0000171040

ORIGINAL

AZ CORP COMMISSION
DOCKET CONTROL

Transcript Exhibit(s)

2016 JUN 16 PM 3 50

Docket #(s): E-00000J-14-0023

Arizona Corporation Commission
DOCKETED
JUN 16 2016
DOCKETED BY

Exhibit #: TASC 1, 3-13, 15-19

Part 4 of 5

For parts 1-3, see barcodes 0000171007, 0000171008 + 0000171009

For part 5, see barcode 0000171041

2015

PINNACLE WEST CAPITAL CORPORATION ANNUAL REPORT

THIS ANNUAL REPORT FEATURES ART BY ED MELL

Mell brings an architectural eye to the desert, emphasizing graphic elements and stripping away details that do not serve his vision. From landscapes to storms, longhorn cattle to desert flowers, he presents the natural power and beauty of Arizona in bold colors and lines, energizing the vistas with his singular style.

Featured Work: Evening Edges (Cover), Desert Kings (Pg 4-5), Morning Sun (Pg 10-11), Shadowed Rim (Pg 12)

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

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

---

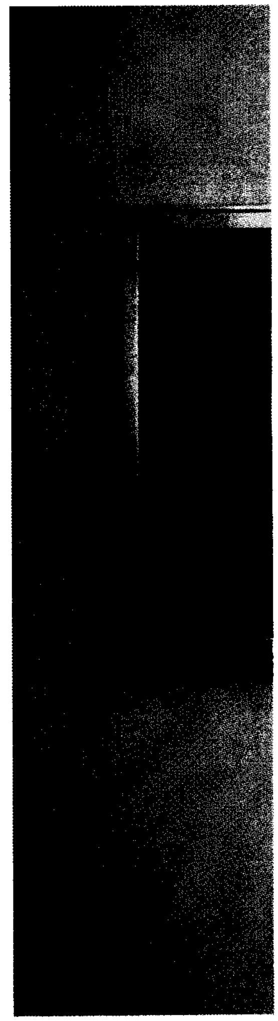
...WITH A SHARPENED FOCUS ON OUR CORE UTILITY BUSINESS.

THE APS VISION

Creating a sustainable energy future for Arizona.

THE APS MISSION

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



DEAR FELLOW SHAREHOLDERS...

Pinnacle West delivered superior value for our shareholders in 2015 by providing our customers with excellent service, managing our operations well and exercising financial discipline.

The company produced net income of $437 million, or $3.92 per share, which constituted a 9.5 percent increase over the previous year. Our consolidated earned return on average common equity was 9.77 percent.

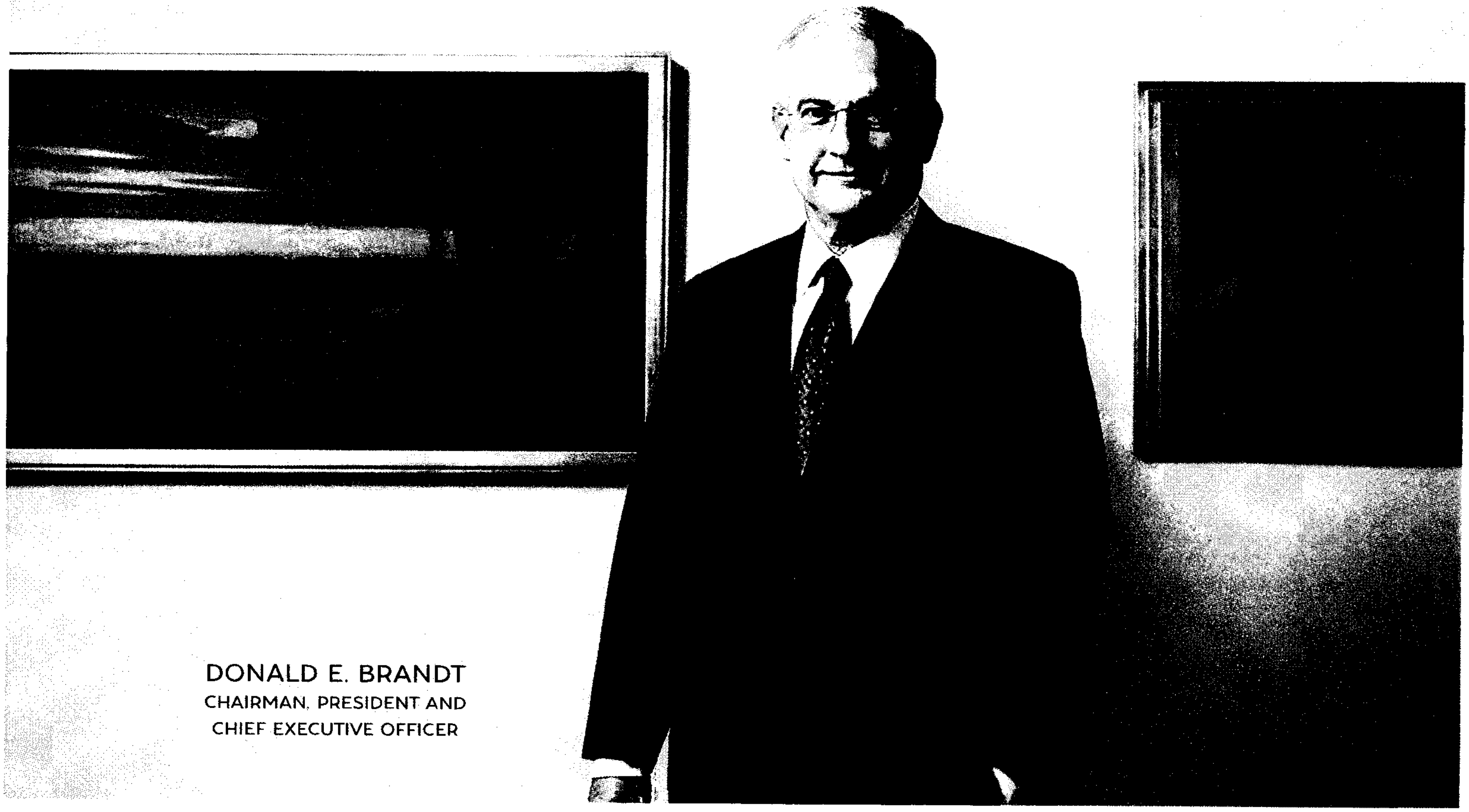
Significantly, we continued to provide our investors with the steady dividend growth which makes our equity attractive in uncertain times. Our Board of Directors approved an increase for the fourth straight year, raising our annual dividend by 5 percent to $2.50 per share.

In difficult market conditions for electric utility equities, the price of Pinnacle West shares declined during 2015 from record highs at the beginning of the year. The company delivered a total return to our shareholders – a combination of share price movement and dividends paid – of (2.0) percent, 42.1 percent and 91.3 percent over the last one, three and five years ending December 31. These results compare favorably with the S&P 1500 Electric Utility Index returns of (5.2) percent, 35.1 percent and 64.0 percent for the same periods.

Pinnacle West shares have performed well thus far in 2016, rising 6.7 percent in value since the beginning of the year to $68.83 per share as of February 29.

Our efforts to strengthen the company's balance sheet continue to produce positive results. Credit rating agencies Fitch and Moody's both upgraded the company in 2015. All three major agencies now rate Pinnacle West the equivalent of A-, the best our credit ratings have been in 30 years.

Looking ahead, we anticipate 2016 earnings per share in the range of $3.90 to $4.10, assuming normal weather. We aim to achieve a return on equity of more than 9.5 percent and, subject to the Board's discretion, to increase the dividend at an annual rate of 5 percent.



DONALD E. BRANDT
CHAIRMAN, PRESIDENT AND
CHIEF EXECUTIVE OFFICER

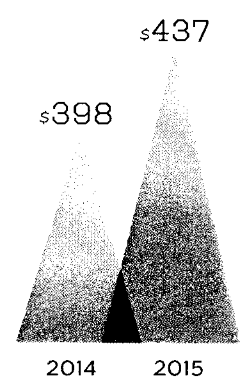
ECONOMIC GROWTH

Arizona's improving economic conditions, coupled with higher retail customer sales, enhanced our ability to deliver superior results for Pinnacle West shareholders in 2015.

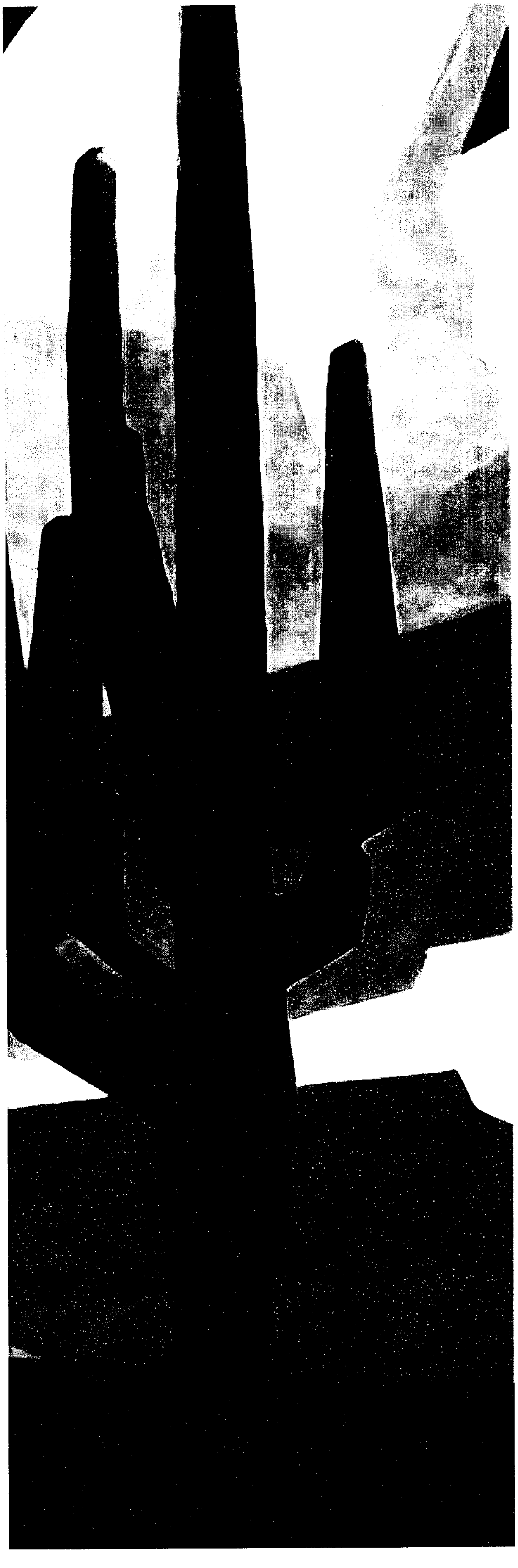
Despite the economic downturn that hit toward the end of the previous decade, Arizona's enduring long-term growth potential has always played an important role in our value proposition. In 2015, we saw further signs of healthy economic recovery.

9.5%

EARNINGS PER SHARE
INCREASE IN 2015



NET INCOME
IN MILLIONS



1,278

MW OF RENEWABLE ENERGY ON OUR SYSTEM

OUR STRONGEST YEAR FOR SALES GROWTH SINCE

2008

Job growth in the Phoenix metropolitan area has outpaced the national average for 18 consecutive quarters. This broad-based trend encompasses construction, healthcare, tourism, finance, business services and consumer services, with each adding jobs at a rate above 3 percent. Notably, the construction sector exceeded the other sectors by adding jobs in the last two quarters of 2015 at a rate of more than 7 percent.

In 2015, the Phoenix housing market recorded its best year since 2007 with nearly 22,000 new permits. Single-family permit activity increased almost 50 percent over the prior year.

Reflecting these improving economic conditions, our customer base grew 1.2 percent in 2015. Weather-adjusted sales increased 0.7 percent, demonstrating that customer and usage growth has overcome the effects of energy efficiency and distributed generation initiatives. 2015 saw the strongest year for sales growth since 2008.

SUPERIOR RELIABILITY AND SERVICE

Arizona Public Service has powered the recovery with service ranked among the industry's leaders in reliability, customer satisfaction and workplace safety. We produce electricity from a diverse, high-performing and increasingly clean portfolio of generation. We have deep roots in our community, giving back more than $10 million in 2015 to charitable causes across Arizona.

We invested $1 billion in 2015 to enhance the Arizona power grid and improve our ability to serve customers, and we plan to invest an additional $3.6 billion in infrastructure enhancements over the next three years. These investments will create value for our customers, benefit Arizona's economy, and drive projected annual rate base growth of 6 to 7 percent through 2018.

APS has three essential elements to its business model, directed at both customers and shareholders. These include:

OUTSTANDING RELIABILITY FOR OUR CUSTOMERS.
APS's electric reliability remained near the top of our industry in 2015, despite one of the most challenging summer storm seasons in recent Arizona history. Our average customer experienced less than one outage – 0.82 per customer – compared to an industry median of 1.025 interruptions.

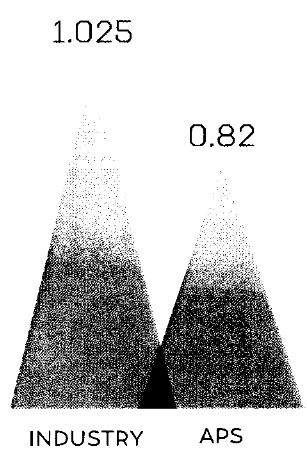
One of our important reliability investments in 2015 was a 110-mile transmission line from the Phoenix metropolitan area to Yuma.

$1 BILLION

INVESTED IN 2015 TO ENHANCE THE ARIZONA POWER GRID

6–7%

PROJECTED ANNUAL RATE BASE GROWTH THROUGH 2018



OUTAGES PER CUSTOMER

The 500-kilovolt line, energized in May 2015, will improve reliability for Yuma customers and strengthen the high-voltage power grid. The transmission construction project was one of the largest in the West, and the largest completed by APS in more than 25 years. Over the next three years we plan to invest $450 million enhancing Arizona's transmission system.

SUPERIOR AND IMPROVING CUSTOMER SATISFACTION. APS ranked in the top 10 for customer satisfaction again in 2015 among large investor-owned utilities, according to J.D. Power and Associates. Satisfaction ratings improved for the third consecutive year.

We introduced new programs and initiatives in 2015 that respond directly to the requests and needs of our customers. Our new APS Notification Center, which provides our customers with information via their smartphones about their electricity usage, billing, and restoration times during power outages, meets these new technological demands.

FORWARD-THINKING GRID MODERNIZATION. We have invested in advanced technologies that enhance system reliability and resilience, and enable future innovations in customer service. These projects, along with our fully deployed advanced meter program, will ensure APS stays at the forefront of grid modernization and can adapt to future requirements more easily.

In November, we announced a partnership with the Department of the Navy to develop a 25-megawatt microgrid project at Marine Corps Air Station Yuma. A microgrid is a term used to describe a small-scale power grid that can operate independently or in conjunction with the area's main electrical grid. This is APS's first microgrid project and the first military base to secure 100 percent backup power. We also plan to install a 40-megawatt solar facility this year to serve some of our large customers.

Technology advances also create new opportunities for utilities to interact with each other for the benefit of our customers. In 2015, we announced plans to join the California Independent System Operator's Energy Imbalance Market. When we begin participation later this year, it will give us more flexibility to manage our energy resources, producing an estimated savings for our customers of between $7 million and $18 million per year.

RANKED IN **TOP 10** FOR CUSTOMER SATISFACTION

HIGH-PERFORMING, CLEANER ENERGY MIX

The electricity we provided our customers in 2015 came from a diverse mix of high-performing and increasingly clean generation. Approximately 47 percent of our energy mix comes from carbon-free resources.

The four main components of our generation capacity include:

NUCLEAR. A vital part of our clean, carbon-free power is generated at the focal point of our fleet: Palo Verde Nuclear Generating Station. The nation's largest producer of power of any kind for 24 years running, Palo Verde had a stellar 2015, achieving its highest-ever net generation, a record 32.5 million megawatt-hours of electricity.

Our team at Palo Verde has taken a leading role in the industry response to the severe natural disaster in Japan in 2011 and the resulting accident at the Fukushima Daiichi nuclear plant. We completed a significant number of enhancements in 2015, investing $125 million in new equipment and modifications to existing facilities to make a safe plant even safer.

COAL. A large number of factors have made us re-examine the role of our coal plants. While federal environmental policy tops the list, economic conditions strongly affect our generation mix. Sustained low gas prices allow us to save money for our customers by reducing coal generation in favor of natural gas. And, America's growing reliance on renewable energy requires the support of flexible generation capable of ramping up and down frequently – something base-load coal facilities do inefficiently.

We must make prudent decisions for our customers and shareholders, while also recognizing the community impacts.

2/3

OF THE WATER USED BY ALL OUR GENERATING FACILITIES COMES FROM RECLAIMED WATER

PALO VERDE

24 YEARS

AS NATION'S LARGEST POWER PRODUCER

47%

OF ELECTRICITY WE PROVIDE COMES FROM CARBON-FREE RESOURCES

WE HAVE INVESTED IN ADVANCED TECHNOLOGIES THAT ENHANCE SYSTEM RELIABILITY AND RESILIENCE, AND ENABLE FUTURE INNOVATIONS IN CUSTOMER SERVICE.

In 2015 we made the decision to close one of three units we own at the Cholla Power Plant. This followed our 2013 closure of the three oldest, least efficient units at our Four Corners Power Plant. These two actions retired 820 megawatts of coal generation, resulting in a 29 percent reduction in carbon emissions from the plants. We also anticipate reductions in mercury emissions of 63 percent, particulates by 43 percent, NO_x by 36 percent and SO_2 by 29 percent.

To meet federal environmental standards, we plan to spend $400 million through 2018 to install selective catalytic reduction pollution controls on the two remaining units at Four Corners, reducing regional haze.

RENEWABLES. Although nuclear power accounts for most of our carbon-free generation, our growing renewable portfolio contributes 1,278 megawatts to that mix. We completed two utility-scale solar plants in 2015: one at Arizona's Luke Air Force Base, and the other an innovative partnership with the City of Phoenix to build a solar plant on top of a former landfill.

These projects concluded our AZ Sun program, which now generates 170 megawatts from nine solar installations across Arizona and brings our overall solar portfolio to 950 megawatts. The program has advanced Arizona's solar leadership, evidenced by the state's number two spot in the nation for overall solar growth as measured by the Solar Electric Power Association.

To advance our leadership in sustainable solar power, APS launched innovative research and development programs in 2015, including our Solar Partner Program, which is installing solar panels on 1,500 customer homes across the Phoenix metro area. The program, the first and largest of its kind in the country, studies solar production in late afternoons as the sun sets, but when customer energy use peaks.

NATURAL GAS. Many people assume in our sunny climate that solar will dependably supply a major portion of our customers' electricity needs. Unfortunately, the sun does not shine to suit our schedule, nor does it necessarily coincide with our customers' electricity demands.

In fact, on the peak customer electricity demand day of 2015, rooftop solar generation did not correspond optimally to customer demand by any measure. Rather, rooftop solar generation peaked at about the noon hour, well before customer demand surged. Our customers' thirst for electricity peaked at 5 p.m., a striking five-hour imbalance. At exactly the same time, rooftop solar generation had declined to only 38 percent of its capacity, and continued falling to zero by 7 p.m., while customer demand remained intense, exceeding the level at noon. That's right, zero! Even in Arizona, the sun does not shine on cue.

This example demonstrates why we need to back up renewable energy with reliable power sources. And, today, that means natural gas.

We are investing $500 million through 2019 to modernize our Ocotillo Power Plant in Tempe, replacing two 1960s-era units with five efficient combustion turbines that can start up and reach full power in less than 10 minutes.

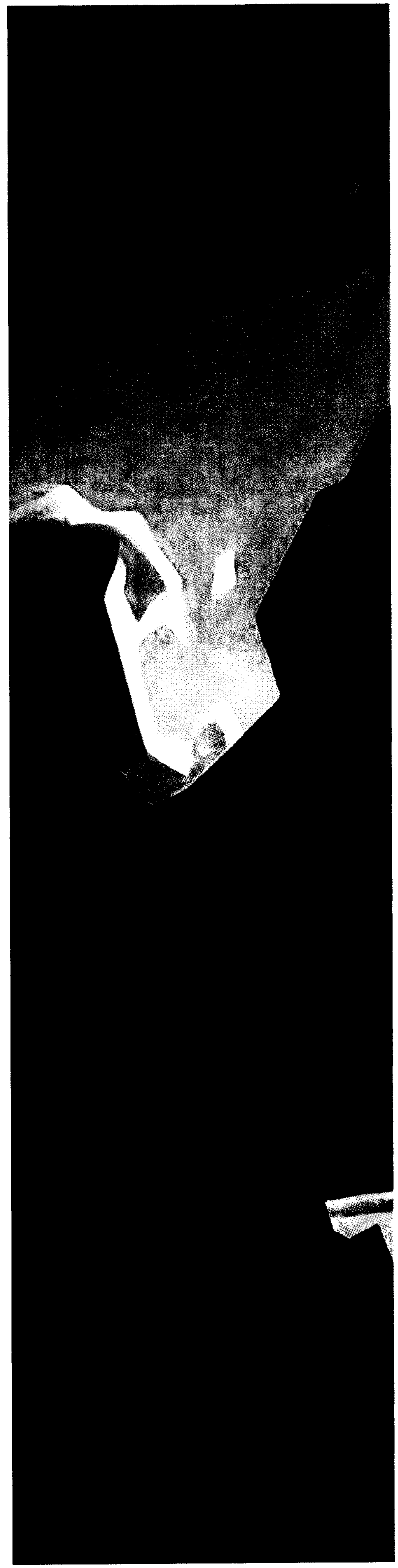
WE ARE INVESTING

$500 MILLION

TO MODERNIZE OUR OCOTILLO POWER PLANT

The Ocotillo project will enable and support the continued growth of renewable resources. The units will also be smaller and quieter and, thanks to an innovative cooling approach, will use 80 percent less water per megawatt-hour.

Recognizing the importance of being good stewards of the state's precious water resources, we added water usage to our top corporate metrics in 2015. We are already a leader in water conservation, with more than two-thirds of the water used by our generating fleet coming from reclaimed water. Palo Verde alone recycles nearly 20 billion gallons of wastewater each year, using no groundwater for its operations.



An important part of our request will be a suggested change in the design of electricity rates. We want to align prices more closely with costs, and to create clear price signals that support cost-reducing customer technologies.

We were the first in the country to raise the issue of rate reform in a serious way. We take pride in that leadership. Now, others in our industry have joined the effort to address rate restructuring. In 2015, the Nevada Public Utilities Commission ruled unanimously to pass a new rate structure that removes much of the unfairness from that state's net metering rules. The Nevada decision follows last year's ruling in Hawaii that closed the state's net metering program to new solar customers.

COMMUNITY UPDATE

I see our employees as the company's greatest asset. They possess incomparable work expertise and a time-proven commitment to improving the communities where we live and do business. They have demonstrated great generosity with their time, resources and skills, volunteering 127,000 hours during the year – valued at $2.9 million – and contributing $3.9 million to Arizona non-profits through our community services fund. We must add this marvelous effort on the part of our employees to the more than $10 million APS gave back to the community through corporate giving and the APS Foundation.

The future of APS lies in good hands. We have a history of developing the leaders of tomorrow, and unlocking potential in people and places that sometimes get overlooked.

For example, our commitment to veteran support underlines our philosophy of hiring the best and the brightest. When employers know how to translate the leadership and experience these men and women gain in the military into their own businesses, they open up opportunities not only for those they hire, but for the future of their companies. At APS, veterans make up 20 percent of our workforce. They come to us ready to work, grow and shoulder responsibility. We have a stronger future and company because of them.

127,000
HOURS
VOLUNTEERED BY APS EMPLOYEES

$10
MILLION
GIVEN BACK TO THE
COMMUNITY IN 2015

Beyond our employee base, our business relies on partnerships with vendors and suppliers from across Arizona and around the world. We see great value in creating opportunities that promote an equal chance for success, and in 2015 the Edison Electric Institute's Supplier Diversity Executive Council recognized our program's innovation and excellence. Last year, we spent more than $395 million with diverse suppliers – the highest total in our program's 23-year history.

The years ahead promise to bring change to the way we do business, from the way our company generates electricity, to how it flows to and from our customers, and to the way our rates are structured to ensure fairness.

I have great optimism about these future changes and challenges. Your company has the resources and strengths to address them and flourish. We will continue to be a driving force in the communities we serve, nurture constructive relationships with our regulators, and ensure a solid future for APS and Pinnacle West by developing our leaders of tomorrow.

Thank you for your investment.

DONALD E. BRANDT
CHAIRMAN, PRESIDENT AND
CHIEF EXECUTIVE OFFICER

FINANCIAL INFORMATION

BOARD MEMBERS & OFFICERS

PINNACLE WEST BOARD MEMBERS

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

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

RICHARD P. FOX 2014
Independent Business Consultant

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

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

DALE E. KLEIN, PH.D. 2010
Associate Director of the Energy Institute, University of Texas at Austin; Associate Vice Chancellor for Research, University of Texas System; Former Chairman, U.S. Nuclear Regulatory Commission

HUMBERTO S. LOPEZ 1995
President, HSL Properties, Inc.

KATHRYN L. MUNRO 1999
Principal, BridgeWest LLC

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

DAVID P. WAGENER 2014
Managing Partner, Wagener Capital Management

PINNACLE WEST OFFICERS

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

DAVID P. FALCK 2009
Executive Vice President & General Counsel

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

ROBERT S. AIKEN 1986
Vice President, Federal Affairs

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

LEE R. NICKLOY 2010
Vice President & Treasurer

DIANE WOOD 1998
Secretary

ARIZONA PUBLIC SERVICE OFFICERS

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

RANDALL K. EDINGTON 2007
Executive Vice President & Chief Nuclear Officer, Palo Verde Nuclear Generating Station

DAVID P. FALCK
Executive Vice President & General Counsel

JAMES R. HATFIELD
Executive Vice President & Chief Financial Officer

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

ROBERT S. BEMENT 2007
Senior Vice President, Site Operations, Palo Verde Nuclear Generating Station

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

JEFFREY B. GULDNER 2004
Senior Vice President, Public Policy

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

DWIGHT C. MIMS 2007*
Senior Vice President, Regulatory & Oversight, Palo Verde Nuclear Generating Station

ANN C. BECKER 2001
Vice President, Environmental & Chief Sustainability Officer

JOHN J. CADOGAN 2009
Vice President, Nuclear Engineering, Palo Verde Nuclear Generating Station

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

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

PATRICK DINKEL 1986
Vice President, Transmission & Distribution Operations

DONNA M. EASTERLY 1984
Vice President, Chief Procurement Officer

BARBARA M. GOMEZ 1978
Vice President, Human Resources

DAVID A. HANSEN 1980
Vice President, Fossil Generation

JOHN S. HATFIELD 2010
Vice President, Communications

BRYAN KEARNEY 2014
Vice President & Chief Information Officer

BARBARA D. LOCKWOOD 1999
Vice President, Regulation

TAMMY D. MCLEOD 1995
Vice President, Resource Management

LEE R. NICKLOY
Vice President & Treasurer

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

DIANE WOOD
Secretary

**Retiring October 2016*

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

PUBLIC POLICY

Earlier this year we notified the Arizona Corporation Commission that we plan to file a request in June 2016 for an adjustment to our rates. If approved, the changes would likely take effect in 2017. Five years have passed since our last request.

We have begun meeting with stakeholders to preview the issues that will be addressed in our filing. Long-time investors in Pinnacle West will recall that APS concluded its last two rate cases constructively through settlement agreements. We always pursue an equitable and harmonious resolution of these matters. However, we anticipate this year might be more contentious due to the expected participation of the national rooftop solar leasing companies. These companies have a vested financial interest in delay and a track record of disrupting regulatory proceedings across the country.

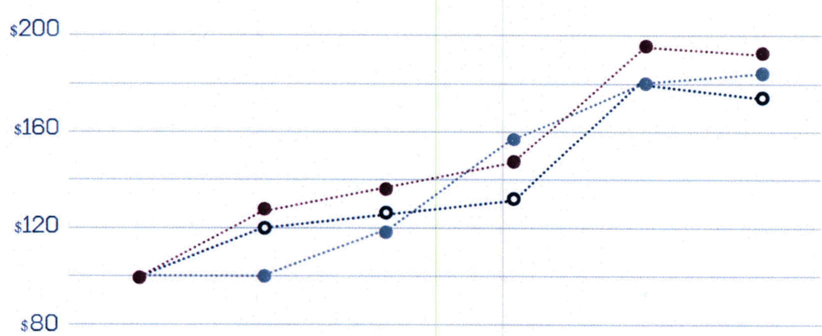
PINNACLE WEST HIGHLIGHTS

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

	2015	2014	2013
STOCK SUMMARY			
Stock price per share — year-end	$64.48	$68.31	$52.92
Market capitalization — year-end	$7,156	$7,553	$5,831
Common shares outstanding — year-end	111.1	110.6	110.2
PER SHARE HIGHLIGHTS (DILUTED)			
Earnings per share — net income attributable to common shareholders	$3.92	$3.58	$3.66
Indicated annual dividend — year-end	$2.50	$2.38	$2.27
CAPITAL EXPENDITURES	$1,060	$883	$986
OPERATING STATISTICS			
Retail electric sales (GWh)	27,951	27,585	28,088
Total electric sales (GWh)	34,291	32,781	31,864
Average retail revenue (per kWh)	11.76¢	11.60¢	11.51¢
Generating capacity owned or leased — year-end (MW)	6,186	6,426	6,394
Generation output (GWh)	27,452	26,922	26,173
System peak load (MW)	7,031	7,007	6,927
Electric customers — year-end	1,190,242	1,174,760	1,161,026
Employees — year-end	6,407	6,366	6,433

STOCK PERFORMANCE COMPARISON

(value of $100 invested as of December 31, 2010, with dividends reinvested)



	2010	2011	2012	2013	2014	2015
PINNACLE WEST COMMON STOCK	$100	$122	$134	$145	$195	$191
EDISON ELECTRIC INSTITUTE INDEX	$100	$120	$122	$138	$178	$171
S&P 500 INDEX	$100	$102	$118	$157	$178	$181

CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(dollars in millions)

	2015	2014	2013
Year Ended December 31,			
CONDENSED CONSOLIDATED STATEMENTS OF INCOME			
Operating revenues	$3,496	$3,492	$3,455
Fuel and purchased power	(1,101)	(1,180)	(1,096)
Other operating expenses	(1,540)	(1,501)	(1,513)
Operating income	855	811	846
Net other income	18	19	11
Interest expense	(179)	(185)	(187)
Income taxes	(238)	(221)	(230)
Net income	456	424	440
Less: Net income attributable to noncontrolling interests	19	26	34
Net income attributable to common shareholders	$437	$398	$406
December 31,			
CONDENSED CONSOLIDATED BALANCE SHEETS			
Assets			
Current assets	$890	$974	$1,044
Investments and other assets	800	786	727
Property, plant and equipment - net	11,809	11,194	10,889
Deferred debits	1,529	1,335	827
Total assets	$15,028	$14,289	$13,487
Liabilities and Equity			
Current liabilities, excluding current maturities of long-term debt	$1,085	$1,176	$1,078
Long-term debt	3,820	3,390	3,315
Deferred credits and other	5,404	5,204	4,753
Total equity	4,719	4,519	4,341
Total liabilities and equity	$15,028	$14,289	$13,487
Year Ended December 31,			
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS			
Cash and cash equivalents at beginning of year	$8	$10	$26
Net cash flow provided by operating activities	1,094	1,100	1,153
Net cash flow used for investing activities	(1,066)	(923)	(1,009)
Net cash flow provided by (used for) financing activities	4	(179)	(160)
Cash and cash equivalents at end of year	$40	$8	$10

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

FORWARD-LOOKING STATEMENTS

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

SHAREHOLDER INFORMATION

INVESTORS ADVANTAGE PLAN AND SHAREHOLDER ACCOUNT INFORMATION

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

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

FORM 10-K

Pinnacle West's 2015 Annual Report on Form 10-K filed with the Securities and Exchange Commission is available on our website or by writing to the Office of the Secretary.

STATISTICAL REPORT

A detailed Statistical Report for Financial Analysis for 2011 to 2015 is available on our website.

CORPORATE RESPONSIBILITY REPORT

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

INVESTOR RELATIONS CONTACT

Paul Mountain (602) 250-4952

ADMINISTRATIVE INFORMATION

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

ANNUAL MEETING OF SHAREHOLDERS

May 18, 2016 10:30 a.m. (MST)
Heard Museum
2301 North Central Ave.
Phoenix, Arizona 85004

CORPORATE HEADQUARTERS

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

CORPORATE WEBSITE

pinnaclewest.com

STOCK LISTING

Ticker symbol:
PNW on New York
Stock Exchange

TRANSFER AGENT AND REGISTRAR

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

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

DOCUMENTS INCORPORATED BY REFERENCE

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

For the fiscal year ended December 31, 2015

OR

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

For the transition period from to

Commission File Number	Registrants; State of Incorporation; Addresses; 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	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	New York Stock Exchange
ARIZONA PUBLIC SERVICE COMPANY	None	None

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

ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value $2.50 per share

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

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐

ARIZONA PUBLIC SERVICE COMPANY Yes ☒ No ☐

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

PINNACLE WEST CAPITAL CORPORATION Yes ☐ No ☒

ARIZONA PUBLIC SERVICE COMPANY Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐

ARIZONA PUBLIC SERVICE COMPANY Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION Yes ☒ No ☐

ARIZONA PUBLIC SERVICE COMPANY Yes ☒ No ☐

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

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

PINNACLE WEST CAPITAL CORPORATION

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

ARIZONA PUBLIC SERVICE COMPANY

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

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

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

PINNACLE WEST CAPITAL CORPORATION $6,271,269,171 as of June 30, 2015

ARIZONA PUBLIC SERVICE COMPANY $0 as of June 30, 2015

The number of shares outstanding of each registrant's common stock as of February 12, 2016

PINNACLE WEST CAPITAL CORPORATION 111,004,916 shares

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

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 18, 2016 are incorporated by reference into Part III hereof.

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

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

GLOSSARY OF NAMES AND TECHNICAL TERMS

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

FORWARD-LOOKING STATEMENTS

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

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

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

PART I

ITEM 1. BUSINESS

Pinnacle West

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

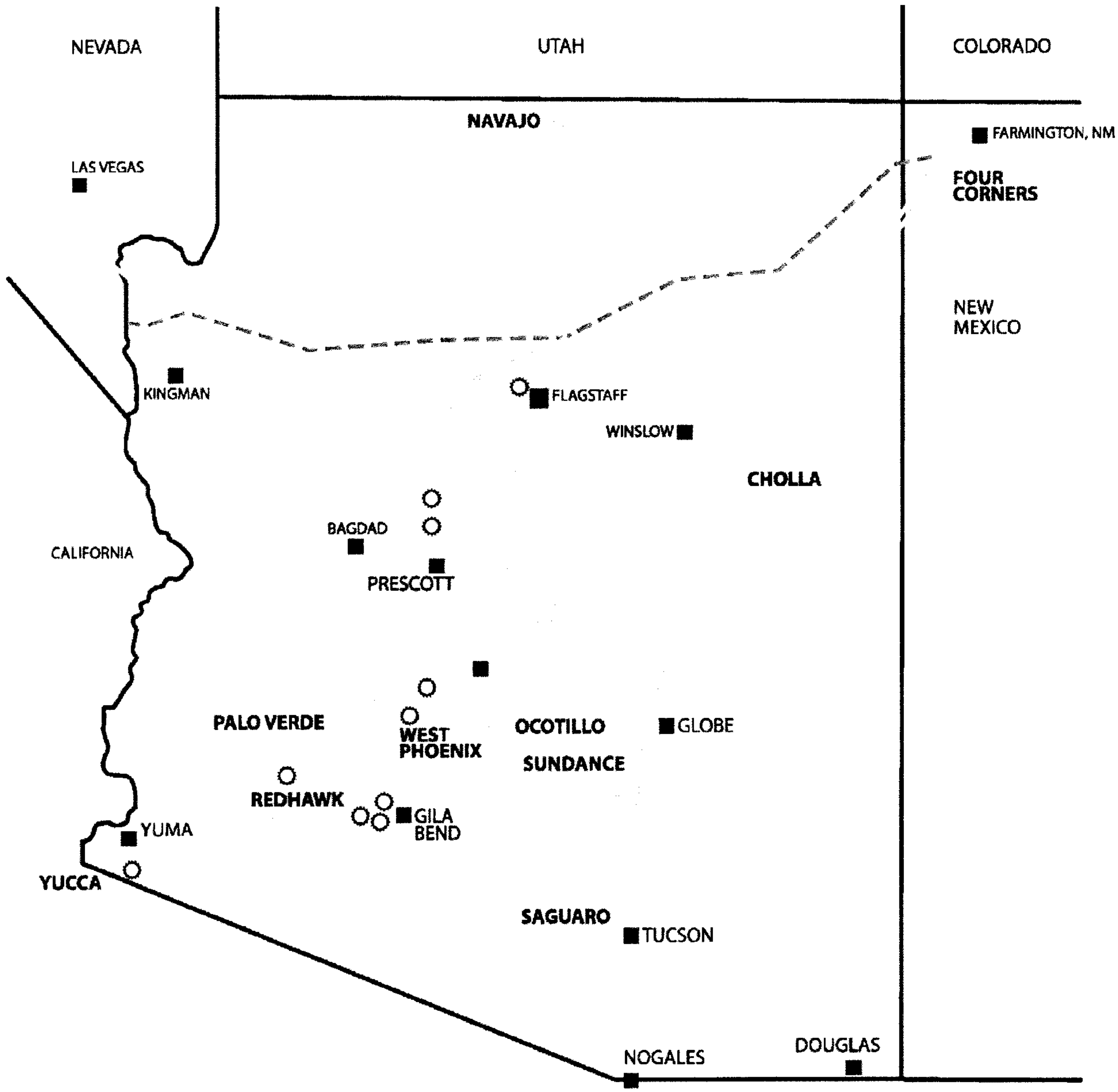
Pinnacle West's other subsidiaries are El Dorado and BCE. Additional information related to these subsidiaries is provided later in this report.

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

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

APS currently provides electric service to approximately 1.2 million customers. We own or lease 6,186 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 2015, no single purchaser or user of energy accounted for more than 1.3% of our electric revenues.

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



APS Retail Electric Service Territory

Major APS Power Plants

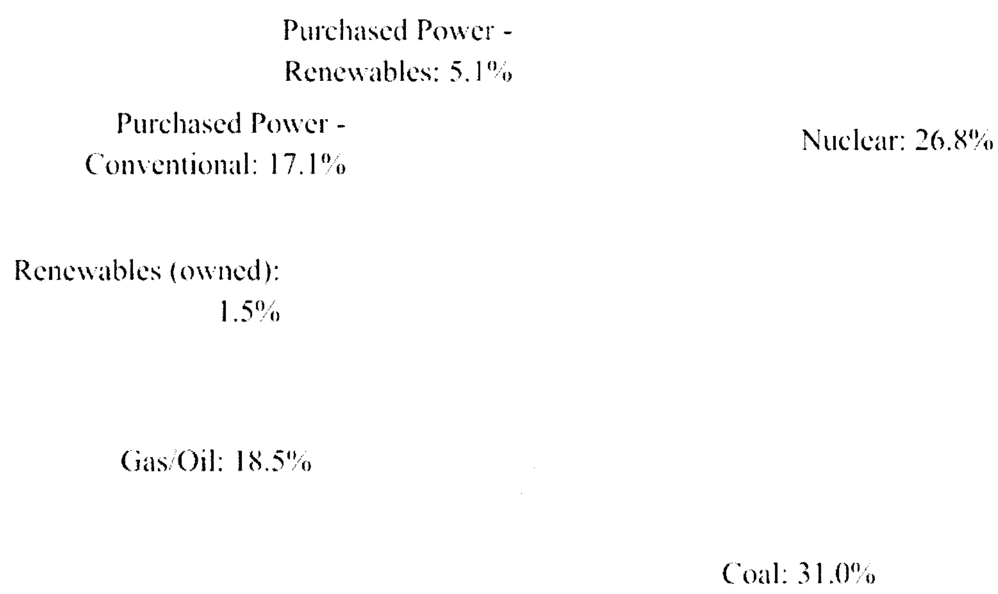
Principal APS Transmission Lines

Transmission Lines Operated for Others

APS Solar Power Plants

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 2015 were as follows:



Generation Facilities

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

Coal-Fueled Generating Facilities

Four Corners — Four Corners was originally a 5-unit coal-fired power plant, which is located in the northwestern corner of New Mexico. APS operates the plant and owns 100% of Four Corners Units 1, 2 and 3 and 63% of Four Corners Units 4 and 5 following the acquisition of SCE's interest in Units 4 and 5 described below. As of December 30, 2013, APS retired Units 1, 2 and 3. APS has a total entitlement from Four Corners of 970 MW.

On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for SCE's interest was approximately $182 million. In connection with APS's most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustment was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed in Note 3, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031 (the "2016 Coal Supply Agreement"). El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has 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. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

EPA, in its final regional haze rule for Four Corners, required the Four Corners' owners to elect one of two emissions alternatives to apply to the plant. On December 30, 2013, APS, on behalf of the co-owners, notified EPA that they chose the alternative BART compliance strategy requiring the permanent closure of Units 1, 2 and 3 by January 1, 2014 and installation and operation of SCR controls on Units 4 and 5 by July 31, 2018. On December 30, 2013, APS retired Units 1, 2 and 3.

The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. 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 the DOI of a record of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

In 2012, several environmental groups filed a lawsuit in federal district court against OSM challenging OSM's 2012 approval of a permit revision which allowed for the expansion of mining operations into a new area of the mine that serves Four Corners ("Area IV North"). In April 2015, the court issued an order invalidating the permit revision, thereby prohibiting mining in Area IV North until OSM takes action to cure the defect in its permitting process identified by the court. On December 29, 2015, OSM took action to cure the defect in its permitting process by issuing a revised environmental assessment and finding of no new significant impact, and reissued the permit. This action is subject to possible judicial review.

Cholla — Cholla was originally a 4-unit coal-fired power plant, which is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operates that unit for PacifiCorp. On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 387 MW.

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 long-term coal transportation contract that runs through 2017. See "Current and Future Resources - Future Resources and Resource Plan" below for a discussion of future plans for Cholla.

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

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

Nuclear

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

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

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

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

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

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates and conversion services through 2018 and 45% of its requirements in 2019-2025. The participants have also contracted for 100% of Palo Verde's enrichment services through 2020 and 20% of its enrichment services for 2021-2026; and all of Palo Verde's fuel assembly fabrication services through 2022.

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

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

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE. This lawsuit sought to recover damages incurred due to DOE's failure to accept Palo Verde's spent nuclear fuel for the period beginning January 1, 2007 through June 30, 2011. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million.

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, was for $42.0 million (APS's share of this amount was $12.2 million), and payment was received on June 1, 2015. APS's second claim made pursuant to the terms of the August 18, 2014, settlement agreement, which was for the period July 1, 2014 through June 30, 2015, and was for $12.0 million (APS's share of this amount is $3.6 million), was submitted to the DOE on November 2, 2015. The second claim is presently being reviewed by DOE.

Amounts recovered in the lawsuit and settlement were recorded as adjustments to regulatory liability and had no impact on current income.

The One-Mill Fee — In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE's 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the "one-mill fee") paid by the nation's commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by APS in its retail rates. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE ("Secretary") with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE's revised one-mill fee adequacy determination, the D.C. Circuit reopened the proceedings. On November 19, 2013, the D.C. Circuit found that the DOE did not conduct a legally adequate fee assessment and ordered the Secretary to notify Congress of his intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the D.C. Circuit's order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress' disapproval. On May 16, 2014, the DOE notified all commercial nuclear power plant operators who are party to a Standard Contract that it reduced the one-mill fee to zero, thus effectively terminating the one-mill fee.

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

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

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

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

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

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

On September 6, 2012, the NRC Commissioners issued a directive to the NRC staff to proceed directly with development of a generic environmental impact statement to support an updated Waste Confidence Decision. The NRC Commissioners also directed the staff to establish a schedule to publish a final rule and environmental impact study within 24 months of September 6, 2012.

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

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

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

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

Impact of Earthquake and Tsunami in Japan on Nuclear Energy Industry — On March 11, 2011, an earthquake measuring 9.0 on the Richter Scale occurred off the coast of Japan causing a series of seven tsunamis. As a result, the Fukushima Daiichi Nuclear Power Station experienced severe damage.

