restricted stock units that are cash settled are classified as liability awards. All performance shares are 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 typically elect to receive payment in either 100% stock, 100% cash, 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.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 100% cash, 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, cash, 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 on non-financial 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 recipients 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 the 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

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and interest rates. Risks associated with market volatility are managed 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 natural gas. 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. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may 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.

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 4. Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**December 31, 2021**	**December 31, 2020**
Power	GWh	—	368
Gas	Billion cubic feet	155	205

Gains and Losses from Derivative Instruments

The following table provides information about APS's gains and losses from derivative instruments in designated cash flow accounting hedging relationships (dollars in thousands):

	Financial Statement	Year Ended December 31,		
Commodity Contracts	**Location**	**2021**	**2020**	**2019**
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	$ —	$ (763)	$ (1,512)

(a) During the years ended December 31, 2021, 2020, and 2019, we had no gains or 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 no amounts will be reclassified from accumulated OCI into income. For APS, the delivery period for all derivative instruments in designated cash flow accounting hedging relationships have lapsed.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2021	2020	2019
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ 216,847	$ (3,178)	$ (84,953)

(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. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables provide information about the fair value of our risk management activities reported on a gross basis and the impacts of offsetting. 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, 2021: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 66,777	$ (3,346)	$ 63,431	$ 50	$ 63,481
Investments and other assets	48,302	(1,394)	46,908	—	46,908
Total assets	115,079	(4,740)	110,339	50	110,389
Current liabilities	(6,084)	3,346	(2,738)	(1,635)	(4,373)
Deferred credits and other	(1,394)	1,394	—	—	—
Total liabilities	(7,478)	4,740	(2,738)	(1,635)	(4,373)
Total	$ 107,601	$ —	$ 107,601	$ (1,585)	$ 106,016

(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 $1,635 and cash margin provided to counterparties of $50.

As of December 31, 2020: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 5,870	$ (2,939)	$ 2,931	$ —	$ 2,931
Investments and other assets	3,150	(1,332)	1,818	—	1,818
Total assets	9,020	(4,271)	4,749	—	4,749
Current liabilities	(9,211)	2,939	(6,272)	(1,285)	(7,557)
Deferred credits and other	(12,394)	1,332	(11,062)	—	(11,062)
Total liabilities	(21,605)	4,271	(17,334)	(1,285)	(18,619)
Total	$ (12,585)	$ —	$ (12,585)	$ (1,285)	$ (13,870)

(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 $1,285.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2021, we have three counterparties for which our exposure represents approximately 38% of Pinnacle West's $110 million of risk management assets. This exposure relates to master agreements with counterparties and all three are rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties 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 (dollars in thousands):

	December 31, 2021
Aggregate fair value of derivative instruments in a net liability position	$ 7,478
Cash collateral posted	—
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	2,658

(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 $88 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 2021, 2020 and 2019 (dollars in thousands):

	2021	2020	2019
Other income:			
Interest income	$ 6,726	$ 12,210	$ 10,377
Investment gains (losses) — net	—	2,358	—
Debt return on Four Corners SCR deferral (Note 4)	14,955	15,865	19,541
Debt return on Ocotillo modernization project (Note 4)	23,366	26,121	20,282
Miscellaneous	53	149	63
Total other income	$ 45,100	$ 56,703	$ 50,263
Other expense:			
Non-operating costs	$ (13,008)	$ (12,400)	$ (10,663)
Investment gains (losses) — net	(1,367)	—	(1,835)
Miscellaneous	(11,021)	(45,376) (a)	(5,382)
Total other expense	$ (25,396)	$ (57,776)	$ (17,880)

(a) The 2020 miscellaneous amount includes donations of approximately $10 million to the APS Foundation and approximately $25.2 million related to the CCT plan. See Note 4.

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2021, 2020 and 2019 (dollars in thousands):

	2021	2020	2019
Other income:			
Interest income	$ 4,692	$ 9,621	$ 6,998
Debt return on Four Corners SCR deferral (Note 4)	14,955	15,865	19,541
Debt return on Ocotillo modernization project (Note 4)	23,366	26,121	20,282
Miscellaneous	40	148	63
Total other income	$ 43,053	$ 51,755	$ 46,884
Other expense:			
Non-operating costs	$ (10,080)	$ (10,659)	$ (9,612)
Miscellaneous	(8,817)	(43,035) (a)	(3,378)
Total other expense	$ (18,897)	$ (53,694)	$ (12,990)

(a) The 2020 miscellaneous amount includes donations of approximately $10 million to the APS Foundation and approximately $25.2 million related to the CCT plan. See Note 4.