Following the earthquake and tsunamis, the NRC established a task force to conduct a systematic and methodical review of NRC processes and regulations to determine whether the agency should make additional improvements to its regulatory system. On March 12, 2012, the NRC issued the first regulatory requirements based on the recommendations of the Near Term Task Force. With respect to Palo Verde, the NRC issued two orders requiring safety enhancements regarding: (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at the plant; and (2) enhancement of spent fuel pool instrumentation.

The NRC has issued a number of guidance documents regarding implementation of these requirements. Palo Verde has met the NRC's imposed deadlines for installation of equipment to address these requirements, but has minor additional work to perform in 2016. Palo Verde has spent approximately $125 million on capital enhancements as of December 31, 2015 (APS's share is 29.1%).

Natural Gas and Oil Fueled Generating Facilities

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe (discussed below); Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has one oil-only power plant, Douglas, located in the town of Douglas, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,179 MW. Gas for these plants is financially hedged up to three years in advance of purchasing and the gas is generally purchased one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2024. Fuel oil is acquired under short-term purchases delivered primarily to West Phoenix, where it is distributed to APS's other oil power plants by truck.

Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction begins.

Solar Facilities

To date, APS has begun operation of 170 MW of utility scale solar through its AZ Sun Program, discussed below. These facilities are owned by APS and are located in multiple locations throughout Arizona.

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

In December 2014, the ACC voted that it had no objection to APS implementing a 10 MWdc (approximately 8.5 MWac) residential rooftop program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. Under this program, APS will own, operate and maintain approximately 1,500 residential systems. The program will target specific distribution feeders in an effort to maximize potential system benefits, while employing multiple "use cases" that will lead to a better understanding of the byproducts stemming from the multitude of complex technical interactions occurring as distributed energy resources are employed on the APS grid.

Purchased Power Contracts

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

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of December 31, 2015 is summarized in the table below. All capacity values are based on net capacity unless otherwise noted.

Type	Dates Available	Capacity (MW)
Purchase Agreement (a)	Year-round through June 14, 2020	60
Exchange Agreement (b)	May 15 to September 15 annually through 2020	480
Tolling Agreement	Year-round through May 2017	514
Tolling Agreement	Summer seasons through October 2019	560
Day-Ahead Call Option Agreement	Summer seasons through summer 2016	150
Demand Response Agreement (c)	Summer seasons through 2024	25
Renewable Energy (d)	Various	629

(a) Up to 60 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.

(b) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).

(c) The capacity under this agreement may be increased in 5 MW increments in each of 2015 and 2016 and 10 MW increments in years 2017 through 2024, up to a maximum of 50 MW.

(d) 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 2015 peak one-hour demand on its electric system was recorded on August 15, 2015 at 7,031 MW, compared to the 2014 peak of 7,007 MW recorded on July 23, 2014. APS's reserve margin at the time of the 2015 peak demand, calculated using system load serving capacity, was 28%. Excluding certain contractual rights to call on additional capacity on short notice, which APS may use in the event of unusual weather or unplanned outages, the 2015 reserve margin was 21%. APS anticipates the reserve margin for 2016 will be approximately 24%. Due to expiring purchase contracts and anticipated load growth, APS anticipates additional resources will be needed by 2017 in order to maintain its 15% planning reserve criteria.

Future Resources and Resource Plan

On May 8, 2015, the ACC acknowledged APS's 2014 resource plan. Under the ACC's resource planning rule, APS's next resource plan would be due on April 1, 2016. On September 16, 2015, however, the ACC issued an order extending the timeframe for all utilities, including APS, to file their next resource plans. The new schedule is designed to allow utilities additional time to consider the impacts of the Clean Power Plan and improve the resource planning process by allowing more time for input and review by the ACC and applicable stakeholders. Under the revised schedule, APS will file a preliminary resource plan on March 1, 2016 and a final resource plan on April 3, 2017. The revised schedule provides that the ACC will complete its review by February 1, 2018.

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

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 6% of retail electric sales in 2016 and increases annually until it reaches 15% in 2025. In APS's 2009 retail rate case settlement agreement (the "2009 Settlement Agreement"), APS committed to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2015.

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 6% in 2016. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

	2016	2020	2025
RES as a % of retail electric sales	**6%**	**10%**	**15%**
Percent of RES to be supplied from distributed energy resources	30%	30%	30%

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,328 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,278 MW are currently in operation and 50 MW are under contract for development or are under construction. Renewable resources in operation include 189 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 427 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. In September 2015, APS completed construction of its 170 MW AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. See Note 3 for additional details about the AZ Sun Program.

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

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/ Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	Gila Bend, AZ	2011		17	
Cotton Center	Gila Bend, AZ	2011		17	
Hyder Phase 1	Hyder, AZ	2011		11	
Hyder Phase 2	Hyder, AZ	2012		5	
Chino Valley	Chino Valley, AZ	2012		19	
Hyder II	Hyder, AZ	2013		14	
Foothills	Yuma, AZ	2013		35	
Gila Bend	Gila Bend, AZ	2014		32	
Luke AFB	Glendale, AZ	2015		10	
Desert Star	Buckeye, AZ	2015		10	
Subtotal AZ Sun Program				170	
Multiple Facilities	AZ	Various		4	
Distributed Energy:					
APS Owned (a)	AZ	Various		15	9 (c)
Total APS Owned				189	9
Purchased Power Agreements					
Solar:					
Solana	Gila Bend, AZ	2013	30	250	
RE Ajo	Ajo, AZ	2011	25	5	
Sun E AZ 1	Prescott, AZ	2011	30	10	
Saddle Mountain	Tonopah, AZ	2012	30	15	
Badger	Tonopah, AZ	2013	30	15	
Gillespie	Maricopa County, AZ	2013	30	15	
Wind:					
Aragonne Mesa	Santa Rosa, NM	2006	20	90	
High Lonesome	Mountainair, NM	2009	30	100	
Perrin Ranch Wind	Williams, AZ	2012	25	99	
Geothermal:					
Salton Sea	Imperial County, CA	2006	23	10	
Biomass:					
Snowflake	Snowflake, AZ	2008	15	14	
Biogas:					
Glendale Landfill	Glendale, AZ	2010	20	3	
NW Regional Landfill	Surprise, AZ	2012	20	3	
Total Purchased Power Agreements				629	—
Distributed Energy					
Solar (b)					
Third-party Owned	AZ	Various		427	41
Agreement 1	Bagdad, AZ	2011	25	15	
Agreement 2	AZ	2011-2012	20-21	18	
Total Distributed Energy				460	41
Total Renewable Portfolio				1,278	50

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

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

(c) This amount represents the Solar Partner Program consisting of approximately 1,500 APS-owned rooftop solar systems. We are in the process of installing these systems and expect all to be installed and operational by mid-2016, at which time the 9 MW will be considered "in operation" for purposes of this table.

Demand Side Management

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

Government Awards

Through various DOE initiatives, the Federal government made a number of programs available for utilities to develop renewable resources, improve reliability and create jobs. In 2015, APS completed its work on a $3 million financial award for a high penetration photovoltaic generation study related to the Community Power Project in Flagstaff, Arizona.

Competitive Environment and Regulatory Oversight

Retail

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

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

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

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. As a result, as of January 1, 2001, all of APS's retail customers were eligible to choose alternate energy suppliers. Although some very limited retail competition existed in APS's service territory in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. In 2000, the Arizona Superior Court found that the rules were in part unconstitutional and in other respects unlawful, the latter finding being primarily on procedural grounds, and invalidated all ACC orders authorizing competitive electric services providers to operate in Arizona. In 2004, the Arizona Court of Appeals invalidated some, but not all of the rules and upheld the invalidation of the orders authorizing competitive electric service providers. In 2005, the Arizona Supreme Court declined to review the Court of Appeals' decision.

In 2008, the ACC directed the ACC staff to investigate whether such retail competition was in the public interest and what legal impediments remain to competition in light of the Court of Appeals' decision referenced above. The ACC staff's report on the results of its investigation was issued on August 12, 2010. The report stated that additional analysis, discussion and study of all aspects of the issue are required in order to perform a proper evaluation. While the report did not make any specific recommendations other than to conduct more workshops, the report did state that the current retail electric competition rules are incomplete and in need of modification.

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

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS's corporate affiliates have made contributions or donations under APS' brand name; and the degree to which APS and Pinnacle West are "intertwined" in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2015, approximately 5.2% of APS's electric operating revenues resulted from such sales and services. APS's wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS's Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and fuels. The majority of these activities are undertaken to mitigate risk in APS's portfolio.

Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent attempts by Congress to pass legislation that would regulate greenhouse gas ("GHG") emissions, and it is unclear whether the 114th Congress will consider a climate change bill. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is enacted and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide ("CO_2") equivalent emitted.

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

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

On June 2, 2014, EPA issued two proposed rules to regulate GHG emissions from modified and reconstructed electric generating units ("EGUs") pursuant to Section 111(b) of the Clean Air Act and existing fossil fuel-fired power plants pursuant to Clean Air Act Section 111(d). On August 3, 2015, EPA finalized each of these carbon pollution standards for existing, new, modified, and reconstructed EGUs.

EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

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

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

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

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

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

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

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

Company Response to Climate Change Initiatives. We have undertaken a number of initiatives that address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. (See "Energy Sources and Resource Planning - Current and Future Resources" above for details of these plans and initiatives.) APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass, and we expect the percentage of renewable energy in our resource portfolio to increase over the coming years.

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

EPA Environmental Regulation

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

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

Cholla. In 2007, ADEQ required APS to perform a BART analysis for Cholla pursuant to the Clean Air Visibility Rule. APS completed the BART analysis for Cholla and submitted its BART recommendations to ADEQ in early 2008. The recommendations include the installation of certain pollution control equipment that APS believes constitutes BART. ADEQ reviewed APS's recommendations and submitted its proposed BART State Implementation Plan ("SIP") for Cholla and other sources in Arizona in early 2011.

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ's BART emissions limits for sulfur dioxide ("SO_2") and emissions of particulate matter ("PM"), but added a SO_2 removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ's BART determinations for oxides of nitrogen ("NO_x") and promulgated a Federal Implementation Plan ("FIP") establishing a new, more stringent "bubbled" NO_x emission rate applicable to the two BART-eligible Cholla units owned by APS and the other BART-eligible unit owned by PacifiCorp.

APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 (which occurred on October 1, 2015) and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Four Corners. On August 6, 2012, EPA issued its final BART determination for Four Corners, which requires APS to install and operate SCR control technology on Units 4 and 5 by July 31, 2018. (APS retired Four Corners Units 1-3 on December 30, 2013.) APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016. In December 2015, NTEC notified APS of its intention to exercise its option to acquire the 7% interest from APS. The cost of the controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. On January 18, 2013, EPA issued a proposed BART rule for the Navajo Plant, which would require installation of SCR technology in order to achieve a new, more stringent plant-wide NO_x emission limit. In addition, EPA proposed a "better than BART" alternative and solicited comment on other options that could set longer time frames for installing pollution controls if the Navajo Plant can achieve additional emission reductions. On July 26, 2013, a group of stakeholders, including SRP, the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NO_x emission reductions and result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination. On July 28, 2014, EPA issued a final Navajo Plant BART rule approving the alternative stakeholder plan. Depending on which alternate operating scenario the Navajo Plant participants ultimately select, the required NO_x emission reductions could be achieved by either closing one of the three 750 MW units at the plant or curtailing energy production across all three units, such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe, and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this petition.

Mercury and other Hazardous Air Pollutants. In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excluding costs related to Cholla Unit 2, which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

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

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule's requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

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

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards ("NAAQS") at a level of 70 parts per billion ("ppb"). With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA is expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. Depending on when EPA approves attainment designations for the Arizona and Navajo Nation jurisdictions in which our fossil generation units are located, revisions to SIPs and FIPs, respectively, implementing required controls to achieve the new 70 ppb standard are expected to be in place between 2020 and 2021. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

Clean Air Act Citizen Lawsuit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's New Source Performance Standards ("NSPS") program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

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

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. 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.

Navajo Nation Environmental Issues

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

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

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

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

Water Supply

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its needs. However, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future operations of the plant. The effect of the drought cannot be fully assessed at this time, and APS cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

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

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

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

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

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

BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

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

El Dorado

El Dorado owns minority interests in several energy-related investments and Arizona community-based ventures. El Dorado's short-term goal is to prudently realize the value of its existing investments. As of December 31, 2015, El Dorado had total assets of approximately $9 million. El Dorado is not expected to contribute in any material way to our future financial performance, nor will it require any material amounts of capital over the next three years.

OTHER INFORMATION

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE is 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, 2015
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	93
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,309
BCE	400 North Fifth Street Phoenix, AZ 85004	2014	5
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—
Total			6,407

The APS number includes employees at jointly-owned generating facilities (approximately 2,830 employees) for which APS serves as the generating facility manager. Approximately 1,673 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW") or the United Security Professionals of America ("USPA"). APS concluded negotiations with IBEW representatives over the new collective bargaining agreement in April 2015, and the new agreement is in place until March 31, 2018. The contract provides an average wage increase of 2.0% for the first year, 2.25% for the second year and 3.0% for the third year. The Company concluded negotiations with the USPA over the terms of a new collective bargaining agreement in May of 2014, and the new agreement is in place until May 31, 2017.

WHERE TO FIND MORE INFORMATION

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

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

ITEM 1A. RISK FACTORS

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

REGULATORY RISKS

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

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

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

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

In a recent appellate challenge to an ACC rate decision regarding a water company (referred to in Note 3 as "SIB"), the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors or surcharges outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

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

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

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS's corporate affiliates have made contributions or donations under APS' brand name; and the degree to which APS and Pinnacle West are "intertwined" in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

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

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including Palo Verde. As a result of the March 2011 earthquake and tsunamis that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, various industry organizations analyzed information from the Japan incident and develop action plans for U.S. nuclear power plants. Additionally, the NRC performed its own independent review of the events at Fukushima Daiichi, including a review of the agency's processes and regulations in order to determine whether the agency should promulgate additional regulations and possibly make more fundamental changes to the NRC's system of regulation. As a result of the Fukushima event, the NRC has directed nuclear power plants to implement the first tier recommendations of the NRC's Near Term Task Force. In response to these recommendations, Palo Verde expects to spend approximately $0.5 million for capital enhancements to the plant over the next year in addition to the approximate $125 million that has already been spent on capital enhancements as of December 31, 2015 (APS's share is 29.1%). We cannot predict whether these amounts will increase or whether additional financial and/or operational requirements on Palo Verde and APS may be imposed.

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

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

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

Coal Ash. In December 2014, EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners and in a dry landfill storage area at the Navajo Plant. To the extent the rule requires the closure or modification of these CCR units or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal.

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

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

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

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

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

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

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

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

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

In 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. The use of such products by customers within our territory results in some level of competition. APS cannot predict when, and the extent to which, additional service providers will enter APS's service territory, increasing the level of competition in the market.

Proposals to enable or support retail electric competition are made from time to time in legislative or other forums in Arizona. We cannot predict future regulatory or legislative action that might result in increased competition.

OPERATIONAL RISKS

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

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

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

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

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement was 25% of the overall RES requirement of 3% in 2011 and increased to 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some or all of their own energy needs. Reduced demand due to these energy efficiency and distributed energy requirements, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

Customer and Sales Growth. For the three years 2013 through 2015, APS's retail customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. For the three years 2013 through 2015 APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2016 through 2018, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. Actual customer and sales growth may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Additionally, recovery of a substantial portion of our fixed costs of providing service is based upon the volumetric amount of our sales. If our customer growth rate does not continue to improve as projected, or if it declines, or if the Arizona economy fails to improve, we may be unable to reach our estimated demand level and sales projections, which could have a negative impact on our financial condition, results of operations and cash flows.

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

The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS's business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. 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. Concerns over physical security of these assets is also increasing, which may require us to incur additional capital and operating costs to address. Damage to certain of our facilities due to vandalism or other deliberate acts could lead to outages or other adverse effects.

The inability to successfully develop or acquire generation resources to meet reliability requirements, 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 certain regulatory approvals create uncertainty surrounding our generation portfolio. The current abundance of low, stably priced natural gas, together with environmental and other concerns surrounding coal-fired generation resources, create strategic questions related to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements such as the EES and the RES. The development of any generation facility is subject to many risks, including risks related to financing, siting, permitting, technology, the construction of sufficient transmission capacity to support these facilities and stresses to generation and transmission resources from intermittent generation characteristics of renewable resources.

APS's inability to adequately develop or acquire the necessary generation resources could have a material adverse impact on our business and results of operations.

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

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

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

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

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

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

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

Certain APS power plants and portions of the transmission lines that carry power from these plants 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 outcome of pending and future approvals by applicable governing bodies with respect to renewals of these leases, easements and rights-of-way.

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

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 19% of our owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $111 million (but not more than $16.6 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power plant in the United States. Although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

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

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

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

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

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

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

APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as established or mature as APS's existing technologies and equipment. Widespread installation and acceptance of new technologies could 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 business.

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 subsidies for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APS's existing generating facilities less economical and impact their operational patterns and long-term viability.

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

Like most companies in the electric utility industry, our workforce is maturing, with approximately 36% of employees eligible to retire by the end of 2018. Although we have undertaken efforts to recruit and train new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability of qualified personnel, the need to negotiate collective bargaining agreements with union employees and potential work stoppages. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

FINANCIAL RISKS

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

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

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

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

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

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

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

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

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

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

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

Employee healthcare costs in recent years have continued to rise. Most of the Patient Protection and Affordable Care Act provisions have been implemented; however, costs and other effects of the legislation, which may include the cost of compliance and potentially increased costs of providing for medical insurance for our employees, cannot be determined with certainty at this time.

Our cash flow depends on the performance of APS.

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

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

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

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

The market price of our common stock may be volatile.

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

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;

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

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

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

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

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of the Board of Directors and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise; and
- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2015 fiscal year and that remain unresolved.

ITEM 2. PROPERTIES

Generation Facilities

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

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1%	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 4, 5 (c)	2	63%	Coal	Base Load	970
Cholla (d)	2		Coal	Base Load	387
Navajo (e)	3	14%	Coal	Base Load	315
Ocotillo	2		Gas	Peaking	220
Total Steam					1,892
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo	2		Gas	Peaking	110
Saguaro 1, 2	2		Gas/Oil	Peaking	110
Saguaro 3	1		Gas	Peaking	79
Douglas	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas/Oil	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Cotton Center	1		Solar	As Available	17
Hyder	1		Solar	As Available	16
Paloma	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend	1		Solar	As Available	32
Hyder II	1		Solar	As Available	14
Foothills	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star	1		Solar	As Available	10
APS Owned Distributed Energy			Solar	As Available	15
Multiple facilities			Solar	As Available	4
Total Solar					189
Total Capacity					6,186

(a) 100% unless otherwise noted.
(b) See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Nuclear" in Item 1 for details regarding leased interests in Palo Verde. The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.
(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and El Paso (7%). The plant is operated by APS.
(d) Cholla Unit 2's last day of service was on October 1, 2015.
(e) The other participants are Salt River Project (21.7%), Nevada Power Company (11.3%), the United States Government (24.3%), Tucson Electric Power Company (7.5%) and Los Angeles Department of Water & Power (21.2%). The plant is operated by Salt River Project.

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.

Transmission and Distribution Facilities

Current Facilities. APS's transmission facilities consist of approximately 6,070 pole miles of overhead lines and approximately 49 miles of underground lines, 5,847 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,077 miles of overhead lines and approximately 18,071 miles of underground primary cable, all of which are located in Arizona. APS distribution facilities reflect an actual net gain of 169 miles in 2015. 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, 2015:

	Percent Owned (Weighted-Average)
Morgan — Pinnacle Peak System	64.6%
Palo Verde — Estrella 500kV System	50.0%
Round Valley System	50.0%
ANPP 500kV System	33.4%
Navajo Southern System	22.7%
Four Corners Switchyards	49.8%
Palo Verde — Yuma 500kV System	19.3%
Phoenix — Mead System	17.1%
Palo Verde — Morgan System	87.7%
Hassayampa — North Gila System	80.0%
Cholla 500 Switchyard	85.7%
Saguaro 500 Switchyard	75.0%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2015 plan, APS projects it will develop 275 miles of new lines over the next ten years. One significant project currently under development is a new 500kV path that will span from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminate at a bulk substation in the northeast part of Phoenix. The Palo Verde to Morgan System includes Palo Verde-Delaney-Sun Valley-Morgan. The project consists of four phases. The first phase, Morgan to Pinnacle Peak 500kV, is currently in-service. The second and third phases, Delaney to Palo Verde 500kV and Delaney to Sun Valley 500kV, are under construction and are expected to be energized by May 2016. The fourth phase, Morgan to Sun Valley 500kV, has been permitted and is in final design and development. In total, the projects consist of over 100 miles of new 500kV lines, with many of those miles constructed with the capability to string a 230kV line as a second circuit.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which are included in APS's 2015 transmission plan, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which are intended to support the transmission of renewable energy to Phoenix and California. The North Gila to Hassayampa line went into service in May 2015.

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

NERC Critical Infrastructure Protection Requirements. In 2014, APS initiated a comprehensive project to ensure compliance with Version 5 of NERC's Critical Infrastructure Protection Requirements (CIP V.5) which will become effective April 1, 2016. APS will be incurring incremental capital expenditures through 2017 associated with the CIP V.5 compliance implementation project estimated to be approximately $52 million.

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

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under rights-of-way from the federal government. The right-of-way and lease for the Navajo Plant expire in 2019 and the right-of-way and lease for Four Corners were scheduled to expire in 2016. In March, 2011, the Navajo Nation Council signed a resolution approving a 25-year extension to the existing Four Corners lease term and providing Navajo Nation consent to renewal of the related rights-of-way. The effectiveness of the lease amendment also required the approval of the DOI, as did the 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. The record of decision provides the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

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

ITEM 3. LEGAL PROCEEDINGS

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

See Note 3 for ACC and FERC-related matters.

See Note 10 for information regarding environmental matters, Superfund–related matters, matters related to a September 2011 power outage and a New Mexico tax matter.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF PINNACLE WEST

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The executive officers, their ages at February 19, 2016, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	61	Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS	2009-Present
		President of APS	2013-Present
		President of Pinnacle West	2008-Present
		Chief Executive Officer of APS	2008-Present
Robert S. Bement	60	Senior Vice President, Site Operations, PVNGS, of APS	2011-Present
Denise R. Danner	60	Vice President, Controller and Chief Accounting Officer of Pinnacle West; Chief Accounting Officer of APS	2010-Present
		Vice President and Controller of APS	2009-Present
Patrick Dinkel	52	Vice President, Transmission and Distribution Operations of APS	2014-Present
		Vice President, Resource Management of APS	2012-2014
		Vice President, Power Marketing, Resource Planning and Acquisition of APS	2011-2012
		Vice President, Power Marketing and Resource Planning of APS	2010-2011
Randall K. Edington	62	Executive Vice President and Chief Nuclear Officer, PVNGS, of APS	2007-Present
David P. Falck	62	Executive Vice President and General Counsel of Pinnacle West and APS	2009-Present
		Secretary of Pinnacle West and APS	2009-2012
Daniel T. Froetscher	54	Senior Vice President, Transmission, Distribution & Customers of APS	2014-Present
		Vice President, Energy Delivery of APS	2008-2014
Barbara M. Gomez	61	Vice President, Human Resources of APS	2014-Present
		Vice President, Chief Procurement Officer of APS	2013-2014
		Vice President, Supply Chain Management of APS	2010-2013
Jeffrey B. Guldner	50	Senior Vice President, Public Policy of APS	2014-Present
		Senior Vice President, Customers and Regulation of APS	2012-2014
		Vice President, Rates and Regulation of APS	2007-2012
James R. Hatfield	58	Executive Vice President of Pinnacle West and APS	2012-Present
		Chief Financial Officer of Pinnacle West and APS	2008-Present
		Senior Vice President of Pinnacle West and APS	2008-2012
John S. Hatfield	50	Vice President, Communications of APS	2010-Present
Tammy D. McLeod	54	Vice President, Resource Management of APS	2014-Present
		Vice President and Chief Customer Officer of APS	2007-2014
Lee R. Nickloy	49	Vice President and Treasurer of Pinnacle West and APS	2010-Present
Mark A. Schiavoni	60	Executive Vice President and Chief Operating Officer of APS	2014-Present
		Executive Vice President, Operations of APS	2012-2014
		Senior Vice President, Fossil Operations of APS	2009-2012

PART II

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

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange. At the close of business on February 12, 2016, Pinnacle West's common stock was held of record by approximately 20,570 shareholders.

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

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

2014	High	Low	Close	Dividends Per Share
1st Quarter	$ 55.99	$ 51.15	$ 54.66	$ 0.5675
2nd Quarter	58.06	53.71	57.84	0.5675
3rd Quarter	57.95	52.13	54.64	0.5675
4th Quarter	71.11	54.59	68.31	0.595

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

The chart below sets forth the dividends paid on APS's common stock for each of the four quarters for 2015 and 2014.

Common Stock Dividends
(Dollars in Thousands)

Quarter	2015	2014
1st Quarter	$ 65,800	$ 62,500
2nd Quarter	65,900	62,600
3rd Quarter	65,900	62,700
4th Quarter	69,300	65,800

The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. As of December 31, 2015, APS did not have any outstanding preferred stock.

Issuer Purchases of Equity Securities

The following table contains information about our purchases of our common stock during the fourth quarter of 2015.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 – October 31, 2015	61,471	$ 65.74	—	—
November 1 – November 30, 2015	—	—	—	—
December 1 – December 31, 2015	—	—	—	—
Total	61,471	$ 65.74	—	—

(1) Represents shares of common stock withheld by Pinnacle West to satisfy tax withholding obligations upon the vesting of performance shares.

ITEM 6. SELECTED FINANCIAL DATA

PINNACLE WEST CAPITAL CORPORATION – CONSOLIDATED

The selected data presented below as of and for the years ended December 31, 2015, 2014, 2013, 2012 and 2011 are derived from the Consolidated Financial Statements. The data should be read in connection with the Consolidated Financial Statements including the related notes included in Item 8 of this Form 10-K.

	2015	2014	2013	2012	2011
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues	$ 3,495,443	$ 3,491,632	$ 3,454,628	$ 3,301,804	$ 3,241,379
Income from continuing operations	$ 456,190	$ 423,696	$ 439,966	$ 418,993	$ 355,634
Income (loss) from discontinued operations – net of income taxes	—	—	—	(5,829)	11,306
Net income	456,190	423,696	439,966	413,164	366,940
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,622	27,467
Net income attributable to common shareholders	$ 437,257	$ 397,595	$ 406,074	$ 381,542	$ 339,473
COMMON STOCK DATA					
Book value per share – year-end	$ 41.30	$ 39.50	$ 38.07	$ 36.20	$ 34.98
Earnings per weighted-average common share outstanding:					
Continuing operations attributable to common shareholders – basic	$ 3.94	$ 3.59	$ 3.69	$ 3.54	$ 3.01
Net income attributable to common shareholders – basic	$ 3.94	$ 3.59	$ 3.69	$ 3.48	$ 3.11
Continuing operations attributable to common shareholders – diluted	$ 3.92	$ 3.58	$ 3.66	$ 3.50	$ 2.99
Net income attributable to common shareholders – diluted	$ 3.92	$ 3.58	$ 3.66	$ 3.45	$ 3.09
Dividends declared per share	$ 2.44	$ 2.33	$ 2.23	$ 2.67	$ 2.10
Weighted-average common shares outstanding – basic	111,025,944	110,626,101	109,984,160	109,510,296	109,052,840
Weighted-average common shares outstanding – diluted	111,552,130	111,178,141	110,805,943	110,527,311	109,864,243
BALANCE SHEET DATA (a)					
Total assets	$ 15,028,258	$ 14,288,890	$ 13,486,826	$ 13,357,123	$ 13,089,837
Liabilities and equity:					
Current liabilities	$ 1,442,317	$ 1,559,143	$ 1,618,644	$ 1,083,542	$ 1,342,705
Long-term debt less current maturities	3,462,391	3,006,573	2,774,605	3,176,596	2,997,873
Deferred credits and other	5,404,093	5,204,072	4,753,117	4,994,696	4,818,673
Total liabilities	10,308,801	9,769,788	9,146,366	9,254,834	9,159,251
Total equity	4,719,457	4,519,102	4,340,460	4,102,289	3,930,586
Total liabilities and equity	$ 15,028,258	$ 14,288,890	$ 13,486,826	$ 13,357,123	$ 13,089,837

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

SELECTED FINANCIAL DATA

ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

	2015	2014	2013	2012	2011
			(dollars in thousands)		
OPERATING RESULTS					
Electric operating revenues	$ 3,492,357	$ 3,488,946	$ 3,451,251	$ 3,293,489	$ 3,237,241
Fuel and purchased power costs	1,101,298	1,179,829	1,095,709	994,790	1,009,464
Other operating expenses	1,779,075	1,716,325	1,733,677	1,693,170	1,673,394
Operating income	611,984	592,792	621,865	605,529	554,383
Other income	33,332	36,358	20,797	16,358	24,974
Interest expense — net of allowance for borrowed funds	176,109	181,830	183,801	194,777	215,584
Net income	469,207	447,320	458,861	427,110	363,773
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,613	27,524
Net income attributable to common shareholder	$ 450,274	$ 421,219	$ 424,969	$ 395,497	$ 336,249
BALANCE SHEET DATA (a)					
Total assets	$ 14,982,182	$ 14,190,362	$ 13,359,517	$ 13,220,050	$ 13,011,056
Liabilities and equity:					
Total equity	$ 4,814,794	$ 4,629,852	$ 4,454,874	$ 4,222,483	$ 4,051,406
Long-term debt less current maturities	3,337,391	2,881,573	2,649,604	3,051,596	2,872,872
Total capitalization	8,152,185	7,511,425	7,104,478	7,274,079	6,924,278
Current liabilities	1,424,708	1,532,464	1,580,847	1,043,087	1,322,714
Deferred credits and other	5,405,289	5,146,473	4,674,192	4,902,884	4,764,064
Total liabilities and equity	$ 14,982,182	$ 14,190,362	$ 13,359,517	$ 13,220,050	$ 13,011,056

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

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

INTRODUCTION

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

OVERVIEW

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

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. The March 2011 earthquake and tsunamis in Japan and the resulting accident at Japan's Fukushima Daiichi nuclear power station had a significant impact on nuclear power operators worldwide. In the aftermath of the accident, the NRC conducted an independent assessment to consider actions to address lessons learned from the Fukushima events. The independent assessment, named the "Near Term Task Force," recommended a number of proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. The NRC has directed nuclear power plants to begin implementing some of the Near Term Task Force's recommendations. To implement these recommendations, Palo Verde expects to spend approximately \$0.5 million for capital enhancements to the plant through 2016 in addition to the approximate \$125 million that has already been spent on capital enhancements as of December 31, 2015 (APS's share is 29.1%).

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

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

Cholla

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

Four Corners

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

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has 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. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015. On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction can begin.

Transmission and Delivery. APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects through 2018, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better monitor their energy use and needs, minimize system outage durations, as well as the number of customers that experience outages, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 6% of retail electric sales in 2016 and increases annually until it reaches 15% in 2025. In the 2009 Settlement Agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2015. A component of the RES targets development of distributed energy systems.

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

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

APS has developed owned solar resources through the ACC-approved AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the project to the electric grid.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

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

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

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

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

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

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Utility Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. On June 1, 2011, APS filed a rate case with the ACC. APS and other parties to the retail rate case subsequently entered into the 2012 Settlement Agreement detailing the terms upon which the parties have agreed to settle the rate case. See Note 3 for details regarding the 2012 Settlement Agreement terms and for information on APS's FERC rates.

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

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

As part of APS's acquisition of SCE's interest in Units 4 and 5 of Four Corners, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Net Metering. On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB"). In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

Financial Strength and Flexibility. Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities, and may readily access these facilities ensuring adequate liquidity for each company. Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Other Subsidiaries.

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

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

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 2013 through 2015, retail electric revenues comprised approximately 93% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Customer and Sales Growth. Retail customers in APS's service territory increased 1.2% for the year ended December 31, 2015 compared with the prior year. For the three years 2013 through 2015, APS's customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.7% for the year ended December 31, 2015 compared with the prior year, reflecting the effects of improving economic conditions and customer growth, partially offset by customer conservation and energy efficiency and distributed renewable generation initiatives. For the three years 2013 through 2015, APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2016 through 2018, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy could further impact these estimates.

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

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

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

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. On September 30, 2014, Pinnacle West announced plan design changes to the group life and medical postretirement benefit plan, which reduced net periodic benefit costs. See Note 7.

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

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.0% of the assessed value for 2015, 10.7% for 2014 and 10.5% for 2013. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement.)

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

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

RESULTS OF OPERATIONS

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

Operating Results – 2015 compared with 2014.

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

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

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

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

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

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

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

- A decrease of $14 million in fossil generation costs primarily related to lower planned outage costs;
- A decrease of $13 million for costs related to corporate support;
- A decrease of $8 million related to costs for demand-side management, renewable energy and similar regulatory programs, which is partially offset in operating revenues and purchased power;
- An increase of $9 million related to higher nuclear generation costs;
- An increase of $6 million in customer service costs including costs related to a new customer information system; and
- An increase of $1 million related to other miscellaneous factors.

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

- An increase of $34 million related to the absence of 2014 Four Corners cost deferrals and the related 2015 amortization;
- An increase of $16 million related to the Four Corners acquisition adjustment;
- An increase of $20 million due to increased plant in service;
- An increase of $10 million related to the regulatory treatment of the Palo Verde sale leaseback, which is offset in noncontrolling interests; and
- A decrease of $3 million due to other miscellaneous factors.

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

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

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

Operating Results – 2014 compared with 2013.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2014 was $398 million, compared with $406 million for the prior year. The results reflect a decrease of approximately $4 million for the regulated electricity segment primarily due to higher fossil generation costs, lower retail sales due to the effects of weather, higher property taxes, and lower retail transmission revenues. These negative factors were partially offset by lower operations and maintenance expenses related to lower employee benefit costs, higher other income, and increased revenues for lost fixed cost recovery. All other segment's income was lower by $4 million primarily related to El Dorado's investment losses.

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

	Year Ended December 31, 2014	Year Ended December 31, 2013	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,309	$ 2,356	$ (47)
Operations and maintenance	(908)	(925)	17
Depreciation and amortization	(417)	(416)	(1)
Taxes other than income taxes	(172)	(164)	(8)
All other income and expenses, net	28	11	17
Interest charges, net of allowance for borrowed funds used during construction	(185)	(187)	2
Income taxes	(224)	(232)	8
Less income related to noncontrolling interests (Note 18)	(26)	(34)	8
Regulated electricity segment income	405	409	(4)
All other	(7)	(3)	(4)
Net Income Attributable to Common Shareholders	$ 398	$ 406	$ (8)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $47 million lower for the year ended December 31, 2014 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)		
Effects of weather	$ (45)	$ (16)	$ (29)
Lower demand side management regulatory surcharges, offset by renewable energy regulatory surcharges and purchased power	—	20	(20)
Lower retail transmission revenues	(7)	—	(7)
Lower retail sales due to changes in customer usage patterns and related pricing, partially offset by customer growth	(4)	—	(4)
Higher net fuel and purchased power costs, including related deferrals and higher off-system sales margins	78	79	(1)
Lost fixed cost recovery	12	—	12
Miscellaneous items, net	3	1	2
Total	$ 37	$ 84	$ (47)

Operations and maintenance. Operations and maintenance expenses decreased $17 million for the year ended December 31, 2014 compared with the prior year primarily because of:

- A decrease of $33 million related to costs for demand-side management, renewable energy and similar regulatory programs, which were partially offset in operating revenues and purchased power;
- A decrease of $20 million related to lower employee benefit costs;
- An increase of $33 million in generation costs, primarily related to an increased ownership share in Four Corners, a portion of which is deferred in depreciation and amortization, and higher fossil maintenance costs; and
- An increase of $3 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $1 million higher for the year ended December 31, 2014 compared with the prior year primarily related to higher plant balances of approximately $23 million, partially offset by higher Four Corners cost deferrals in the current year of approximately $22 million.

Taxes other than income taxes. Taxes other than income taxes were $8 million higher for the year ended December 31, 2014 compared with the prior year primarily due to higher property tax rates and higher plant balances.

All other income and expenses, net. All other income and expenses, net, were $17 million higher for the year ended December 31, 2014 compared with the prior year due to the debt return on the Four Corners acquisition, an increase in the allowance for equity funds used during construction due to higher balances, and other non-operating income.

Income taxes. Income taxes were $8 million lower for the year ended December 31, 2014 compared with the prior year primarily due to the effects of lower pretax income in the current year.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2015, APS's common equity ratio, as defined, was 55%. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

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

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029) which combined the tax and government funding bills (The Protecting Americans from Tax Hikes Act and Omnibus Bill) containing an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $375-$425 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West Consolidated during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $82 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Consolidated Balance Sheet as of December 31, 2015.

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, 2015, 2014 and 2013 (dollars in millions):

Pinnacle West Consolidated

	2015	2014	2013
Net cash flow provided by operating activities	$ 1,094	$ 1,100	$ 1,153
Net cash flow used for investing activities	(1,066)	(923)	(1,009)
Net cash flow provided by (used for) financing activities	4	(179)	(161)
Net increase (decrease) in cash and cash equivalents	$ 32	$ (2)	$ (17)

Arizona Public Service Company

	2015	2014	2013
Net cash flow provided by operating activities	$ 1,100	$ 1,124	$ 1,194
Net cash flow used for investing activities	(1,060)	(922)	(1,009)
Net cash flow used for financing activities	(22)	(201)	(185)
Net increase in cash and cash equivalents	$ 18	$ 1	$ —

Operating Cash Flows

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

2014 Compared with 2013. Pinnacle West's consolidated net cash provided by operating activities was $1,100 million in 2014 compared to $1,153 million in 2013, a decrease of $53 million in net cash provided. The decrease is primarily related to $99 million in higher fuel and purchased power costs, a $39 million increase in cash collateral posted, $34 million of higher pension contributions in 2014, and other changes in working capital. The decrease is partially offset by a $121 million increase in income tax refunds net of payments (primarily related to a $135 million income tax refund received in the first quarter of 2014). APS's operating cash flows included income tax refunds of approximately $86 million in 2014 compared with payments of $8 million in 2013.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 116% funded as of January 1, 2015 and is estimated to be approximately 116% funded as of January 1, 2016. Under GAAP, the qualified pension plan was 89% funded as of January 1, 2015 and is estimated to be approximately 88% funded as of January 1, 2016. See Note 7 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $100 million in 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to our contributions to our other postretirement benefit plans, we made a contribution of approximately $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

Investing Cash Flows

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

2014 Compared with 2013. Pinnacle West's consolidated net cash used for investing activities was $923 million in 2014, compared to $1,009 million in 2013, a decrease of $86 million in net cash used. The decrease in net cash used for investing activities is primarily related to APS's purchase of SCE's interest in Units 4 and 5 of Four Corners of approximately $209 million in 2013, partially offset by an increase of approximately $123 million in other 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,		
	2016	**2017**	**2018**
APS			
Generation:			
Nuclear Fuel	$ 81	$ 78	$ 81
Renewables	110	1	1
Environmental	235	199	130
New Gas Generation	77	237	112
Other Generation	134	133	222
Distribution	357	345	376
Transmission	123	210	120
Other (a)	88	82	82
Total APS	$ 1,205	$ 1,285	$ 1,124

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. The estimated renewables capital expenditures include a planned utility-scale solar facility, which is subject to regulatory approval. We have not included estimated costs for Cholla's compliance with MATS or EPA's regional haze rule since we have challenged the regional haze rule judicially and we have proposed a compromise strategy to EPA, which, if approved, would allow us to avoid expenditures related to environmental control equipment. The portion of estimated costs for 2016 through 2018 for installation of pollution control equipment needed to ensure Four Corners' compliance with EPA's regional haze rules have been included in the table above. Costs related to the Navajo Plant's compliance with the regional haze rules are not included in the table above, as they are expected to be incurred post-2018. The portion of estimated costs for 2016 through 2018 for incremental costs to comply with the CCR rule for Four Corners and Cholla have also been included in the table above.

On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest. The table above does not include capital expenditures related to El Paso's 7% interest in Four Corners Units 4 and 5 of $27 million in 2016 and $20 million in 2017. We are monitoring the status of other 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

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

2014 Compared with 2013. Pinnacle West's consolidated net cash used for financing activities was $179 million in 2014, compared to $161 million in 2013, an increase of $18 million in net cash used. The increase in net cash used for financing activities is primarily due to $530 million in higher repayments of long-term debt, a $67 million net reduction in funds received through short-term borrowings, and $11 million in higher dividend payments, partially offset by $595 million in higher issuances of long-term debt (see below).

Significant Financing Activities. On December 16, 2015, the Pinnacle West Board of Directors declared a quarterly dividend of $0.625 per share of common stock, payable on March 1, 2016, to shareholders of record on February 1, 2015. During 2015, Pinnacle West increased its indicated annual dividend from $2.38 per share to $2.50 per share. For the year ended December 31, 2015, Pinnacle West's total dividends paid per share of common stock were $2.41 per share, which resulted in dividend payments of $260 million.

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla

Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

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

At December 31, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities.

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

Other Financing Matters. See Note 3 for information regarding the PSA approved by the ACC.

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

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2015, the ratio was approximately 47% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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

See Note 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 12, 2016 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

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

Off-Balance Sheet Arrangements

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

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2015 (dollars in millions):

	2016	2017-2018	2019-2020	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$ 542	$ 414	$ 1,011	$ 4,422	$ 6,389
Pinnacle West	2	127	—	—	129
Total long-term debt payments, including interest	544	541	1,011	4,422	6,518
Fuel and purchased power commitments (b)	643	1,174	1,064	7,559	10,440
Renewable energy credits (c)	42	80	80	432	634
Purchase obligations (d)	233	512	37	213	995
Coal reclamation	15	34	39	262	350
Nuclear decommissioning funding requirements	2	4	4	62	72
Noncontrolling interests (e)	23	46	46	226	341
Operating lease payments	9	16	11	61	97
Total contractual commitments	$ 1,511	$ 2,407	$ 2,292	$ 13,237	$ 19,447

(a) The long-term debt matures at various dates through 2045 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2015 (see Note 6).

(b) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 3 and 10). These amounts include commitments incurred assuming an additional 7% in the 2016 Coal Supply Agreement.

(c) Contracts to purchase renewable energy credits in compliance with the RES (see Note 3).

(d) These contractual obligations include commitments for capital expenditures and other obligations.

(e) Payments to the noncontrolling interests relate to the Palo Verde Sale Leaseback (see Note 18).

This table excludes $34 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2016, 2017 and 2018 (see Note 7).

CRITICAL ACCOUNTING POLICIES

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

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $1,364 million of regulatory assets and $1,140 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2015.

Included in the balance of regulatory assets at December 31, 2015 is a regulatory asset of $619 million for pension benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2015 reported pension liability on the Consolidated Balance Sheets and our 2015 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (329)	$ (11)
Decrease 1%	399	16
Expected long-term rate of return on plan assets:		
Increase 1%	—	(13)
Decrease 1%	—	13

(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, 2015 other postretirement benefit obligation and our 2015 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Other Postretirement Benefit Obligation**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (84)	$ (3)
Decrease 1%	107	6
Healthcare cost trend rate (b):		
Increase 1%	100	9
Decrease 1%	(80)	(6)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(4)
Decrease 1%	—	4

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

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

Fair Value Measurements

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

OTHER ACCOUNTING MATTERS

During the fourth quarter of 2015, we early adopted two new accounting standards related to balance sheet presentation of debt issuance costs, and balance sheet presentation of deferred income taxes. The adoption of these standards did not impact our results of operations or cash flows.

During the first quarter of 2016, we will be adopting new consolidation accounting guidance. We do not expect the adoption of this guidance to have a material impact on our financial statements.

We are currently evaluating the impacts of adopting new revenue recognition guidance and financial instrument recognition and measurement guidance. These two new accounting standards will be effective for us on January 1, 2018.

See Note 2 for additional information related to accounting matters.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

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

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

Pinnacle West – Consolidated

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

2014	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
2015	0.40%	$ 147	0.03%	$ 32	4.32%	$ 352
2016	—	—	0.04%	44	6.15%	314
2017	—	—	0.82%	157	—	—
2018	—	—	—	—	1.75%	32
2019	—	—	—	—	8.75%	500
Years thereafter	—	—	0.27%	49	4.90%	1,940
Total		$ 147		$ 282		$ 3,138
Fair value		$ 147		$ 282		$ 3,558

The tables below present contractual balances of APS's long-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

APS — Consolidated

2015	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
2016	0.01%	$ 44	6.15%	$ 314
2017	—	—	—	—
2018	1.02%	50	1.75%	32
2019	—	—	8.75%	500
2020	—	—	2.20%	250
Years thereafter	0.23%	49	4.64%	2,490
Total		$ 143		$ 3,586
Fair value		$ 143		$ 3,839

2014	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
2015	0.40%	$ 147	0.03%	$ 32	4.32%	$ 352
2016	—	—	0.04%	44	6.15%	314
2017	—	—	0.03%	32	—	—
2018	—	—	—	—	1.75%	32
2019	—	—	—	—	8.75%	500
Years thereafter	—	—	0.27%	49	4.90%	1,940
Total		$ 147		$ 157		$ 3,138
Fair value		$ 147		$ 157		$ 3,558

Commodity Price Risk

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

The following table shows the net pretax changes in mark-to-market of our derivative positions in 2015 and 2014 (dollars in millions):

	2015	2014
Mark-to-market of net positions at beginning of year	$ (115)	$ (73)
Increase in regulatory asset	(44)	(64)
Recognized in OCI:		
Change in mark-to-market losses for future deliveries	(1)	—
Mark-to-market losses realized during the period	6	22
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$ (154)	$ (115)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2015 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	2016	2017	2018	2019	2020	Total fair value
Observable prices provided by other external sources	$ (65)	$ (40)	$ (16)	$ —	$ —	$ (121)
Prices based on unobservable inputs	(11)	(7)	(7)	(6)	(2)	(33)
Total by maturity	$ (76)	$ (47)	$ (23)	$ (6)	$ (2)	$ (154)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2015 and 2014 (dollars in millions):

	December 31, 2015 Gain (Loss)		December 31, 2014 Gain (Loss)	
	Price Up 10%	**Price Down 10%**	**Price Up 10%**	**Price Down 10%**
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$ 2	$ (2)	$ 3	$ (3)
Natural gas	35	(35)	29	(29)
Total	$ 37	$ (37)	$ 32	$ (32)

(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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Pinnacle West. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 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 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

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

	Year Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$ 3,495,443	$ 3,491,632	$ 3,454,628
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	868,377	908,025	924,727
Depreciation and amortization	494,422	417,358	415,708
Taxes other than income taxes	171,812	172,295	164,167
Other expenses	4,932	2,883	7,994
Total	2,640,841	2,680,390	2,608,305
OPERATING INCOME	854,602	811,242	846,323
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	621	9,608	1,704
Other expense (Note 17)	(17,823)	(21,746)	(16,024)
Total	18,013	18,652	11,261
INTEREST EXPENSE			
Interest charges	194,964	200,950	201,888
Allowance for borrowed funds used during construction (Note 1)	(16,259)	(15,457)	(14,861)
Total	178,705	185,493	187,027
INCOME BEFORE INCOME TAXES	693,910	644,401	670,557
INCOME TAXES (Note 4)	237,720	220,705	230,591
NET INCOME	456,190	423,696	439,966
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 437,257	$ 397,595	$ 406,074
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,026	110,626	109,984
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	111,552	111,178	110,806
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 3.94	$ 3.59	$ 3.69
Net income attributable to common shareholders — diluted	$ 3.92	$ 3.58	$ 3.66

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,		
	2015	2014	2013
NET INCOME	$ 456,190	$ 423,696	$ 439,966
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(810)	(213)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932 and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(13,302), $1,307, and $(6,156) (Note 7)	20,163	(2,761)	9,421
Total other comprehensive income	23,393	9,912	35,955
COMPREHENSIVE INCOME	479,583	433,608	475,921
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 460,650	$ 407,507	$ 442,029

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

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

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 39,488	$ 7,604
Customer and other receivables	274,691	297,740
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Deferred income taxes (Note 4)	—	122,232
Income tax receivable (Note 4)	589	3,098
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Other current assets	37,242	38,817
Total current assets	890,516	973,435
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 16)	12,106	17,620
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Other assets	52,518	54,047
Total investments and other assets	799,820	785,533
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,975	119,755
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,808,944	11,194,330
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	185,997	152,290
Other	128,835	129,215
Total deferred debits	1,528,978	1,335,592
TOTAL ASSETS	$ 15,028,258	$ 14,288,890

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

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

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 297,480	$ 295,211
Accrued taxes (Note 4)	138,600	140,613
Accrued interest	56,305	52,603
Common dividends payable	69,363	65,790
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	197,861	178,962
Total current liabilities	1,442,317	1,559,143
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	3,462,391	3,006,573
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,723,425	2,582,636
Regulatory liabilities (Notes 1, 3, 4 and 7)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	480,998	453,736
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	9,524	19,377
Other	186,345	188,286
Total deferred credits and other	5,404,093	5,204,072
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,095,402 and 110,649,762 issued at respective dates	2,541,668	2,512,970
Treasury stock at cost; 115,030 shares at end of 2015 and 78,400 shares at end of 2014	(5,806)	(3,401)
Total common stock	2,535,862	2,509,569
Retained earnings	2,092,803	1,926,065
Accumulated other comprehensive loss:		
Pension and other postretirement benefits (Note 7)	(37,593)	(57,756)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total accumulated other comprehensive loss	(44,748)	(68,141)
Total shareholders' equity	4,583,917	4,367,493
Noncontrolling interests (Note 18)	135,540	151,609
Total equity	4,719,457	4,519,102
TOTAL LIABILITIES AND EQUITY	$ 15,028,258	$ 14,288,890

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,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 456,190	$ 423,696	$ 439,966
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,664	496,487	492,322
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	236,819	159,023	249,296
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(22,219)	(52,672)	(44,991)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	2,509	132,419	(133,094)
Other current assets	3,145	4,384	(17,913)
Accounts payable	(34,266)	(353)	45,414
Accrued taxes	(2,013)	9,615	6,059
Other current liabilities	603	17,892	(7,513)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term income tax receivable	—	—	137,270
Change in unrecognized tax benefits	(10,328)	2,778	(91,425)
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in other long-term assets	2,426	(56,561)	(42,389)
Change in other long-term liabilities	(81,959)	(80,993)	(24,050)
Net cash flow provided by operating activities	1,094,327	1,099,627	1,153,307
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,076,087)	(910,634)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,259)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(3,184)	347	(2,059)
Net cash flow used for investing activities	(1,066,233)	(922,668)	(1,009,401)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	731,126	136,307
Repayment of long-term debt	(415,570)	(652,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(260,027)	(246,671)	(235,244)
Common stock equity issuance - net of purchases	19,373	15,288	17,319
Distributions to noncontrolling interests	(35,002)	(20,482)	(17,385)
Other	1	161	299
Net cash flow provided by (used for) financing activities	3,790	(178,881)	(160,582)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	31,884	(1,922)	(16,676)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	7,604	9,526	26,202
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 39,488	$ 7,604	$ 9,526

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, 2012	109,837,957	$2,466,923	(95,192)	$ (4,211)	$ 1,624,102	$ (114,008)	$ 129,483	$ 4,102,289
Net income		—		—	406,074	—	33,892	439,966
Other comprehensive income		—		—	—	35,955	—	35,955
Dividends on common stock ($2.23 per share)		—		—	(244,903)	—	—	(244,903)
Issuance of common stock	442,746	24,635		—	—	—	—	24,635
Purchase of treasury stock (a)		—	(174,290)	(9,727)	—	—	—	(9,727)
Reissuance of treasury stock for stock-based compensation and other		—	170,538	9,630	—	—	—	9,630
Net capital activities by noncontrolling interests		—		—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	110,280,703	2,491,558	(98,944)	(4,308)	1,785,273	(78,053)	145,990	4,340,460
Net income		—		—	397,595	—	26,101	423,696
Other comprehensive income		—		—	—	9,912	—	9,912
Dividends on common stock ($2.33 per share)		—		—	(256,803)	—	—	(256,803)
Issuance of common stock	369,059	21,412		—	—	—	—	21,412
Purchase of treasury stock (a)		—	(139,746)	(7,893)	—	—	—	(7,893)
Reissuance of treasury stock for stock-based compensation and other		—	160,290	8,800	—	—	—	8,800
Net capital activities by noncontrolling interests		—		—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	110,649,762	2,512,970	(78,400)	(3,401)	1,926,065	(68,141)	151,609	4,519,102
Net income		—		—	437,257	—	18,933	456,190
Other comprehensive income		—		—	—	23,393	—	23,393
Dividends on common stock ($2.44 per share)		—		—	(270,519)	—	—	(270,519)
Issuance of common stock	445,640	28,698		—	—	—	—	28,698
Purchase of treasury stock (a)		—	(154,751)	(10,136)	—	—	—	(10,136)
Reissuance of treasury stock for stock-based compensation and other		—	118,121	7,731	—	—	—	7,731
Net capital activities by noncontrolling interests		—		—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	111,095,402	$2,541,668	(115,030)	$ (5,806)	$ 2,092,803	$ (44,748)	$ 135,540	$ 4,719,457

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

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

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for APS. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 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 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiary (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Arizona Public Service Company and subsidiary as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

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

	Year Ended December 31,		
	2015	2014	2013
ELECTRIC OPERATING REVENUES	$ 3,492,357	$ 3,488,946	$ 3,451,251
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	853,135	882,442	897,824
Depreciation and amortization	494,298	417,264	415,612
Income taxes (Note 4)	260,143	245,036	256,864
Taxes other than income taxes	171,499	171,583	163,377
Total	2,880,373	2,896,154	2,829,386
OPERATING INCOME	611,984	592,792	621,865
OTHER INCOME (DEDUCTIONS)			
Income taxes (Note 4)	14,302	7,676	11,769
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	2,834	11,295	3,896
Other expense (Note 17)	(19,019)	(13,403)	(20,449)
Total	33,332	36,358	20,797
INTEREST EXPENSE			
Interest on long-term debt	180,123	186,323	188,011
Interest on short-term borrowings	7,376	6,796	6,605
Debt discount, premium and expense	4,793	4,168	4,046
Allowance for borrowed funds used during construction (Note 1)	(16,183)	(15,457)	(14,861)
Total	176,109	181,830	183,801
NET INCOME	469,207	447,320	458,861
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 450,274	$ 421,219	$ 424,969

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,		
	2015	2014	2013
NET INCOME	$ 469,207	$ 447,320	$ 458,861
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(809)	(214)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932, and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(11,776), $4,655, and $(6,003) (Note 7)	18,006	(7,635)	9,190
Total other comprehensive income	21,236	5,039	35,723
COMPREHENSIVE INCOME	490,443	452,359	494,584
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 471,510	$ 426,258	$ 460,692

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

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

	December 31, 2015	December 31, 2014
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$ 16,218,724	$ 15,539,811
Accumulated depreciation and amortization	(5,590,937)	(5,394,650)
Net	10,627,787	10,145,161
Construction work in progress	812,845	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,820	119,600
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,804,976	11,194,024
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Assets from risk management activities (Note 16)	12,106	17,620
Other assets	34,455	33,362
Total investments and other assets	781,757	764,848
CURRENT ASSETS		
Cash and cash equivalents	22,056	4,515
Customer and other receivables	274,428	297,712
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Deferred income taxes (Note 4)	—	55,253
Other current assets	35,765	38,693
Total current assets	870,755	900,117
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	182,625	149,260
Other	127,923	128,026
Total deferred debits	1,524,694	1,331,373
TOTAL ASSETS	$ 14,982,182	$ 14,190,362

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

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

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	2,148,493	1,968,718
Accumulated other comprehensive (loss):		
Pension and other postretirement benefits (Note 7)	(19,942)	(37,948)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total shareholder equity	4,679,254	4,478,243
Noncontrolling interests (Note 18)	135,540	151,609
Total equity	4,814,794	4,629,852
Long-term debt less current maturities (Note 6)	3,337,391	2,881,573
Total capitalization	8,152,185	7,511,425
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Accounts payable	291,574	289,930
Accrued taxes (Note 4)	144,488	131,110
Accrued interest	56,003	52,358
Common dividends payable	69,400	65,800
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	180,535	167,302
Total current liabilities	1,424,708	1,532,464
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,764,489	2,571,365
Regulatory liabilities (Notes 1, 3, and 4)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	459,065	424,508
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	35,251	45,740
Other	142,683	144,823
Total deferred credits and other	5,405,289	5,146,473
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 14,982,182	$ 14,190,362

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,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 469,207	$ 447,320	$ 458,861
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,540	496,393	492,226
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	223,069	155,401	278,101
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(21,040)	(52,466)	(46,552)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	—	135,179	(134,590)
Other current assets	4,498	3,766	(17,112)
Accounts payable	(34,891)	(2,355)	47,870
Accrued taxes	13,378	8,650	5,760
Other current liabilities	(3,718)	33,970	(9,005)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in long-term income tax receivable	—	—	137,665
Change in unrecognized tax benefits	(10,328)	2,778	(91,244)
Change in other long-term assets	(813)	(62,739)	(46,675)
Change in other long-term liabilities	(82,628)	(85,642)	(24,969)
Net cash flow provided by operating activities	1,100,030	1,124,167	1,194,691
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,072,053)	(910,084)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,183)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(1,093)	347	(2,067)
Net cash flow used for investing activities	(1,060,032)	(922,118)	(1,009,409)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	606,126	136,307
Repayment of long-term debt	(415,570)	(527,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(266,900)	(253,600)	(242,100)
Noncontrolling interests	(35,002)	(20,482)	(17,385)
Net cash flow used for financing activities	(22,457)	(201,259)	(185,056)
NET INCREASE IN CASH AND CASH EQUIVALENTS	17,541	790	226
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,515	3,725	3,499
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 22,056	$ 4,515	$ 3,725
Supplemental disclosure of cash flow information:			
Cash paid (received) during the year for:			
Income taxes, net of refunds	$ 14,831	$ (86,054)	$ 7,524
Interest, net of amounts capitalized	167,670	173,436	180,757
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 83,798	$ 44,712	$ 33,184
Dividends declared but not paid	69,400	65,800	62,500
Liabilities assumed related to acquisition of SCE's Four Corners' interest	—	—	145,609

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, 2012	71,264,947	$ 178,162	$ 2,379,696	$1,624,237	$ (89,095)	$ 129,483	$ 4,222,483
Net income		—	—	424,969	—	33,892	458,861
Other comprehensive income		—	—	—	35,723	—	35,723
Dividends on common stock		—	—	(244,800)	—	—	(244,800)
Other		—	—	(8)	—	—	(8)
Net capital activities by noncontrolling interests		—	—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	71,264,947	178,162	2,379,696	1,804,398	(53,372)	145,990	4,454,874
Net income		—	—	421,219	—	26,101	447,320
Other comprehensive income		—	—	—	5,039	—	5,039
Dividends on common stock		—	—	(256,900)	—	—	(256,900)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	71,264,947	178,162	2,379,696	1,968,718	(48,333)	151,609	4,629,852
Net income		—	—	450,274	—	18,933	469,207
Other comprehensive income		—	—	—	21,236	—	21,236
Dividends on common stock		—	—	(270,500)	—	—	(270,500)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	71,264,947	$ 178,162	$ 2,379,696	$2,148,493	$ (27,097)	$ 135,540	$ 4,814,794

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

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

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

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

Accounting Records and Use of Estimates

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

Regulatory Accounting

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

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

See Note 3 for additional information.

Electric Revenues

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

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

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

Allowance for Doubtful Accounts

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

Property, Plant and Equipment

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

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

Pinnacle West's property, plant and equipment included in the December 31, 2015 and 2014 consolidated balance sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	**2015**	**2014**
Generation	$ 7,336,902	$ 7,158,729
Transmission	2,494,744	2,247,309
Distribution	5,543,561	5,339,322
General plant	847,025	797,703
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation	117,385	121,255
Intangible assets, net of accumulated amortization	123,975	119,755
Nuclear fuel, net of accumulated amortization	123,139	125,201
Total property, plant and equipment	$ 11,808,944	$ 11,194,330

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

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 11.

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

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2015 were as follows:

- Fossil plant — 19 years;
- Nuclear plant — 28 years;
- Other generation — 25 years;
- Transmission — 39 years;
- Distribution — 33 years; and
- Other — 7 years.

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

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $430 million in 2015, $396 million in 2014, and $400 million in 2013. For the years 2013 through 2015, the depreciation rates ranged from a low of 0.30% to a high of 12.37%. The weighted-average depreciation rate was 2.74% in 2015, 2.77% in 2014, and 3.00% in 2013.

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 8.02% for 2015, 8.47% for 2014, and 8.56% for 2013. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Materials and Supplies

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

Fair Value Measurements

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

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

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

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

See Note 13 for additional information about fair value measurements.

Derivative Accounting

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

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

Loss Contingencies and Environmental Liabilities

Pinnacle West and APS are involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Pinnacle West and APS record a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Retirement Plans and Other Postretirement Benefits

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

Nuclear Fuel

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

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

Income Taxes

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

Cash and Cash Equivalents

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

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

	Year ended December 31,		
	2015	2014	2013
Cash paid (received) during the period for:			
Income taxes, net of refunds	$ 6,550	$ (102,154)	$ 18,537
Interest, net of amounts capitalized	170,209	177,074	184,010
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 83,798	$ 44,712	$ 33,184
Dividends declared but not paid	69,363	65,790	62,528
Liabilities assumed relating to acquisition of SCE Four Corners' interest (see Note 3)	—	—	145,609

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS's software, on Pinnacle West's Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $58 million in 2015, $53 million in 2014, and $53 million in 2013. Estimated amortization expense on existing intangible assets over the next five years is $48 million in 2016, $36 million in 2017, $18 million in 2018, $9 million in 2019, and $3 million in 2020. At December 31, 2015, the weighted-average remaining amortization period for intangible assets was 5 years.

Investments

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

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

Business Segments

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

Preferred Stock

At December 31, 2015, Pinnacle West had 10 million shares of serial preferred stock authorized with no par value, none of which was outstanding, and APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50 and $100 par values, none of which was outstanding.

2. New Accounting Standards

In May 2014, new revenue recognition guidance was issued. This guidance provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The new revenue standard will be effective for us on January 1, 2018. The guidance may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application. We are currently evaluating this new guidance and the impacts it may have on our financial statements.

In February 2015, new consolidation accounting guidance was issued that amends many aspects of the guidance relating to the analysis and consolidation of variable interest entities. The new guidance is effective for us, and will be adopted, during the first quarter of 2016; and may be adopted using either a full retrospective or modified retrospective approach. We do not expect the adoption of this guidance to have a material impact on our financial statements.

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

During the fourth quarter of 2015 we elected to early adopt the following accounting standard updates:

- Balance sheet presentation of deferred income taxes. See Note 4.
- Balance sheet presentation of debt issuance costs: Adopted on a retrospective basis, the new guidance requires debt issuance costs to be presented on the balance sheets as a direct reduction to the related debt liabilities. Prior to the adoption of this guidance we were required to present debt issuance costs as an asset on the balance sheets. As a result of adopting this guidance, our December 31, 2015 Consolidated Balance Sheet includes $28 million of debt issuance costs as a reduction to our long-term

debt. Our December 31, 2014 Consolidated Balance Sheet presents $25 million of debt issuance costs as a reduction to long-term debt; this amount was previously presented as a component of non-current other deferred debits. The adoption of this guidance did not impact our results of operations or cash flows. Debt issuance costs continue to be amortized as interest expense. See Note 6.

3. Regulatory Matters

Retail Rate Case Filings with the Arizona Corporation Commission

Upcoming Rate Case Filing

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

Prior Rate Case Filing

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

Settlement Agreement

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

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

- An authorized return on common equity of 10.0%;
- A capital structure comprised of 46.1% debt and 53.9% common equity;
- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;
- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:

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

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

Cost Recovery Mechanisms

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

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

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

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan for review by and approval of the ACC.

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

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

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

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

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

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

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- An adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- The PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- The PSA rate includes (a) a "Forward Component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "Historical Component," under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- The PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Beginning balance	$ 6,926	$ 20,755
Deferred fuel and purchased power costs - current period	(14,997)	26,927
Amounts charged to customers	(1,617)	(40,756)
Ending balance	$ (9,688)	$ 6,926

The PSA rate for the PSA year beginning February 1, 2016 is $0.001678 per kWh, as compared to $0.000887 per kWh for the prior year. This new rate is comprised of a forward component of $0.001975 per kWh and a historical component of $(0.000297) per kWh. On October 15, 2015, APS notified the ACC that it was initiating a PSA transition component of $(0.004936) per kWh for the months of November 2015, December 2015, and January 2016. The PSA transition component is a mid-year adjustment to the PSA rate that may be established when conditions change sufficiently to cause high balances to accrue in the PSA balancing account. The transition component expired on February 1, 2016. Any uncollected (overcollected) deferrals during the PSA year, after accounting for the transition component, will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2017.

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

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

Effective June 1, 2014, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $5.9 million for the twelve-month period beginning June 1, 2014 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2014.

Effective June 1, 2015, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2015.

APS's formula rate protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate protocols and may require companies such as APS to make changes to their protocols in the future.

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

APS files for a LFCR adjustment every January. APS filed its 2014 annual LFCR adjustment on January 15, 2014, requesting a LFCR adjustment of $25.3 million, effective March 1, 2014. The ACC approved APS's LFCR adjustment without change on March 11, 2014, which became effective April 1, 2014. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 2, 2015, effective for the first billing cycle of March. APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase), to be effective for the first billing cycle of March 2016.

Net Metering

On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

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

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

Four Corners

On December 30, 2013, APS purchased SCE's 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE's interest in Units 4 and 5 and the closure of Units 1-3 was $70 million as of December 31, 2015 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Cholla

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Regulatory Assets and Liabilities

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

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 619,223	$ —	$ 485,037
Retired power plant costs	2033	9,913	127,518	9,913	136,182
Income taxes - AFUDC equity	2045	5,495	133,712	4,813	118,396
Deferred fuel and purchased power — mark-to-market (Note 16)	2018	71,852	69,697	51,209	46,233
Four Corners cost deferral	2024	6,689	63,582	6,689	70,565
Income taxes — investment tax credit basis adjustment	2045	1,766	48,462	1,716	46,200
Lost fixed cost recovery	2016	45,507	—	37,612	—
Palo Verde VIEs (Note 18)	2046	—	18,143	—	34,440
Deferred compensation	2036	—	34,751	—	34,162
Deferred property taxes	(d)	—	50,453	—	30,283
Loss on reacquired debt	2034	1,515	16,375	1,435	16,410
Tax expense of Medicare subsidy	2024	1,520	12,163	1,528	13,756
Transmission vegetation management	2016	4,543	—	9,086	4,543
Mead-Phoenix transmission line CIAC	2050	332	11,040	332	11,372
Deferred fuel and purchased power (b) (c)	2015	—	—	6,926	—
Coal reclamation	2026	418	6,085	418	6,503
Pension and other postretirement benefits deferral	2015	—	—	4,238	—
Other	Various	5	2,942	819	5
Total regulatory assets (e)		$ 149,555	$ 1,214,146	$ 136,734	$ 1,054,087

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. See Note 7 for further discussion.

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

(c) Subject to a carrying charge.
(d) Per the provision of the 2012 Settlement Agreement.
(e) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."

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

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$ —	$ 277,554	$ —	$ 295,546
Removal costs	(a)	39,746	240,367	31,033	272,825
Other postretirement benefits	(d)	34,100	179,521	32,317	198,599
Income taxes — deferred investment tax credit	2045	3,604	97,175	3,505	92,727
Income taxes - change in rates	2045	1,113	72,454	371	72,423
Spent nuclear fuel	2047	3,051	67,437	4,396	65,594
Renewable energy standard (b)	2017	43,773	4,365	24,596	22,677
Demand side management (b)	2017	6,079	19,115	31,335	—
Sundance maintenance	2030	—	13,678	—	12,069
Deferred fuel and purchased power (b) (c)	2016	9,688	—	—	—
Deferred gains on utility property	2019	2,062	6,001	2,062	8,001
Four Corners coal reclamation	2031	—	8,920	—	1,200
Other	Various	2,550	7,565	934	9,535
Total regulatory liabilities		$ 145,766	$ 994,152	$ 130,549	$ 1,051,196

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal (see Note 11).
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 7.

4. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, investment tax credit basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to deferred taxes resulting from investment tax credits ("ITC") and the change in income tax rates.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the statement of income.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 18). As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS Consolidated Statements of Income.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Total unrecognized tax benefits, January 1	$ 44,775	$ 41,997	$ 133,422	$ 44,775	$ 41,997	$ 133,241
Additions for tax positions of the current year	2,175	4,309	3,516	2,175	4,309	3,516
Additions for tax positions of prior years	—	751	13,158	—	751	13,158
Reductions for tax positions of prior years for:						
Changes in judgment	(10,244)	(2,282)	(108,099)	(10,244)	(2,282)	(107,918)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(2,259)	—	—	(2,259)	—	—
Total unrecognized tax benefits, December 31	$ 34,447	$ 44,775	$ 41,997	$ 34,447	$ 44,775	$ 41,997

During the year ended December 31, 2013, Internal Revenue Service ("IRS") guidance was released which provided clarification regarding an APS tax accounting method change approved by the IRS in the third quarter of 2009. As a result of this guidance, uncertain tax positions decreased $67 million. Additionally, the IRS finalized the examination of tax returns for the years ended December 31, 2008 and 2009, which further reduced uncertain tax positions by approximately $41 million. These reductions in uncertain tax positions, materially offset by an increase in deferred tax liabilities, resulted in a cash refund that was received in the first quarter of 2014.

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		
	2015	2014	2013	2015	2014	2013
Tax positions, that if recognized, would decrease our effective tax rate	$ 9,523	$ 11,207	$ 9,827	$ 9,523	$ 11,207	$ 9,827

As of the balance sheet date, the tax year ended December 31, 2012 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 2011.

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		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest expense/(benefit) recognized	$ (161)	$ 752	$ (3,716)	$ (161)	$ 752	$ (3,716)

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		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest accrued	$ 804	$ 965	$ 213	$ 804	$ 965	$ 213

Additionally, as of December 31, 2015, we have recognized less than $1 million of interest expense to be paid on the underpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

The components of income tax expense are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Current:						
Federal	$ (12,335)	$ 25,054	$ (81,784)	$ 6,485	$ 40,115	$ (97,531)
State	4,763	10,382	10,537	7,813	15,598	11,983
Total current	(7,572)	35,436	(71,247)	14,298	55,713	(85,548)
Deferred:						
Federal	221,505	167,365	279,973	208,326	165,027	305,389
State	23,787	17,904	21,865	23,217	16,620	25,254
Total deferred	245,292	185,269	301,838	231,543	181,647	330,643
Income tax expense	$ 237,720	$ 220,705	$ 230,591	$ 245,841	$ 237,360	$ 245,095

On the APS Consolidated Statements of Income, federal and state income taxes are allocated between operating income and other income.

The following chart compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Federal income tax expense at 35% statutory rate	$ 242,869	$ 225,540	$ 234,695	$ 250,267	$ 239,638	$ 246,384
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	18,265	18,149	21,387	20,433	21,148	23,970
Credits and favorable adjustments related to prior years resolved in current year	(2,169)	—	(3,356)	(1,892)	—	(3,231)
Medicare Subsidy Part-D	837	830	823	837	830	823
Allowance for equity funds used during construction (see Note 1)	(9,711)	(8,523)	(6,997)	(9,711)	(8,523)	(6,997)
Palo Verde VIE noncontrolling interest (see Note 18)	(6,626)	(9,135)	(11,862)	(6,626)	(9,135)	(11,862)
Investment tax credit amortization	(5,527)	(4,928)	(3,548)	(5,527)	(4,928)	(3,548)
Other	(218)	(1,228)	(551)	(1,940)	(1,670)	(444)
Income tax expense	$ 237,720	$ 220,705	$ 230,591	$ 245,841	$ 237,360	$ 245,095

During the fourth quarter of 2015, we prospectively adopted guidance requiring deferred income tax assets and liabilities to be presented as non-current on the balance sheet and eliminating the requirement to present a current portion. As a result of this guidance all deferred income tax assets and liabilities are presented as net non-current deferred income tax liabilities on the Consolidated Balance Sheet as of December 31, 2015. Prior periods have not been restated.

The following table shows the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2015	2014	2015	2014
Current asset	$ —	$ 122,232	$ —	$ 55,253
Long-term liability	(2,723,425)	(2,582,636)	(2,764,489)	(2,571,365)
Deferred income taxes — net	$ (2,723,425)	$ (2,460,404)	$ (2,764,489)	$ (2,516,112)

On February 17, 2011, Arizona enacted legislation (H.B. 2001) that included a four-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in Arizona. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $75 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

On April 4, 2013, New Mexico enacted legislation (H.B. 641) that included a five-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in New Mexico. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $2 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

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

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2015	2014	2015	2014
DEFERRED TAX ASSETS				
Risk management activities	$ 70,498	$ 57,505	$ 70,498	$ 57,505
Regulatory liabilities:				
Asset retirement obligation and removal costs	216,765	229,772	216,765	229,772
Unamortized investment tax credits	100,779	96,232	100,779	96,232
Other postretirement benefits	83,034	90,496	83,034	90,496
Other	60,707	60,409	60,707	60,409
Pension liabilities	191,028	205,227	181,787	194,541
Renewable energy incentives	60,956	65,169	60,956	65,169
Credit and loss carryforwards	59,557	68,347	—	—
Other	149,033	138,729	176,016	161,379
Total deferred tax assets	992,357	1,011,886	950,542	955,503
DEFERRED TAX LIABILITIES				
Plant-related	(3,116,752)	(2,958,369)	(3,116,752)	(2,958,369)
Risk management activities	(10,626)	(12,171)	(10,626)	(12,171)
Other postretirement assets	(71,737)	(59,170)	(70,986)	(58,495)
Regulatory assets:				
Allowance for equity funds used during construction	(54,110)	(48,286)	(54,110)	(48,286)
Deferred fuel and purchased power	—	(2,498)	—	(2,498)
Deferred fuel and purchased power — mark-to-market	(55,020)	(38,187)	(55,020)	(38,187)
Pension benefits	(240,692)	(191,747)	(240,692)	(191,747)
Retired power plant costs (see Note 3)	(53,420)	(57,255)	(53,420)	(57,255)
Other	(108,441)	(99,123)	(108,441)	(99,123)
Other	(4,984)	(5,484)	(4,984)	(5,484)
Total deferred tax liabilities	(3,715,782)	(3,472,290)	(3,715,031)	(3,471,615)
Deferred income taxes — net	$ (2,723,425)	$ (2,460,404)	$ (2,764,489)	$ (2,516,112)

As of December 31, 2015, the deferred tax assets for credit and loss carryforwards relate primarily to federal general business credits of approximately $82 million, which first begin to expire in 2031, and other federal and state loss carryforwards of $3 million, which first begin to expire in 2019. The credit and loss carryforwards amount above has been reduced by $26 million of unrecognized tax benefits.

5. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2015 and 2014 (dollars in thousands):

	December 31, 2015			December 31, 2014		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facility	$ 200,000	$1,000,000	$1,200,000	$ 200,000	$ 1,000,000	$ 1,200,000
Outstanding Commercial Paper Borrowings	—	—	—	—	(147,400)	(147,400)
Amount of Credit Facility Available	$ 200,000	$1,000,000	$1,200,000	$ 200,000	$ 852,600	$ 1,052,600
Weighted-Average Commitment Fees	0.125%	0.100%		0.175%	0.125%	

Pinnacle West

At December 31, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

APS

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 10 for a discussion of APS's other outstanding letters of credit.

Debt Provisions

On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of 7% of APS's capitalization, and $500 million (which is required to be used for costs relating to purchases of natural gas and power). This financing order is set to expire on December 31, 2017. See Note 6 for additional long-term debt provisions.

6. Long-Term Debt and Liquidity Matters

All of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2015 and 2014 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2015	December 31, 2014
APS				
Pollution control bonds:				
Variable	2029-2038	(b)	$ 92,405	$ 156,405
Fixed	2024-2034	1.75%-5.75%	211,150	249,300
Total pollution control bonds			303,555	405,705
Senior unsecured notes	2016-2045	2.20%-8.75%	3,375,000	2,875,000
Palo Verde sale leaseback lessor notes	2015	8.00%	—	13,420
Term loan	2018	(c)	50,000	—
Unamortized discount			(10,374)	(9,206)
Unamortized premium			4,686	4,866
Unamortized debt issuance cost	(d)		(27,896)	(24,642)
Total APS long-term debt			3,694,971	3,265,143
Less current maturities	(e)		357,580	383,570
Total APS long-term debt less current maturities			3,337,391	2,881,573
Pinnacle West				
Term loan	2017	(f)	125,000	125,000
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 3,462,391	$ 3,006,573

(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 0.01%-0.24% at December 31, 2015 and 0.03%-0.27% at December 31, 2014.
(c) The weighted-average interest rate was 1.024% at December 31, 2015.
(d) In the fourth quarter of 2015, we adopted a new accounting standard related to balance sheet presentation of debt issuance costs. See Note 2 for additional details.
(e) Current maturities include $108 million of pollution control bonds expected to be remarketed in 2016 and $250 million in senior unsecured notes that mature in 2016.
(f) The weighted-average interest rate was 1.174% at December 31, 2015 and 1.019% at December 31, 2014.

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
2016	$ 357,580	$ 357,580
2017	125,000	—
2018	82,000	82,000
2019	500,000	500,000
2020	250,000	250,000
Thereafter	2,538,975	2,538,975
Total	$ 3,853,555	$ 3,728,555

Debt Fair Value

Our long-term debt fair value estimates are based on quoted market prices for the same or similar issues, and are classified within Level 2 of the fair value hierarchy. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 125,000	$ 125,000	$ 125,000	$ 125,000
APS	3,694,971	3,981,367	3,265,143	3,714,108
Total	$ 3,819,971	$ 4,106,367	$ 3,390,143	$ 3,839,108

Credit Facilities and Debt Issuances

APS

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

See "Lines of Credit and Short-Term Borrowings" in Note 5 and "Financial Assurances" in Note 10 for discussion of APS's separate outstanding letters of credit.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2015, the ratio was approximately 47% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

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

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

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2015, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. Since APS was in compliance with this common equity ratio requirement, this restriction does not materially affect Pinnacle West's ability to meet its ongoing capital requirements.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017. See Note 5 for additional short-term debt provisions.

7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. We calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors an other postretirement benefit plan (Pinnacle West Capital Corporation Group Life and Medical Plan) for the employees of Pinnacle West and its subsidiaries. This plan provides medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan, which required an interim remeasurement of the benefit obligation for the plan. Effective January 1, 2015, those eligible retirees and dependents over age 65 and on Medicare can choose to be enrolled in a Health Reimbursement Arrangement (HRA). The Company will provide a subsidy allowing post-65 retirees to purchase a Medicare supplement plan on a private exchange network. The remeasurement of the benefit obligation included updating the assumptions. The remeasurement reduced net periodic benefit costs in 2014 by $10 million ($5 million of which reduced expense). The remeasurement also resulted in a decrease in Pinnacle West's other postretirement benefit obligation of $316 million, which was offset by the related regulatory asset and accumulated other comprehensive income.

Because of the plan changes, the Company is currently in the process of seeking IRS and regulatory approval to move approximately $100 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 13 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. In its 2009 retail rate case settlement, APS received approval to defer a portion of pension and other postretirement benefit cost increases incurred in 2011 and 2012. We deferred pension and other postretirement benefit costs of approximately $14 million in 2012 and $11 million in 2011. Pursuant to an ACC regulatory order, we began amortizing the regulatory asset over three years beginning in July 2012. We amortized approximately $5 million in 2015, $8 million in 2014, $8 million in 2013 and $4 million in 2012.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction, billed to electric plant participants or charged to the regulatory asset or liability) (dollars in thousands):

	Pension			Other Benefits		
	2015	2014	2013	2015	2014	2013
Service cost-benefits earned during the period	$ 59,627	$ 53,080	$ 64,195	$ 16,827	$ 18,139	$ 23,597
Interest cost on benefit obligation	123,983	129,194	112,392	28,102	41,243	41,536
Expected return on plan assets	(179,231)	(158,998)	(146,333)	(36,855)	(46,400)	(45,717)
Amortization of:						
Prior service cost (credit)	594	869	1,097	(37,968)	(9,626)	(179)
Net actuarial loss	31,056	10,963	39,852	4,881	1,175	11,310
Net periodic benefit cost	$ 36,029	$ 35,108	$ 71,203	$ (25,013)	$ 4,531	$ 30,547
Portion of cost charged to expense	$ 20,036	$ 21,985	$ 38,968	$ (10,391)	$ 6,000	$ 18,469

The following table shows the plans' changes in the benefit obligations and funded status for the years 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Change in Benefit Obligation				
Benefit obligation at January 1	$ 3,078,648	$ 2,646,530	$ 682,335	$ 890,418
Service cost	59,627	53,080	16,827	18,139
Interest cost	123,983	129,194	28,102	41,243
Benefit payments	(137,115)	(128,550)	(24,988)	(29,054)
Actuarial (gain) loss	(91,340)	378,394	(55,256)	150,188
Plan amendments	—	—	—	(388,599)
Benefit obligation at December 31	3,033,803	3,078,648	647,020	682,335
Change in Plan Assets				
Fair value of plan assets at January 1	2,615,404	2,264,121	834,625	748,339
Actual return on plan assets	(44,690)	292,992	(2,399)	105,223
Employer contributions	100,000	175,000	791	770
Benefit payments	(127,940)	(116,709)	—	(19,707)
Fair value of plan assets at December 31	2,542,774	2,615,404	833,017	834,625
Funded Status at December 31	$ (491,029)	$ (463,244)	$ 185,997	$ 152,290

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans with an accumulated obligation in excess of plan assets as of December 31, 2015 and 2014 (dollars in thousands):

	2015	2014
Projected benefit obligation	$ 3,033,803	$ 3,078,648
Accumulated benefit obligation	2,873,467	2,873,741
Fair value of plan assets	2,542,774	2,615,404

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Noncurrent asset	$ —	$ —	$ 185,997	$ 152,290
Current liability	(10,031)	(9,508)	—	—
Noncurrent liability	(480,998)	(453,736)	—	—
Net amount recognized	$ (491,029)	$ (463,244)	$ 185,997	$ 152,290

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Net actuarial loss	$ 679,501	$ 577,976	$ 127,124	$ 148,006
Prior service cost (credit)	609	1,203	(341,301)	(379,269)
APS's portion recorded as a regulatory (asset) liability	(619,223)	(485,037)	213,621	230,916
Income tax expense (benefit)	(23,663)	(36,890)	925	851
Accumulated other comprehensive loss	$ 37,224	$ 57,252	$ 369	$ 504

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets and liabilities into net periodic benefit cost in 2016 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$ 38,923	$ 3,784
Prior service cost (credit)	527	(37,884)
Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2016	$ 39,450	$ (34,100)

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,			
	2015	2014	2015	2014		2013
				January - September	October - December	
Discount rate – pension	4.37%	4.02%	4.02%	4.88%	4.88%	4.01%
Discount rate – other benefits	4.52%	4.14%	4.14%	5.10%	4.41%	4.20%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets - pension	N/A	N/A	6.90%	6.90%	6.90%	7.00%
Expected long-term return on plan assets - other benefits	N/A	N/A	4.45%	6.80%	4.25%	7.00%
Initial healthcare cost trend rate (pre-65 participants)	7.00%	7.00%	7.00%	7.50%	7.50%	7.50%
Initial healthcare cost trend rate (post-65 participants)	5.00%	5.00%	5.00%	7.50%	5.00%	7.50%
Ultimate healthcare cost trend rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Number of years to ultimate trend rate (pre-65 participants)	4	4	4	4	4	4
Number of years to ultimate trend rate (post-65 participants)	0	0	0	4	0	4

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 2016, we are assuming a 6.90% long-term rate of return for pension assets and 4.74% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final reports on its recommended mortality basis ("RP-2014 Mortality Tables Report" and "Mortality Improvement Scale MP-2014 Report"). At December 31, 2014, we updated our mortality assumptions using the recommended basis with modifications to better reflect our plan experience and additional data regarding mortality trends. The updated mortality assumptions resulted in a $67 million increase in Pinnacle West's pension and other postretirement obligations, which was offset by the related regulatory asset, regulatory liability and accumulated other comprehensive income.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs. A one percentage point change in the assumed initial and ultimate healthcare cost trend rates would have the following effects (dollars in thousands):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 8,834	$ (5,890)
Effect on service and interest cost components of net periodic other postretirement benefit costs	9,069	(6,949)
Effect on the accumulated other postretirement benefit obligation	100,322	(80,332)

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.

Long-term fixed income assets, also known as liability-hedging assets, are designed 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, other government agencies, and corporations. Long-term fixed income assets may also include interest rate swaps, U.S. Treasury futures and other instruments.

Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments include investments in real estate, private equity and various other strategies. The plan may hold investments in return-generating assets by holding securities in partnerships and common and collective trusts.

Based on the IPS, and given the pension plan's funded status at year-end 2015, the long-term fixed income assets had a target allocation of 58% with a permissible range of 55% to 61% and the return-generating assets had a target allocation of 42% with a permissible range of 39% to 45%. The return-generating assets have additional target allocations, as a percent of total plan assets, of 22% equities in U.S. and other developed markets, 6% equities in emerging markets, and 14% in alternative investments. The pension plan IPS does not provide for a specific mix of long-term fixed income assets, but does expect the average credit quality of such assets to be investment grade. As of December 31, 2015, long-term fixed income assets represented 60% of total pension plan assets, and return-generating assets represented 40% of total pension plan assets.

As of December 31, 2015, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. Some of these asset allocation target mixes vary with the plan's funded status. As of December 31, 2015, investment in fixed income assets represented 40% of the other postretirement benefit plan total assets, and non-fixed income assets represented 60% of the other postretirement benefit plan's assets. Fixed income assets are primarily invested in corporate bonds of investment-grade U.S. issuers, and U.S. Treasuries. Non-fixed income assets are primarily invested in large cap U.S. equities in diverse industries, and international equities in both emerging and developed markets.

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 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. 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. Exchange traded mutual funds, are classified as Level 1, as the valuation for these instruments is 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. The NAV for trusts investing in exchange traded equities is derived from the quoted active market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2015, the plans were able to transact in the common and collective trusts at NAV and classifies these investments as Level 2.

Investments in partnerships are also valued using the concept of NAV, which is derived from the value of the partnerships' underlying assets. The plan's partnerships holdings relate to investments in high-yield fixed income instruments and assets of privately held portfolio companies. Certain partnerships also include funding commitments that may require the plan to contribute up to $75 million to these partnerships; as of December 31, 2015, approximately $40 million of these commitments have been funded. Partnerships are classified as Level 2 if the plan is able to transact in the partnership at the NAV, otherwise the partnership is classified as Level 3.