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. Prior to April 1, 2021, the lease terms allowed APS the right to retain the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amended lease agreement with one of the VIE lessor trust entities relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2022 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 of $17 million for 2021, and $19 million for 2020 and 2019. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Consolidated Balance Sheets include the following amounts relating to the VIEs (dollars in thousands):

	December 31, 2021	December 31, 2020
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 94,166	$ 98,036
Equity-Noncontrolling interests	115,260	119,290

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 to be 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 $315 million beginning in 2022, and up to $501 million over the lease extension terms.

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. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments 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 investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. 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. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2021 and 2020, APS was reimbursed $15 million and $14 million, respectively, for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below. On January 4, 2021, an additional $106 million of investments were transferred from APS other postretirement benefit trust assets into the active union employee medical account, see Note 8.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	December 31, 2021				
	Fair Value				
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 640,312	$ 47,570	$ 687,882	$ 451,387	$ —
Available for sale-fixed income securities	682,227	309,904	992,131 (a)	24,283	(4,063)
Other	(27,782)	936	(26,846) (b)	—	—
Total	$ 1,294,757	$ 358,410	$ 1,653,167	$ 475,670	$ (4,063)

(a) As of December 31, 2021, the amortized cost basis of these available-for-sale investments is $972 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2020				
	Fair Value				
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 639,851	$ 37,337	$ 677,188	$ 421,666	$ —
Available for sale-fixed income securities	516,412	216,668	733,080 (a)	46,581	(398)
Other	(17,828)	504	(17,324) (b)	—	—
Total	$ 1,138,435	$ 254,509	$ 1,392,944	$ 468,247	$ (398)

(a) As of December 31, 2020, the amortized cost basis of these available-for-sale investments is $687 million.
(b) Represents net pending securities sales and purchases.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Year Ended December 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 134,610	$ 49	$ 134,659
Realized losses	(8,431)	(7)	(8,438)
Proceeds from the sale of securities (a)	1,457,305	263,661	1,720,966
2020			
Realized gains	12,194	176	12,370
Realized losses	(5,553)	(15)	(5,568)
Proceeds from the sale of securities (a)	675,035	144,484	819,519
2019			
Realized gains	11,024	108	11,132
Realized losses	(6,972)	—	(6,972)
Proceeds from the sale of securities (a)	473,806	245,228	719,034

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at December 31, 2021, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 31,070	$ 36,852	$ 40,870	$ 108,792
1 year – 5 years	195,975	41,931	158,235	396,141
5 years – 10 years	155,202	1,775	21,846	178,823
Greater than 10 years	299,980	8,395	—	308,375
Total	$ 682,227	$ 88,953	$ 220,951	$ 992,131

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 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance at December 31, 2019	$ (56,522)		$ (574)		$ (57,096)
OCI (loss) before reclassifications	(8,370)		(2,089)		(10,459)
Amounts reclassified from accumulated other comprehensive loss	4,167	(a)	592	(b)	4,759
Balance at December 31, 2020	(60,725)		(2,071)		(62,796)
OCI (loss) before reclassifications	2,439		1,077		3,516
Amounts reclassified from accumulated other comprehensive loss	4,401	(a)	18	(b)	4,419
Balance at December 31, 2021	$ (53,885)		$ (976)		$ (54,861)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.
(b) 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.

Changes in Accumulated Other Comprehensive Loss — APS

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance at December 31, 2019	$ (34,948)		$ (574)		$ (35,522)
OCI (loss) before reclassifications	(9,568)		(18)		(9,586)
Amounts reclassified from accumulated other comprehensive loss	3,598	(a)	592	(b)	4,190
Balance at December 31, 2020	(40,918)		—		(40,918)
OCI (loss) before reclassifications	2,043		(18)		2,025
Amounts reclassified from accumulated other comprehensive loss	3,995	(a)	18	(b)	4,013
Balance at December 31, 2021	$ (34,880)		$ —		$ (34,880)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.
(b) 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.