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2015, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2015
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 1,893	$ —	$ —	$ —	$ 1,893
Fixed income securities:					
Corporate	—	1,108,736	—	—	1,108,736
U.S. Treasury	274,778	—	—	—	274,778
Other (a)	—	113,008	—	—	113,008
Equities:					
U.S. companies	233,021	—	—	—	233,021
International companies	14,680	—	—	—	14,680
Common and collective trusts:					
U.S. equities	—	130,097	—	—	130,097
International equities	—	185,892	—	—	185,892
Real estate	—	150,359	—	—	150,359
Partnerships	—	127,840	42,097	—	169,937
Mutual funds - International equities	116,307	—	—	—	116,307
Short-term investments and other	—	29,599	—	14,467	44,066
Total Pension Plan	$ 640,679	$ 1,845,531	$ 42,097	$ 14,467	$ 2,542,774
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 240	$ —	$ —	$ —	$ 240
Fixed income securities:					
Corporate	—	217,026	—	—	217,026
U.S. Treasury	131,435	—	—	—	131,435
Other (a)	—	31,106	—	—	31,106
Equities:					
U.S. companies	253,193	—	—	—	253,193
International companies	12,390	—	—	—	12,390
Common and collective trusts:					
U.S. equities	—	81,516	—	—	81,516
International equities	—	28,539	—	—	28,539
Real estate	—	13,512	—	—	13,512
Mutual funds - International equities	52,568	—	—	—	52,568
Short-term investments and other	5,065	3,331	—	3,096	11,492
Total Other Benefits	$ 454,891	$ 375,030	$ —	$ 3,096	$ 833,017

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2014, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2014
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 387	$ —	$ —	$ —	$ 387
Fixed Income Securities:					
Corporate	—	1,162,096	—	—	1,162,096
U.S. Treasury	291,817	—	—	—	291,817
Other (a)	—	113,265	—	—	113,265
Equities:					
U.S. Companies	246,387	—	—	—	246,387
International Companies	18,069	—	—	—	18,069
Common and collective trusts:					
U.S. Equities	—	127,336	—	—	127,336
International Equities	—	317,167	—	—	317,167
Real estate	—	129,715	—	—	129,715
Partnerships	—	138,337	27,929	—	166,266
Short-term investments and other	—	26,016	—	16,883	42,899
Total Pension Plan	$ 556,660	$ 2,013,932	$ 27,929	$ 16,883	$ 2,615,404
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 318	$ —	$ —	$ —	$ 318
Fixed Income Securities:					
Corporate	—	187,961	—	—	187,961
U.S. Treasury	130,967	—	—	—	130,967
Other (a)	—	35,291	—	—	35,291
Equities:					
U.S. Companies	265,106	—	—	—	265,106
International Companies	17,813	—	—	—	17,813
Common and collective trusts:					
U.S. Equities	—	88,258	—	—	88,258
International Equities	—	85,746	—	—	85,746
Real Estate	—	11,657	—	—	11,657
Short-term investments and other	—	7,408	—	4,100	11,508
Total Other Benefits	$ 414,204	$ 416,321	$ —	$ 4,100	$ 834,625

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

The following table shows the changes in fair value for assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2015 and 2014 (dollars in thousands):

	Pension	
Partnerships	**2015**	**2014**
Beginning balance at January 1	$ 27,929	$ 8,660
Actual return on assets still held at December 31	2,789	927
Purchases	13,187	19,984
Sales	(1,808)	(1,642)
Transfers in and/or out of Level 3	—	—
Ending balance at December 31	$ 42,097	$ 27,929

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 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to contributions to our other postretirement benefit plans, we made a contribution of $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans. APS funds its share of the contributions. APS's share of the pension plan contribution was $100 million in 2015, $175 million in 2014, and $140 million in 2013. APS's share of the contributions to the other postretirement benefit plan was $1 million in 2015, $1 million in 2014, and $14 million in 2013.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

Year	Pension	Other Benefits
2016	$ 152,146	$ 26,468
2017	171,005	28,444
2018	170,534	30,490
2019	180,700	32,438
2020	188,988	33,982
Years 2021-2025	1,023,451	184,335

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 2015, 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 $9 million for 2015, $9 million for 2014, and $9 million for 2013.

8. Leases

We lease certain vehicles, land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $17 million in 2015, $18 million in 2014, and $18 million in 2013. APS's lease expense was $14 million in 2015, $15 million in 2014, and $15 million in 2013.

Estimated future minimum lease payments for Pinnacle West's and APS's operating leases, excluding purchased power agreements, are approximately as follows (dollars in thousands):

Year	Pinnacle West Consolidated	APS
2016	$ 9,182	$ 8,797
2017	8,557	8,317
2018	7,045	6,880
2019	6,121	5,961
2020	4,835	4,680
Thereafter	61,251	61,101
Total future lease commitments	$ 96,991	$ 95,736

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 18 for a discussion of VIEs.

9. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our consolidated statement 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, 2015 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1%		$ 1,744,137	$ 1,067,376	$ 22,228
Palo Verde Unit 2 (a)	16.8%		583,633	356,767	4,142
Palo Verde Common	28.0%	(b)	643,201	231,609	64,069
Palo Verde Sale Leaseback		(a)	351,050	233,665	—
Four Corners Generating Station	63.0%		857,555	577,321	77,317
Navajo Generating Station Units 1, 2 and 3	14.0%		274,640	168,132	4,460
Cholla common facilities (c)	63.3%	(b)	158,623	53,777	1,390
Transmission facilities:					
ANPP 500kV System	33.4%	(b)	109,348	36,576	1,594
Navajo Southern System	22.7%	(b)	62,139	19,361	397
Palo Verde — Yuma 500kV System	19.3%	(b)	14,043	5,226	133
Four Corners Switchyards	49.8%	(b)	38,420	9,833	1,687
Phoenix — Mead System	17.1%	(b)	39,089	13,173	151
Palo Verde — Estrella 500kV System	50.0%	(b)	89,832	18,359	1,008
Morgan — Pinnacle Peak System	64.6%	(b)	129,855	11,087	2,592
Round Valley System	50.0%	(b)	703	286	—
Palo Verde — Morgan System	87.7%	(b)	12	—	133,813
Hassayampa - North Gila System	80.0%	(b)	164,854	1,159	—
Cholla 500 Switchyard	85.7%	(b)	547	15	—
Saguaro 500 Switchyard	75.0%	(b)	773	26	—

(a) See Note 18.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

10. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

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

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, and was for $42.0 million (APS's share of this amount was $12.2 million), was received on June 1, 2015. APS's $12.2 million share was recorded as an adjustment to a regulatory liability and had no impact on the amount of current reported net income. APS's second claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2014 through June 30, 2015, was filed for $12.0 million (APS's share of this amount would be $3.6 million), and has been submitted to, but not yet approved by, the DOE in the fourth quarter of 2015.

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 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 $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of $13.1 billion of liability coverage is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum retrospective premium assessment per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to an annual limit of $19 million per incident, to be periodically adjusted for inflation. Based on APS's ownership interest in the three Palo Verde units, APS's maximum potential retrospective premium assessment per incident for all three units is approximately $111 million, with a maximum annual retrospective premium assessment of approximately $16.6 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of replacement generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $23.1 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $61.7 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2016 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $876 million in 2016; $949 million in 2017; $737 million in 2018; $603 million in 2019; $498 million in 2020; and $7.8 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Years Ended December 31,					
	2016	2017	2018	2019	2020	Thereafter
Coal take-or-pay commitments (a)	$ 170,714	$ 195,428	$ 189,588	$ 193,818	$ 198,160	$ 2,270,974

(a) Total take-or-pay commitments are approximately $3.2 billion. The total net present value of these commitments is approximately $2.2 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 payments under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2015	2014	2013
Total payments	$ 211,327	$ 236,773	$ 188,496

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 $42 million in 2016; $40 million in 2017; $40 million in 2018; $40 million in 2019; $40 million in 2020; and $432 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 amounts incurred for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $202 million at December 31, 2015 and $198 million at December 31, 2014. Under our current coal supply agreements, we expect to make payments for the final mine reclamation as follows: $15 million in 2016; $16 million in 2017; $18 million in 2018; $19 million in 2019; $20 million in 2020; and $262 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

Superfund-Related Matters

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

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

Southwest Power Outage

On September 8, 2011 at approximately 3:30 PM, a 500 kV transmission line running between the Hassayampa and North Gila substations in southwestern Arizona tripped out of service due to a fault that occurred at a switchyard operated by APS. Approximately ten minutes after the transmission line went off-line, generation and transmission resources for the Yuma area were lost, resulting in approximately 69,700 APS customers losing service.

On September 6, 2013, a purported consumer class action complaint was filed in Federal District Court in San Diego, California, naming APS and Pinnacle West as defendants and seeking damages for loss of perishable inventory and sales as a result of interruption of electrical service. APS and Pinnacle West filed a motion to dismiss, which the court granted on December 9, 2013. On January 13, 2014, the plaintiffs appealed the lower court's decision. The appeal is now fully briefed and pending before the United States Court of Appeals for the Ninth Circuit, which heard oral argument on February 9, 2016. A written decision on the case is expected 30-60 days after oral argument. We believe the District Court's decision will be upheld on appeal, but cannot predict the outcome at the appellate court. If the District Court's decision is reversed, the case would be remanded for discovery and trial, and there is insufficient information at this time to reasonably estimate any possible loss or range of loss to APS and Pinnacle West.

Clean Air Act Citizen Lawsuit

On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's NSPS program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new requirements on Four Corners, Cholla and the Navajo Plant. EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants.

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

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process.

Cholla. APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule's requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed EGUs. EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

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

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

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

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

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

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

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

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard, greenhouse gas emissions, and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, 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.

Notice of Intent to Sue Related to Four Corners

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the DOI's review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

New Mexico Tax Matter

On May 23, 2013, the New Mexico Taxation and Revenue Department ("NMTRD") issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). APS's share of the Assessment is approximately $12 million. For procedural reasons, on behalf of the Four Corners co-owners, including APS, the coal supplier made a partial payment of the Assessment and immediately filed a refund claim with respect to that partial payment in August 2013. The NMTRD denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed a complaint with the New Mexico District Court contesting both the validity of the Assessment and the refund claim denial. On June 30, 2015, the court ruled that the Assessment was not valid and further ruled that APS and the other Four Corners co-owners receive a refund of all of the contested amounts previously paid under the applicable tax statute. The NMTRD filed an appeal of the decision on August 31, 2015. The parties are engaged in settlement discussions and we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain debt arrangements, commodity contract collateral obligations, and other transactions. As of December 31, 2015, standby letters of credit totaled $79 million and will expire in 2016. As of December 31, 2015, surety bonds expiring through 2018 totaled $158 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, 2015.

11. Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets.

The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such transmission and distribution assets. Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites.

In 2015, a revision to the estimated cash flows for the decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the ARO in the amount of $24 million. Also in 2015, Four Corners spent $32 million in actual decommissioning costs. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 10 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million. Finally, in 2015 there was a revision in estimated cash flows for the Cholla decommissioning, which resulted in a decrease of the ARO in the amount of $3 million.

In 2014, an update to the 2013 decommissioning study was completed for Palo Verde nuclear generation facility to incorporate additional spent fuel related charges resulting in an increase to the ARO in the amount of $20 million. Also in 2014, an updated Four Corners Units 1-3 coal-fired power plant decommissioning study was finalized, which resulted in an increase to the ARO of $24 million. In addition, Four Corners spent $30 million in actual decommissioning costs. Finally, in 2014 APS also recognized an ARO related to a new solar facility on leased property that requires the land to be returned to its original condition upon decommissioning of the plant, which resulted in an increase to the ARO of $6 million.

The following table shows the change in our asset retirement obligations for 2015 and 2014 (dollars in thousands):

	2015	2014
Asset retirement obligations at the beginning of year	$ 390,750	$ 346,729
Changes attributable to:		
Accretion expense	25,163	23,567
Settlements	(32,048)	(29,497)
Estimated cash flow revisions	17,556	43,899
Newly incurred obligation	42,155	6,052
Asset retirement obligations at the end of year	$ 443,576	$ 390,750

As mentioned above, decommissioning activities for Four Corners Units 1-3 began in January 2014. Decommissioning activities for Cholla ash ponds began in January 2015. Thus, $29 million of the total ARO of $444 million at December 31, 2015, is classified as a current liability on the balance sheet. At December 31, 2014, $32 million of the total ARO of $391 million was classified as a current liability on the balance sheet.

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

12. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2015 and 2014 is provided in the tables below (dollars in thousands, except per share amounts). Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

	2015 Quarter Ended				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 671,219	$ 890,648	$ 1,199,146	$ 734,430	$ 3,495,443
Operations and maintenance	214,944	210,965	220,449	222,019	868,377
Operating income	67,684	231,973	445,111	109,834	854,602
Income taxes	7,947	67,371	139,555	22,847	237,720
Net income	20,727	127,507	261,978	45,978	456,190
Net income attributable to common shareholders	16,122	122,902	257,116	41,117	437,257
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.15	$ 1.11	$ 2.32	$ 0.37	$ 3.94
Net income attributable to common shareholders — Diluted	0.14	1.10	2.30	0.37	3.92

	2014 Quarter Ended				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 686,251	$ 906,264	$ 1,172,667	$ 726,450	$ 3,491,632
Operations and maintenance	212,882	211,222	223,418	260,503	908,025
Operating income	75,170	254,113	421,775	60,184	811,242
Income taxes	6,405	74,540	134,753	5,007	220,705
Net income	24,691	141,384	248,086	9,535	423,696
Net income attributable to common shareholders	15,766	132,458	243,961	5,410	397,595
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.14	$ 1.20	$ 2.20	$ 0.05	$ 3.59
Net income attributable to common shareholders — Diluted	0.14	1.19	2.20	0.05	3.58

Selected Quarterly Financial Data (Unaudited) - APS

APS's quarterly financial information for 2015 and 2014 is as follows (dollars in thousands):

	2015 Quarter Ended,				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 670,668	$ 889,723	$ 1,198,380	$ 733,586	$ 3,492,357
Operations and maintenance	209,947	208,031	216,011	219,146	853,135
Operating income	61,333	162,704	301,238	86,709	611,984
Net income attributable to common shareholder	19,868	125,362	261,187	43,857	450,274

	2014 Quarter Ended,				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 685,545	$ 905,578	$ 1,172,190	$ 725,633	$ 3,488,946
Operations and maintenance	208,285	208,059	212,430	253,668	882,442
Operating income	69,635	180,394	287,928	54,835	592,792
Net income attributable to common shareholder	19,518	134,916	251,047	15,738	421,219

13. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes exchange traded equities, exchange traded derivative instruments, exchange traded mutual funds, cash equivalents, and investments in U.S. Treasury securities.

Level 2 — Utilizes quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable (such as yield curves). This category includes non-exchange traded contracts such as forwards, options, swaps and certain investments in fixed income securities. This category also includes certain investments that are valued and redeemable based on NAV, such as common and collective trusts and commingled funds.

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 7 for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent short-term investments with original maturities of three months or less in exchange traded money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

Option contracts are primarily valued using a Black-Scholes option valuation model, which utilizes both observable and unobservable inputs such as broker quotes, interest rates and price volatilities.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions and the use of option valuation models with significant unobservable inputs.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

Investments Held in our Nuclear Decommissioning Trust

The nuclear decommissioning trust invests in fixed income securities and equity securities. Equity securities are held indirectly through commingled funds. The commingled funds are valued based on the concept of NAV, which is a value primarily derived from the quoted active market prices of the underlying equity securities. We may transact in these commingled funds on a semi-monthly basis at the NAV. We classify these investments as Level 2. 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 fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

Cash equivalents reported within Level 1 represent investments held in a short-term investment exchange-traded mutual fund, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper.

Fixed income securities issued by the U.S. Treasury held directly by the nuclear decommissioning trust are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 19 for additional discussion about our nuclear decommissioning trust.

Fair Value Tables

The following table presents the fair value at December 31, 2015 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2015
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 22,992	$ 30,364	$ (25,345)	(b)	$ 28,011
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	314,957	—	—		314,957
Fixed income securities:						
Cash and cash equivalent funds	12,260	—	—	(335)	(c)	11,925
U.S. Treasury	117,245	—	—	—		117,245
Corporate debt	—	96,243	—	—		96,243
Mortgage-backed securities	—	99,065	—	—		99,065
Municipal bonds	—	72,206	—	—		72,206
Other	—	23,555	—	—		23,555
Subtotal nuclear decommissioning trust	129,505	606,026	—	(335)		735,196
Total	$ 129,505	$ 629,018	$ 30,364	$ (25,680)		$ 763,207
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (144,044)	$ (63,343)	$ 39,698	(b)	$ (167,689)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Represents nuclear decommissioning trust net pending securities sales and purchases.

The following table presents the fair value at December 31, 2014 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2014
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 20,769	$ 32,598	$ (21,962)	(b)	$ 31,405
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	309,620	—	—		309,620
Fixed income securities:						
U.S. Treasury	118,843	—	—	—		118,843
Cash and cash equivalent funds	—	11,453	—	(7,245)	(c)	4,208
Corporate debt	—	109,379	—	—		109,379
Mortgage-backed securities	—	88,465	—	—		88,465
Municipal bonds	—	69,139	—	—		69,139
Other	—	14,212	—	—		14,212
Subtotal nuclear decommissioning trust	118,843	602,268	—	(7,245)		713,866
Total	$ 118,843	$ 623,037	$ 32,598	$ (29,207)		$ 745,271
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (95,061)	$ (73,984)	$ 58,767	(b)	$ (110,278)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Represents nuclear decommissioning trust net pending securities sales and purchases.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote and option model inputs. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 3).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Our option contracts classified as Level 3 primarily relate to purchase heat rate options. The significant unobservable inputs at December 31, 2015 for these instruments include electricity prices, and volatilities. The significant unobservable inputs at December 31, 2014 for these instruments include electricity prices, gas prices and volatilities. If electricity prices and electricity price volatilities increase, we would expect the fair value of these options to increase, and if these valuation inputs decrease, we would expect the fair value of these options to decrease. If natural gas prices and natural gas price volatilities increase, we would expect the fair value of these options to decrease, and if these inputs decrease, we would expect the fair value of the options to increase. The commodity prices and volatilities do not always move in corresponding directions. The options' fair values are impacted by the net changes of these various inputs.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2015 and December 31, 2014:

	December 31, 2015 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 24,543	$ 54,679	Discounted cash flows	Electricity forward price (per MWh)	$15.92 - $40.73	$ 26.86
Option Contracts (b)	—	5,628	Option model	Electricity forward price (per MWh)	$23.87 - $44.13	$ 33.91
				Electricity price volatilities	40% - 59%	52%
				Natural gas price volatilities	32% - 40%	35%
Natural Gas:						
Forward Contracts (a)	5,821	3,036	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.18 - $3.14	$ 2.61
Total	$ 30,364	$ 63,343				

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

Commodity Contracts	December 31, 2014 Fair Value (thousands) Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Electricity:						
Forward Contracts (a)	$ 29,471	$ 55,894	Discounted cash flows	Electricity forward price (per MWh)	$19.51 - $56.72	$ 35.27
Option Contracts (b)	—	15,035	Option model	Electricity forward price (per MWh)	$32.14 - $66.09	$ 45.83
				Natural gas forward price (per MMBtu)	$3.18 - $3.29	$ 3.25
				Electricity price volatilities	23% - 63%	41%
				Natural gas price volatilities	23% - 41%	31%
Natural Gas:						
Forward Contracts (a)	3,127	3,055	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.98 - $4.13	$ 3.45
Total	$ 32,598	$ 73,984				

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2015 and 2014 (dollars in thousands):

Commodity Contracts	Year Ended December 31, 2015	2014
Net derivative balance at beginning of period	$ (41,386)	$ (49,165)
Total net gains (losses) realized/unrealized:		
Included in earnings	—	102
Included in OCI	(452)	(239)
Deferred as a regulatory asset or liability	(4,009)	(482)
Settlements	14,809	12,080
Transfers into Level 3 from Level 2	(6,256)	(2,090)
Transfers from Level 3 into Level 2	4,315	(1,592)
Net derivative balance at end of period	$ (32,979)	$ (41,386)
Net unrealized gains included in earnings related to instruments still held at end of period	$ —	$ —

Amounts included in earnings are recorded in either operating revenues or fuel and purchased power depending on the nature of the underlying contract.

Transfers reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying value of our net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our short-term borrowings are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values.

14. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for continuing operations attributable to common shareholders for the years ended December 31, 2015, 2014 and 2013 (in thousands, except per share amounts):

	2015	2014	2013
Net income attributable to common shareholders	$ 437,257	$ 397,595	$ 406,074
Weighted average common shares outstanding — basic	111,026	110,626	109,984
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	526	552	822
Weighted average common shares outstanding — diluted	111,552	111,178	110,806
Earnings per average common share attributable to common shareholders — basic	$ 3.94	$ 3.59	$ 3.69
Earnings per average common share attributable to common shareholders — diluted	$ 3.92	$ 3.58	$ 3.66

15. Stock-Based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key-employees, and non-officer members of the Board of Directors. Awards granted under the 2012 Long-Term Incentive Plan ("2012 Plan") may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2012 Plan authorizes up to 4.6 million common shares to be available for grant. As of December 31, 2015, 2.8 million common shares were available for issuance under the 2012 Plan. During 2015, 2014, and 2013, the Company has granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. The Company has not granted stock options since 2004 and has no stock options outstanding. Awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"), and no new awards may be granted under the 2007 Plan.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $19 million in 2015, $33 million in 2014, and $25 million in 2013. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $7 million in 2015, $13 million in 2014, and $10 million in 2013.

As of December 31, 2015, there were approximately $14 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. These costs are expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $21 million in 2015, $20 million in 2014 and $20 million in 2013.

The following table is a summary of awards granted and the weighted-average fair value for the three years ended 2015, 2014 and 2013.

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2015	2014	2013	2015	2014	2013
Units granted	152,651	179,291	182,240	151,430	166,244	176,332
Weighted-average grant date fair value	$ 64.12	$ 54.89	$ 55.14	$ 64.97	$ 54.86	$ 55.45

(a) Units granted includes awards that will be cash settled of 45,104 in 2015, 49,018 in 2014, and 52,620 in 2013.

(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2015 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, 2015	480,933 (a)	$ 51.27	324,230	$ 54.92
Granted	152,651	64.12	151,430	64.97
Change in performance factor	—	—	40,496	54.98
Vested	(198,424)	49.20	(202,480)	54.98
Forfeited	(6,873)	56.78	(7,844)	57.89
Nonvested at December 31, 2015	428,287	56.69	305,832	59.78
Vested Awards Outstanding at December 31, 2015	106,712		202,480	

(a) Includes 127,634 of awards that will be cash settled and 353,299 of awards that will be settled in shares.

(b) Nonvested performance shares are reflected at target payout level. The increase or decrease in the number of shares from the target level to the estimated actual payout level is included in the increase for performance factor amounts in the year the award vests.

Share-based liabilities paid relating to restricted stock unit awards was $10 million, $9 million and $10 million in 2015, 2014 and 2013, respectively. This includes cash used to settle restricted stock units of $3 million, $3 million and $4 million in 2015, 2014 and 2013, respectively. Share-based liabilities paid relating to performance share awards was $16 million, $12 million and $15 million in 2015, 2014 and 2013, respectively.

Restricted Stock Units, Stock Grants, and Stock Units

Restricted stock units have been granted to officers and key employees. Restricted stock units typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights, equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested restricted stock units from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

In December 2012, a retention award of 50,617 restricted stock units was granted to the Chairman of the Board, President, and Chief Executive Officer of Pinnacle West. This award will vest and will be paid in shares of common stock on December 31, 2016, provided that he remains employed with the Company until the vesting date. The award can be increased up to an additional 33,745 restricted stock units payable in stock if certain performance requirements are met.

Restricted stock unit awards 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.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, or 50% in cash and 50% in stock.

Performance Share Awards

Performance share awards have been granted to officers and key employees. Performance share awards contain two performance element criteria that affect the number of shares received after the end of a three-year performance period if performance criteria conditions are met. The performance share grant criteria is based 50% upon the percentile ranking of Pinnacle West's total shareholder return at the end of the three-year performance period, as compared with the total shareholder return of all relevant companies in a specified utility index and the other 50% is based upon six non-financial separate performance metrics. The exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved the employee is not entitled to the dividends on those shares.

Performance share awards are accounted for as 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. Management evaluates the probability of meeting the performance criteria at each balance sheet date. If performance criteria are not achieved, no compensation cost is recognized and any previously recognized compensation cost is reversed.

16. Derivative Accounting

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

On June 1, 2012, we elected to discontinue cash flow hedge accounting treatment for the significant majority of our contracts that had previously been designated as cash flow hedges. This discontinuation is due to changes in PSA recovery (see Note 3), which now allows for 100% deferral of the unrealized gains and losses relating to these contracts. For those contracts that were de-designated, all changes in fair value after May 31, 2012 are no longer recorded through OCI, but are deferred through the PSA. The amounts previously recorded in accumulated OCI relating to these instruments will remain in accumulated OCI, and will transfer to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if we determine it is probable that the forecasted transaction will not occur. Cash flow hedge accounting treatment will continue for a limited number of contracts that are not subject to PSA recovery.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 13 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of OCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As cash flow hedge accounting has been discontinued for the significant majority of our contracts, after May 31, 2012, effectiveness testing is no longer being performed for these contracts.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2015, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	2,487	GWh
Gas	182	Billion cubic feet

Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the years ended December 31, 2015, 2014 and 2013 (dollars in thousands):

	Financial Statement	Year Ended December 31,		
Commodity Contracts	Location	2015	2014	2013
Loss Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ (615)	$ (372)	$ (353)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(5,988)	(21,415)	(44,219)
Gain Recognized in Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Fuel and purchased power (b)	—	—	—

(a) During the years ended December 31, 2015, 2014, and 2013, we had no losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.

(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $4 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the years ended December 31, 2015, 2014 and 2013 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2015	2014	2013
Net Gain Recognized in Income	Operating revenues	$ 574	$ 324	$ 289
Net Loss Recognized in Income	Fuel and purchased power (a)	(108,973)	(66,367)	(10,449)
Total		$ (108,399)	$ (66,043)	$ (10,160)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Consolidated Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Consolidated Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014, include gross liabilities of $3 million and $4 million, respectively, of derivative instruments designated as hedging instruments.

The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting as of December 31, 2015 and 2014. 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, 2015: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 37,396	$ (22,163)	$ 15,233	$ 672	$ 15,905
Investments and other assets	15,960	(3,854)	12,106	—	12,106
Total assets	53,356	(26,017)	27,339	672	28,011
Current liabilities	(113,560)	40,223	(73,337)	(4,379)	(77,716)
Deferred credits and other	(93,827)	3,854	(89,973)	—	(89,973)
Total liabilities	(207,387)	44,077	(163,310)	(4,379)	(167,689)
Total	$ (154,031)	$ 18,060	$ (135,971)	$ (3,707)	$ (139,678)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $18,060.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $4,379, and cash margin provided to counterparties of $672.

As of December 31, 2014: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 28,557	$ (15,127)	$ 13,430	$ 355	$ 13,785
Investments and other assets	24,810	(7,190)	17,620	—	17,620
Total assets	53,367	(22,317)	31,050	355	31,405
Current liabilities	(86,055)	33,829	(52,226)	(7,443)	(59,669)
Deferred credits and other	(82,990)	32,388	(50,602)	—	(50,602)
Total liabilities	(169,045)	66,217	(102,828)	(7,443)	(110,271)
Total	$ (115,678)	$ 43,900	$ (71,778)	$ (7,088)	$ (78,866)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $43,900.
(c) Represents cash collateral and 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 $7,443, and cash margin provided to counterparties of $355.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including one counterparty for which our exposure represents approximately 87% of Pinnacle West's $28 million of risk management assets as of December 31, 2015. This exposure relates to a long-term traditional wholesale contract with a counterparty that has a high credit quality. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at December 31, 2015 (dollars in thousands):

	December 31, 2015
Aggregate fair value of derivative instruments in a net liability position	**$ 207,387**
Cash collateral posted	18,060
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	**112,301**

(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 $161 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 2015, 2014 and 2013 (dollars in thousands):

	2015	2014	2013
Other income:			
Interest income	$ 493	$ 1,010	$ 1,629
Debt return on the purchase of Four Corners units 4 & 5	—	8,386	—
Miscellaneous	128	212	75
Total other income	$ 621	$ 9,608	$ 1,704
Other expense:			
Non-operating costs	$ (11,292)	$ (9,657)	$ (8,207)
Investment loss — net	(2,080)	(9,426)	(3,711)
Miscellaneous	(4,451)	(2,663)	(4,106)
Total other expense	$ (17,823)	$ (21,746)	$ (16,024)

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2015, 2014 and 2013 (dollars in thousands):

	2015	2014	2013
Other income:			
Interest income	$ 163	$ 689	$ 1,234
Debt return on the purchase of Four Corners units 4 & 5	—	8,386	—
Gain on disposition of property	716	1,197	1,024
Miscellaneous	1,955	1,023	1,638
Total other income	$ 2,834	$ 11,295	$ 3,896
Other expense:			
Non-operating costs (a)	$ (11,648)	$ (10,397)	$ (9,626)
Loss on disposition of property	(2,219)	(615)	(4,992)
Miscellaneous	(5,152)	(2,391)	(5,831)
Total other expense	$ (19,019)	$ (13,403)	$ (20,449)

(a) As defined by FERC, includes non-operating utility income and expense (items excluded from utility rate recovery).

18. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. The original lease was scheduled to end on December 31, 2015; however, the lease agreements include fixed rate renewal options which APS exercised on July 7, 2014. As a result, APS will retain the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually for the period 2016 through 2023, and about $16 million annually for the period 2024 through

2033. 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.

The fixed rate renewal periods 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. Predominately due to the fixed rate renewal periods, 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 and interest expense, resulting in an increase in net income for 2015, 2014 and 2013 of $19 million, $26 million and $34 million, respectively, entirely attributable to the noncontrolling interests. The income attributable to the noncontrolling interests decreased in 2015 and 2014 compared with the prior year because of lower rent income resulting from the lease extensions.

In accordance with the regulatory treatment, higher depreciation expense and a regulatory liability were recorded in consolidation to offset the decrease in the noncontrolling interests' share of net income that resulted from the lease extensions. Accordingly, income attributable to Pinnacle West shareholders was not impacted by the consolidation or the lease extensions. Consolidation of these VIEs also results in changes to our Consolidated Statements of Cash Flows, but does not impact net cash flows.

Our Consolidated Balance Sheets at December 31, 2015 and December 31, 2014 include the following amounts relating to the VIEs (dollars in thousands):

	December 31, 2015	December 31, 2014
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 117,385	$ 121,255
Current maturities of long-term debt	—	13,420
Equity-Noncontrolling interests	135,540	151,609

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. Other than the VIEs' assets reported on our consolidated financial statements, the creditors of the VIEs have no other recourse to the assets of APS or Pinnacle West, except in certain circumstances, such as a default by APS under the lease.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS could 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 extension period, APS may be required to pay the noncontrolling equity participants approximately $288 million beginning in 2016, and up to $465 million over the lease extension term.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

19. Nuclear Decommissioning Trusts

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Consolidated Balance Sheets. See Note 13 for a discussion of how fair value is determined and the classification of the nuclear decommissioning trust investments within the fair value hierarchy. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have deferred realized and unrealized gains and losses (including other-than-temporary impairments on investment securities) in other regulatory liabilities. The following table includes the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust fund assets at December 31, 2015 and December 31, 2014 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2015			
Equity securities	$ 314,957	$ 157,098	$ (115)
Fixed income securities	420,574	11,955	(2,645)
Net payables (a)	(335)	—	—
Total	$ 735,196	$ 169,053	$ (2,760)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2014			
Equity securities	$ 309,620	$ 159,274	$ (15)
Fixed income securities	411,491	17,260	(1,073)
Net payables (a)	(7,245)	—	—
Total	$ 713,866	$ 176,534	$ (1,088)

(a) Net payables relate to pending purchases and sales of securities.

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in thousands):

	Year Ended December 31,		
	2015	2014	2013
Realized gains	$ 5,189	$ 4,725	$ 5,459
Realized losses	(6,225)	(4,525)	(6,706)
Proceeds from the sale of securities (a)	478,813	356,195	446,025

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2015 is as follows (dollars in thousands):

		Fair Value
Less than one year	$	14,001
1 year – 5 years		117,356
5 years – 10 years		114,769
Greater than 10 years		174,448
Total	$	420,574

20. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,			
		2015		2014
Balance at beginning of period	$	(68,141)	$	(78,053)
Derivative Instruments				
OCI (loss) before reclassifications		(957)		(810)
Amounts reclassified from accumulated other comprehensive loss (a)		4,187		13,483
Net current period OCI (loss)		3,230		12,673
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications		16,980		(5,419)
Amounts reclassified from accumulated other comprehensive loss (b)		3,183		2,658
Net current period OCI (loss)		20,163		(2,761)
Balance at end of period	$	(44,748)	$	(68,141)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

Changes in Accumulated Other Comprehensive Loss - APS

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Balance at beginning of period	$ (48,333)	$ (53,372)
Derivative Instruments		
OCI (loss) before reclassifications	(957)	(809)
Amounts reclassified from accumulated other comprehensive loss (a)	4,187	13,483
Net current period OCI (loss)	3,230	12,674
Pension and Other Postretirement Benefits		
OCI (loss) before reclassifications	14,726	(10,415)
Amounts reclassified from accumulated other comprehensive loss (b)	3,280	2,780
Net current period OCI (loss)	18,006	(7,635)
Balance at end of period	$ (27,097)	$ (48,333)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating revenues	$ 550	$ 642	$ 799
Operating expenses	12,733	23,507	24,930
Operating loss	(12,183)	(22,865)	(24,131)
Other			
Equity in earnings of subsidiaries	446,508	411,528	420,926
Other expense	(3,302)	(3,276)	(1,999)
Total	443,206	408,252	418,927
Interest expense	2,672	3,663	3,226
Income before income taxes	428,351	381,724	391,570
Income tax benefit	(8,906)	(15,871)	(14,504)
Net income attributable to common shareholders	437,257	397,595	406,074
Other comprehensive income — attributable to common shareholders	23,393	9,912	35,955
Total comprehensive income — attributable to common shareholders	$ 460,650	$ 407,507	$ 442,029

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, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,432	$ 3,088
Accounts receivable	93,093	99,958
Current deferred income taxes	—	66,979
Income tax receivable	14,895	7,329
Other current assets	197	124
Total current assets	125,617	177,478
Investments and other assets		
Investments in subsidiaries	4,815,236	4,630,570
Deferred income taxes	41,065	—
Other assets	43,422	43,051
Total investments and other assets	4,899,723	4,673,621
Total Assets	$ 5,025,340	$ 4,851,099
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 5,901	$ 5,250
Accrued taxes	6,904	12,220
Common dividends payable	69,363	65,790
Other current liabilities	33,120	38,992
Total current liabilities	115,288	122,252
Long-term debt less current maturities	125,000	125,000
Deferred credits and other		
Deferred income taxes	—	12,055
Pension liabilities	21,933	29,228
Other	43,662	43,462
Total deferred credits and other	65,595	84,745
Common stock equity		
Common stock	2,535,862	2,509,569
Accumulated other comprehensive loss	(44,748)	(68,141)
Retained earnings	2,092,803	1,926,065
Total Pinnacle West Shareholders' equity	4,583,917	4,367,493
Noncontrolling interests	135,540	151,609
Total Equity	4,719,457	4,519,102
Total Liabilities and Equity	$ 5,025,340	$ 4,851,099

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,		
	2015	2014	2013
Cash flows from operating activities			
Net income	$ 437,257	$ 397,595	$ 406,074
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(446,508)	(411,528)	(420,926)
Depreciation and amortization	92	94	95
Deferred income taxes	12,967	4,406	(28,806)
Accounts receivable	11,336	(22,945)	21,671
Accounts payable	637	2,017	(2,449)
Accrued taxes and income tax receivables — net	(12,882)	(1,795)	1,402
Dividends received from subsidiaries	266,900	253,600	242,100
Other	(6,995)	18,432	(15,065)
Net cash flow provided by operating activities	262,804	239,876	204,096
Cash flows from investing activities			
Construction work in progress	(3,462)	—	—
Investments in subsidiaries	(3,491)	(10,236)	(3,400)
Repayments of loans from subsidiaries	157	322	2,149
Advances of loans to subsidiaries	(1,010)	(1,450)	(2,099)
Net cash flow used for investing activities	(7,806)	(11,364)	(3,350)
Cash flows from financing activities			
Issuance of long-term debt	—	125,000	—
Dividends paid on common stock	(260,027)	(246,671)	(235,244)
Repayment of long-term debt	—	(125,000)	—
Common stock equity issuance	19,373	15,288	17,319
Other	—	161	298
Net cash flow used for financing activities	(240,654)	(231,222)	(217,627)
Net increase (decrease) in cash and cash equivalents	14,344	(2,710)	(16,881)
Cash and cash equivalents at beginning of year	3,088	5,798	22,679
Cash and cash equivalents at end of year	$ 17,432	$ 3,088	$ 5,798

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2015	$ 3,094	$ 4,073	$ —	$ 4,042	$ 3,125
2014	3,203	3,942	—	4,051	3,094
2013	3,340	4,923	—	5,060	3,203

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2015	$ 3,094	$ 4,073	$ —	$ 4,042	$ 3,125
2014	3,203	3,942	—	4,051	3,094
2013	3,340	4,923	—	5,060	3,203

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, 2015. 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, 2015. 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)" on page 74 of this report and "Management's Report on Internal Control over Financial Reporting (Arizona Public Service Company)" on page 83 of this report.

(c) Attestation Reports of the Registered Public Accounting Firm

Reference is made to "Report of Independent Registered Public Accounting Firm" on page 75 of this report and "Report of Independent Registered Public Accounting Firm" on page 84 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, 2015 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF PINNACLE WEST

Reference is hereby made to “Information About Our Board and Corporate Governance,” “Proposal 1 — Election of Directors” and to “Section 16(a) Beneficial Ownership Reporting Compliance” in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 18, 2016 (the “2016 Proxy Statement”) and to the “Executive Officers of Pinnacle West” section in Part I of this report.

Pinnacle West has adopted a Code of Ethics for Financial Executives that applies to financial executives including Pinnacle West’s Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller, Treasurer, and General Counsel, the President and Chief Operating Officer of APS and other persons designated as financial executives by the Chair of the Audit Committee. The Code of Ethics for Financial Executives is posted on Pinnacle West’s website (*www.pinnaclewest.com)*. Pinnacle West intends to satisfy the requirements under Item 5.05 of Form 8-K regarding disclosure of amendments to, or waivers from, provisions of the Code of Ethics for Financial Executives by posting such information on Pinnacle West’s website.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to “Directors’ Compensation,” “Report of the Human Resources Committee,” “Executive Compensation,” and “Human Resources Committee Interlocks and Insider Participation” in the 2016 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 2016 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2015 with respect to the 2012 Plan and 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	1,611,402	—	2,763,056
Equity compensation plans not approved by security holders	—	—	-
Total	1,611,402	—	2,763,056

(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 2012 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 2007 Plan. However, if an award under the 2012 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 2012 Plan.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under two 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; and (b) the 2012 Plan, which was approved by our shareholders at our 2012 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 2016 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pinnacle West

Reference is hereby made to "Accounting and Auditing Matters — Audit Fees and — Pre-Approval Policies" in the 2016 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	2014	2015
Audit Fees (1)	$ 2,062,685	$ 2,014,747
Audit-Related Fees (2)	212,600	233,555
Tax Fees (3)	8,857	—
All Other Fees (4)	—	10,000

(1) The aggregate fees billed for services rendered for the audit of annual financial statements and for review of financial statements included in Reports on Form 10-Q.

(2) The aggregate fees billed for assurance services that are reasonably related to the performance of the audit or review of the financial statements that are not included in Audit Fees reported above, which primarily consist of fees for employee benefit plan audits performed in 2015 and 2014.

(3) The aggregate fees billed primarily related to tax compliance and tax planning.

(4) The aggregate fees billed for advice relating to the development of a statement of work for the Company's system integrator for its new Customer Information System.

Pinnacle West's Audit Committee pre-approves each audit service and non-audit service to be provided by APS's registered public accounting firm. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve audit and non-audit services to be performed by the independent public accountants if the services are not expected to cost more than $50,000. The Chair must report any pre-approval decisions to the Audit Committee at its next scheduled meeting. All of the services performed by Deloitte & Touche LLP for APS in 2015 were pre-approved by the Audit Committee or the Chair of the Audit Committee consistent with the pre-approval policy.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

See the Index to Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

The documents listed below are being filed or have previously been filed on behalf of Pinnacle West or APS and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
3.1	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010	3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form 18 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.3.1	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.4	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File No. 1-4473	2/20/2009
4.1	Pinnacle West	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.1 to Pinnacle West June 28, 2011 Form 8-K Report, File No. 1-8962	6/28/2011
4.2	Pinnacle West APS	Indenture dated as of January 1, 1995 among APS and The Bank of New York Mellon, as Trustee	4.6 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1/11/1995
4.2a	Pinnacle West APS	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1/11/1995
4.3	Pinnacle West APS	Indenture dated as of November 15, 1996 between APS and The Bank of New York, as Trustee	4.5 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333- 15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11/22/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.3a	Pinnacle West APS	First Supplemental Indenture dated as of November 15, 1996	4.6 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11/22/1996
4.3b	Pinnacle West APS	Second Supplemental Indenture dated as of April 1, 1997	4.10 to APS's Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report, File No. 1-4473	4/9/1997
4.3c	Pinnacle West APS	Third Supplemental Indenture dated as of November 1, 2002	10.2 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
4.4	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities	4.1 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.5	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Subordinated Unsecured Debt Securities	4.2 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.6	Pinnacle West 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	Eighth Supplemental Indenture dated as of June 15, 2004	4.1 to APS's Registration Statement No. 333-106772 by means of June 24, 2004 Form 8-K Report, File No. 1-4473	6/28/2004
4.6c	Pinnacle West APS	Ninth Supplemental Indenture dated as of August 15, 2005	4.1 to APS's Registration Statements Nos. 333-106772 and 333-121512 by means of August 17, 2005 Form 8-K Report, File No. 1-4473	8/22/2005
4.6d	APS	Tenth Supplemental Indenture dated as of August 1, 2006	4.1 to APS's July 31, 2006 Form 8-K Report, File No. 1-4473	8/3/2006
4.6e	Pinnacle West APS	Eleventh Supplemental Indenture dated as of February 26, 2009	4.6e to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6f	Pinnacle West APS	Twelfth Supplemental Indenture dated as of August 25, 2011	4.6f to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6g	Pinnacle West APS	Thirteenth Supplemental Indenture dated as of January 13, 2012	4.6g to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6h	Pinnacle West APS	Fourteenth Supplemental Indenture dated as of January 10, 2014	4.6h to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6i	Pinnacle West APS	Fifteenth Supplemental Indenture dated as of June 18, 2014	4.6i to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6j	Pinnacle West APS	Sixteenth Supplemental Indenture dated as of January 12, 2015	4.6j to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6k	Pinnacle West APS	Seventeenth Supplemental Indenture dated as of May 19, 2015	4.1 to Pinnacle West/APS May 14, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/19/2015
4.6l	Pinnacle West 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
4.7	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
10.1.1	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS's September 30, 1991 Form 10-Q Report, File No. 1-4473	11/14/1991
10.1.1a	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.1b	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.1c	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS's 1996 Form 10-K Report , File No. 1-4473	3/28/1997
10.1.1d	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1.1e	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002	10.2 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.1f	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002	10.4 to Pinnacle West's March 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.1g	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 19, 2003	10.3 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.1h	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 19, 2003	10.5 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.1i	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of May 1, 2007	10.1 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/9/2007
10.1.1j	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of May 1, 2007	10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 104473	5/9/2007
10.1.2	Pinnacle West APS	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962	3/26/1992
10.1.2a	Pinnacle West APS	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.1.2b	Pinnacle West APS	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.3 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.2c	Pinnacle West APS	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 20, 1996	10.1 to APS's June 30, 1996 Form 10-Q Report, File No. 1-4473	8/9/1996
10.1.2d	Pinnacle West APS	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of December 16, 1996	APS 10.5 to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.1.2e	Pinnacle West APS	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000	10.1 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.2f	Pinnacle West APS	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002	10.3 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.2g	Pinnacle West APS	Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of December 19, 2003	10.4 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.2h	Pinnacle West APS	Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of April 1, 2007	10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962	2/27/2008
10.2.1[b]	Pinnacle West 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
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.2.3[b]	Pinnacle West APS	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.3a[b]	Pinnacle West APS	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4[b]	Pinnacle West APS	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10A to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.2.4a[b]	Pinnacle West APS	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4b[b]	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4c[b]	Pinnacle West APS	Third Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective as of January 1, 2002	10.3 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
10.2.4d[b]	Pinnacle West APS	Fourth Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective January 1, 2003	10.64 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.2.5[b]	Pinnacle West APS	Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates (as amended and restated effective January 1, 2016)		
10.3.1[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplement 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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)		
10.4.1[b]	APS	Letter Agreement dated December 20, 2006 between APS and Randall K. Edington	10.78 to Pinnacle West/APS 2006 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/28/2007
10.4.2[b]	APS	Letter Agreement dated July 22, 2008 between APS and Randall K. Edington	10.3 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-4473	8/7/2008
10.4.3[b]	Pinnacle West APS	Letter Agreement dated June 17, 2008 between Pinnacle West/APS and James R. Hatfield	10.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008
10.4.4[b]	APS	Supplemental Agreement dated December 26, 2008 between APS and Randall K. Edington	10.4.10 to Pinnacle West/APS 2008 Form 10-K Report, File No. 1-4473	2/20/2009
10.4.5[b]	APS	Description of 2010 Palo Verde Specific Compensation Opportunity for Randall K. Edington	10.4.13 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.4.6[b]	Pinnacle West	Letter Agreement dated May 21, 2009, between Pinnacle West and David P. Falck	10.4 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File No. 1-8962	5/6/2010
10.4.7[b]	APS	Supplemental Agreement dated June 19, 2012 between APS and Randall K. Edington	10.1 to Pinnacle West/APS June 30, 2012 Form 10-Q Report File Nos. 1-8962 and 1-4473	8/2/2012
10.4.8[b]	APS	Description of 2016 Palo Verde Specific Compensation Opportunity for Randall K. Edington	Pinnacle West/APS December 15, 2015 Form 8-K Report, File No. 1-4473	12/21/2015
10.4.9[b]	APS	Supplemental Agreement dated December 14, 2014 between APS and Randall K. Edington	10.4.9 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
10.5.1[bd]	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:[a]	Date Filed
10.5.3[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.5.4[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.4 to Pinnacle West/APS 2012 Form 10-K, File Nos. 1-8962 and 1-4473	2/22/2013
10.6.1[b]	Pinnacle West	Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders, File No. 1-8962	4/20/2007
10.6.1a[b]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report, File No. 1-8962	4/20/2007
10.6.1b[bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2009
10.6.1c[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6.1d[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6.1e[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.4 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.1f[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.5 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.1g[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (Supplemental 2010 Award)	10.6 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.2[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11/6/2007
10.6.3[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
10.6.4[bd]	Pinnacle West APS	Summary of 2016 CEO Variable Incentive Plan and Officer Variable Incentive Plan		
10.6.5	Pinnacle West	Description of Restricted Stock Unit Grant to Donald E. Brandt	Pinnacle West/APS December 24, 2012 Form 8-K Report, File No. 1-8962	12/26/2012

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.6.6[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
10.6.6a[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.1 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6b[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6c[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8c to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6.6d[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8d to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6.6e[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan		
10.6.6f[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
10.6.6g[bd]	Pinnacle West	Master Amendment to Restricted Stock Unit Agreements	10.4 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.7.1	Pinnacle West 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. 1-8962	7/25/1985
10.7.1c	Pinnacle West APS	Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.1 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7.1d	Pinnacle West APS	Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7.2	Pinnacle West APS	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: ᵃ	Date Filed
10.7.2a	Pinnacle West APS	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Site dated April 25, 1985	10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.7.3	Pinnacle West APS	Application and Grant of APS rights-of-way and easements, Four Corners Site	5.05 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7.3a	Pinnacle West APS	Application and Amendment No. 1 to Grant of APS rights-of-way and easements, Four Corners Site dated April 25, 1985	10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.7.4a	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement Amendment No. 6	10.7 to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3/14/2001
10.7.4b	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement Amendment No. 7, dated December 30, 2013, among APS, El Paso Electric Company, Public Service Company of New Mexico, SRP, SCE, and Tucson Electric Power Company	10.3 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2014
10.8.1	Pinnacle West APS	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS's Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8.2	Pinnacle West APS	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8.3	Pinnacle West APS	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS's Form S-7 Registration Statement, File No. 2-394442	3/16/1971
10.8.4	Pinnacle West APS	Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976, Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998	10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
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	Five-Year Credit Agreement dated as of May 9, 2014, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.3 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.11.2	Pinnacle West	Term Loan Agreement dated as of December 31, 2014 among Pinnacle West, as Borrower, JPMorgan Chase Bank, N.A., as Agent, U.S. Bank Association, as Syndication Agent, TD Bank, N.A., The Bank of Nova Scotia and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and such institutions compromising the lenders party thereto	10.11.2 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
10.11.3	Pinnacle West	Five-Year Credit Agreement, dated as of May 9, 2014, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.4 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.11.4	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.2 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.11.4a	Pinnacle West APS	Amendment No. 1 to the Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated December 22, 2011	10.11.5a to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
10.11.5	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.3 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.11.5a	Pinnacle West APS	Amendment No. 1 to the Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated December 22, 2011	10.11.6a to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
10.11.6	APS	Five-Year Credit Agreement dated as of September 2, 2015 among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.11.7	APS	Term Loan Agreement dated as of June 26, 2015 among APS, as Borrower, Toronto Dominion (Texas) LLC, as Agent, Citibank, N.A., as Syndication Agent, and such institutions compromising the lenders party thereto	10.1 to Pinnacle West/APS June 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/30/2015
10.12.1[c]	Pinnacle West APS	Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
10.12.1a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
10.12.1b[c]	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.12.1c[c]	Pinnacle West APS	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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
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
10.13.1	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.13.3	Pinnacle West APS	Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP	10.104 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13.4	Pinnacle West APS	Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP	10.105 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13.5	Pinnacle West APS	Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and SRP	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.14.1	Pinnacle West APS	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386	3/13/1985
10.15.1	Pinnacle West APS	Territorial Agreement between APS and SRP	10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.2	Pinnacle West APS	Power Coordination Agreement between APS and SRP	10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.3	Pinnacle West APS	Memorandum of Agreement between APS and SRP	10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.3a	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998	10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473	6/26/1998
10.16	Pinnacle West APS	Purchase and Sale Agreement dated November 8, 2010 by and between SCE and APS	10.1 to Pinnacle West/APS November 8, 2010 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/8/2010
10.17	Pinnacle West APS	Proposed Settlement Agreement dated January 6, 2012 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 73183)	10.17 to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges		
12.2	APS	Ratio of Earnings to Fixed Charges		
12.3	Pinnacle West	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements		
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
31.2	Pinnacle West	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
31.4	APS	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
32.1[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		
32.2[c]	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
99.1	Pinnacle West APS	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.1a	Pinnacle West APS	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.2[c]	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.2ac	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.2b[c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.3[c]	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3a[c]	Pinnacle West APS	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
99.3b[c]	Pinnacle West 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
99.4c	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
99.4a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 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
99.4b[c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.5	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.5a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
99.5b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.6	Pinnacle West APS	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to APS's November 18, 1986 Form 10-K Report, File No. 1-4473	1/20/1987
99.6a	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.6b	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
99.7	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
99.7a	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
99.8[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
99.9	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
99.10	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
99.11	Pinnacle West	Purchase Agreement by and among Pinnacle West Energy Corporation and GenWest, L.L.C. and Nevada Power Company, dated June 21, 2005	99.5 to Pinnacle West/APS June 30, 2005 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/9/2005
101.INS	Pinnacle West APS	XBRL Instance Document		
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 Securities and Exchange Commission located in Washington, D.C.