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,		
	2021	2020	2019
Operating expenses	$ 10,245	$ 7,901	$ 12,451
Other			
Equity in earnings of subsidiaries	628,916	566,147	562,946
Other expense	(4,919)	(4,586)	(3,957)
Total	623,997	561,561	558,989
Interest expense	10,672	14,021	15,069
Income before income taxes	603,080	539,639	531,469
Income tax benefit	(15,640)	(10,920)	(6,851)
Net income attributable to common shareholders	618,720	550,559	538,320
Other comprehensive income (loss) — attributable to common shareholders	7,935	(5,700)	(9,388)
Total comprehensive income — attributable to common shareholders	$ 626,655	$ 544,859	$ 528,932

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, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	$ 594	$ 19
Accounts receivable	125,457	123,980
Income tax receivable	1,498	14,719
Other current assets	13	298
Total current assets	127,562	139,016
Investments and other assets		
Investments in subsidiaries	6,797,528	6,400,339
Deferred income taxes	19,520	7,589
Other assets	57,608	52,595
Total investments and other assets	6,874,656	6,460,523
Total Assets	$ 7,002,218	$ 6,599,539
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 3,071	$ 5,669
Accrued taxes	19,855	16,998
Common dividends payable	95,988	93,531
Short-term borrowings	13,300	169,000
Current maturities of long-term debt	150,000	—
Operating lease liabilities	107	90
Other current liabilities	14,684	15,306
Total current liabilities	297,005	300,594
Long-term debt less current maturities (Note 7)	647,139	496,321
Pension liabilities	14,537	17,541
Operating lease liabilities	1,576	1,683
Other	20,501	30,607
Total deferred credits and other	36,614	49,831
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
Common stock equity		
Common stock	2,696,342	2,671,193
Accumulated other comprehensive loss	(54,861)	(62,796)
Retained earnings	3,264,719	3,025,106
Total Pinnacle West Shareholders' equity	5,906,200	5,633,503
Noncontrolling interests	115,260	119,290
Total Equity	6,021,460	5,752,793
Total Liabilities and Equity	$ 7,002,218	$ 6,599,539

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, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 618,720	$ 550,559	$ 538,320
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(628,916)	(566,147)	(562,946)
Depreciation and amortization	93	76	76
Deferred income taxes	(11,381)	33,007	(35,831)
Accounts receivable	8,897	(7,903)	182
Accounts payable	(2,598)	(1,964)	(2,129)
Accrued taxes and income tax receivables — net	16,079	9,610	16,400
Dividends received from subsidiaries	376,500	357,500	336,300
Other	4,214	20,163	(1,300)
Net cash flow provided by operating activities	381,608	394,901	289,072
Cash flows from investing activities			
Investments in subsidiaries	(145,266)	(137,881)	1,557
Repayments of loans from subsidiaries	4,017	932	4,190
Advances of loans to subsidiaries	(12,256)	(7,261)	(4,165)
Net cash flow provided by (used for) investing activities	(153,505)	(144,210)	1,582
Cash flows from financing activities			
Issuance of long-term debt	300,000	496,950	—
Short-term debt borrowings under revolving credit facility	—	211,690	49,000
Short-term debt repayments under revolving credit facility	(19,000)	(230,690)	(65,000)
Short-term borrowings and (repayments) — net	(136,700)	73,325	54,275
Dividends paid on common stock	(369,478)	(350,577)	(329,643)
Repayment of long-term debt	—	(450,000)	—
Common stock equity issuance and purchases — net	(2,350)	(1,389)	692
Net cash flow used for financing activities	(227,528)	(250,691)	(290,676)
Net decrease in cash and cash equivalents	575	—	(22)
Cash and cash equivalents at beginning of year	19	19	41
Cash and cash equivalents at end of year	$ 594	$ 19	$ 19

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 Pinnacle West on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

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, 2021. 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, 2021. 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, 2021, 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.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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" and "Proposal 1 — Election of Directors" in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 18, 2022 (the "2022 Proxy Statement") and to the "Information about our Executive Officers" 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 "Director Compensation," "Executive Compensation," and "Human Resources Committee Interlocks and Insider Participation" in the 2022 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" in the 2022 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2021, with respect to the the 2021 Plan, 2012 Plan, the 2007 Plan, under which our equity securities are outstanding or currently authorized for issuance.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,243,225	—	1,241,996
Equity compensation plans not approved by security holders	—	—	—
Total	1,243,225	—	1,241,996

(a) This amount includes shares subject to outstanding performance share awards and restricted stock unit awards at the maximum amount of shares issuable under such awards. However, payout of the performance share awards is contingent on the Company reaching certain levels of performance during a three-year performance period. If the performance criteria for these awards are not fully satisfied, the award recipient will receive less than the maximum number of shares available under these grants and may receive nothing from these grants.

(b) The weighted-average exercise price in this column does not take performance share awards or restricted stock unit awards into account, as those awards have no exercise price.

(c) Awards under the 2021 Plan can take the form of options, stock appreciation rights, restricted stock, performance shares, performance share units, performance cash, stock grants, stock units, dividend equivalents, and restricted stock units. Additional shares cannot be awarded under the 2012 Plan and the 2007 Plan. However, if an award under the 2012 Plan or the 2007 Plan is forfeited, terminated or canceled or expires, the shares subject to such award, to the extent of the forfeiture, termination, cancellation, or expiration, may be added back to the shares available for issuance under the 2021 Plan.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under three equity compensation plans that were previously approved by our shareholders: (a) the 2007 Plan, which was approved by our shareholders at our 2007 annual meeting of shareholders and under which no new stock awards may be granted; (b) the 2012 Plan, as amended, which was approved by our shareholders at our 2012 annual meeting of shareholders and the first amendment to the 2012 Plan was approved by our shareholders at our 2017 annual meeting of shareholders and under which no new stock awards may be granted; and (c) the 2021 Plan which was approved by our shareholders at our 2021 annual meeting of shareholders. See Note 15 of the Notes to Consolidated Financial Statements for additional information regarding these plans.

Equity Compensation Plans Not Approved by Security Holders

The Company does not have any equity compensation plans under which shares can be issued that have not been approved by the shareholders.

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 2022 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pinnacle West

Reference is hereby made to "Audit Matters — Audit Fees and — Pre-Approval Policies" in the 2022 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	2021	2020
Audit Fees (1)	$ 2,580,260	$ 2,414,909
Audit-Related Fees (2)	333,905	323,067

(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 2021 and 2020.

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 $100,000. 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 2021 were pre-approved by the Audit Committee or the Chair 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 February 19, 2020	3.1 to Pinnacle West/APS February 25, 2020 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/25/2020
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 20, 2017 Form 8-K Report, File No. 1-8962	6/20/2017
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
4.3	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
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.4a	Pinnacle West	Fourth Supplemental Indenture dated as of June 17, 2020	4.1 to Pinnacle West June 10, 2020 Form 8-K Report, File No. 1-8962	6/16/2020
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 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 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 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
4.6c	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
4.6d	Pinnacle West 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
4.6e	Pinnacle West 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
4.6f	Pinnacle West 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
4.6g	Pinnacle West 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
4.6h	Pinnacle West 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
4.6i	Pinnacle West 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
4.6j	Pinnacle West 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
4.6k	Pinnacle West 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
4.6l	Pinnacle West APS	Twenty-First Supplemental Indenture dated as of September 11, 2017	4.1 to Pinnacle West/APS September 11, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	9/11/2017