[b]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

[e]Furnished herewith as an Exhibit.

SIGNATURES

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

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: February 19, 2016

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Pinnacle West Capital Corporation, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 19, 2016
/s/ James R. Hatfield (James R. Hatfield, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 19, 2016
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 19, 2016

/s/ Denis A. Cortese (Denis A. Cortese, M.D.)	Director	February 19, 2016
/s/ Richard P. Fox (Richard P. Fox)	Director	February 19, 2016
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 19, 2016
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr., Ph.D.)	Director	February 19, 2016
/s/ Dale E. Klein (Dale E. Klein, Ph.D.)	Director	February 19, 2016
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 19, 2016
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 19, 2016
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 19, 2016
/s/ David P. Wagener (David P. Wagener)	Director	February 19, 2016

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 19, 2016

/s/ Donald E. Brandt

(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Arizona Public Service Company, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 19, 2016
/s/ James R. Hatfield (James R. Hatfield, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 19, 2016
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 19, 2016

/s/ Denis A. Cortese (Denis A. Cortese, M.D.)	Director	February 19, 2016
/s/ Richard P. Fox (Richard P. Fox)	Director	February 19, 2016
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 19, 2016
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr., Ph.D.)	Director	February 19, 2016
/s/ Dale E. Klein (Dale E. Klein, Ph.D.)	Director	February 19, 2016
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 19, 2016
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 19, 2016
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 19, 2016
/s/ David P. Wagener (David P. Wagener)	Director	February 19, 2016

PINNACLE WEST
CAPITAL CORPORATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
TASC 3
ADMITTED

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-______

Direct Testimony of

Dallas J. Dukes

on Behalf of

UNS Electric, Inc.

May 5, 2015

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Senior Director of Pricing and Economic Forecasting for Tucson Electric Power Company ("TEP"). I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UNS Energy Corporation ("UNS Energy"), including UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please describe your background and work experience.

A. I hold a Bachelors of Science degree with a concentration in Accounting from Indiana University and a Masters in Business Administration from Anderson University. I am also a Certified Public Accountant. I have 25 years of experience within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your Direct Testimony?

A. I discuss the more significant Company proposals to change both residential and small commercial customer classes' rate structures. These changes include: (1) raising the basic service charges for residential and small general service customers; (2) eliminating one of the volumetric rate tiers from standard residential customer rate; (3) creating a new net-metering rider that allows the customer with distributed generation ("DG customer") to offset energy consumption with energy production at the retail rate and to sell excess energy production to UNS Electric at the Renewable Credit Rate; (4) requiring partial requirements customers (including new net-metering DG customers) to choose from one of the two proposed three-part rate tariffs applicable for their service requirement. UNS Electric is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities. While the Company understands that there are several foundational rate-design principles, the primary principle remains that rates should reflect cost-based recovery. With that in mind, the Company's proposals address the many changes to the utility industry in recent years – including energy efficiency, distributed generation and demand response – that have contributed to flat or declining energy sales.

Right now, UNS Electric's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. The two-part rate structure of a basic service charge and energy charges is antiquated and does not reflect the modern and burgeoning market for new distributed energy and demand-management options. The energy (kWh) consumption from seasonal customers and distributed generation customers (for example) is not reflective of the fixed costs imposed on the utility. Put simply, UNS Electric's ability to recover these fixed costs is limited.

Consequently, these unrecovered fixed costs are shifted to other customers under the present rate design. In particular, higher-use customers pay a higher percentage share of fixed costs despite the fact that the fixed costs to serve similar lower-use customers is the same. This phenomenon has created the mistaken belief that a customer using less energy reduces the utility's cost to serve that customer – instead of simply a lower utilization of fixed assets that must remain ready to serve that customer.

I further detail how UNS Electric is proposing a three-part rate design that adds a demand charge to the basic service charge and the energy charge. Specifically, the demand charges would recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it. This rate structure would more accurately reflect the cost of providing service while maintaining consistency with the Company's rate design objectives. I list the precedent for three-part rate designs to residential customers. I also explain that such a design (all of its three components) will provide proper price signals so that customers can make informed choices about energy usage. In my testimony, I detail the specifics of the Company's proposed three-part rate proposals for residential (RES-01 Demand and RES-01 Demand TOU) and small commercial (SGS-10 Demand and SGS-10 Demand TOU) customers. I also provide the rate impacts using several average energy (kWh) usages. Ultimately, I explain how the three-part rate rewards customers who improve their load factor consistent with more efficient use of the electric utility system – and how it is not the case that residential customers with very low usage will necessarily benefit less from such a structure.

Even so, the Company is not proposing to move all residential and small-commercial customers to a three-part rate structure in this case. With regards to the two-part rate structure, UNS Electric proposes to increase the basic service charge to a level much closer to the appropriate minimum system-cost level. The Company also seeks to remove one of the rate tiers from the standard residential rate (RES-01). Specifically, UNS Electric seeks to increase the Basic Service Charge to $20.00 per month for tariff RES-01, Residential Service – while having only two tiers in the volumetric Delivery Services-Energy charges (0-400 kWh and usage over 400 kWh). The Company's proposals here will begin the move toward a more balanced rate structure that addresses the issues I have highlighted above.

Regarding the Company's proposal for the adoption of a new net-metering rider, that rider will only apply to net metering DG customers that submit a completed application for interconnection to UNS Electric's grid facilities after June 1, 2015. Existing net-metering DG customers and those with interconnection applications submitted before June 1, 2015 (and ultimately approved) will stay on the current rider for up to 20 years from the date of approval. New net metering DG customers, in the meantime, would be compensated for any excess energy with a bill credit at the Renewable Credit Rate. Further, the Company will purchase excess energy from the DG customer during the billing cycle (that is, eliminating the banking option). This is a further step to send more accurate price signals to net metered customers about their true energy costs. Still, DG customers still see a significant savings on their electric bill, as I show through an example I detail later in my testimony. In other words, the new net-metering rider reduces, but does not eliminate, the subsidy provided to applicable DG customers.

I also explain that, since DG customers with net metering are partial requirements customers, the current two-part rate design options are ill-equipped in accounting for how these customers use UNS Electric's system. This is because two-part rates are designed to recover costs based on average consumption levels for full-requirements customers. So, it is appropriate to require all DG customers to be on a three-part rate schedule. While further mitigating the cost shift I describe in preceding paragraphs, I show how DG customers still save on their total electric bill. These customers can also reduce bills through decreasing billing demand or energy usage.

Finally, I discuss the Company's proposal for an Economic Development Rider. Because UNS Electric's service territory has been very slow to recover and because it has lost several of its largest customers (resulting in fewer sales) this rider together will help put the UNS Electric service territory in a better competitive position to attract and expand business load. The EDR will be available to customers with projected peak demand of 1,000 kW or more and a load factor of 75% or higher and for five years from the effective date – providing discounts on monthly electric bills according to a declining schedule. Potential participants must meet several criteria to qualify and the discounts will only apply to the qualifying additional loads from business expansion or retention – with total program participation limited to 50 MW. I detail the criteria and further describe the discounts to qualifying customers in the last section of my testimony.

II. REQUESTED REVENUE INCREASE.

Q. What is the overall revenue increase being requested by UNS Electric?

A. UNS Electric is requesting a $22.6 million increase to test year adjusted non-fuel revenues. This increase will be offset by a proposed $14.9 million reduction in fuel cost and revenues due to the acquisition of Gila River, lower power market costs and adjustments to test year sales. UNS Electric's proposed base rates also will include $4.3 million in transmission costs currently being recovered through the Transmission Cost Adjustor. In addition, UNS

Electric is proposing a one-year credit to the purchased power and fuel adjustment clause ("PPFAC") to reflect the deferred savings accrued as a result of the Deferred Accounting Order related to the acquisition of Gila River (estimated at $9.3 million). As a result of these factors, UNS Electric's request would decrease revenue by approximately $5.8 million, or 3.6%, in the first year after new rates take effect. In year two, after the deferred savings are fully credited, the Company's revenue would rise to a level that represents an increase of approximately $3.5 million, or 2.1%, over test year adjusted retail revenue.

Summary of Requested Retail Rate Impact

			Yr. 1	Yr. 2
	Requested Non-fuel Increase	$ 22,622		
Less:	TCA Added To Base Rates	(4,292)		
	Reduction in Base Fuel Rates	(14,870)		
	Gila River Deferred Savings (est.)		$ (9,300)	$ -
	Net (Reduction)/Additional Retail Revenue		$ (5,840)	$ 3,460
	Test Year Adjusted Retail Revenue (Excluding TCA Revenue)	$ 147,107		
Plus:	Revenue Paid Through TCA Tracker	4,292		
	Base Fuel Changes Due to Gila & Market Rate Changes	12,345		
	Test Year Adjusted Retail Revenue		$ 163,744	$ 163,744
	Percentage Impact		-3.57%	2.11%

III. RATE DESIGN.

A. Overview.

Q. Is UNS Electric proposing changes to its residential, commercial, and industrial rates?

A. Yes. I will be discussing the more significant rate changes that UNS Electric is proposing for the residential and small commercial customer classes. UNS Electric witness Craig Jones will be discussing other proposed rate design changes.

Q. What are the rate design changes UNS Electric is proposing?

A. To better align rate design with cost-causation and to reduce inter-class inequities, UNS Electric is proposing the following changes for the residential and small commercial (small general service) rate classes:

- Increase the basic service charge to $20 for standard residential customer rates (Rates RES-01, RES-01 TOU, RES-01 TOU SP).
- Increase the basic service charge to $30 for small general service customer rates (Rates SGS-10, SGS-10 TOU).
- Eliminate one of the volumetric rate tiers from standard residential customer rates (Rates RES-01).
- Offer two three-part rate structure options to all customers meeting the applicability requirements for the residential and small general service rate classes.
- Freeze and grandfather the current Rider-4 (Net Metering for Certain Partial Requirement Services (NM-PRS)), Pre June 1, 2015. Rider-4 will have a proposed expiration date of May 31, 2035.

- Create a new Rider-10 (NM-PRS), Post June 1, 2015, that discontinues the banking of kilowatt-hours ("kWh") but allows a net metered customer to: (i) continue to offset energy consumption with energy production at the retail rate and (ii) sell excess energy production to UNS Electric at the Renewable Credit Rate as described in the testimony of Carmine Tilghman.
- Require partial requirement customers qualifying for the new Rider-10 to choose from one of the two proposed three-part rate tariffs applicable for their service requirement.

Q. What are the guidelines or criteria adhered to in evaluating its proposed rate design modifications?

A. UNS Electric is generally following the principles outlined over five decades ago by Professor James C. Bonbright in his work, "Principles of Public Utility Rates," which was reissued in its second edition in 1988. While Professor Bonbright's "Principles" go back five decades, they continue to serve as the foundation for reasonable rate design objectives.

Q. What are those foundational principles?

A. They are as follows:

- The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirement under the fair-return standard.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

- Avoidance of "undue discrimination" in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Q. Is there one principle in rate design that is foundational or primary?

A. Yes. The principle of cost-causation, i.e. rates should reflect cost based recovery. The further away you get from this fundamental foundation, the closer you get to unduly burdensome and discriminatory rate structures that allow for both intra- & inter- class subsidization.

Q. Have fundamental changes occurred in the utility industry since Bonbright's principles were formulated?

A. Yes. At the time Bonbright's principles were formulated the utility industry was typically experiencing steady year-over-year growth in kWh sales and expanding its generation, transmission and distribution systems. In addition, customers had little to no options for alternative power supplies or the ability to control their demand on the expanding utility systems.

However, today there is a growing market of energy efficiency, distributed generation and demand response options available to our customers. New digital metering technology and communication applications also allow today's electrical customers to monitor how and when they use power and the grid.

These factors have contributed to flat or declining kWh sales. Rooftop solar and net metering have become significant factors, especially in Arizona, including UNS Electric's service territory. So the discussion of appropriate pricing and incentive structures has become more complex and necessary as it is a much more important issue.

Q. What do you mean by appropriate pricing structures?

A. To address that, I first need to discuss the cost structure of UNS Electric. The majority of utility costs are fixed – that is, they do not vary with usage. In the case of UNS Electric, its fixed costs stem from investment in and maintenance of equipment and infrastructure and the salaries of employees that are needed to provide safe, reliable power regardless of individual customers' kWh consumption.

Like any electric utility, UNS Electric must do so to meet the potential maximum demand of every customer. It would be cost prohibitive and economically unsound to invest in an electrical system scaled differently to meet the unique and constantly changing demands of each individual customer.

The Company has an obligation to invest in and maintain an infrastructure that is capable of meeting these maximum potential demands of every customer in its service territory. For that reason, UNS Electric incurs essentially the same costs to serve a residential customer who uses 10 kilowatts ("kW") for ten hours per month (100 kWh) as it does to serve a neighbor who uses 10 kW for 100 hours per month (1,000 kWh). The only completely avoidable cost is the variable cost related to the energy production, primarily fuel, purchased power and any O&M costs directly related to energy production or procurement.

Q. Are UNS Electric's residential & small commercial pricing structures presently designed appropriately based on the principal of cost causation?

A. No. The Company's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. For decades, rate designs for these classes have incorporated a very simplistic two part rate structure; a basic service charge (customer charge) and energy charges. This was defensible because these customers typically had relatively similar usage levels and patterns. It also allowed utilities to avoid the higher cost of meters capable of measuring demand.

Historically, basic service charges have been limited to bare minimum levels while inclining price rate tiers have been added, forcing customers who use more power to pay an increasingly disproportional share of the fixed costs incurred on behalf of all customers. Today, though, customers have access to a burgeoning market of distributed energy resources ("DER") and demand management opportunities. The growing inequities that result from these new options are exacerbated by utility rates that have become even more inequitable. Thus, UNS Electric is proposing rate design changes that are designed to address those inequities.

As I described above, customers' individual kWh consumption is not indicative of the fixed costs they impose on their utility. A few examples to illustrate this point are summarized below.

- Seasonal Customers. Portions of UNS Electric's service territory have many customers who only live in their homes for just part of the year. Under the Company's current rates, these customers only pay a portion of the fixed costs associated with providing safe, reliable service to their homes.
- Vacant homes or businesses. Vacant homes and unoccupied apartments with little to no consumption generate far less revenue for UNS Electric than is needed to cover the fixed costs they impose on the Company.
- Distributed Generation ("DG") Customers. Customers with DG power systems still rely on UNS Electric to supply the full potential kW requirements of their home whenever they need it. These customers also need the local distribution grid to support the reliable operation of their systems and to accept any excess

power they generate. While UNS Electric must provide the infrastructure to address these needs, it cannot recover the cost of these services from DG system users under current rates, which rely heavily on energy charges to recover fixed costs. This inequity is exacerbated by net metering, which allows customers to "bank" their systems' excess energy for free and exchange it for on-demand service from their utility.

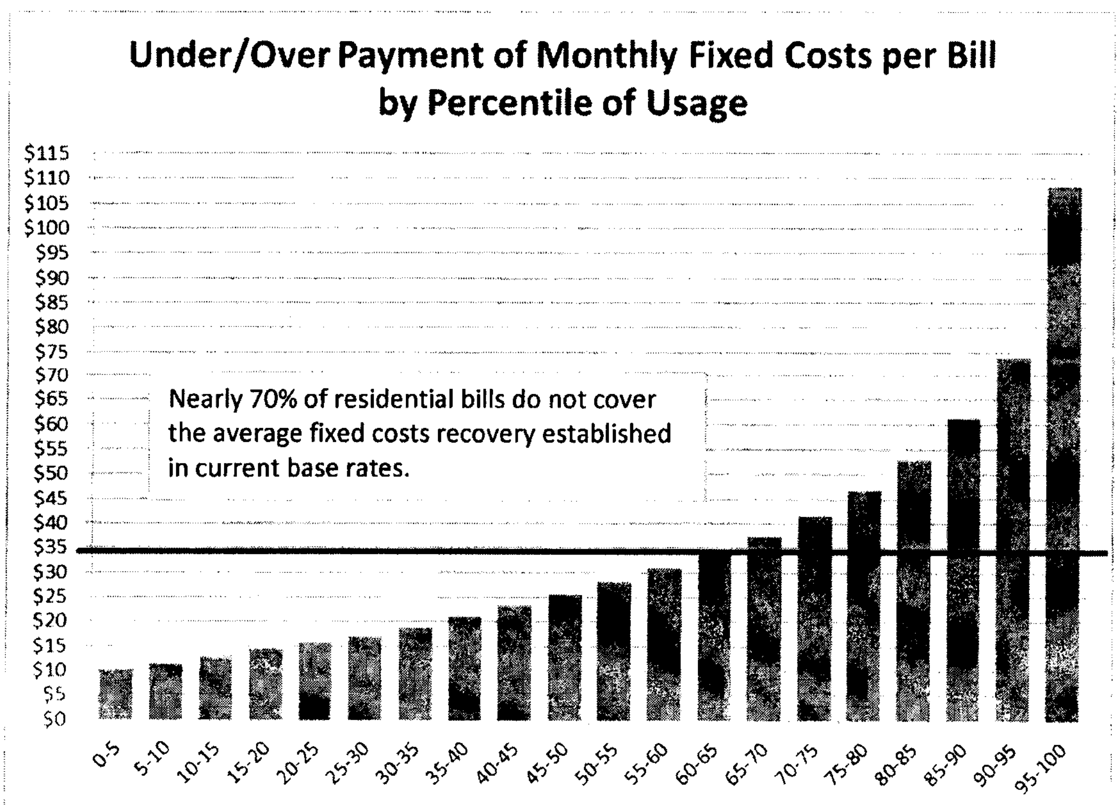
The situations described above limit UNS Electric's ability to recover its fixed service costs. Nearly one out of every four residential (Residential RES-01) bills issued by UNS Electric during the test year – 205,129 to be precise – reflected usage of 300 kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers. UNS Electric recovered only $10 to $16 in fixed costs per month from these customers – two to three times less than their fair share of the fixed costs the Company incurs to provide service on their behalf. Those fixed costs are described in more detail in the testimony of UNS Electric witness Craig Jones.

In future rate filings those unrecovered costs would be shifted to other customers under the present volumetric rate design. Another way to look at it is: if each of those bills would have recovered just the test year average fixed cost recovery for the residential class of $35, the additional cost recovery would at a minimum have been an additional $4 million. That is more than UNS Electric's approved revenue increase in its last rate decision and more than the net requested rate increase in this proceeding.

Q. Does the inclining block rate structure also contribute to these intra-class inequities?

A. Yes. As discussed above, kWh consumption doesn't directly correlate with how much of the system a customer may require at any point in time.

UNS Electric recovered, on average, $35 in fixed costs per bill from residential customers during the test year. As shown in the chart below, though, approximately two-thirds of the bills issued in the last 4 years to residential customers (applying the current RES-01 rate) did not provide fixed cost recovery equivalent to the class average established in the most recent rate decision. This means that about one-third of residential customers' bills recovered above average amounts of fixed costs, while two-thirds recovered below average amounts. There is no cost basis for such a disparity and as such this structure is unduly burdensome and unequitable to the higher consumption users.



Because we've been billing this way for so long, we've sent improper price signals to our customers. Customers have been led to believe that if they use less energy during a particular billing period, their utility's costs are reduced by a comparable amount. But such reductions simply result in lower utilization of fixed utility assets that must remain at the ready to power every light, appliance, fan, air conditioner, computer, television and other equipment their customers might choose to use.

Q. Has UNS Electric experienced a reduction in energy sales and use-per-customer ("UPC") for the residential and small commercial rate classes?

A. Yes, Since 2007 UNS Electric has seen a decline of 8% in its UPC in just the residential customer class alone.

Q. What do you believe is driving these reductions?

A. There are several factors contributing to lower consumption, including: adoption of energy efficiency measures; more energy efficient building codes and appliance standards; increased use of distributed generation; challenging economic conditions; and other conservation efforts by UNS Electric's customers.

Q. Have these sales and UPC reductions resulted in lower costs for customers?

A. On the whole, they have not. While individual customers have enjoyed lower bills due to energy efficiency and DG systems, their bill savings have not resulted in equivalent system demand reductions. The level of investment and maintenance required to meet customer demand has not been reduced; rather, the burden of paying for it has been shifted from customers who use less energy to those who use more.

Q. Why is it important to distinguish between system savings and individual savings?

A. UNS Electric witnesses Craig Jones and Carmine Tilghman will provide more detail about the cost drivers associated with the electric distribution system and the relationship with peak demand. Broadly speaking, though, the distribution system is a network designed primarily to meet the non-coincidental peak demands of customers. The transmission and generation systems, by contrast, are designed to meet the coincidental peaks of the distribution system, with reserves and margins for growth and planning purposes.

When customers reduce their energy consumption through temporary vacancies or intermittent solar DG systems, their peak demand typically does not change. In the case of DG customers, it could even grow as a result of oversized generating facilities being added to maximize energy production; that is further discussed in the testimony of Carmine Tilghman.

So while customers enjoy bill savings from their reduced usage, the Company's fixed system costs for distribution service are not reduced. System savings can be realized in future years through reductions in the system's coincidental peak demand. So customers need to be given the proper price signals and incentives through rates to promote those beneficial changes.

Q. How could residential and small commercial rates be structured to most accurately reflect the costs of providing electric service?

A. The closest rate structure from a cost recovery only basis is a straight fixed-variable ("SFV") design. Under this method, the monthly basic service charge recovers all fixed service costs, while variable charges reflect those costs directly tied to energy usage.

Q. Is UNS Electric proposing SFV rates in this proceeding?

A. No. Adoption of strict SFV rates would result in dramatic rate increases for customers at lower kWh consumption levels and not provide adequate price signals to customers to reduce their impacts on the electrical system. This is not consistent with the Company's rate design objectives and would violate the utility ratemaking principal of gradualism.

Q. What type of rate structure would more accurately reflect the cost of providing service and also be consistent with the Company's rate design objectives?

A. A three-part rate design consistent with those presently employed for larger customers would be more appropriate and provide a balance between fixed cost recover, cost causation and price signals incenting more efficient use of the utility system.

Q. How would costs be recovered through the three-part rate design proposed by the Company in this proceeding?

A. Three-part rates, incorporate the following components:

- **Basic Service Charge** – To recover fixed costs directly attributable to the customer, including the meter, service line, on-site equipment, meter reading and equipment, customer support and billing and minimum distribution system cost.
- **Demand Charges** – To recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it.
- **Energy Charges** – To recover variable costs directly attributable to the customers' energy use.

Q. Do any utilities use three-part rates for residential and small commercial customers?

A. Yes. At least eight utilities offer three-part rates to residential customers in at least 9 states:

1. Alabama Power (Alabama)
2. **Arizona Public Service ("APS")** (Arizona)
3. Black Hills (South Dakota, Wyoming)
4. Dominion (Virginia, North Carolina)
5. Duke Energy (North Carolina, South Carolina)
6. Georgia Power (Georgia)
7. **Salt River Project** (Arizona)
8. Xcel Energy (Colorado)

In Arizona, APS' optional residential three-part rate has been in effect since the 1980's. Approximately 10 percent of that company's residential customers use that rate.

Q. Why does UNS Electric prefer that all customers use three-part rates?

A. Three-part rates more fairly allocate costs to the customers within a class that "cause" them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers.

The Basic Service Charge should be designed to recover the average unavoidable fixed costs that utilities incur each month. It should provide customers with a more accurate price signal that reflects the costs incurred to assure minimum service from the electrical grid to provide safe and reliable service.

Similarly, the Demand Charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve their individual peak load. They then can make proper usage and equipment purchase decisions that would reduce that portion of their bill while producing system benefits.

Finally, Energy Charges should reflect costs that are entirely avoidable when energy consumption is reduced.

B. Proposed Changes to the Standard Two-Part Rates.

Q. Is UNS Electric requesting that all residential and small commercial customers be migrated to a three-part rate structure?

A. Although UNS Electric is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure. Presently, UNS Electric doesn't have the capability to measure demand for every customer and is not advocating a forced migration to such a structure at this time. UNS Electric is requesting to begin moving toward a more balanced rate structure that would make such a move possible in the future.

Q. What are reasonable steps that can be taken in this proceeding to begin this transition?

A. For the standard residential and small general service rates, we can start by moving the basic service charge much closer to the appropriate minimum system cost recovery level. In addition, we can remove one of the rate tiers from the standard residential rate. These changes will provide for more equitable recovery of fixed cost and reduce intra-class subsidization. The Company is proposing these changes at a level that it believes will provide for significant improvement of the rate structures without undue rate shock.

Q. What changes specifically are you requesting for residential customers?

A. For tariff RES-01, Residential Service, we are requesting an increase in the Basic Service Charge to $20.00 per month. The Company is also requesting the elimination of the third tier in the volumetric Delivery Services-Energy charges. In other words, the RES-01 will have one tier from 0 – 400 kWh and another for all usage over 400 kWh. The respective charges for the two tiers will be $0.030810 per kWh for the first 400 kWh and $0.050810 per kWh for all remaining kWh.

C. <u>Net Metering Rider Modifications.</u>

Q. Is UNS Electric requesting changes to its net-metering tariffs? What changes are you proposing for customers qualifying for Net Metering?

A. Yes. We are proposing the adoption of Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. The Company's proposed net metering tariff is described in the testimony of Carmine Tilghman. The applicable three-part standard offer tariffs will be <u>mandatory</u> for Net Metering customers taking service under this Rider.

Q. Will Rider-10 apply to all Net Metering customers?

A. No. Rider-10 will only apply to Net Metering customers that submit completed application for interconnection to UNS Electric's grid facilities after June 1, 2015. All currently existing Net Metering customers and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider-4 for a period not to exceed twenty years. UNS Electric is proposing that the Rider-4 expire no later than May 31, 2035.

Q. How will the Company purchase the excess energy produced by the Net Metering customer's facility?

A. Net Metering customers would be compensated for any excess energy their DG facility produces and delivers to UNS Electric with a credit on their current monthly UNS

Electric bill using the Renewable Credit Rate. Net Metering customers could carry over unused bill credits to future months if they exceed the amount of their current bill.

Q. What is the Renewable Credit Rate and how is it developed?

A. The Renewable Credit Rate is the price at which UNS Electric will compensate customers with DG for the excess energy produced by the customer's generation facility as discussed in Carmine Tilghman's testimony.

Q. If adopted, what issues will be remedied by UNS Electric's Net Metering tariff proposal?

A. First, eliminating the banking option for excess energy production will no longer give DG customers the impression that their excess energy can be stored on UNS Electric's system for future use. By simply purchasing the excess energy from the customer during their billing cycle, as opposed to allowing customers to use the kWh credits at a later time, UNS Electric will send more accurate price signals to Net Metered customers about their true energy costs.

Second, eliminating the banking option helps to partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements. The bypass of fixed cost recovery by DG customers can be illustrated with an example.

The table below presents the average monthly fixed cost recovery and average pre-tax monthly bills using UNS Electric's proposed rates for three types of residential customers at monthly electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The three customer types all take service under standard offer tariff RES-01 and the bills in this table are calculated with the RES-01 rates proposed in this application. The first case is a customer with no DG, the second a DG customer with Net Metering and banking of excess kWh, and the third a DG customer with Net Metering and utility purchase of excess kWh as proposed in this application. The DG customers have solar PV systems sized to produce a kWh output that would yield zero excess kWh on an annual basis and the load profiles for each customer size are from actual UNS Electric customer data.

Monthly Usage	No DG	Net Metering with Banking of Excess kWh	Net Metering with Purchase of Excess kWh
500 kWh per Month			
Monthly Fixed Cost Recovery	$37.61	$20.20	$28.88
Average Monthly Bill (pre-tax)	$63.79	$23.38	$28.22
Unrecovered Fixed Costs	NA	$17.41	$8.73
Monthly Bill Savings	NA	$40.41	$35.56
900 kWh per Month			
Monthly Fixed Cost Recovery	$57.72	$20.34	$37.27
Average Monthly Bill (pre-tax)	$102.05	$23.55	$33.93
Unrecovered Fixed Costs	NA	$37.38	$20.45
Monthly Bill Savings	NA	$78.50	$68.12
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$72.97	$20.39	$44.61
Average Monthly Bill (pre-tax)	$130.93	$23.62	$39.33
Unrecovered Fixed Costs	NA	$52.58	$28.36
Monthly Bill Savings	NA	$107.30	$91.60
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$88.20	$20.61	$52.85
Average Monthly Bill (pre-tax)	$159.76	$23.89	$45.46
Unrecovered Fixed Costs	NA	$67.58	$35.35
Monthly Bill Savings	NA	$135.87	$114.31

In this example, a residential customer on RES-01 using 900 kWh per month and no DG system would pay an average of $57.72 per month in fixed costs. The fixed cost recovery in this case consists of the fixed Basic Service Charge and the variable Delivery Services-Energy charges at that level of consumption. By contrast, the same customer with a DG system that produces the same annual kWh as consumed pays an average of $20.34 per month if allowed to bank kWh produced in excess of usage at any time in order to offset consumption at a later time. This results in a fixed cost recovery shortfall of $37.38. With a $20.00 per month Basic Service Charge, this customer is paying only $0.34 per month above the Basic Service Charge for the fixed costs associated with the generation capacity, transmission, and distribution infrastructure provided to serve the customer.

The same DG customer under the regime where UNS Electric purchases the excess kWh generated as proposed in this filing pays $37.27 in fixed costs. In this case UNS Electric recovers $16.93 more of its fixed costs than under the banking scheme, but is still $20.45 short of the fixed costs recovered from the non-DG customer. Keep in mind that the $16.93 in fixed costs that is bypassed using the banking scheme, like the utility infrastructure it is paying for, does not go away. It will ultimately have to be recovered from the other customers on the system who are not Net Metering customers. Because UNS Electric purchases the excess kWh production, there are now $16.93 less in fixed costs that must be recovered from customers without Net Metering.

Q. Customers with DG systems undertake a significant capital investment to reduce their electric bills. How would this proposal impact their savings?

A. Under this proposal, DG customers would still see significant savings on their electric bills. In the example above, the monthly pre-tax bill savings for a Net Metering customer using 900 kWh per month is reduced by $10.38, from $78.50 to $68.12. This is still a 67% reduction in that DG customer's monthly electric bill.

Q. Will this change to UNS Electric's treatment of Net Metering completely eliminate the shifting of fixed costs due to DG?

A. No. The adoption of the new net-metering rider, which no longer allows for energy banking, will reduce but not eliminate the subsidy. However, when combined with the proposed standard offer three-part tariff, the magnitude of cost shifts to non-DG customers will be greatly reduced.

Q. Why is UNS Electric proposing that new Net Metering customers be required to take standard offer service on a three-part tariff?

A. As I mentioned earlier, the proposed Net Metering changes will not fully mitigate the DG cost shift. The DG customers' usage patterns and load profiles are no longer those of a full requirements customer – in which the standard volumetric rate is designed to recover cost based upon. They are partial requirement customers and as such the three-part rate design is more appropriate. The three-part rate design is presently the Commission approved structure for UNS Electric's partial requirement customers in the larger rate classes.

The cost shift is also increased by the fact that a majority of the fixed costs to serve residential and small commercial customers are recovered through variable energy usage charges. These usage based charges have built in rate tiers that charge more for usage when a customer's consumption reaches each subsequent threshold. Assuming that fixed costs can fairly and equitably be recovered primarily through volumetric rates ignores the ever <u>increasing</u> magnitude of the cost shift created by DG customers, as well as energy efficiency and conservation.

DG customers avoid paying a substantial portion of their fixed costs of the system by avoiding these higher consumption levels. When the energy produced by a DG system is used by the customer and netted against the energy that would be delivered by the utility, the fixed costs embedded in the variable utility charges go unrecovered. Furthermore, the recovery of these fixed costs is being avoided primarily at the higher tier rates in the inverted block rate structure.

D. Three-Part Rate Proposals.

Q. Please summarize UNS Electric's new three-part rate proposals for residential customers.

A. For the residential class, UNS Electric is proposing RES-01 Demand and RES-01 Demand TOU. For RES-01 Demand, we are proposing the same $20.00 per month Basic Service Charge that we are proposing for RES-01. Also, we are proposing a two-tier monthly Demand Charge with the break point at 7 kW. Billing demand will be based on the 1-hour maximum measured demand during the billing month. The Delivery Service-Energy charges have a single tier and are reduced significantly from those in RES-01 to reflect the fixed cost recovery being more properly recovered through the demand charges. All other charges are identical to those in RES-01. For RES-01 Demand TOU, the Basic Service, Demand, Delivery Services-Energy, and all other charges except Base Power are the same as those for RES-01 Demand. The Base Power Charges vary by time of use.

Q. How would the proposed three-part rates impact residential customer bills?

A. The table below shows average monthly bills (pre-tax) for residential customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The customers in this example are full-requirements customers taking service under RES-01 and RES-01 Demand at proposed rates. The following customer examples were developed from UNS Electric's residential customers' usage data. It is evident from the comparisons presented in this table that customers at the lower end of the usage spectrum pay higher monthly bills on the three-part rate than on the two-part rate.

Bills calculated using the three-part rate will exceed bills using the two-part rate at lower levels of consumption. As usage increases, customers on the three-part tariff will have lower monthly bills.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill		
		RES-01	RES-01 Demand	Difference
500 kWh	19.4%	$70.16	$79.66	$9.49
900 kWh	22.4%	$112.26	$116.94	$4.68
1,200 kWh	25.0%	$144.02	$142.59	($1.43)
1,500 kWh	27.0%	$175.74	$170.38	($5.36)

Q. From this information, can one conclude that residential customers with very low usage will benefit less from a three-part rate than higher usage customers?

A. No. One other piece of information in this table is the average monthly load factor for each customer profile. Load factor is a concept that indicates how a customer is using energy relative to the peak demand that the customer incurs. One commonly used definition of the load factor is the average demand over a period divided by peak demand. By this definition as average demand increases relative to peak demand, the load factor increases. It also follows that as a customer uses more energy, i.e., more kWh, for any given peak demand, the load factor increases. It is generally accepted that a higher load factor implies a more efficient use of the utility system.

The load profiles used for these bill comparisons were developed from 2014 UNS Electric residential customer load data. One trend that is evident is that higher usage customers generally have higher load factors. As shown in the table above, the lower usage customers on the three-part rate see a negative impact, which decreases and becomes a positive benefit at higher usage levels. This occurs because the load factor is increasing not peak usage. The higher usage customers are using more kWh per kW than lower usage customers. As I mentioned earlier, Delivery Services-Energy charges in the three-part rate are approximately 70% lower than those in the two-part rate and the benefits of the lower per kWh charges begin to take over as load factor increases.

Q. What can one conclude from these results?

A. The three-part rate with a demand charge rewards customers with higher load factors, all else equal. More important, a three-part rate will reward customers who improve their load factor. If residential customers choose to take service on a three-part rate they will reduce their electric bills by improving their load factor or maintaining a higher load factor. As I mentioned earlier, higher load factors are consistent with more efficient use of the electric utility system. Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all UNS Electric customers as the system is used more efficiently.

Q. Are there other ways customers can benefit from a three-part rate design?

A. Absolutely. Customers continue to have more options to save in the future when technology can help them manage and reduce demand. As a simple example, consider someone with two air conditioning units, a pool pump and an electric water heater. That person (or UNS Electric through energy efficiency programs) could invest in systems that prevent all four appliances from coming on at one time. The units are cycled and thus the impact on the system and their demand charge is reduced as it relates to those pieces of equipment. These types of control systems are currently available and properly designed rate structures and customer education programs could lead to more installations and system benefits, by providing the proper economic incentive.

Q. Could a three-part rate structure for residential and small commercial customers encourage development of business models and customer applications aimed at reducing customers' individual demand?

A. Yes. A three-part rate structure will provide customers pricing options that could lead to earlier adoption of new energy technologies. For example, UNS Electric and other companies will be incentivized to combine technologies like solar panels, energy storage and demand control systems to maximize customer savings and profitability of their programs.

Q. Please summarize UNS Electric's new three-part rate proposal for small commercial customers.

A. The small commercial three-part rate tariffs UNS Electric is proposing are SGS-10 Demand and SGS-10 Demand TOU. We are proposing a Basic Service Charge of $30.00 per month for a SGS-10 Demand and a two-tiered Demand Charge with a break point at 15 kW. The second tier in the SGS-10 Delivery Service-Energy charges has been removed for the three-part rate and the energy charges are reduced significantly to reflect the fixed cost recovery being more appropriately recovered through demand charges. For SGS-10 Demand TOU the Basic Service, Demand, Delivery Service-Energy, and all other charges except Base Power are the same as those for SGS-10 Demand. The Base Power Charges vary by time of use.

Q. Is UNS Electric proposing that all residential and small commercial customers take service on three-part rate tariffs?

A. No. At this time UNS Electric is proposing three-part rate tariffs as optional for residential and small commercial customers who are not taking service under the Net Metering Rider-10. All residential and commercial Net Metering Rider-10 customers will be required to take service under the applicable three-part standard offer tariff.

E. Partial Requirements Customers.

Q. In your summary you state that UNS Electric is proposing that partial requirement customers qualifying for the new Net Metering Rider-10 must choose from one of the two proposed three-part rate tariffs applicable for their service requirement. Why is UNS Electric proposing to require these customers to use a three-part rate tariff?

A. Simply stated, the Company's current two-part rate design options do not account for how these customers use the system and will never properly recover a fair level of fixed costs. **The two-part rates are designed to recover costs based on the average consumption levels of full-requirements customers** - and as presently designed and proposed rely on energy charges to recover fixed cost. Also as discussed above, even with the changes we are proposing to our present full requirement tariffs (higher Basic Service Charge and elimination of a tier) – these new rates will continue to recover the majority of fixed cost through volumetric energy rates.

Q. Do UNS Electric's proposed three-part rates for partial-requirements residential and small commercial customers further mitigate the DG cost shifting covered earlier?

A. Yes. The table below presents monthly fixed cost recovery and average monthly electric bills for the same four residential customer profiles that I presented earlier. The examples in this case are for a full-requirements residential customer on RES-01 at proposed rates and two partial-requirements Net Metering customers, one on the proposed RES-01 two-part rate and the other on the proposed RES-01 Demand three-part rate. In both of the Net Metering cases, UNS Electric is purchasing the excess output of the DG system at the Renewable Credit Rate.

As is evident from the results in this table, the three-part rate goes a long way toward further mitigating the DG cost shift. For the 900 kWh per month customer I discussed earlier, only $0.34 per month in fixed costs is now bypassed. Furthermore, the customer is still saving $47.90 per month on their total electric bill, which is a savings of 47%. Even the low-usage customer at 500 kWh per month, while paying $6.17 per month more in fixed costs than the full-requirements customer, is saving $20.58 per month on the total electric bill, a savings of 32%. For the larger 1,500 kWh per month Net Metering customer on the proposed three-part rate total monthly bill savings are 57%.

Monthly Usage	RES-01 - Full Requirements	RES-01 - Net Metering	RES-01 Demand - Net Metering
500 kWh per Month			
Monthly Fixed Cost Recovery	$37.61	$28.88	$43.78
Average Monthly Bill (pre-tax)	$63.79	$28.22	$43.21
Unrecovered Fixed Costs	NA	$8.73	($6.17)
Monthly Bill Savings	NA	$35.56	$20.58
900 kWh per Month			
Monthly Fixed Cost Recovery	$57.72	$37.27	$57.38
Average Monthly Bill (pre-tax)	$102.05	$33.93	$54.15
Unrecovered Fixed Costs	NA	$20.45	$0.34
Monthly Bill Savings	NA	$68.12	$47.90
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$72.97	$44.61	$65.18
Average Monthly Bill (pre-tax)	$130.93	$39.33	$60.02
Unrecovered Fixed Costs	NA	$28.36	$7.79
Monthly Bill Savings	NA	$91.60	$70.91
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$88.20	$52.85	$75.49
Average Monthly Bill (pre-tax)	$159.76	$45.46	$68.23
Unrecovered Fixed Costs	NA	$35.35	$12.71
Monthly Bill Savings	NA	$114.31	$91.53

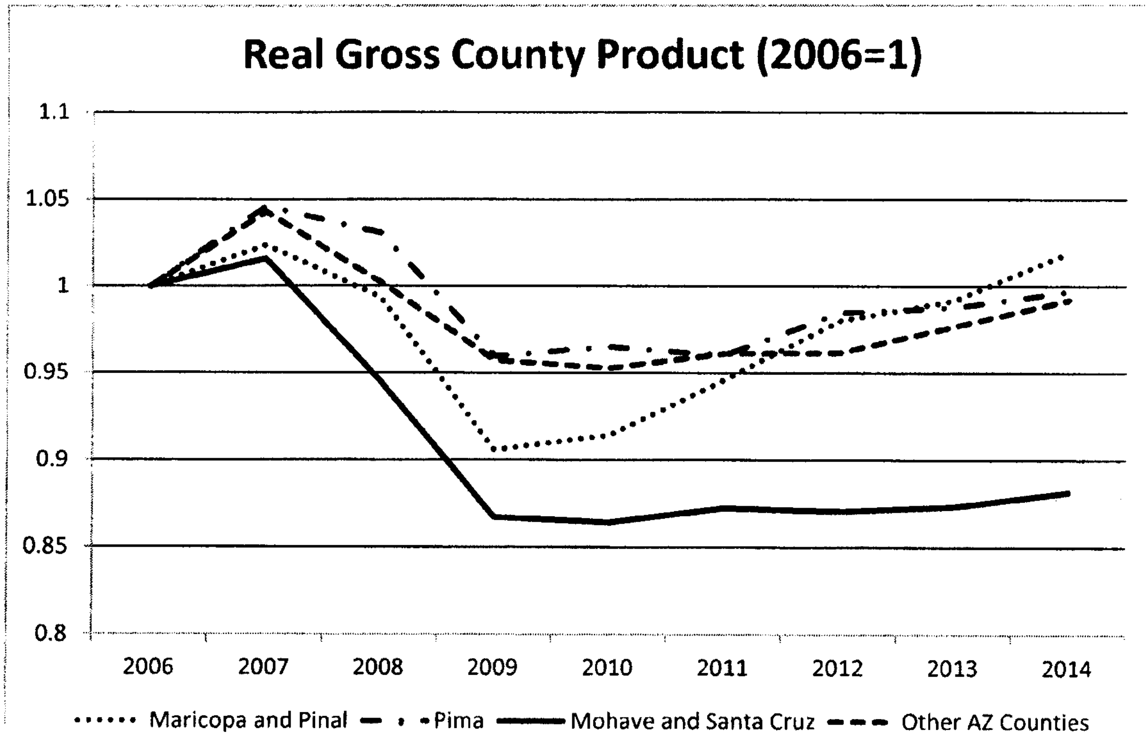
Q. You showed how residential DG customers with Net Metering will continue to see significant bill savings on the proposed three-part tariff. Are there any other opportunities for these customers to lower their monthly bills and realize added savings?

A. Yes. The incentive still exists for DG customers to reduce bills by decreasing billing demand or energy usage. However, because volumetric energy charges embodied in the three-part rate are much lower than those in the two-part rate, the potential savings from reduced energy use are not as high as those from reducing peak demand. Regardless, peak demand reductions that are greater than energy use reductions on a percentage basis will yield a higher load factor and provide benefits to the customer and the electric system.

F. <u>Economic Development Rider.</u>

Q. Why is UNS Electric proposing an Economic Development Rider in this proceeding?

A. The UNS Electric service territory has been very slow to recover from the economic downturn post 2007 and has also lost several of its largest customers in the past few years. Both of which has resulted in fewer sales units to spread the fixed cost of the system over and thus more cost being allocated to the remaining customers. I've already discussed the declining sales in the UNS Electric service territory and those impacts on customers' bills. Below is a chart showing the recovery of Real Gross County Product for Maricopa, Pinal, Pima and other Arizona counties – as opposed to the UNS Electric service counties, Mohave and Santa Cruz - these two counties have seen little to no improvement since 2009.



Q. Do you believe an Economic Development Rider could assist business growth in these areas?

A. Yes. The inclusion of this additional incentive along with the rate design changes discussed in UNS Electric witness Craig Jones' testimony, reducing rates for the business classes - should put the UNS Electric service territory in a better competitive position to attract and expand business load. This would be beneficial to the entire customer base and the State of Arizona.

Q. Please describe UNS Electric's proposed Economic Development Rider.

A. UNS Electric is proposing to offer Rider 13, Economic Development Rider ("EDR") to current or potential commercial and industrial customers that meet certain economic development criteria within the UNS Electric service areas. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher. The EDR will be available for five years from the effective date and provides qualifying customers with discounts on monthly electric bills according to a declining schedule over a five-year period at which point the discount is terminated. The discounts will apply only to the qualifying additional loads from new or expanding business operations and total program participation will be limited to 50 MW of applicable load.

Q. What are the qualifying criteria for the proposed EDR?

A. In addition to demand and load factor, customers must meet several criteria to qualify for the proposed EDR. First, potential EDR customers must qualify for at least one of two Arizona state tax credit programs designed to promote business recruitment, retention, and expansion. Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525) program provides a tax credit for net increases in full-time employees residing in the state and hired in qualified employment positions. The Qualified Facility Tax Credit (A.R.S. § 41-1512) program provides for a refundable tax credit for qualifying capital investment in a manufacturing facility that creates new jobs paying at least 125 percent of the median county wage and covering at least 80 percent of employee's health care premiums.

Q. Please describe the discounts available to customers qualifying for the proposed EDR.

A. All provisions, charges, and adjustments in the participants' applicable standard offer retail rate schedule will continue to apply. The proposed EDR will apply discounts on electric bills specific only to the qualifying additional load of participating customers. Economic Development is defined as new or expanding business operations that build new facilities. The discounts for Economic Development will be 20% in Year 1, declining to 2.5% in Year 5, and terminating after Year 5. Economic Redevelopment is defined as new or expanding business operations that occupy existing <u>vacant</u> facilities. The discounts for business expansion that qualifies as Economic Redevelopment will be 30% in Year 1, declining to 5% in Year 5, and zero after Year 5.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT TASC 4 ADMITTED

WORKPAPER

Unit Cost Analysis - winter visitors, apartments & duel fuel homes

Unit/Customer/month (@ customer's meter)

Customer Type	4 CP kW	kWh	4 CP kW	NCP kW	NCP kW	Ind Max kW	Customers	Customers	Customers	Customers	kWh
E-12, ET-1 & ET-2 non-solar	2.88	923	2.88	3.62	3.62	6.11	1.00	1.00	1.00	1.00	923
winter visitor	0.13	243	0.13	0.15	0.15	0.38	1.00	1.00	1.00	1.00	243
apartment	1.83	633	1.83	2.01	2.01	5.05	1.00	1.00	1.00	1.00	633
duel fuel[1]	5.03	1239	5.03	5.65	5.65	8.44	1.0000	1.0000	1.0000	1.0000	1239
Functional Unit Cost ($/Unit/month)[2]	**9.285**	**0.0405**	**1.769**	**(0.124)**	**2.890**	**1.401**	**8.109**	**5.033**	**0.959**	**0.381**	**0.0038**

Functional Unit Cost ($/Customer/month)

Customer Type	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total Cost	Base Bill	Over/(Under) Recovery	Base Revenue / Unadjusted kWh
E-12, ET-1 & ET-2 non-solar	**$ 26.71**	**$ 37.35**	**$ 5.09**	**$ (0.45)**	**$ 10.46**	**$ 8.55**	**$ 8.11**	**$ 5.03**	**$ 0.96**	**$ 0.38**	**$ 3.51**	**$ 105.71**	**$ 106.31**	**$ 0.60**	0.1152
winter visitor	$ 1.23	$ 9.82	$ 0.23	$ (0.02)	$ 0.42	$ 0.53	$ 8.11	$ 5.03	$ 0.96	$ 0.38	$ 0.92	$ 27.63	$ 31.92	$ 4.29	
apartment	$ 16.97	$ 25.62	$ 3.23	$ (0.25)	$ 5.82	$ 7.07	$ 8.11	$ 5.03	$ 0.96	$ 0.38	$ 2.41	$ 75.35	$ 76.04	$ 0.69	
duel fuel[1]	$ 46.67	$ 50.15	$ 8.89	$ (0.70)	$ 16.32	$ 11.83	$ 8.11	$ 5.03	$ 0.96	$ 0.38	$ 4.72	$ 152.36	$ 144.23	$ (8.13)	
E-12, ET-1 & ET-2 solar	**$ 30.24**	**$ 21.51**	**$ 8.35**	**$ 2.88**	**$ 13.30**	**$ 10.04**	**$ 7.33**	**$ 5.03**	**$ 0.96**	**$ 0.38**	**$ 4.33**	**$ 104.36**	**$ 43.58**	**$ (60.78)**	

Customer Count

Customer Type	E-12	ET-1	ET-2	Total	% TOU
E-12, ET-1 & ET-2 non-solar	468,372	140,698	288,729	897,799	48%
winter visitor	4,735	103	85	4,923	4%
apartment	79,883	3,004	32,958	115,845	31%
duel fuel[1]	73	158	131	362	80%
E-12, ET-1 & ET-2 solar	10,305	11,654	5,119	27,078	62%

Residential COS % 87%	Scaled to 100% Total Cost	Base Bill	o/(u) Recovery	% of Cost to Serve
E-12, ET-1 & ET-2 non-solar	$ 121.51	$ 106.31	$ (15.20)	87%
winter visitor	$ 31.76	$ 31.92	$ 0.17	101%
apartment	$ 86.61	$ 76.04	$ (10.57)	88%
duel fuel[1]	$ 175.13	$ 144.23	$ (30.90)	82%
E-12, ET-1 & ET-2 solar	$ 119.95	$ 43.58	$ (76.37)	36%

1. Duel fuel customers in sample have natural gas forced air furnaces. Some may also have between one and three gas appliances (range, oven, dryer). All live in single family detached homes and are located in low country. Customers were taken from 2011 residential saturation survey.
2. Functional unit cost based on E-12, ET-1 & ET-2 residential targeted ROR @ 4.99%.

EXHIBIT
TASC 5
judicial notice

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

JLM

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY REQUESTING COMMISSION APPROVAL OF NEW DISTRIBUTIVE GENERATION TARIFFS PURSUANT TO TITLE 17, SECTION 156 OF THE OKLAHOMA STATUTES	)	CAUSE NO. PUD 201500274 ORDER NO. **651669**

Hearing: December 1-2, 2015 in Courtroom B
2101 North Lincoln Blvd., Oklahoma City, Oklahoma 73105
Before Administrative Law Judge Jacqueline T. Miller

Appearances: William J. Bullard, Kimber L. Shoop, Patrick D. Shore, and Stephanie G. Houle, Attorneys *representing* Oklahoma Gas and Electric Company
Natasha M. Scott, Deputy General Counsel *representing* Public Utility Division, Oklahoma Corporation Commission
Ronald E. Stakem and Jack G. Clark, Jr., Attorneys *representing* OG&E Shareholders Association
Thomas P. Schroedter and Jennifer H. Castillo, Attorneys *representing* Oklahoma Industrial Energy Consumers
Jim Roth, Dominic D. Williams, Deborah R. Thompson and Thad Culley, Attorneys *representing* the Alliance for Solar Choice
Laurie Williams and Jacquelyn Dill, Attorneys *representing* Sierra Club
Dara M. Derryberry, Assistant Attorney General *representing* Office of Attorney General, State of Oklahoma

FINAL ORDER

The Corporation Commission of the State of Oklahoma ("Commission") being regularly in session and the undersigned Commissioners present and participating, there comes on for consideration and action the Application of Oklahoma Gas and Electric Company ("OG&E" or "Company") for an Order of the Commission approving certain tariffs to be applied to customers with distributed generation ("DG") facilities as of November 1, 2014, pursuant to 17 O.S. §156.

I. PROCEDURAL HISTORY

On July 31, 2015, Oklahoma Gas and Electric Company ("OG&E") filed an Application initiating this cause along with the direct testimony of Roger D. Walkingstick, a Motion for Protective Order, Motion to Determine Notice Requirements and Approve Form of Notice and a Motion for Procedural Schedule.

On August 5, 2015, the Attorney General filed an Entry of Appearance for Jerry J. Sanger. On August 6, 2015, OIEC filed an Entry of Appearance. On August 12, 2015, the Alliance for Solar Choice ("TASC") filed a Motion to Associate Counsel and Entries of Appearance for Thad Culley, William L. Humes, Jim Roth and Dominic D. Williams. On

The Commission further finds that the statute provides that a higher fixed charge for customers within the same class of service that have DG is one means to avoid subsidization between customers within that class of service and shall be deemed in the public interest.[6]

The Commission further finds that OG&E's existing tariffs could create the opportunity for subsidies between DG participants and non-participants; however, the Commission is not persuaded a subsidy has been demonstrated in this Cause. Further, the Commission is not convinced that the proposed tariffs charge DG customers only the amount required to recover the full costs necessary to serve these customers. The Commission finds that it is appropriate at this time to address any DG issues relating to 17 O.S. § 156 in OG&E's current general rate proceeding, Cause No. PUD 201500273. Review of any proposed DG tariff(s) in the rate case will allow the Commission to perform a full and thorough evaluation based upon updated information, and no party has alleged that this course of action would result in a violation of 17 O.S.§ 156.

The Commission further finds that there is no basis to deem OG&E's application and proposed tariffs as constituting alleged inappropriate or prohibited single issue ratemaking. This Commission has, at various times, and for good cause shown, granted various requests for stand-alone riders or trackers and done so outside the context of a general rate case.

The Commission further finds that the items on PUD's Checklist for Distributive Generation Tariff Filings were not completely considered and addressed in this Cause. The Commission recognizes the value of these items and encourages all the parties to submit relevant information in future filings relating to DG, as well as methods by which to inform and educate customers.

The Commission further finds that the Motion to Dismiss filed by TASC is moot due to the Cause proceeding to merit hearing.

V. ORDER

Based upon the above and foregoing the Commission orders the following:

1. The application to approve the tariffs proposed by the Applicant in this cause is hereby denied; and

2. Updated proposals by OG&E to address the issues set forth in 17 O.S. §156 should be examined and determined in its current general rate proceeding, Cause No. PUD 201500273.

3. The existing NEBO tariff remains in effect until further order of the Commission.

[6] 17 O.S. § 156 (D).

EXHIBIT
TASC 6
Judicial Notice

Decision No. C15-0990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 14M-0235E

IN THE MATTER OF COMMISSION CONSIDERATION OF RETAIL RENEWABLE DISTRIBUTED GENERATION AND NET METERING.

DECISION CLOSING PROCEEDING

Mailed Date: September 15, 2015
Adopted Date: August 26, 2015

I. BY THE COMMISSION

A. Statement

1. The Commission opened this proceeding on March 18, 2014, finding that a Commission-directed inquiry into net metering and potential impacts of the expansion of retail renewable distributed generation in Colorado was timely and in the public interest.[1]

B. Discussion

2. On April 9, 2014, we convened a Commissioners' Information Meeting (CIM) to hear participants' views on the specific net metering issues the Commission should address. We also encouraged participants to file comments.

3. On June 9, 2014, we determined that it was necessary, based on the presentations at the CIM and responsive filings, to gather additional information through a series of panel discussions.[2] We also invited the submission of legal briefs on certain questions suggested in the participants' comments following the CIM.[3]

[1] Decision No. C14-0294

[2] Decision No. C14-0615-I

[3] *Id.*

4. On July 24, 2014, we convened the first panel session. Public Service Company of Colorado (Public Service) and representatives of Colorado's on-site solar industry made presentations on the projected growth of on-site solar in Colorado; the cost of on-site solar for non-solar customers and customers with solar; and, the financial impacts of net metering on Colorado's regulated electric utilities.[4]

5. The Commission held its second panel session on October 1, 2014. We invited Bryan Hannegan, Associate Director of the National Renewable Energy Laboratory (NREL) to discuss a report on alternative approaches to quantifying the benefits (and costs) of on-site solar.[5] Representatives of electric utilities and the on-site solar industry presented information on customer benefits from on-site solar, systems benefits of on-site solar, and the quantification of those benefits. The Interstate Renewable Energy Council (IREC) also shared findings from a report on the costs and benefits of on-site solar.[6]

6. For the third panel discussion on December 1, 2014, we were joined by Commissioner Beverly Jones Heydinger from the Minnesota Public Utilities Commission, Commissioner Susan Bitter Smith from the Arizona Corporation Commission, Commissioner David Noble from the Nevada Public Utilities Commission and, Dr. Dan Arvizu, Director of NREL. We hosted a round-table discussion about how other states are assessing the costs and benefits of net metering and their approaches to resolving the issues surrounding net metering.

[4] Attachment A to Decision No. C14-0776-I provided a list of questions for participants to respond.

[5] Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System, Technical Report NREL/TP-6A20-62447 September 2014.

[6] A Regulator's Guidebook: Calculating The Benefits And Costs Of Distributed Solar Generation.

7. On April 23, 2015, we held a fourth panel session to hear from the Electric Power Research Institute (EPRI), SolarCity, IREC, Western Resource Advocates (WRA), and Public Service about on-site storage, distribution system design and ancillary benefits, and photovoltaic (PV) system size and orientation. The Regulatory Assistance Project (RAP) provided background on the design and use of a minimum customer bill as a potential approach for utilities to address any under-recovery of fixed costs. Representatives of Public Service and the on-site solar industry shared their respective views on how a minimum bill should be structured. We then solicited comments addressing topics discussed during the fourth panel session and summaries of participants' positions on the primary issues raised in this proceeding.[7]

8. The following persons participated in this proceeding through presentations at the panel sessions or filings: The Alliance for Solar Choice; Black Hills/Colorado Electric Utility, L.P.; the City and County of Denver; Climax Molybdenum Company; Colorado Energy Consumer Group; Colorado Rural Electric Association; the Colorado Energy Office; Colorado Forest Energy LLC; Colorado Office of Consumer Counsel; Staff of the Colorado Public Utilities Commission; Colorado Solar Energy Industries Association; EPRI; Leslie Glustrom; Intermountain Rural Electric Association; IREC; Interwest Energy Alliance; Karey Christ-Janer; La Plata Electric Association; NREL; Public Service; Lee Rayburn; Redlands Water and Power Company; RAP; Renewable Energy Systems America; Sierra Club Environmental Law Program; SolarCity; Solar Energy Industries Association; Southeast Colorado Solar Coalition; the Vote Solar Initiative; Wal-Mart Stores, Inc. and Sam's West Inc.; and WRA.

[7] Decision No. C15-0158-I issued February 17, 2015.

C. Findings and Conclusions

9. This proceeding provided the Commission with extensive information regarding the possible costs and benefits of net metering and potential solutions to the issues raised by various participants. The scope of this proceeding was informational; therefore, we defer consideration of specific claims and requests for relief to future adjudicated proceedings, as proposed by many of the participants.

10. We have reviewed all of the information provided by the participants and have considered their legal arguments, comments, and recommendations. Based upon this review, we conclude that we will not change our rules governing net metering or retail renewable distributed generation in 4 *Code of Colorado Regulations* (CCR) 723-3 of the Commission's Rules Regulating Electric Utilities, any program for the acquisition or development of on-site solar systems offered by qualifying retail utilities under § 40-2-124(1)(e), C.R.S., or any rate or tariff for retail electric service provided by the investor-owned electric utilities.

II. <u>ORDER</u>

A. The Commission Orders That:

1. This Proceeding is closed.

2. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

3. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING August 26, 2015.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JOSHUA B. EPEL

PAMELA J. PATTON

GLENN A. VAAD

Commissioners

EXHIBIT
TASC 7
ADMITTED

aps

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AZ CORP COMMISSION
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ORIGINAL

March 1, 2016

Arizona Corporation Commission
DOCKETED

MAR 01 2016

DOCKETED BY KG

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

RE: Arizona Public Service Company's Preliminary 2017 Integrated Resource Plan; Docket No. E-00000V-15-0094.

Attached, please find Arizona Public Service's Preliminary 2017 Integrated Resource Plan (IRP), as required by the IRP Timeline approved in Decision No. 75269 (September 16, 2015).

If you have any questions regarding this information, please contact Kerri A. Carnes at (602) 250-3341.

Sincerely,

Debra Orr for

Kerri A. Carnes

KC/kr
cc: Parties of Record

Copies of the foregoing delivered/mailed this 1st
day of March, 2016, to:

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PRELIMINARY

2017 Integrated Resource Plan

Filed in Compliance with ACC Decision 75269

March 01, 2016

aps

As part of the preparation for the Preliminary 2017 Integrated Resource Plan, APS held a public IRP Stakeholder Workshop on 02/09/16 that covered topics ranging from changing load shapes to resource procurement for its upcoming Request for Proposal. The full agenda included:

IRP Process
Energy Demand Forecast and Economic Conditions
Evolving Load Shape, Markets and Resource Implications
Clean Power Plan Overview
Resource Needs
Action Plan Update
EIM Overview
Energy Efficiency
Renewable Energy Program
Technology
Assumptions, Portfolios & Sensitivities
2016 All Source Request for Proposal (RFP) Solicitation Overview

Presentations from the IRP Stakeholder Workshop can be found at www.aps.com/resources

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Preliminary 2017 Integrated Resource Plan (IRP)

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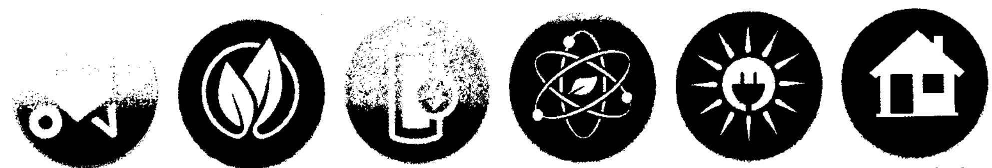
PRELIMINARY PLAN HIGHLIGHTS

Load Forecast
Page 9

+2.7%

APS forecasts that over the course of the 2017-2032 Planning Period, annual load will increase by 2.7% and annual retail sales by 2.6%, prior to the effects of energy efficiency (EE) and rooftop solar generation. The forecast is based on expectations for population growth, increased saturation of personal electronics, the trends toward larger homes, greater economic activity and greater metropolitan infill.

Portfolios / Scenarios
Page 11



Coal Strategy | **Carbon Reduction Portfolio** | Battery Energy Storage Systems | **Small Modular Reactors (SMR)** | **Expanded Renewables** | **Expanded Demand Side Management**

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- Natural gas
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- Coal

Sensitivities
Page 10

- Natural gas prices
- Carbon dioxide (CO2) prices
- Load forecast
- Technology pricing

Action Plan
Page16

- Conduct All Source Request for Proposal (RFP) and plan for future needs
  - Conduct RFP in March 2016 for 2020 delivery
  - Begin initial site planning for post-2020 resource needs
- Complete Solar Innovation Study
  - 75-home study on advanced technologies
  - 125-home study based on third-party custom-designed technology packages
- Complete Solar Partners Program and related pilots
  - APS-owned rooftop solar research and development program
- Complete customer solar project
  - Construct 40 MW SAT solar project
- Complete initial microgrid projects
  - Partner with customers to develop on-site backup generation
- Participate in CAISO-Energy Imbalance Market
  - Go-live date: October 2016
- Complete Ocotillo Modernization Project
  - Replace 1960s steam generators with quick-start natural gas CT units
- Further develop and implement coal strategy
  - Continue to implement Cholla Power Plant strategy and evaluate continuing role of Navajo Generating Station

STRATEGIC FOCUS

Introduction

The energy paradox that has been building momentum in Arizona and other solar-rich regions is no longer a theoretical possibility; it is an operational reality. On one hand, as the state's economy recovers from the recession, the forecast for peak energy demand is on the rise. On the other hand, in a state that boasts the #2 national ranking in total solar installations[1], the net demand for non-summer mid-day energy is on a decline. The divergent nature of these two trends requires utilities to not only re-examine how to balance supply with demand, but also how to plan for the future. Having sufficient resources to meet peak load is no longer the only objective; having the right type of resources and a wide spectrum of customer options are also necessary and will become more so as solar energy continues to grow not only in APS's service territory, but regionally as well.

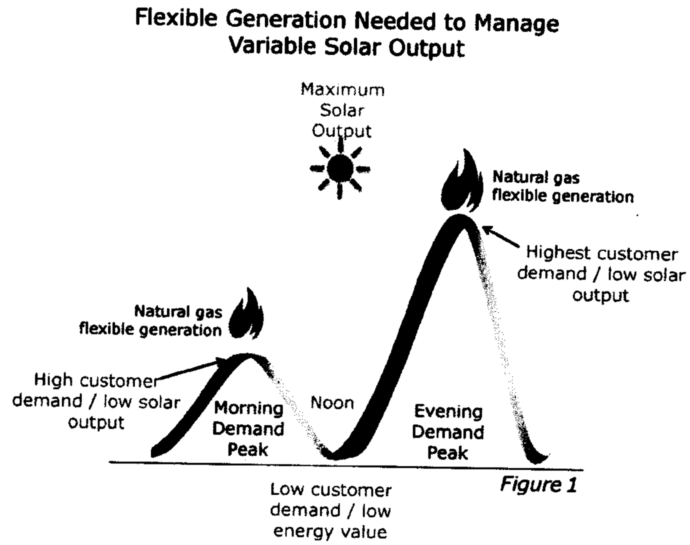


Figure 1

To meet these challenges, APS is focused on:

- Evolving Load Patterns – As more variable generation enters the resource mix, the more loads decline during midday hours then rapidly ramp up towards the evening hours. This trend is redefining what resources are needed to respond to the increasing peaks and troughs of today's demand profile.

- Changing Resource Needs – Flexible generation is particularly suited to manage increasingly dynamic operating conditions. The Ocotillo Modernization Project is one example of how APS is responding to this need, while other examples include battery storage and other advanced technologies.

- Increasing Market Participation – Market solutions can provide another layer of flexibility by offering platforms such as the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) which not only pools resources from participating utilities but also adds five- and fifteen-minute transaction capabilities.

- Enhancing Customer Engagement – Advanced grid technologies are transforming energy systems to fit a 21st century model. Two-way communications between APS and its customers and other technologies such as Advanced Distribution Management

Systems (ADMS), Communicating Fault Indicators and Integrated Volt/VAR Control are expected to be deployed to improve reliability, elevate customer satisfaction and provide the foundation for further innovations to come.

- Clean Power Plan - The Clean Power Plan (CPP) is a comprehensive regulation aimed at reducing nationwide carbon emissions from existing electric generating units by 32%. To achieve that goal, the Environmental Protection Agency (EPA) assigned each state a reduction target, with Arizona's being 33.6%. On February 09, 2016, the Supreme Court issued a stay on the enforcement of the CPP. APS continues to monitor the legal challenges to this regulation and to plan for potential compliance in the event the CPP is ultimately upheld.

Providing a Platform for the Future

APS's 2014 Integrated Resource Plan (IRP) focused on the need for flexible generation to manage these challenges - a theme that is expected to remain dominant in the 2017 IRP. Critical in helping achieve a dynamic equilibrium, rapidly responding units can be ramped down or turned off when solar energy production is at its highest, then ramped up to meet customer needs as the sun starts to set. This ability to meet both minimum and maximum load requirements within hours increases system costs, yet accommodates the impact that variable generation has on the electric system and helps integrate the increasing levels of solar generation that are forecast to grow well beyond the requirements of Arizona Corporation Commission's (ACC) Renewable Energy Standard (RES).

The challenge to integrate increasing variable resources is shaping a future of expanded solutions

Providing customers a seamless and reliable energy platform under these evolving operating conditions will require more than just new generation types. It will require a diversified array of solutions. In April 2015, APS announced its decision to participate in the EIM which is not only expected to provide cost savings to customers, but also to allow access to a large and diverse pool of resources that can quickly respond to the variability of renewable energy resources and their effects on net customer demand profiles. Other solutions include advanced grid technology investments to improve reliability and provide for data analytics of real-time system needs and performance.

Finally, as new solutions become part of the operating system, the evaluation of traditional resources will also come into play. While APS continues to execute its plans for the Four Corners Generating Station, its focus turns to its remaining coal facilities. The Cholla Power Plant and the Navajo Generating Station have key decisions ahead and will be evaluated relative to how APS can reliably and affordably continue serving customers' energy needs.

Evolving Load Patterns

The new norm in solar abundant regions with slow population growth and high levels of rooftop solar generation like Arizona is declining minimum loads and sharply changing patterns of maximum loads. To examine these new demand shapes, the focus has shifted from traditional load curves (total demand before the effects of customer and other variable resources) to net load curves (total demand after accounting for customer and other variable energy resources). Figures 2 and 3 illustrate the difference in net load curves during summer and non-summer months. The difference is particularly evident in the non-summer months when overall demand is low and renewable energy resources have the effect of producing a dual peak – one in the morning and a larger one in the evening. The effect is less in the summer months as variable energy resource impacts are diluted across higher overall demand.

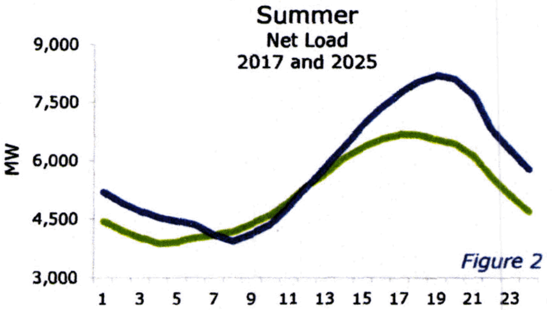


Figure 2

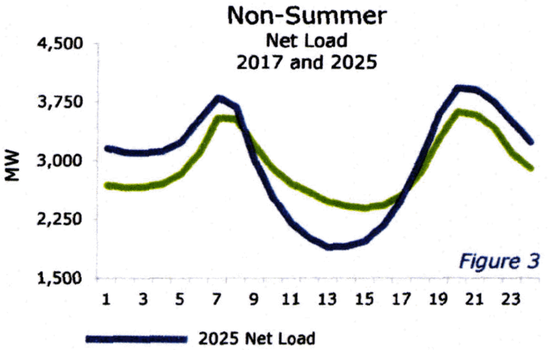


Figure 3

As solar energy expands its contribution to the portfolio mix, the difference between load and net load curves will become more significant, especially in non-summer months. With that difference, two factors emerge: solar generation in the midday hours causing the need to ramp generating units down or turn them off to make room, and the need to quickly respond to increasing demand in the early evening hours as the sun sets.

In terms of wholesale market pricing, solar generation is impactful. In regions with high penetration of variable energy resources, such as the West, short-term market prices of electricity have fallen to zero and then gone negative at times – meaning the buyer gets paid to take electricity because there is too much energy on the system. This phenomenon is a price signal from the wholesale power markets that there is more generation than demand. Because utilities continue to have less flexible generation resources in their portfolios, making room for low or negatively priced wholesale power can be difficult. Although forecast increases in load from population growth and advances in energy storage technologies can act as a slight offset, they will not approach the growth rate of variable energy resources and their impacts on wholesale pricing and resource portfolios.

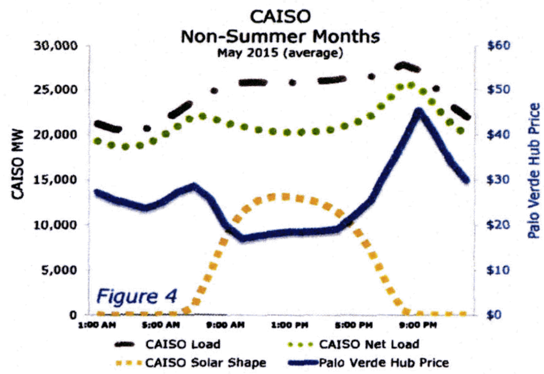
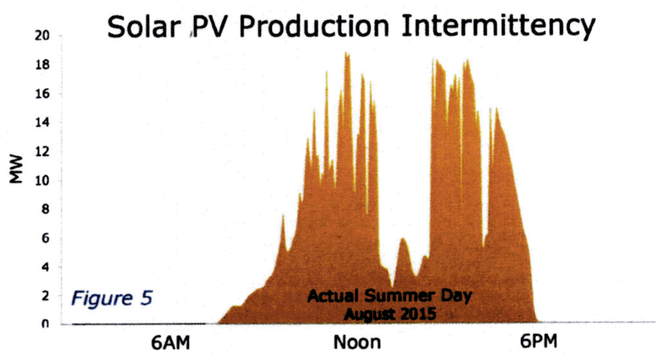
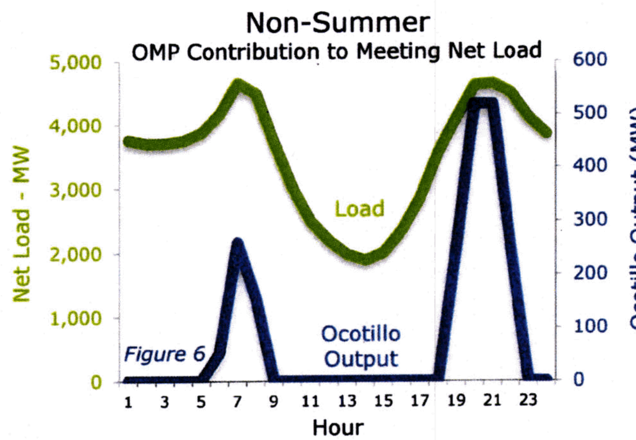


Figure 4

Changing Resource Needs



Higher penetration levels of variable energy resources, related changes in net demand patterns and continued low natural gas pricing have challenged the traditional diverse resource mix model. What has not changed is the need to continuously balance supply and demand. Providing a platform to integrate these increasingly dynamic operating conditions requires a transformation in the traditional utility resource portfolio towards more flexibly dispatched peaking resources. Figure 5 illustrates the variability of solar generation for which fast-starting, fast-ramping resources are ideally suited. Incorporating flexible resources into the portfolio will not only help counter-balance the variability and unique needs of a more renewable-driven mix, it will allow customers to benefit from the changing wholesale market prices produced in midday hours when solar production is at its highest.



The Ocotillo Modernization Project (OMP) currently underway is an example of how APS is responding to the flexible resource needs on its system. The project, scheduled to be completed in 2019, consists of replacing two 1960s-era steam generators with five fast-starting, fast-ramping natural gas combustion turbine (CT) units with capacities of 102 MW each. Figure 6 uses the net load graph for a non-summer month and illustrates how OMP's operational characteristics may respond to the dual peaks created by solar penetration. To manage the challenges of meeting peak summer demand, APS plans to also add market combined cycle (CC) natural gas units to its system during the 2017-2032 Planning Period. In Arizona, having both types of natural gas-fired resources is important for a balanced natural gas fleet.

As technologies advance, so do flexible options. Battery storage, small reciprocating engines and updated customer price signals are some of the solutions also being proposed. Similar to CTs, small reciprocating engines are fast-starting and fast-ramping, making them well-suited for managing the variability of renewable resources. While still not economically viable or sufficiently mature for wide-scale deployment, battery storage may offer similar flexibility by capturing solar energy produced during daylight hours, then sending that energy to the grid in the evening when it is most needed by customers. With its ability to both consume energy and supply it, battery storage may become an important part of APS's future resource picture.

Increasing Market Participation

APS's 2014 Integrated Resource Plan's focus on flexibility was based on three defining energy market trends: (1) increased penetration of renewable energy, which requires a transformation of the fleet toward higher levels of flexible generation to integrate it; (2) the favorable price outlook for natural gas, which makes the development of natural gas based flexible assets economically viable; and (3) the technological advancements that provide for enhanced real-time management of the electric system and related energy dispatch, a critical component to accommodate the variability that comes with increasing penetration of renewable energy.

As these trends are as prevalent across the Western region as they are in APS's service territory, the flexibility concept can be applied on an even broader scale. Every hour of every day, APS transacts with regional wholesale market participants to bring affordable, reliable electric service to our customers. Those interactions have long been a part of meeting load, managing APS's system and contributing to the overall reliability of the regional electric system. It is a natural evolution then to extend that ability to access markets from a bilateral transaction model to a more structured inter-system pool to provide APS with an added layer of real-time flexibility and economic opportunity. Within the Western Interconnection, the most comprehensive approach to respond to these changes and still maintain the participating utility's autonomy is the CAISO's EIM.

Figure 7

Last April APS announced its decision to participate in the EIM. The annual cost savings to APS customers from these benefits are expected to be approximately $7 million. Although significant, the economic benefits were not the sole determinant in the decision. Optimizing generation dispatch across multiple participants gives EIM participating utilities more tools to provide a platform to integrate growing renewable energy supplies. Traditionally, utilities have had to dispatch their own generation to handle demand/supply imbalances, supplementing any remaining needs by transacting bilaterally in the day-ahead and hourly wholesale markets. The EIM not only pools resources from participating utilities, it also adds five- and fifteen-minute capabilities to further optimize resource decisions.

EIM participation is voluntary and does not require APS to join the CAISO. Utilities that participate in the EIM do not relinquish control of their generating or transmission assets, and they maintain all of their respective system reliability and compliance responsibilities. The EIM is designed to complement each utility's existing energy trading practices and does not alter an individual utility's resource planning and procurement responsibilities. Each EIM participant is required to procure or develop sufficient resources to meet its own unique customer demand needs and to satisfy its own operational requirements such as having sufficient flexible ramping capabilities to meet non-summer net load curve challenges.

Enhancing Customer Engagement

With new technologies, changing customer preferences and an evolving resource mix, energy systems across the country are being transformed to fit a 21st century model. This new model is expected to not only pave the way for a more interactive relationship between APS and its customers but also between customers and the energy they use.

One example of how these technologies will benefit customers is the strategic deployment of advanced two-way communicating devices that allow the utility to monitor the electric system in real time, while providing timely information to customers, enabling them to manage their individual energy needs. In July 2014, APS reached full deployment of advanced meters (AMI) with 1.25 million meters installed, including 30,000 solar production meters, which on an average day provide 40 million data points.

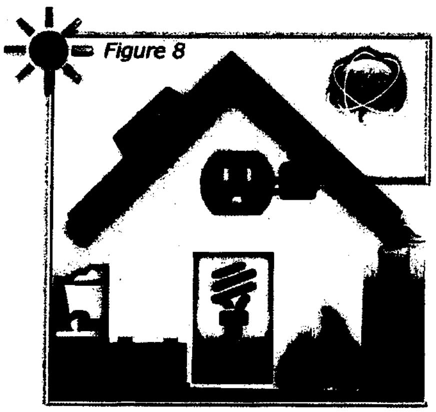


Figure 8

Other technologies include (1) Advanced Distribution Management System (ADMS), which provides the distribution system the enhanced operational platform similar to what is used for the transmission system, (2) Communicating Fault Indicators that can detect and locate problems on the system in real time to enable faster power restoration and (3) Integrated Volt / VAR Control, a software application that provides round-the clock voltage management, including self-adjustments to ensure voltage levels stay within a pre-determined range. During the 2017-2021 Action Plan Period, APS expects to increase the deployment of these technologies and others to improve reliability, elevate customer satisfaction and provide the foundation for further innovations to come.

Energy efficiency (EE) opportunities are also providing customers a greater role in managing how they use energy. New and emerging technologies such as home energy management systems and smart thermostats offer customers new opportunities for managing their energy use and, importantly, peak demand. As these devices become more economic and integrated with each other, customer systems will offer automatic responses to changing utility price signals in real time, optimizing the operation of key appliances and energy systems to manage peak demand and reduce costs. APS is currently conducting the Solar Innovation Study to further explore these integrated distributed energy resource solutions and the benefits they can provide. Future APS planning efforts will increasingly incorporate this integrated distributed energy resource perspective in developing resource plans.

As advancements continue to permeate the industry, adjustments to current programs and technologies will also be needed. Avoided costs have decreased due to low natural gas and wholesale power prices, challenging the cost-effectiveness of some Demand Side Management (DSM) programs, particularly those that incent savings during midday hours when solar generation is at its highest and wholesale power prices are among their lowest. Consistent with system resource needs, DSM programs will need to focus on energy savings during late afternoon and early-evening high-demand periods, and provide less focus on midday savings. This can be done by carefully targeting savings to the load profiles that best fit resource needs and integrating energy efficiency with load shifting and demand response opportunities such as Behavioral Demand Response and Smart Thermostat Demand Response Programs.

Clean Power Plan

Supreme Court Stay of Clean Power Plan

On February 9, 2016, the Supreme Court issued a stay on the enforcement of the EPA's Clean Power Plan (CPP). The stay will remain in effect while legal challenges to the CPP are resolved in the U.S. Court of Appeals - D.C. Circuit and during any further appeal to the Supreme Court. APS continues to monitor the legal challenges to the CPP and continues to plan for potential compliance in the event the CPP is ultimately upheld.

Clean Power Plan - Overview

On August 3, 2015, the Environmental Protection Agency (EPA), under Section 111(d) of the Clean Air Act, finalized the Clean Power Plan (CPP). One of the most comprehensive regulations in the agency's history, the CPP is aimed at reducing overall carbon dioxide (CO2) emissions from existing electricity generating units (EGUs) by 32% by 2030. Although the overall goal is national, compliance is at the state level, with EPA assigning each state interim and final reduction targets and giving them the option to comply individually or as part of a multi-state effort.[2,3] The three building blocks determined by the EPA to comply with the CPP include: Building Block 1 - reducing the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants; Building Block 2 – increasing generation from natural gas plants in exchange for reducing generation from coal-fired power plants; and Building Block 3 - increasing generation from zero-emitting renewable energy sources in exchange for reducing generation from existing coal-fired power plants.[4]

Arizona's state emission reduction target is 33.6%, slightly above the national target of 32%. In terms of emissions rate reduction, the state's goals from a 2012 baseline emissions rate of 1,552 lbs. of CO2/MWh include the interim 2022-2029 goal of 1,173 lbs. of CO2/MWh and the final 2030 goal of 1,031 lbs. of CO2/MWh.[5]

While APS's Coal Strategy as outlined in the September 2014 IRP Supplement was not designed with compliance to the CPP in mind, APS anticipates that it will be in a position to meet its compliance requirements should the CPP be upheld. This projection is based on the assumption that ADEQ will select a rate-based compliance plan. Should the ADEQ select a mass-based compliance plan, additional compliance costs beyond what are contemplated in the Coal Strategy will likely be required. In addition, further compliance costs may arise as EPA determines whether, or how, the CPP will be implemented on the Navajo Nation, as currently proposed by the EPA.

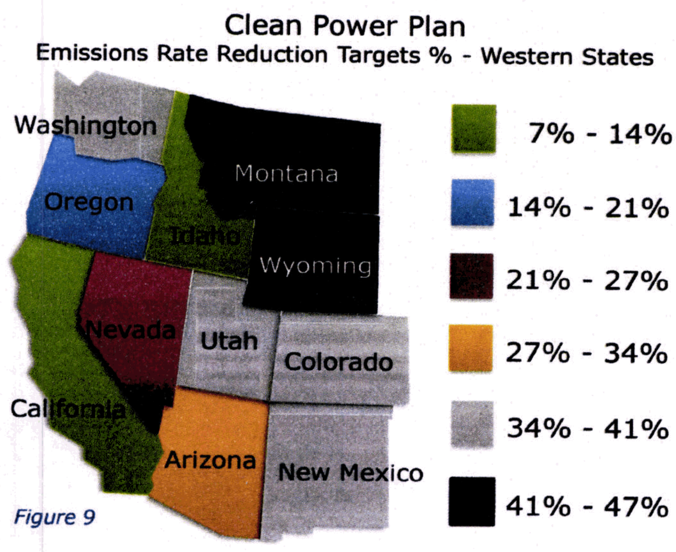


Figure 9

Load Forecast

Evaluation of Load Forecasting Techniques

As required in Decision No. 75068, APS submitted on October 30, 2015 a re-examination of its load forecasting techniques. The re-examination focused on the components which have the largest impact on overall load growth: population growth forecast (and by extension, the residential customer growth forecast), the residential use per customer forecast, and the commercial & industrial (C&I) customer electricity demand forecast. To determine the validity of its current techniques, APS tested six different models for its residential use per customer forecast and five different models for its C&I demand forecast. Although the conclusion of these assessments was that the current models remain the preferred method for developing projections, APS will continue to periodically re-examine methodologies as part of good business practice.