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6m	Pinnacle West APS	Twenty-Second Supplemental Indenture dated as of August 9, 2018	4.1 to Pinnacle West/APS August 9, 2018 Form 8-K Report, File Nos. 1-8962 and 1-4473	8/9/2018
4.6n	Pinnacle West APS	Twenty-Third Supplemental Indenture dated as of February 28, 2019	4.1 to Pinnacle West/APS February 28, 2019 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/28/2019
4.6o	Pinnacle West APS	Twenty-Fourth Supplemental Indenture dated as of August 19, 2019	4.1 to Pinnacle West/APS August 16, 2019 Form 8-K Report, File Nos. 1-8962 and 1-4473	8/16/2019
4.6p	Pinnacle West APS	Twenty-Fifth Supplemental Indenture dated as of November 20, 2019	4.1 to Pinnacle West/APS November 20, 2019 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/20/2019
4.6q	Pinnacle West APS	Twenty-Sixth Supplemental Indenture dated as of May 22, 2020	4.1 to Pinnacle West/APS May 22, 2020 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2020
4.6r	Pinnacle West APS	Twenty-Seventh Supplemental Indenture dated as of September 11, 2020	4.1 to Pinnacle West/APS September 11, 2020 Form 8-K Report, File Nos. 1-8962 and 1-4473	9/11/2020
4.6s	Pinnacle West APS	Twenty-Eighth Supplemental Indenture dated as of August 16, 2021	4.1 to Pinnacle West/APS August 16, 2021 Form 8-K Report, File Nos. 1-8962 and 1-4473	8/16/2021
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 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
4.9	Pinnacle West APS	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934		
10.1.1	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVGS 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 APS	Amendment No. 1 to Decommissioning Trust Agreement (PVGS 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1.1b	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVGS 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
10.1.1d	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVGS 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 APS	Amended and Restated Decommissioning Trust Agreement (PVGS 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 PVGS 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 APS	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVGS 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.1.2b	Pinnacle West APS	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVGS 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
10.1.2d	Pinnacle West APS	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVGS 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 APS	Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVGS 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 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 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 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 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 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.2.2[b]	Pinnacle West 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 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 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
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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	10.64b 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
10.3.1[b]	Pinnacle West 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 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 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 APS	First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2a to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.3.2b[b]	Pinnacle West APS	Second Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2b to Pinnacle West/APS 2017 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/23/2018
10.4.1[b]	Pinnacle West 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
10.4.2[b]	Pinnacle West APS	Transition and Separation Agreement between Pinnacle West/APS and James R. Hatfield	10.1 to Pinnacle West/APS August 24, 2021 form 8-K; File Nos. 1-8962 and 1-4473	8/24/2021
10.4.3[b]	Pinnacle West APS	Offer of Employment Letter dated July 19, 2018 between Pinnacle West and Robert E. Smith	10.4.5 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4.4[b]	Pinnacle West APS	Supplemental Agreement dated October 17, 2018 between Pinnacle West and Robert E. Smith	10.4.6 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4.5[b]	Pinnacle West APS	Discretionary Credit Award Agreement dated June 19, 2019 between Pinnacle West and Theodore Geisler	10.4.4 to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.4.6a[b]	Pinnacle West APS	Retention Agreement dated December 19, 2008 between APS and Maria Lacal	10.4.5a to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4.6b[b]	Pinnacle West APS	First Amendment to the Retention Agreement dated May 24, 2011 between APS and Maria Lacal	10.4.5b to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4.7[b]	Pinnacle West APS	Medical Retention Agreement dated October 31, 2014 between APS and Maria Lacal	10.4.6 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4.8[b]	Pinnacle West APS	Discretionary Credit Award Agreement dated October 31, 2014 between APS and Maria Lacal	10.4.7 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4.9[b]	Pinnacle West APS	Discretionary Credit Award Agreement dated September 29, 2016 between APS and Maria Lacal	10.4.8 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.5.1[bd]	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77bd to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
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
10.5.5[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
10.6.4[bd]	Pinnacle West APS	Summary of 2022 Variable Incentive Plan and Officer Variable Incentive Plan		
10.6.5[b]	Pinnacle West 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
10.6.5a[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
10.6.5b[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
10.6.5c[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
10.6.5d[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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:[a]	Date Filed
10.6.5e[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
10.6.5f[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6f to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.6.5g[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6g to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.6.5h[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, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.6.5i[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.6.5j[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, 2020 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/8/2020
10.6.5k[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.5k to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.6.5l[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.5l to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.6.5m[bd]	Pinnacle West APS	Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2021 Annual Meeting of Shareholders, File No. 1-8962	4/01/2021
10.6.5n[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.6.5o[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.6.5p[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.6.5q[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6.5r[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.6.5s[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.6.5t[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
10.6.5u[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
10.6.5v[bd]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2017 Annual Meeting of Shareholders, File No. 1-8962	3/31/2017
10.7.1	Pinnacle West 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 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
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. 1-89	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.7.4	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 11, dated June 30, 2018, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo Transitional Energy Company, LLC	10.7.4c to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
10.7.4a	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 13, dated June 25, 2021, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo	10.5 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
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
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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
10.10.2	Pinnacle West 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 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 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:[a]	Date Filed
10.10.4	Pinnacle West 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 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 APS	Term Loan Agreement dated as of February 26, 2019 among APS, as Borrower, SunTrust Bank, as Agent, SunTrust Bank, TD Bank, N.A., U.S. Bank National Association and The Bank of Nova Scotia, as Co-Syndication Agents and such institutions compromising the lenders party thereto	10.1 to Pinnacle West/APS March 31, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.11.2	Pinnacle West	Amended and Restated Five-Year Credit Agreements dated as of May 28, 2021, 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, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.11.3	Pinnacle West APS	Amended and Restated Five-Year Credit Agreement dated as of May 28, 2021, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.2 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.11.4	Pinnacle West APS	Five-Year Credit Agreement dated as of May 28, 2021, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.3 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
10.12.1d[c]	Pinnacle West 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 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 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 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12.2b	Pinnacle West 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 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
10.12.2d	Pinnacle West APS	Amendment No. 4, dated April 1, 2021, 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	10.1 to Pinnacle West/APS March 31, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2021
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
10.18	Pinnacle West APS	Proposed Settlement Agreement dated March 27, 2017 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 76295)	10.1 to Pinnacle West/APS March 31, 2017 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2017
10.19	Pinnacle West	Purchase and Sale Agreement, dated June 29, 2018, by and between Navajo Transitional Energy Company, LLC and 4CA	10.2 to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Jeffrey B. Guldner, 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 Theodore N. Geisler, 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 Jeffrey B. Guldner, 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 Theodore N. Geisler, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
32.1[c]	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		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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[c]	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVGS 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
99.1a[c]	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVGS 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
99.1b[c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., PVGS 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
99.2[c]	Pinnacle West 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.2a[c]	Pinnacle West 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
99.2b[c]	Pinnacle West 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
99.3[c]	Pinnacle West 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
99.3a[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. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
99.3b[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
99.4	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVGS 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.4a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVGS 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
99.4b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVGS Funding Corp., Inc., PVGS 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
99.5	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
99.5a	Pinnacle West 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
99.5b	Pinnacle West 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
99.6	Pinnacle West 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.6a	Pinnacle West 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
99.7[c]	Pinnacle West 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
99.8	Pinnacle West 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
99.9	Pinnacle West 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
99.10	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.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document		
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document		

[a] Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the SEC 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.

ITEM 16. FORM 10-K SUMMARY

None.

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 25, 2022

/s/ Jeffrey B. Guldner
(Jeffrey B. Guldner, 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 Theodore N. Geisler and Robert E. Smith, 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/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2022
/s/ Theodore N. Geisler (Theodore N. Geisler, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2022
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2022

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2022
/s/ Denis A. Cortese, M.D. (Denis A. Cortese, M.D.)	Director	February 25, 2022
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2022
/s/ Dale E. Klein, Ph.D. (Dale E. Klein, Ph.D.)	Director	February 25, 2022
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 25, 2022
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 25, 2022
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2022
/s/ William H. Spence (William H. Spence)	Director	February 25, 2022
/s/ James E. Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 2022
/s/ David P. Wagener (David P. Wagener)	Director	February 25, 2022

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 25, 2022

/s/ Jeffrey B. Guldner
(Jeffrey B. Guldner, 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 Theodore N. Geisler and Robert E. Smith, 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/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2022
/s/ Theodore N. Geisler (Theodore N. Geisler, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2022
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2022

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2022
/s/ Denis A. Cortese, M.D. (Denis A. Cortese, M.D.)	Director	February 25, 2022
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2022
/s/ Dale E. Klein (Dale E. Klein, Ph.D.)	Director	February 25, 2022
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 25, 2022
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 25, 2022
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2022
/s/ William H. Spence (William H. Spence)	Director	February 25, 2022
/s/ James E. Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 2022
/s/ David P. Wagener (David P. Wagener)	Director	February 25, 2022