Load Forecast Highlights

APS currently forecasts that annual peak demand will increase by 2.7% and annual retail sales by 2.6%, prior to the effects of energy efficiency (EE) and rooftop solar generation during the 2017-2032 Planning Period. For residential customers, the forecast increase is based on the expectation for larger homes, increased saturation of electronics and higher proportion of APS customers living in the lower desert areas, where temperatures are generally higher than in other parts of our service territory. For C&I customers, the forecast is based on greater economic activity and the increase in related occupied commercial building floor space.

2.7%	2.6%
Peak Demand Growth before EE and Rooftop Solar Generation	Retail Sales Growth before EE and Rooftop Solar Generation

Economic Conditions Highlights

Population growth is the most influential variable in developing a load forecast, providing the basis for several other forecast components such as growth in households and residential customers. The most variable element of population growth is net migration because it is the most sensitive to near-term business cycle effects. In an effort to enhance the modeling and development of the net migration forecast, APS contracted with the Economic and Business Research Center at the University of Arizona to develop a modeling framework which will help ensure that fundamental shifts in migration patterns and behavior are made more transparent in future projections.

2.1%	1.3%
Population Growth	Net Migration Contribution to Growth

Resource Planning – Model, Sensitivities & Uncertainties

Model

The 2017 IRP will document a comprehensive analytical process aimed at meeting future customer needs, achieving regulatory goals and managing environmental impacts during the 2017–2032 Planning Period.

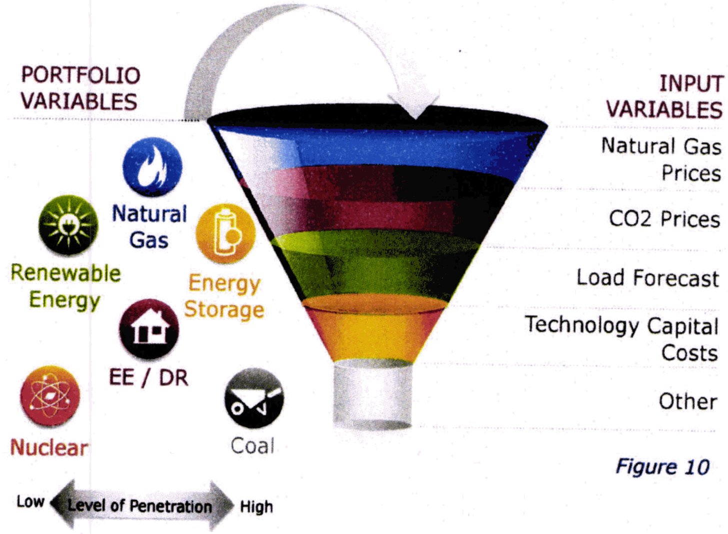


Figure 10

Resources expected to be included in the 2017 IRP are natural gas, nuclear (both large-scale and small modular), renewable energy (on both sides of the meter), coal, energy efficiency, demand response and new technologies such as energy storage. To analyze these resources, APS uses the Ventyx suite of products, including PROMOD and Strategist.

Sensitivities

To create the final portfolios, resources considered for testing in the 2017 IRP will be evaluated in various combinations under parameters specific to each portfolio. These portfolios will then be analyzed by stressing key input variables such as natural gas prices, CO2 prices, technology capital costs and load forecast sensitivities to determine the resiliency of each combination of resources under a variety of conditions.

$ Based on 9/30/2016 Henry Hub forward markets

Natural Gas Prices

$
- Low: $0
- Base: California markets
- High: TBD in 3Q2016

CO2 Prices

$ $300 - $6,500 ($ /kW)

Technology Capital Costs (Installed)

% 90% - 110% of Forecast

Load Forecast Sensitivities

Uncertainties

Notwithstanding that much of the planning process is quantitative in nature, there is also a significant qualitative assessment that includes considerations such as environmental regulation risks, natural gas pipeline availability risks, market capacity contracting risks, and the risks of the technological maturity and energy production capability of new technologies. Although more intangible than the quantitative risks, uncertainties in these areas can be highly impactful and require ongoing monitoring and evaluation of their potential effect on the portfolios.

Portfolios / Scenarios

Portfolios are distinct sets of resources designed to meet customer power needs over the Planning Period. Although all the portfolios incorporate much of the existing fleet, each portfolio focuses on different technology combinations that could become part of APS's energy mix in various proportions. In the 2017 IRP, portfolios other than those listed below may be considered as APS evaluates different combinations of key technologies.

As APS and other parts of the West provide a platform to integrate a higher penetration of variable resources in the energy mix, as well as advanced technologies and distributed energy resources, the need for conventional baseload resources will decline over time.

Coal Strategy

Evaluates early retirement of Cholla Units 1 and 3 and NGS, executes Four Corners strategy

- Reduces future upgrades
- Manages aging fleet concerns
- Expands opportunities for other technologies
- Reduces environmental impacts

Carbon Reduction

Evaluates carbon reduction beyond potential CPP requirements

- **Provides for new technologies, including SMRs and energy storage**
- **Expands use of renewable energy**
- **Reduces environmental impacts**

Battery Energy Storage Systems

Incorporates greater penetration of BESS to further integrate renewables and help manage peak demand

- Captures energy for later use
- Mitigates variability of renewable energy resources
- Provides local voltage management
- Provides ancillary services (non-energy components required for system operation)

Small Modular Reactors

Incorporates new nuclear technology of small modular reactors to reduce carbon footprint and provide baseload power

- Offers modular and scalable architecture
- Factory-fabricated units mitigate risks of schedule overruns
- Reduces environmental impacts

Expanded Renewables

Increases renewable energy portfolio contribution beyond requirements of the RES (to include both distributed and grid-scale renewable energy resources)

- Positions the portfolio in the event of further environmental regulation
- Optimizes use of Arizona's natural resource: the sun
- Reduces environmental impacts

Expanded Demand Side Management

Increases contribution of distributed energy resource solutions such as energy efficiency, demand response, battery storage and smart inverters

- Enhances customer engagement
- Increases penetration of advanced system technologies
- Improves tools for customer energy management
- Reduces environmental impacts

Loads & Resources

The supply-demand gap, depicted in the blue and green areas in Figure 11, refers to the difference between the resources APS has and the resources it needs to meet expected load growth.

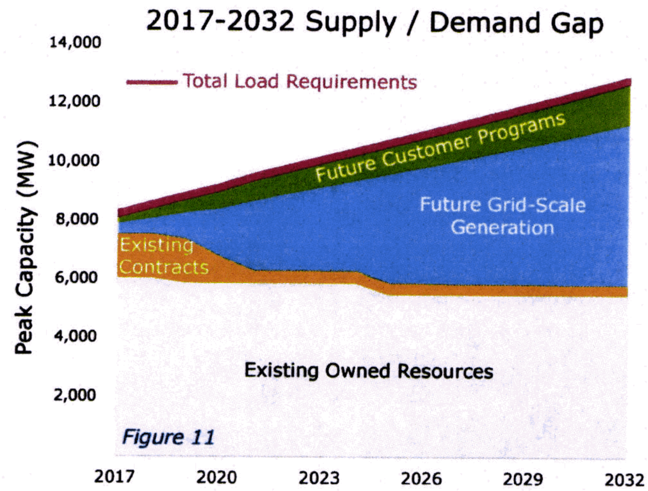


Figure 11

For the 2017-2032 Planning Period, increases in customer load and the expiration of several contracts bring about an immediate need for resources – projected at 675 MW for 2017. By 2022, the need is forecast to be in excess of 3,500 MW and five years after that over 5,400 MW. APS plans to utilize short-term markets to fill remaining near-term needs. For longer-term needs (2020 and beyond), APS will begin procuring resources through the March 2016 All Source RFP and continue its evaluation of resource needs throughout the Planning Period.

TABLE 1 – PRELIMINARY 2017 IRP (Values in MW at Peak)	2017	2022	2027	2032
PROJECTED LOAD REQUIREMENTS (NEEDS)	8,210	9,748	11,252	12,797
EXISTING RESOURCES AS OF JANUARY 2016				
APS-Owned Generation	6,045	5,864	5,475	5,474
Long-Term Contracts	1,489	412	355	342
Total Existing Resources as of January 2016	7,534	6,277	5,830	5,816
FUTURE PROJECTED DISTRIBUTED RESOURCES				
Energy Efficiency (1), (2)	225	629	749	857
Distributed Energy (1), (2)	30	98	175	250
Demand Response (3) & Microgrid (4)	32	107	232	357
Total Future Projected Distributed Resources	287	835	1,156	1,464
FUTURE PROJECTED UTILITY RESOURCES				
Natural Gas	363	2,611	4,084	5,229
Renewable Energy & Energy Storage	25	62	182	288
Total Future Projected Utility Resources	388	2,672	4,266	5,517
TOTAL FUTURE PROJECTED RESOURCE ADDITIONS	675	3,507	5,422	6,981
TOTAL RESOURCES	8,210	9,784	11,252	12,797

(1) Incremental to current levels.

(2) Projections based on technologies expected to be available to customers during the Planning Period and the effect of those technologies on peak load. Energy Efficiency – Post-2020 levels assume EE continues at 22% of retail sales. Distributed Energy – forecast is at time of peak.

(3) Projections based on factors such as comfort impact, usability of technology, load reduction (kW) per household and levels of customer participation during the Planning Period.

(4) Projections based on available technology and customer participation during the Planning Period.

Technologies Evaluated

Due to contract expirations and unit retirements, existing resources and projected customer resources will meet only a portion of future resource needs. The remainder will need to be met with additional resources. These added resources are expected to come from a combination of (a) technologies currently deployed in APS's portfolio, such as natural gas-fired generation, renewable energy resources and demand side management resources, and (b) newer technologies that can play a significant role in meeting customer demand, reducing APS's carbon footprint, further facilitating operational flexibility and addressing aging fleet issues.

Microgrids comprise one area under which many new technologies are emerging as frontrunners. Microgrids are loads that can served by on-site generation and be operated in parallel with (supporting) the electric system or in island mode (stand-alone).

Microgrid Benefits

- Meets customer need for backup power supply
- Highly flexible resource shared with host utility that can respond rapidly to system needs
- Provides peak management, planning reserves and frequency response
- Facilitates future capabilities
  - Renewable energy
  - Smart inverter technology
  - Battery storage

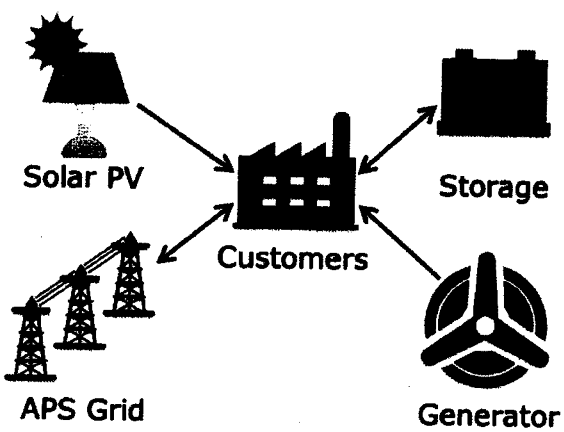


Figure 12

Another new technology APS will incorporate into the 2017 IRP will be battery energy storage systems (BESS) which have modular and scalable architectures.

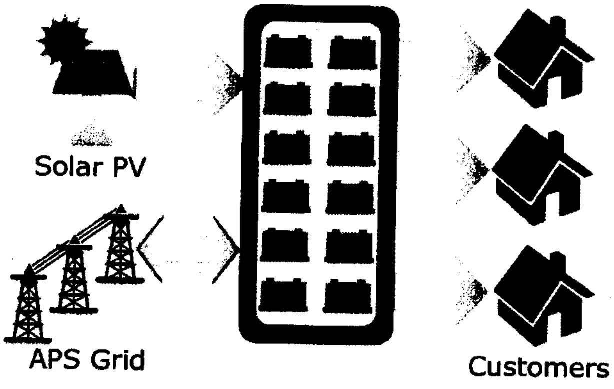


Figure 13

BESS Benefits

- Stores energy at midday and provides power at peak
- Local voltage management
- Distribution upgrade deferment
- Frequency response and other ancillary services
- May reduce environmental impacts

Other Technologies Evaluated

In preparing the 2017 IRP, APS technology evaluations may also include but will not be limited to the following:

DISTRIBUTED ENERGY RESOURCES (DERs)

As energy planners and operators increasingly focus on decentralized resource solutions, greater customer engagement is being achieved through the use of rooftop solar, smart inverters, DSM, battery storage, home energy management systems and smart appliances.

COMBINED CYCLE

Combined cycle natural gas-fired power plants deliver higher fuel efficiency by using residual heat in the gas turbine's exhaust stream. While less flexible than other resources, this technology is suitable for managing summertime peak demand and overall energy needs.

COMBUSTION TURBINE

Combustion turbine natural gas-fired power plants are comprised of a compressor, combustion system (fuel injectors) and turbine. This flexible technology is well-suited for managing peak demand and fast-ramping requirements.

ENERGY STORAGE

In addition to BESS configurations, APS may evaluate the following energy storage technologies:

- Flywheel technologies – used primarily for dynamic system support
- Above- and below-ground compressed air energy storage (CAES) – these technologies store air when energy is available

SMALL MODULAR REACTORS (SMR)

SMRs are smaller in size than traditional nuclear units and can be built in modular arrangements in a manufacturing plant, then shipped to the plant site. Besides providing carbon free electricity, this technology is scalable and standardized, thereby reducing manufacturing and other risks.

SOLAR

Solar configurations will be evaluated for the 2017 IRP based on economics and regulatory requirements. These may include solar PV fixed and single axis tracking and solar thermal-trough technologies.

WIND

Wind systems convert the wind's energy into electricity by using rotating blades to collect the wind's kinetic energy. While wind generation in Arizona is challenging, improvements in technology have increased the viability of this resource within the WECC region.

Action Plan: 2017-2021

The 2017-2021 Action Plan provides specific events anticipated to occur in the near-term that support APS's goal for greater operational flexibility, increased market participation and enhanced customer engagement. Actual events during the 2017-2021 Action Plan Period will be based on conditions prevalent at the time of their undertaking and may differ from what is delineated below. APS will file updates to its Action Plan whenever substantive changes occur, in compliance with Commission Decision No. 75068.

Future Resource Procurement / Development

APS plans to

- Conduct an all-source RFP in March 2016 for 400-600 MW of capacity resources for delivery beginning 2020.
- Begin initial site planning for resource needs beyond 2020.

Solar Innovation Study

APS plans to conduct

- A 75-home research and development study on advanced technologies and innovative rate designs.
- A 125-home study that assists third-party solar PV and DER market to design customer-owned technology packages around existing APS demand rates.

Solar Partners Project

APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with our grid.

Customer Solar Project

APS plans to construct a 40 MW SAT solar PV project at the Saguaro Power Plant in response to customers who want a reduced environmental impact to help meet their long-term energy goals.

EIM

APS expects to begin participation in the CAISO EIM in October 2016. During the Action Plan Period, APS will further enhance internal processes related to EIM participation.

Microgrid

APS has partnered with customers to develop backup generation resources on their business sites. These resources benefit all APS customers, providing flexible resources to help meet peak demand.

Aging Fleet Strategy

Ocotillo Modernization Project

The project, consisting of replacing 1960s-era steam generators with modern quick-start natural gas CT units with capacities of 102 MW each, is planned to be in service by summer 2019.

Coal Fleet

Cholla Unit 2 was retired on October 1, 2015, and APS plans to no longer burn coal in units 1&3 beyond 2025. APS will continue to evaluate the economics of operating Cholla units 1&3, as well as its participation in the Navajo Generating Station.

All-Source RFP

To help meet load requirements for the 2017 IRP Planning Period, APS plans to issue an All Source RFP in March 2016. The RFP will seek competitive proposals for capacity resources totaling approximately 400-600 MW.

Key parameters for the RFP include:

- Technologies Considered
  - Thermal Generation
  - Energy Storage
  - Renewable Energy
  - Non-Supply Side Technologies (EE and DR)
  - Other

- Contract Structures
  - Tolling Power Purchase Agreements for Thermal Technologies
  - Asset Purchase Agreements for existing Thermal Technologies
  - Energy Storage Tolling Agreements
  - Renewable Energy Power Purchase Agreements
  - Load Management Agreements

- Size
  - For supply-side technologies, each proposed facility must be a minimum of 25 MW in size, located on a single site.
  - For non-supply-side technologies, the minimum requirement is 25 MW in size for the aggregated program.

- Delivery
  - No earlier than January 1, 2020, and no later than June 1, 2020.
  - In the case of a proposed asset sale for an existing facility, APS recognizes that pre-sale activities may need to occur prior to June 1, 2020.

- Review
  - The entire RFP process will be monitored and reviewed by a third-party, ACC-approved independent monitor.

- Interconnection
  - Any proposed facility must interconnect directly to the APS system, or in the alternative, the bidder must demonstrate that it has secured firm transmission for delivery from the facility to the APS system.
  - Each proposed facility must be constructed and interconnected to meet the June 1, 2020 deadline.

- Selection Criteria
  - Selection criteria will emphasize meeting peak resource needs and will be discussed in more detail at upcoming Bidder's Webinar.

Sources of Assumptions

Inputs	Sources of Assumptions
Load Forecast:	Bureau of Labor Statistics; U.S. Census Bureau; Bureau of Economic Analysis; National Weather Service
Environmental Regulations:	Environmental Protection Agency; Arizona Department of Environmental Quality
Energy Efficiency Programs:	Energy Efficiency Standard; Navigant Consulting (program evaluation contractor)
Renewable Energy:	Renewable Energy Standard; market data
Resource Costs:	Major equipment vendors; market data acquired through RFP and/or RFI solicitations; industry organizations; customer data from field implementations
Integration Costs:	Solar Photovoltaic Integration Cost Study
Fuel Forecast:	Market, fuel contracts
CO_2:	Market

[1] GTM US Solar Market Insight Q3 2015 Full Report (page 38)
[2] http://www.eenews.net/interactive/clean_power_plan#updated_total_reduction_percentage
[3] Clean Power Plan Implementation – What States Need to Know, National Conference of State Legislatures, January 12, 2016
[4] http://www.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan
[5] http://www.eenews.net/interactive/clean_power_plan/states/arizona
Icons: Sourced from PresentationLoad

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

EXHIBIT
TASC 8
ADMITTED

VS 3.24: **Regarding Attachment ACB - 2DR of Mr. Brown's direct testimony**

Please provide the information requested below regarding the following statement on page 5 of Attachment ACB - 2DR: "The capital costs and financing implications of each distributed solar deployment scenario are first estimated by APS, validated by Seidman, and allocated by economic sector using NREL's JEDI model for distributed solar installations throughout the supply chain in the State of Arizona."

a) Please provide the full set of assumptions used to inform the capital costs and financing implications of each distributed solar deployment scenario that were developed by APS and provided to Seidman. Please provide any associated documents, analyses, spreadsheets, etc. in their native format with formulas and links intact.

b) Please describe what is meant by "validated by Seidman" in the above quoted statement. Please describe the process undertake by Seidman in support of this validation.

c) Please indicate whether Seidman modified any of the assumptions originally provided by APS. If so, please indicate which assumptions were modified and provide an explanation for each modification.

Response:

a) APS15877 provides the assumptions used to develop each distributed energy scenario in tab "DE Capacity & Energy ". The "Expansion_Plan_Summary" tab provides the conventional resources required to serve load under each distributed energy scenario. Changes (increases) in Distributed Energy Net Dependable Capacity in each scenario (rows 104-106) are offset by corresponding reductions in conventional resources in each scenario. Because changes to conventional resources are managed by adjusting the number of 7FA combustion turbines installed in any given year, and the capacity of 7FA combustion turbines is not divisible, mismatches between distributed energy capacity additions and reductions in conventional resources are met with changes in short-term capacity purchases, which are not displayed in these tables.

b) APS provided Seidman with a spreadsheet detailing, for various scenarios, the forecast level of distributed solar

Response to Vote Solar 3.24 continued:

installations, an estimate of their mean costs, and forms of financing/leasing payment over an anticipated economic life of 30 years. This generated annual payment cohorts for installations over a 50-year period (2016-2065). Seidman validated the internal consistency of the framework used to estimate spending patterns for the 2016-2065 time horizon, and checked the base solar installation parameters (costs, discount/interest rates, and payback totals, etc.) against publicly available data.

c) No.

EXHIBIT

TASC 9

judicial notice

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

Arizona Corporation Commission
DOCKETED
AUG 28 2007
DOCKETED BY ne

IN THE MATTER OF NET METERING IN THE GENERIC INVESTIGATION OF DISTRIBUTED GENERATION

DOCKET NO.E-00000A-99-0431

DECISION NO. 69877

ORDER

Open Meeting
August 21 and 22, 2007
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

Introduction

1. Commission Decision No. 67744 directed Staff to schedule workshops to consider outstanding issues concerning distributed generation ("DG"). The second issue to be addressed by the workshops, after DG interconnection, was net metering. A workshop on net metering was held on September 7, 2006. Participants in the workshop included representatives from utilities, government agencies, environmental advocacy groups, consumers, advocates for renewable resources, advocates for distributed generation, renewable resource providers, and others.

2. Staff requested written comments from interested parties on issues related to net metering. Comments were received from a.k.a. Green, American Solar Electric, Arizona

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Cooperatives,[1] Arizona Public Service Company ("APS"), Arizona Solar Energy Association, Sally R. Day, Distributed Energy Association of Arizona, Solar Advocates,[2] Jim Stack, and UniSource Energy.[3]

3. In addition, the Energy Policy Act of 2005 requires each state regulatory authority to consider certain PURPA[4] standards, including one on net metering. The Commission may decline to implement the standard or adopt a modified standard. The Commission was required to begin its consideration by August 8, 2007, and must complete its consideration by August 8, 2008. On January 23, 2006, Staff filed a memo in Docket Control that Net Metering was being addressed in Docket No. E-00000A-99-0431.

Consideration of the PURPA Standard on Net Metering.

4. The Energy Policy Act of 2005 requires each state regulatory authority to consider a PURPA standard on net metering. The standard would apply to utilities with greater than 500,000 MWh in annual retail sales. The Commission may decline to implement the standard or adopt a modified standard. The standard is as follows:

> *Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.*

5. The Commission is required to consider the three purposes of PURPA in its determination of whether to adopt the net metering standard. The three purposes of PURPA are as follows:

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[1] The Grand Canyon State Electric Cooperative Association filed comments on behalf of its Arizona cooperative members ("Arizona Cooperatives") which are: Duncan Valley Electric Cooperative, Inc.; Graham County Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc.

[2] Solar Advocates include American Solar Electric Inc., the Greater Tucson Coalition for Solar Energy; the Annan Group; Code Electric; SunEdison; and the Vote Solar Initiative.

[3] UniSource Energy includes Tucson Electric Power Company and UNS Electric, Inc.

[4] Public Utility Regulatory Policies Act of 1978.

- conservation of energy supplied by electric utilities,
- optimal efficiency of electric utility facilities and resources, and
- equitable rates for electric consumers.

6. Having net metering may facilitate the installation of DG and thus reduce the amount of energy to be supplied by electric utilities. The presence of DG may improve the efficiency of electric utility facilities and thus reduce costs for electric consumers.

Benefits and Costs of Net Metering

7. The U. S. Department of Energy ("DOE")[5] has identified the following potential benefits of DG:

- reduced peak loads,
- provision of ancillary services such as reactive power and voltage support,
- improved power quality,
- decreased vulnerability of the electrical system,
- increased resiliency of other critical infrastructure sectors, and
- reduced land use effects.

8. DG might also provide reduced transmission and distribution losses, avoided generation fuel cost, fuel diversification, avoided water use, reduced environmental impacts, and potential deferral or reduction in distribution investment.

9. Net metering provides a financial incentive to encourage the installation of DG, especially renewable resources. DOE describes net metering as a policy option available to states to promote environmentally preferred customer-located DG, and its absence can be viewed as a barrier to deployment. The *Regulator's Handbook on Renewable Energy Programs & Tariffs*[6] lists the following purposes of net metering:

- promoting small-scale renewables;
- enhancing the market for renewables;
- facilitating installation and interconnection of on-site generation;
- reducing customers' electricity bills;
- empowering customers to manage their electricity usage, essentially storing excess power on the grid for use at a later time; and
- lowering the utility system peak demand.

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[5] U.S. Department of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005*, February 2007.

[6] Jan Hamrin, Ph.D; Dan Lieberman; and Meredith Wingate, *Regulator's Handbook on Renewable Energy Programs & Tariffs*, March 2006.

10. According to American Solar Electric, photovoltaic systems are often larger in service territories that offer net metering because it reduces the systems' payback times. Net metering also makes savings predictable. In their written comments, the Solar Advocates point out that net metering makes solar systems effectively cheaper for system owners, and it helps increase solar's peak shaving impact and transmission and distribution effects to benefit all ratepayers. They state that net metering is a critical enabling policy for renewable resources that are intermittent and non-dispatchable.

11. APS and the Arizona Cooperatives, in their written comments, state that customers taking service under net metering rates do not pay the full cost of the transmission and distribution system. Net metering rates do not yield sufficient revenue to cover cost. Therefore, those net metering customers are subsidized by other customers. The Solar Advocates respond that the impact of net metering is equivalent to the impact of a customer who reduces load through conservation. UniSource Energy states that the utility's cost of implementing net metering is all fixed investment and operating expenses incurred above the incremental cost of avoided energy purchased or generated. In the view of UniSource Energy, net metering is a super-subsidy for a class of generation that needs an extra incentive to move renewable technologies to market transformation. A different view is that the subsidy, if there is one at all, is exceeded by the overall benefits provided to the system by the on-site generation.

Staff Analysis

12. Staff believes that net metering should be available in all utility areas because DG can provide benefits, and net metering may facilitate the installation of DG. Several other states have considered and rejected the PURPA standard on net metering, not because of the merits of the standard, but because they already have net metering rules in place. States that have rejected the standard and already have net metering rules in place include California, Colorado, Connecticut, Idaho, Indiana, Iowa, Louisiana, Minnesota, Nevada, Utah, Vermont, Virginia,

...

...

...

Wisconsin, and Wyoming. Ohio adopted the standard and has rules in place. According to the Database of State Incentives for Renewable Energy ("DSIRE"), 36 states have net metering rules.[7]

13. Some concerns have been raised that net metering would result in revenue losses for utilities; although there is some disagreement on the issue. The Arizona Cooperatives, in their written comments, recommend that only utilities with greater than 500,000 MWh in retail sales should be subject to the net metering standard adopted by the Commission because small cooperatives will be impacted to the greatest degree by the loss of revenue and margins associated with net metering.

14. Staff believes that, if revenue losses occur as a result of net metering, the losses would impact utilities of all sizes. The impact of revenue loss on all utilities could be controlled through provisions in rules, such as by a limit on total participation.

15. The electric distribution companies that are regulated by the Commission are listed in the following table.

Electric Distribution Companies in Arizona
(Under Commission Jurisdiction)

With Greater than 500,000 MWh of Arizona Retail Sales in 2005
Arizona Public Service Company
Mohave Electric Cooperative
Morenci Water and Electric Company
Sulphur Springs Valley Electric Cooperative
Trico Electric Cooperative
Tucson Electric Power Company
UNS Electric
With Less than 500,000 MWh of Arizona Retail Sales in 2005
Ajo Improvement Company
Columbus Electric Cooperative
Dixie-Escalante Rural Electric Cooperative
Duncan Valley Electric Cooperative
Garkane Energy Cooperative
Graham County Electric Cooperative
Navopache Electric Cooperative

. . .

[7] www.dsireusa.org

Staff Recommendations

16. Staff recommends that the Commission adopt the PURPA standard on net metering.

17. Staff also recommends that the standard be applied to all electric distribution companies in Arizona that are regulated by the Commission.

18. Staff further recommends that the Commission direct Staff to begin a rulemaking process to draft rules on net metering. The draft rules should address, at a minimum, the following issues:

- customer sector participation,
- types of generation resources,
- project size,
- total participation,
- metering,
- treatment of net excess generation, and
- responsibility for costs.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction the subject matter of the application.

2. The Commission, having reviewed the application and Staff's Memorandum dated August 7, 2007, concludes that it is in the public interest to direct Staff to begin a rulemaking process on net metering.

ORDER

IT IS THEREFORE ORDERED that the PURPA standard on net metering, as included in Finding of Fact No. 4, that would apply to all electric distribution companies in Arizona that are regulated by the Commission is adopted.

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IT IS FURTHER ORDERED that Staff is to begin a rulemaking process to draft rules on net metering. The draft rules should address, at a minimum, the issues listed in Finding of Fact No. 18.

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

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I DEAN S. MILLER, Interim Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 28 day of August, 2007.

DEAN S. MILLER
Interim Executive Director

DISSENT: ______________________

DISSENT: ______________________

EGJ:BEK:lhm\KL

SERVICE LIST FOR: GENERIC INVESTIGATION OF DISTRIBUTED GENERATION
DOCKET NO. E-00000A-99-0431

Mr. Jeff Schiegel
SWEEP
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Annan Group
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Ms. Valerie Rauluk
Greater Tucson Coalition For Solar Energy
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Mr. Ernest G. Johnson
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Mr. Christopher C. Kempley
Chief Counsel
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

EXHIBIT

TASC-10

~~ADMITTED~~

ORIGINAL

TEP

Tucson Electric Power

88 East Broadway Blvd., Post Office Box 711
Tucson, Arizona 85702

RECEIVED

2015 MAY -1 P 4: 19

AZ CORP COMM
DOCKET CONTROL

May 1, 2015

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

Re: Tucson Electric Power Company's Request for Approval of Rider R-8 Lost Fixed Cost Recovery Tariff, Docket No. E-01933A-12-0291, Decision No. 73912

Pursuant to Arizona Corporation Commission ("Commission") Decision No. 73912 (June 27, 2013) ("Decision") and Section 5 of the approved Plan of Administration for Lost Fixed Cost Recovery ("LFCR") Mechanism, Tucson Electric Power Company ("TEP") hereby files the calculated annual LFCR adjustment. Attachment A shows the LFCR rate and supporting Schedules, which consist of the following: 1) LFCR Annual Percentage Adjustment Rates; 2) LFCR Annual Incremental Cap Calculation; 3) LFCR Calculation; 4) LFCR Test Year Rate Calculation; and 5) Distribution and Transmission Revenu Calculation. See Attachment B for the clean and redlined copy of the TEP Rider R-8 Tariff

TEP is proposing an LFCR rate of 0.8565% for energy efficiency and 0.2770% for distributed generation. Based on an average monthly usage of 762 kWh, TEP estimates that this will result in an increase of approximately $0.35 on a residential bill. An analysis of the residential customer bill impact is shown in Attachment C.

In accordance with the Decision, included in this filing is the Full Revenue Decoupling Report ("Report"), which reflects what rates would have been for residential, small commercial and large industrial customers, if full revenue decoupling had been approved in this Decision. The Report contains confidential information and is being provided directly to Commission Staff pursuant to the terms of the Protective Agreement executed in this docket.

TEP respectfully requests that the Commission approve the LFCR rate, as shown in Attachment A, for implementation of the rate by July 1, 2015.

If you have any questions, please contact me at (520) 884-3680.

Sincerely,

Melissa Morales
Regulatory Services

Arizona Corporation Commission
DOCKETED
MAY 01 2015
DOCKETED BY RC

cc: Barbara Keene, ACC (Schedules and CD)
Compliance Section, ACC

ATTACHMENT A

LFCR

Schedules

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rates

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	Energy Efficiency Related Adjustment			
1	Total Lost Fixed Cost Revenue for Current Period	(Sch 2, Line 15, Col C * Sch 3, Line 55, Col E)	$	6,548,760
2	2014 Applicable Company Revenues	Schedule 2, Line 1, Column C	$	764,562,435
3	Percentage Adjustment Applied to Customer's Bills for EE	(Line 1 / Line 2)		0.8565%
	Distributed Generation Related Adjustment			
4	Total Lost Fixed Cost Revenue for Current Period	(Sch 2, Line 15, Col C * Sch 3, Line 56, Col E)	$	2,118,143
5	2014 Applicable Company Revenues	Schedule 2, Line 1, Column C	$	764,562,435
6	Percentage Adjustment Applied to Customer's Bills for DG	(Line 4 / Line 5)		0.2770%

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	2014 Applicable Company Revenues		$	764,562,435
2	Allowed Cap %			1.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	7,645,624
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 57, Column C	$	8,985,229
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	8,985,229
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	5,433,759
10	Lost Fixed Cost Revenue - Billed [1]		$	4,895,192
11	LFCR Balancing Account	(Line 9 - Line 10)	$	538,567
11a	Prior Period Correction [2]		$	(856,893)
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11 + Line 11a)	$	3,233,144
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	-
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.4229%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 + Line 11a - Line 13)	$	8,666,902

[1] Amount billed to customers for the collection period of August 2014 through June 2015. Collections for March 2015 through June 2015 are estimated based on 2014 revenues during those same months.

[2] This year's filing includes an adjustment to correct for an issue discovered in the 2014 LFCR filing. The 2014 LFCR filing did not remove test year production when calculating the Lost Fixed Cost Revenue for DG, and we have calculated the impact of this to be $(856,893).

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Residential					
	Energy Efficiency Savings					
1	Current Period			97,644,459	kWh	
2	% of Residential Customers choosing fixed-option			0.0%		
3	Excluded kWh reduction	(Line 1 * Line 2)		-	kWh	
4	Net - Current Period	(Line 1 - Line 3)		97,644,459	kWh	
5	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 6, Column C		86,458,094	kWh	
6	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 6, Column C + Line 4)		184,102,552	kWh	
7	Total Recoverable EE Savings	Line 6		184,102,552	kWh	
8	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh	
9	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 7 * Line 8)	$	5,670,358.62		
	Distributed Generation					
10	Current Period			41,328,794	kWh	
11	% of Residential Customers choosing fixed-option			0.0%		
12	Excluded kWh reduction	(Line 10 * Line 11)		-	kWh	
13	Net - Current Period	(Line 10 - Line 12)		41,328,794	kWh	
14	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 15, Column C		-	kWh	
15	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 15, Column C + Line 13)		41,328,794	kWh	
16	Total Recoverable DG Savings	Line 15		41,328,794	kWh	
17	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh	
18	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 16 * Line 17)	$	1,272,926.86		
	Small General Service					
	Energy Efficiency Savings					
19	Current Period			19,486,492	kWh	
20	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 21, Column C		11,652,268	kWh	
21	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 21, Column C + Line 19)		31,138,760	kWh	
22	Total Recoverable EE Savings	Line 21		31,138,760	kWh	
23	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh	
24	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 22 * Line 23)	$	977,757.05		
	Distributed Generation					
25	Current Period			27,606,981	kWh	
26	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 27, Column C		-	kWh	
27	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 27, Column C + Line 25)		27,606,981	kWh	
28	Total Recoverable DG Savings	Line 27		27,606,981	kWh	
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh	
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	866,859.20		
	Large General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
31	Current Period			6,978	kW	
32	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kW	
33	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 33, Column C + Line 31)		6,978	kW	
34	Total Recoverable EE Savings	Line 33		6,978	kW	
35	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW	
36	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	16,677.67		
	Distributed Generation					
37	Current Period			6,835	kW	
38	Prior Period kW DG losses	Previous Filing, Schedule 3, Line 39, Column C		-	kW	
39	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 39, Column C + Line 37)		6,835	kW	
40	Total Recoverable DG Savings	Line 39		6,835	kW	
41	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW	
42	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 40 * Line 41)	$	16,335.95		
	Large General Service - Delivery Revenue					
	Energy Efficiency Savings					

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting	
43	Current Period			13,009,143	kWh		
44	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 45, Column C		16,632,623	kWh		
45	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 45, Column C + Line 43)		29,641,766	kWh		
46	Total Recoverable EE Savings	Line 45		29,641,766	kWh		
47	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh		
48	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 46 * Line 47)	$	124,495.42			
	Distributed Generation						
49	Current Period			9,480,418	kWh		
50	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 51, Column C		-	kWh		
51	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 51, Column C + Line 49)		9,480,418	kWh		
52	Total Recoverable DG Savings	Line 51		9,480,418	kWh		
53	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh		
54	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 52 * Line 53)	$	39,817.75		Percent of Total	
55	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 9 + 24 + 36 + 48	$	6,789,288.76		75.56%	(Line 55 / Line 57)
56	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 18 + 30 + 42 + 54	$	2,195,939.76		24.44%	(Line 56 / Line 57)
57	Total Lost Fixed Cost Revenue	(Line 55 + Line 56)	$	8,985,228.52			

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation		(B) Reference		(C) Totals
	Residential Customers				
1		Delivery Revenue	Schedule 5, Line 5, Column F	$	111,739,643
2		kWh Billed	Schedule 5, Line 5, Column B		3,627,093,708
3		Lost Fixed Cost Rate	(Line 1 / Line 2)	$	0.0308
	Small General Service				
4		Delivery Revenue	Schedule 5, Line 8, Column F	$	63,186,286
5		kWh Billed	Schedule 5, Line 8, Column B		2,012,114,954
6		Lost Fixed Cost Rate	(Line 4 / Line 5)	$	0.0314
	Large General Service				
7		Delivery Revenue - Demand	Schedule 5, Line 11, Column F	$	8,172,790
8		kW Billed	Schedule 5, Line 11, Column B		3,419,489
9		Lost Fixed Cost Rate	(Line 7 / Line 8)	$	2.3901
	Large General Service				
10		Delivery Revenue	Schedule 5, Line 14, Column F	$	5,319,772
11		kWh Billed	Schedule 5, Line 14, Column B		1,261,678,481
12		Lost Fixed Cost Rate	(Line 10 / Line 11)	$	0.0042

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

	(A)	(B)	(C)		(D)	(E)		(F) B x D x E
Line No.	Rate Schedule	Adjusted Test Year Billing Determinants	Units		Delivery Charge	Demand Stability Factor		Total Delivery Revenue
1	Residential Service (R-01)	3,368,532,306	kWh	$	0.0314	100%	$	105,811,858
2	Residential Service (R-80)	116,359,255	kWh	$	0.0229	100%	$	2,664,627
3	Residential Service (R-201AN)	131,427,481	kWh	$	0.0230	100%	$	3,016,454
4	Residential Service (R-201BN)	10,774,668	kWh	$	0.0229	100%	$	246,705
5	Subtotal - kWh	3,627,093,708	kWh				$	111,739,643
6	Small General Service (GS-10)	1,888,524,435	kWh	$	0.0314	100%	$	59,326,481
7	Small General Service (SGS-76)	123,590,518	kWh	$	0.0312	100%	$	3,859,805
8	Subtotal - kWh	2,012,114,954	kWh				$	63,186,286
9	Large General Service (LGS-13) - kW	2,719,841	kW	$	5.1300	50%	$	6,976,392
10	Large General Service (LGS-85) - kW	699,648	kW	$	3.4200	50%	$	1,196,398
11	Subtotal - kW - Demand	3,419,489	kW				$	8,172,790
12	Large General Service (LGS-13)	1,045,063,814	kWh	$	0.0049	100%	$	5,071,019
13	Large General Service (LGS-85)	216,614,667	kWh	$	0.0011	100%	$	248,753
14	Subtotal - kWh - Delivery	1,261,678,481	kWh				$	5,319,772

CLEAN Statement of Charges

Tucson Electric Power

Tucson Electric Power Company

Sixth Revised Sheet No.: 801-2

Superseding Fifth Revised Sheet No.: 801-2

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Average price by class: Monthly Cap For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large Light & Power Customers: For Lighting Customers:	Monthly Cap $ 3.19 per month $ 20.77 per month $ 779.66 per month $8,000.00 per month $ 11.71 per month	January 1, 2015	74884
Rider R-8 Lost Fixed Cost Recovery (LFCR) Mechanism – Energy Efficiency Lost Fixed Cost Recovery (LFCR) Mechanism – Distributed Generation	0.8565% 0.2770%	Pending	Pending
Rider R-9 – Environmental Compliance Adjustor (ECA)	$0.000191 per kWh	May 1, 2015	73912

REDLINE
Statement of Charges

TEP
Tucson Electric Power

Tucson Electric Power Company

Sixth~~Fifth~~ Revised Sheet No.: 801-2

Superseding Fifth~~Fourth~~ Revised Sheet No. : 801-2

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Average price by class: Monthly Cap For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large Light & Power Customers: For Lighting Customers:	Monthly Cap $ 3.19 per month $ 20.77 per month $ 779.66 per month $8,000.00 per month $ 11.71 per month	January 1, 2015	74884
Rider R-8 Lost Fixed Cost Recovery (LFCR) Mechanism – Energy Efficiency Lost Fixed Cost Recovery (LFCR) Mechanism – Distributed Generation	0.~~4149~~8565% 0.~~3126~~2770%	~~August 1, 2014~~Pending	~~74593~~Pending
Rider R-9 – Environmental Compliance Adjustor (ECA)	$0.000191 per kWh	May 1, 2015	73912

ATTACHMENT C

LFCR

Bill Impacts

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY - LFCR EFFECTIVE JULY 2015
RESIDENTIAL BILL IMPACT

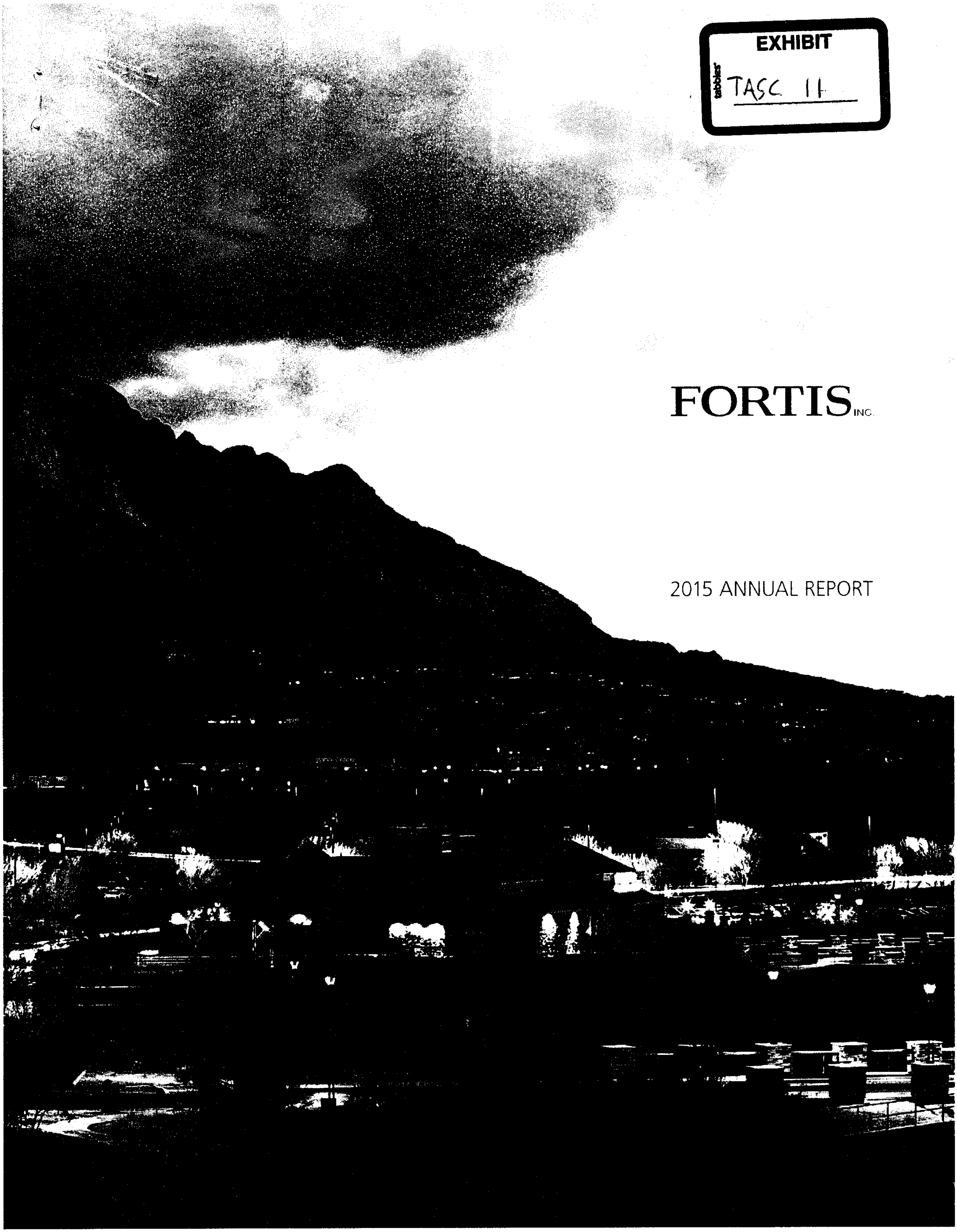
	kWh	Billing Months
Summer kWh	933	5
Winter kWh	640	7
Monthly Weighted Average		762

Summer	Current Rates	Proposed Rates
Customer Charge (Single Phase)	$10.00	$10.00
Energy Charges		
First 500 kWh	$0.056200	$0.056200
501-1,000 kWh	$0.067200	$0.067200
1,001-3,500 kWh	$0.079800	$0.079800
>3,500	$0.088200	$0.088200
Power Supply Charges		
Base Power	$0.035111	$0.035111
PPFAC	$0.006820	$0.006820
LFCR Charges		
LFCR EE	0.4149%	0.8565%
LFCR DG	0.3126%	0.2770%

Summer	Blocks	Current	Proposed	$ Difference	% Difference
		$10.00	$10.00	$0.00	0.00%
	500	$28.10	$28.10	$0.00	0.00%
	433	$29.10	$29.10	$0.00	0.00%
	0	$0.00	$0.00	$0.00	0.00%
	0	$0.00	$0.00	$0.00	0.00%
		$32.76	$32.76	$0.00	0.00%
		$6.36	$6.36	$0.00	0.00%
Subtotal		$106.32	$106.32	$0.00	0.00%
		$0.44	$0.91	$0.47	106.82%
		$0.33	$0.29	-$0.04	-12.12%
Total Summer Bill		$107.09	$107.52	$0.43	0.40%

Winter	Current Rates	Proposed Rates
Customer Charge (Single Phase)	$10.00	$10.00
Energy Charges		
First 500 kWh	$0.056200	$0.056200
501-1,000 kWh	$0.065200	$0.065200
1,001-3,500 kWh	$0.078100	$0.078100
>3,500	$0.087100	$0.087100
Fuel Charges		
Base Power	$0.031532	$0.031532
PPFAC	$0.006820	$0.006820
LFCR Charges		
LFCR EE	0.4149%	0.8565%
LFCR DG	0.3126%	0.2770%

Winter	Blocks	Current	Proposed	$ Difference	% Difference
		$10.00	$10.00	$0.00	0.00%
	500	$28.10	$28.10	$0.00	0.00%
	140	$9.13	$9.13	$0.00	0.00%
	0	$0.00	$0.00	$0.00	0.00%
	0	$0.00	$0.00	$0.00	0.00%
		$20.18	$20.18	$0.00	0.00%
		$4.36	$4.36	$0.00	0.00%
Subtotal		$71.77	$71.77	$0.00	0.00%
		$0.30	$0.61	$0.31	103.33%
		$0.22	$0.20	-$0.02	-9.09%
Total Winter Bill		$72.29	$72.58	$0.29	0.40%
Total Annual		$1,041.48	$1,045.66	$4.18	0.40%
Average Monthly Bill		$86.79	$87.14	$0.35	0.40%



FORTIS INC.

2015 ANNUAL REPORT

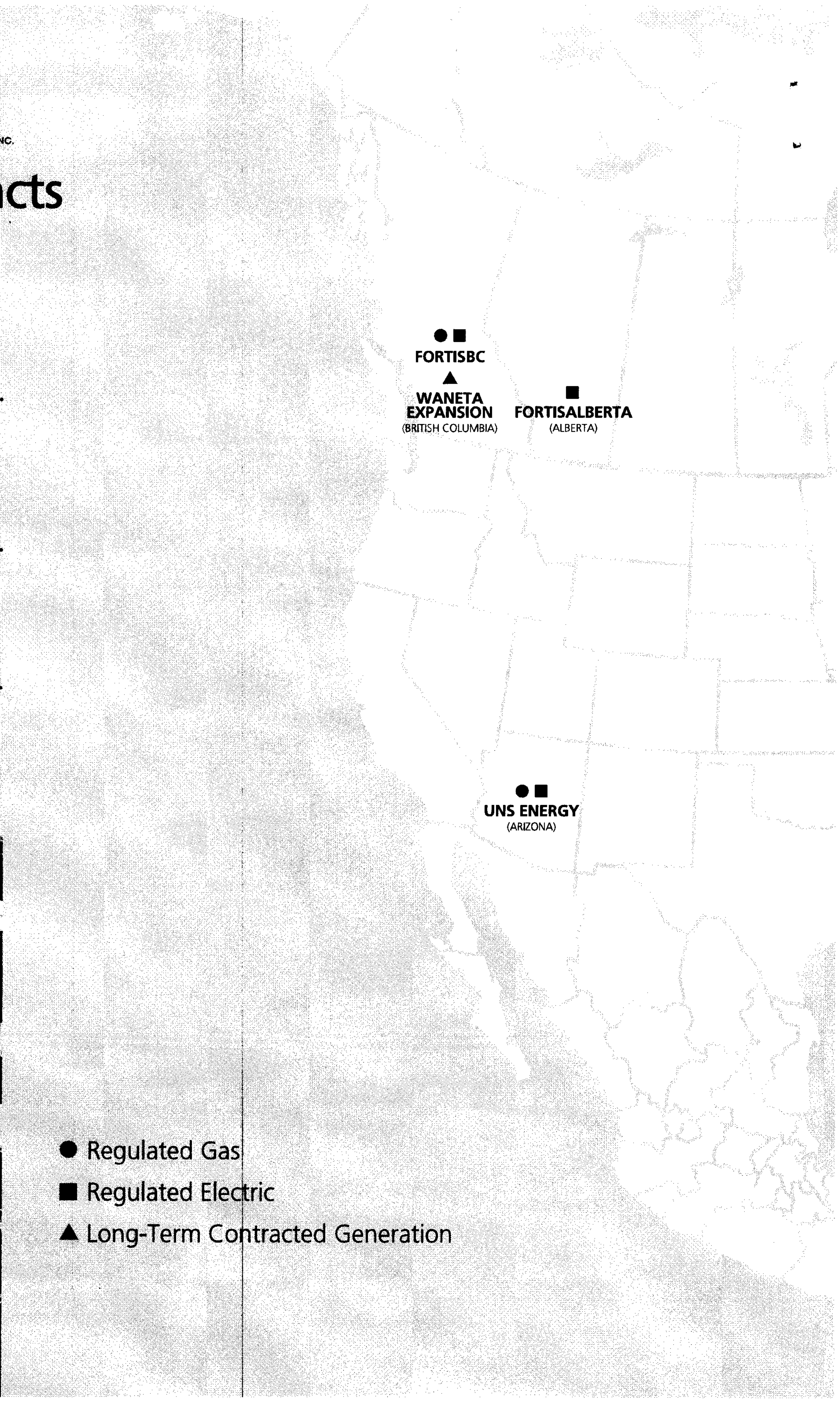
FORTIS INC.
Quick Facts

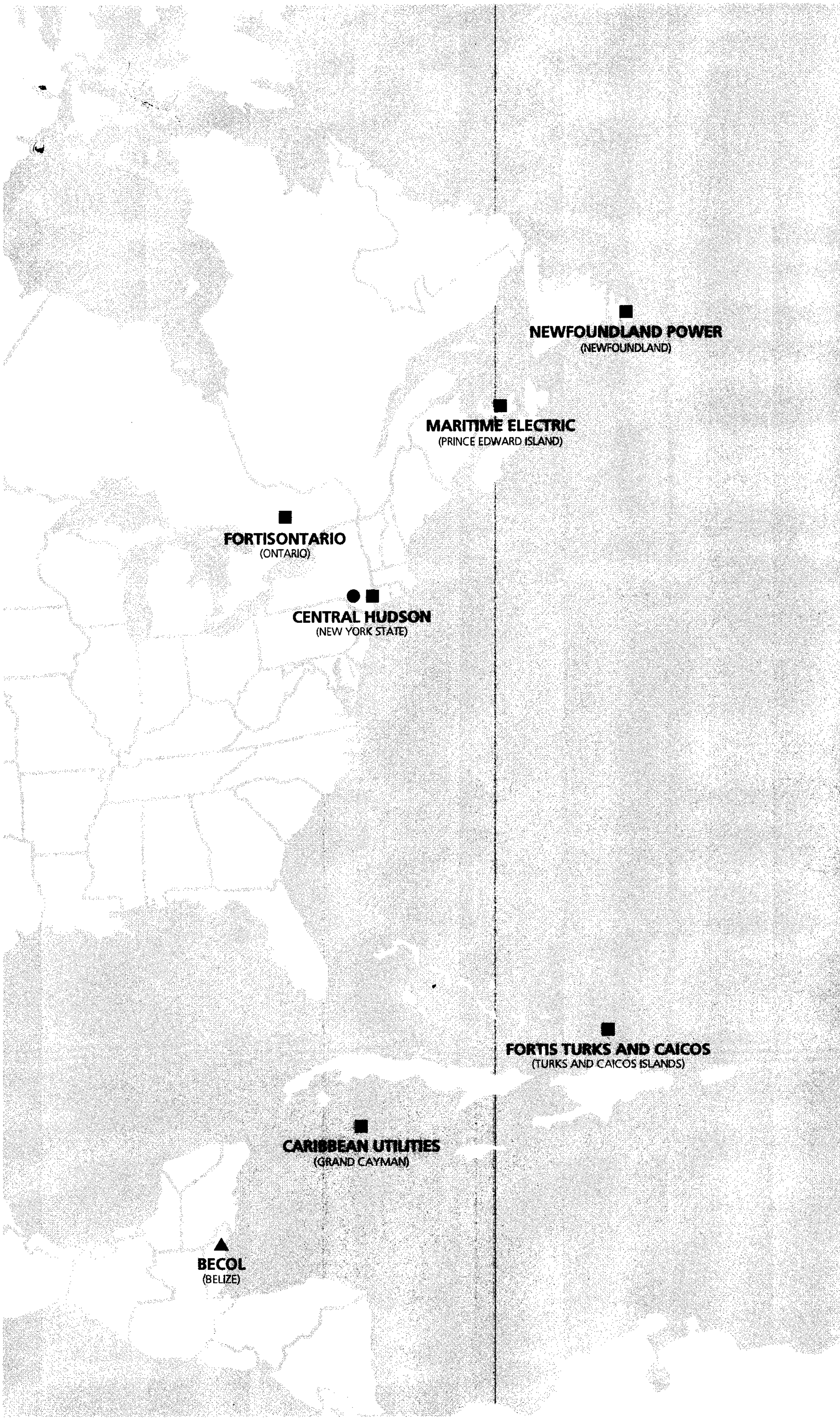
BASED IN
ST. JOHN'S, NL

9 **UTILITY OPERATIONS**
IN CANADA, U.S. AND CARIBBEAN

7,700
EMPLOYEES **STRONG**

$29B
TOTAL **ASSETS**



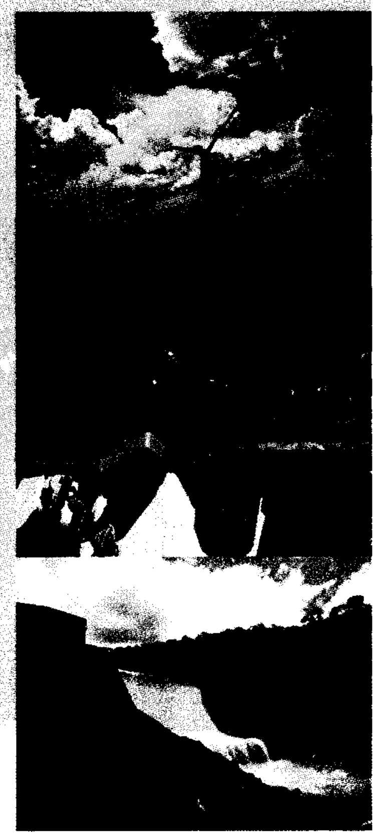


2 **MILLION ELECTRIC**
UTILITY CUSTOMERS

1.2 **MILLION GAS**
UTILITY CUSTOMERS

$10.5B
MARKET CAP
(as of December 31, 2015)

MEMBER OF THE
S&P/TSX 60



Regulated, Low Risk and Diversified

No jurisdiction accounts for more than one-third of total assets or operating earnings.

Business Segments

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	2016F Midyear Rate Base ($B)	2016F Capital Program ($M)
UNS Energy	511,000	152,000	2,015	3,267	109	15,366	13	195	8.9	4.8	485
Central Hudson	300,000	79,000	966	1,059	140	5,132	24	58	3.2	1.6	228
FortisBC [1]	168,000	982,000	2,127	624	1,074	3,116	186	190	8.1	5.0	428
FortisAlberta	539,000	–	1,162	2,733	–	17,132	–	138	3.8	3.0	441
Eastern Canadian [2]	405,000	–	1,033	1,883	–	8,403	–	62	2.3	1.7	174
Caribbean Electric [3]	42,000	–	356	139	–	802	–	34	1.3	0.9	127
TOTAL	**1,965,000**	**1,213,000**	**7,659**	**9,705**	**1,323**	**49,951**	**223**	**677**	**27.6**	**17.0**	**1,883**

(1) Includes FortisBC Energy and FortisBC Electric.

(2) Includes Newfoundland Power, Maritime Electric and FortisOntario.

(3) Includes Caribbean Utilities and Fortis Turks and Caicos. Data includes 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest. Also includes the Corporation's 33% equity investment in Belize Electricity.

Non-Regulated

	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings [2] ($M)	Total Assets ($B)	2016F Capital Program ($M)
Fortis Generation [1]	407	34	844	77	1.0	18 [3]

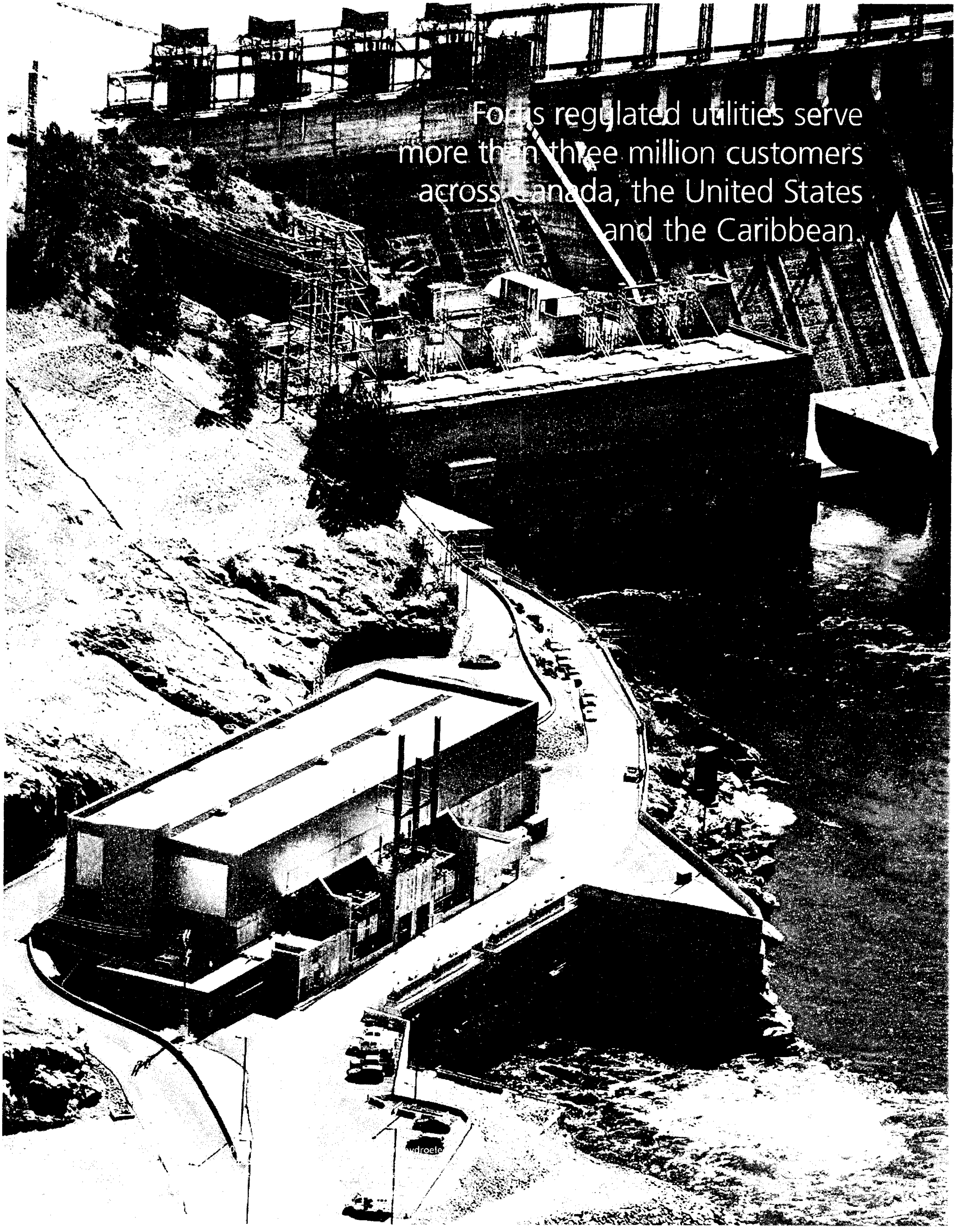
(1) Comprised of investments in British Columbia, Belize and Ontario.

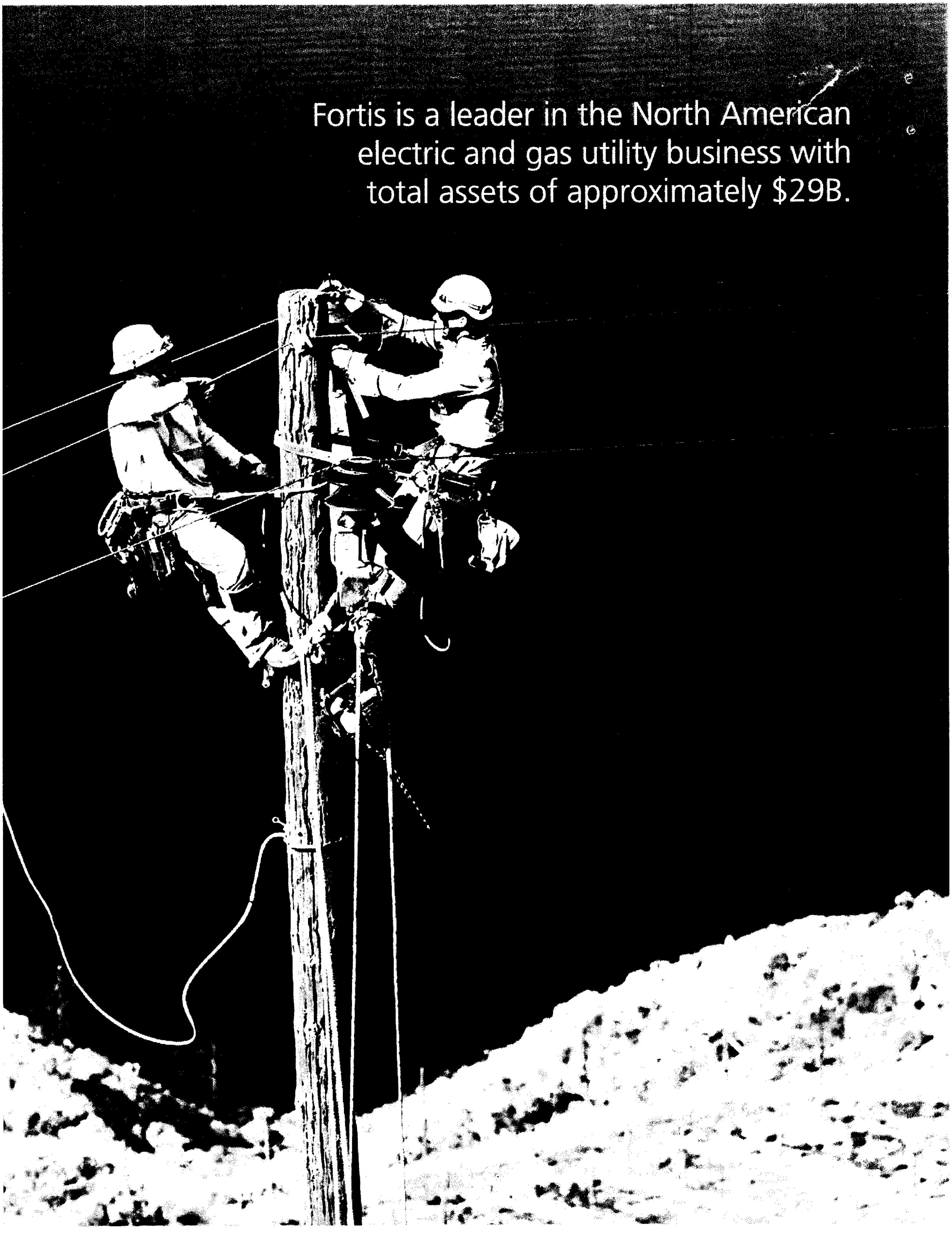
(2) Earnings from non-utility operations were $114 million.

(3) Includes forecast capital expenditures of approximately $15 million at Fortis Generation and $3 million at FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment.

All financial information is presented in Canadian dollars.
Information is for the fiscal year ended December 31, 2015 unless otherwise indicated.

Fortis regulated utilities serve more than three million customers across Canada, the United States and the Caribbean.

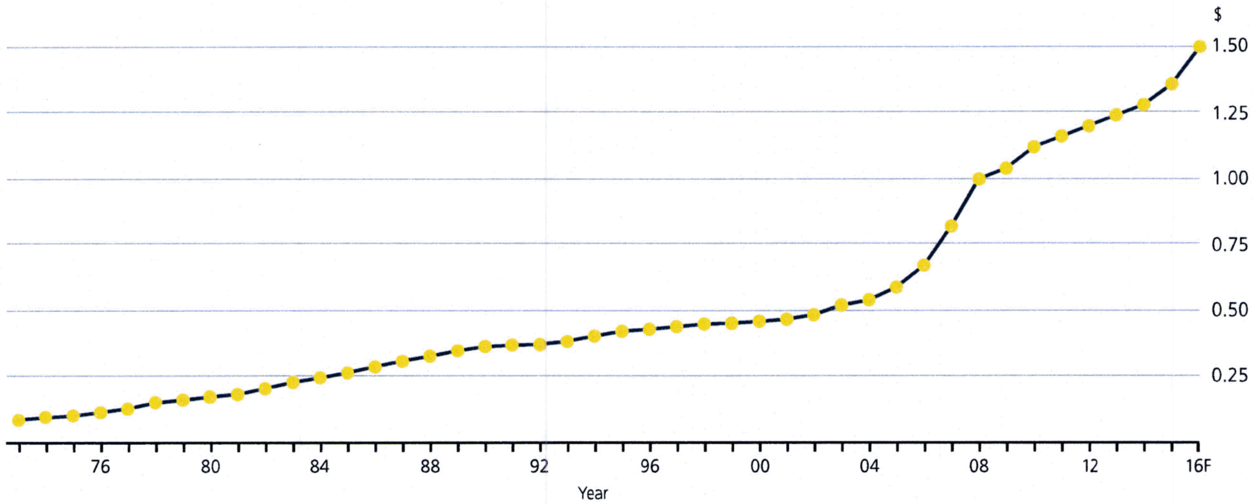



Fortis is a leader in the North American electric and gas utility business with total assets of approximately $29B.

Strong Track Record of Total Shareholder Returns

2015 was the 42nd consecutive year of annual dividend increases and marked the introduction of dividend guidance for the first time, with an annual average dividend growth target of 6% through 2020.

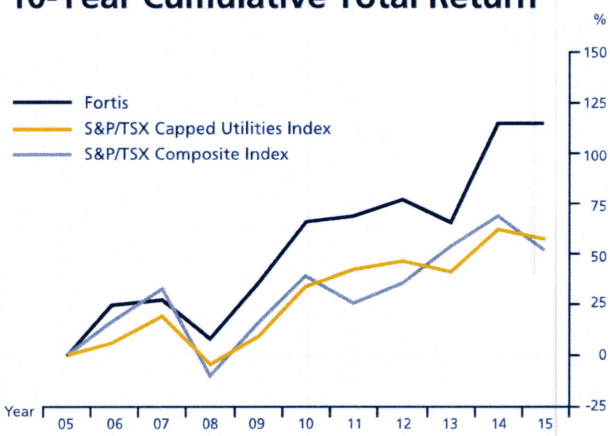
Dividends Paid Per Common Share



Achieved Average Annualized Total Shareholder Return of 8.2% Over the Last 10 Years

The 10-year cumulative total return of 116% for the period ended December 31, 2015 is approximately 60% higher than the performance of the S&P/TSX Capped Utilities and Composite indices.

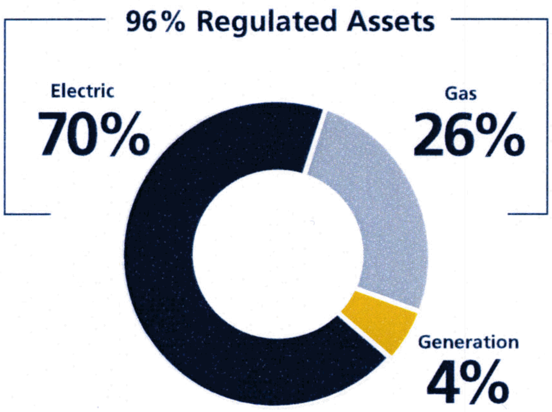
10-Year Cumulative Total Return



Total Assets Increased 9.9%

$29 Billion (as at December 31, 2015)

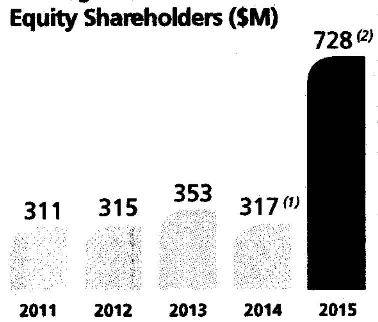
Total Assets



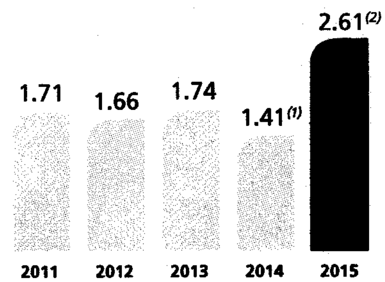
Financial Highlights

Fortis achieved record earnings in 2015, driven by its U.S. utility acquisitions, gains on non-core asset dispositions, completion of the Waneta hydroelectric generating facility (Waneta Expansion) and strong results from its Canadian utilities.

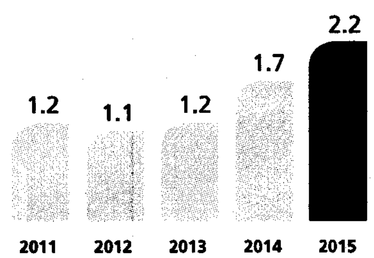
Earnings Attributable to Common Equity Shareholders ($M)



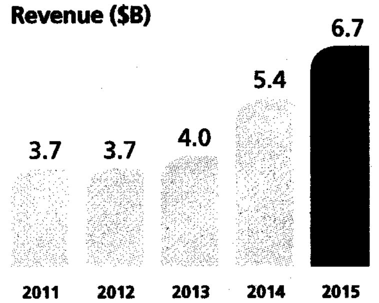
Basic Earnings per Common Share ($)



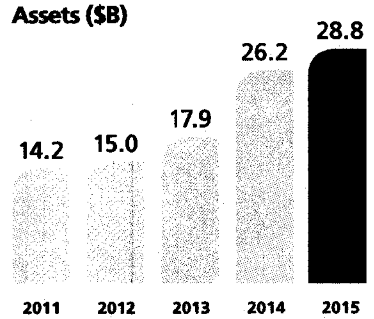
Capital Expenditures ($B)



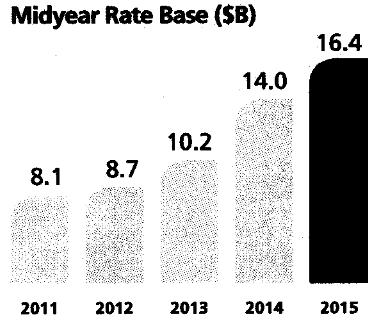
Revenue ($B)



Assets ($B)



Midyear Rate Base ($B)



(1) Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014.

(2) Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and non-recurring items, largely associated with gains on the sale of non-core assets.

All financial information is presented in Canadian dollars.
Information is for the fiscal years ended December 31.

Fortis invested a record $2.2B in 2015 in capital expenditures as part of its five-year $9B capital plan. Energy infrastructure investment will increase Fortis' 2020 rate base to almost $21B.

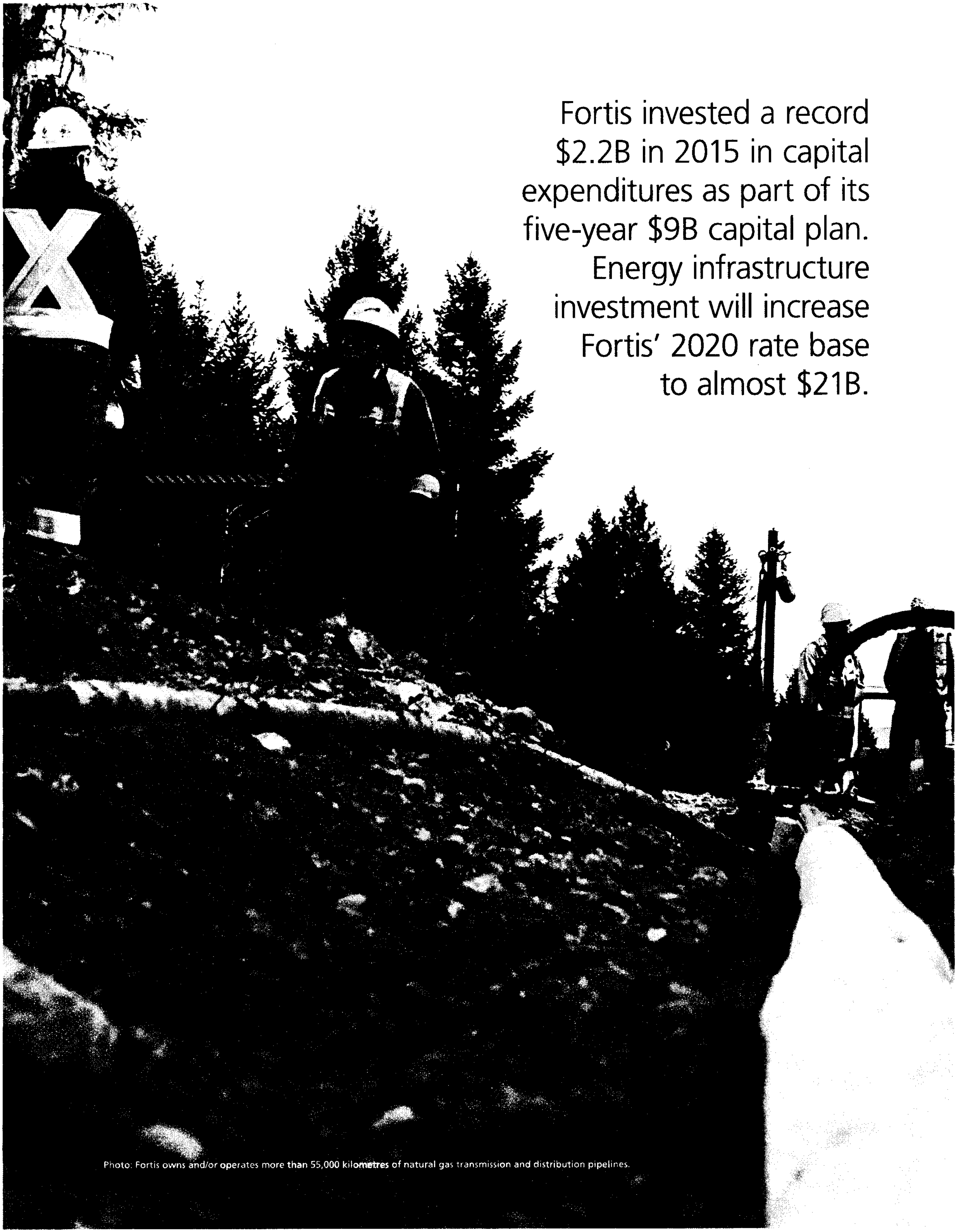


Photo: Fortis owns and/or operates more than 55,000 kilometres of natural gas transmission and distribution pipelines.

Report to Shareholders

2015 was a remarkable year for Fortis

We advanced our business operationally and strategically, delivered record earnings, raised our dividend for the 42^{nd} consecutive year and introduced dividend growth guidance of 6%, on average, annually through 2020. We successfully executed our annual capital expenditure plan, investing a record $2.2 billion in energy infrastructure. Our 2015 results illustrate the underlying strength of our business model, the breadth and depth of the management team, and our ability to drive performance across the organization.

Ongoing focus – strength & growth in our core business

Our priority continues to be the provision of safe, reliable, cost-effective energy service to our customers and the profitable expansion of our existing operations. We remain focused on executing our capital program and pursuing additional investment opportunities within existing service territories. Our stand-alone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions us well for future expansion and leadership in the North American utility sector.

Rate base is expected to be almost $21 billion in 2020

Over the five-year period through 2020, excluding the acquisition of ITC Holdings Corp., our capital program related to our existing operations is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020, exclusive of new acquisitions, and produce a five-year compound annual growth rate of approximately 5%.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value.

Barry Perry, President and CEO, Fortis Inc. (left) and David Norris, Chair of the Board, Fortis Inc. (right).

Report to Shareholders

Strong financial performance

We achieved record net earnings of $728 million, or $2.61 per common share. A number of factors drove our strong financial results in 2015. We were successful in selling non-core assets and achieved significant gains on these sales. The acquisition of UNS Energy, which we completed in August 2014, clearly had an important impact on our results, contributing $195 million in earnings. We also benefitted from the completion of the Waneta hydroelectric generating facility (Waneta Expansion), the strength of the US dollar relative to the Canadian dollar, strong results from our Canadian utilities, and the resetting of customer rates at Central Hudson. Adjusted net earnings attributable to common equity shareholders for 2015 were $589 million, or $2.11 per common share, an increase of $195 million, or $0.36 per common share, over 2014. Cash flow from operations totalled $1.7 billion, 70% higher than last year, largely driven by higher cash earnings.

Record capital investment

Consolidated capital expenditures totalled $2.2 billion in 2015, representing the largest capital program in the history of Fortis. These investments fuel growth in our rate base, which midyear was $16.4 billion. The majority of our capital projects are small and highly executable, but in 2015 we did successfully complete our largest project to date: the $900 million, 335-megawatt (MW) Waneta Expansion. We also continued to advance other projects across our businesses, including the following key projects:

FortisBC Energy – Tilbury LNG Facility Expansion

Construction efforts in 2015 focused on building the storage tank and liquefaction process areas. We expect the project, which includes a second liquefied natural gas (LNG) tank and a new liquefier, to be in service around the end of 2016. Total project costs to the end of 2015 were approximately $326 million, with $181 million invested in 2015.

FortisAlberta – Pole-Management Program

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program. The total capital cost of the program through 2020 is expected to be approximately $336 million, with $41 million invested in 2015, for a total of $200 million to date.

UNS Energy – Residential Solar Program and Pinal Transmission Project

UNS Energy, which ranks among the top 10 utilities in the United States for installing new solar capacity and per-capita additions to its solar energy portfolio, advanced its Residential Solar Program in partnership with local solar companies. This partnership allows UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with US$16 million to be invested in 2016. UNS Energy also completed the Pinal Transmission Project in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt (kV) transmission line in Pinal County that will increase UNS Energy's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

Significant progress in renewable energy

In partnership with Columbia Power Corporation and Columbia Basin Trust, Fortis completed the 335-MW Waneta Expansion near Trail, British Columbia. The output of the Waneta Expansion is being sold to BC Hydro and FortisBC under 40-year contracts. The Waneta Expansion has added a second powerhouse that shares the existing hydraulic head and generates clean, renewable, cost-efficient power from water that would otherwise be spilled. The project included construction of a 10-kilometre, 230-kV transmission line and provides enough energy to power approximately 60,000 homes per year. It was completed six weeks ahead of schedule and on budget while maintaining an excellent safety and environmental protection record.

Solid credit metrics

Maintaining solid investment-grade credit ratings through a strong balance sheet and ample liquidity is a priority for us. As of year-end, we had unused consolidated credit facilities that totalled approximately $2.4 billion.

Underlying confidence in our business allows us to initiate dividend guidance

The strength of our business and the confidence in our future allowed us in 2015 to raise our dividend twice as well as initiate dividend guidance. We ended the year with a quarterly dividend that translates into an annualized dividend of $1.50 per share, and we are targeting average annualized dividend growth of 6% through 2020. We are proud of our 42-year track record of annual dividend increases, and believe that our low-risk, predictable and diversified business will allow us to meet our dividend growth targets.

Sharpening our focus on our core regulated utility businesses

After two major acquisitions in the previous two years, we spent 2015 focusing on our base business and integrating our Arizona utility, UNS Energy. As part of sharpening our focus on our core utility business in 2015, we divested our commercial real estate and hotel business, as well as some small non-regulated generation assets. We realized proceeds of almost $900 million from these sales, which were used primarily to repay credit facility borrowings – largely associated with the acquisition of UNS Energy.

We continue to look for investment opportunities in energy-related infrastructure

While Fortis expects long-term sustainable growth in rate base, earnings, and shareholder returns from investment in its existing utility operations, it is also committed to identifying and executing on opportunities for additional growth through investments in existing service territories.

We delivered on this commitment with the announcement in December of the acquisition of the Aitken Creek Gas Storage Facility (Aitken Creek) for approximately US$266 million. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. We anticipate that this transaction will close in the first half of 2016.

Active regulatory calendar

Fortis focuses on maintaining constructive regulatory relationships and outcomes across its utilities. Our regulatory calendar remains active. There were some important decisions and advancements in 2015, including a three-year rate settlement that saw a resetting of customer rates effective July 1 at Central Hudson; as well as decisions on Capital Tracker Applications and a Generic Cost of Capital Proceeding at FortisAlberta.

We expect 2016 to also be an active year, with the advancement of the general rate applications at Tucson Electric Power for new retail rates effective January 1, 2017 and at Newfoundland Power for new rates effective July 1, 2016; Reforming the Energy Vision proceeding progressing in New York State; Generic Cost of Capital Proceedings in British Columbia and Alberta; and a Capital Tracker application at FortisAlberta.

Empowering leaders to grow the business

We continue to empower the leaders of our utilities to drive performance, discover new investment opportunities and foster talent. Enterprise-wide talent management and development has been elevated to a strategic priority as we prepare for the next stage of growth at Fortis. As part of this initiative we have appointed Nora Duke, Executive Vice President, Corporate Services and Chief Human Resource Officer. Nora is a veteran of Fortis, having spent almost 30 years with the organization, most recently as President and Chief Executive Officer of Fortis Properties.

Environmental sustainability – Fortis at the forefront of industry change

The North American electric utility industry continues to evolve and change. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. With increasing levels of solar usage and plans for a significant shift away from coal generation in Arizona, as well as major regulatory reform ongoing in New York, Fortis subsidiaries in the United States are at the centre of many of the key trends within the industry.

Our strategy is to ensure that we are well positioned to embrace these opportunities, facilitate public policy objectives, and collaborate with customers and regulators on outcomes that preserve the strength of the grid and role of the incumbent utilities. This, in turn, will allow us to deliver on our growth objectives.

Report to Shareholders

Acquisition of ITC Holdings Corp.

Fortis has grown its business through strategic acquisitions that have contributed to the strong organic growth of the Corporation over the past decade. On February 9, 2016, Fortis announced it would be acquiring ITC Holdings Corp. (ITC) in a transaction valued at approximately US$11.3 billion. We expect this accretive acquisition will support our growth strategy, as well as further strengthen and diversify our business.

ITC is the largest independent pure-play electric transmission company in the United States. The Michigan-based company owns and operates high-voltage transmission facilities, serving a combined peak load exceeding 26,000 MW along approximately 15,600 circuit miles of transmission line. ITC's rate base is expected to grow at a compound annual rate of approximately 7.5% through 2018, and its rates are regulated by the Federal Energy Regulatory Commission (FERC), which has been one of the most consistently supportive regulators in North America, providing reasonable returns and equity ratios.

The combined company will be one of the largest investor-owned North American utilities, with an expected consolidated 2016 midyear rate base of $26 billion. Following the completion of the acquisition, our utilities in the United States will represent approximately 60% of our regulated earnings and assets. As part of the ITC transaction, Fortis expects to list its common shares on the New York Stock Exchange (NYSE) under the ticker symbol FTS. Listing on the NYSE will provide access to larger pools of capital and likely increase trading of our shares.

Shareholders can expect to hear more from us in 2016 as we move through key milestones leading up to closing, including shareholder approval for both companies and various regulatory approvals. Closing is expected to occur in late 2016.

Looking forward

Fortis is continuing on its sound and successful, time-tested strategy: a well-managed, low-risk, highly diversified utility that has a measured and disciplined approach to growth.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. We measure our financial and operational performance primarily through growth in earnings per common share and total shareholder return.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

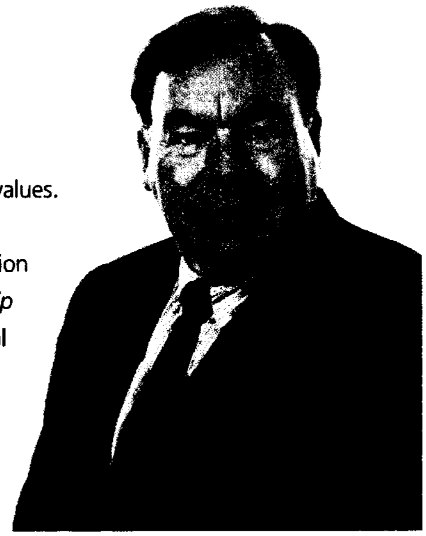
Clearly, we are confident about the future of Fortis. Our success to date and our future prospects have, and will always be, the result of the hard work of our talented and dedicated people, and to the strong corporate culture of Fortis. To each and every one of our employees, your hard work and commitment to customers underpins the success of Fortis. Thank you for your ongoing contribution.

It is with regret that we acknowledge the resignation of Paul Bonavia from our Board in February 2016. Paul withdrew from the Fortis Board in order to remain in compliance with the rules of another entity of which he is a director. We wish to express our genuine gratitude to Paul for his insight and valuable contribution to the Board and extend our best wishes to him for the future. Finally, we also extend our sincerest appreciation to all of our colleagues on the Board of Directors for your continuing dedication, insight and support.

On behalf of the Board of Directors,

David G. Norris Chair of the Board, Fortis Inc.	Barry V. Perry President and Chief Executive Officer, Fortis Inc.

Fortis Inc. – H. Stanley Marshall Memorial Scholarship



H. Stanley Marshall retired as President and CEO from Fortis in 2014, after building a formidable legacy at Fortis. He has left an indelible imprint on our culture, vision and values.

During 2015 Fortis established an endowed scholarship in recognition of his contribution to the Corporation's success. The *Fortis Inc. – H. Stanley Marshall Memorial Scholarship* will support undergraduate students from a Caribbean country entering a professional school or faculty at Memorial University of Newfoundland. Fortis has a strong link to the Caribbean through its operations there, beginning in 1999 with the acquisition of an electric utility in Belize.

Honouring Our Past

In keeping with Fortis' proud Newfoundland history and roots, and honouring its provincial heritage, Fortis became a Centennial Leader with a $3.25 million donation to the *Where Once They Stood We Stand* capital campaign.

With this donation, Fortis became the lead corporate supporter to commemorate Newfoundland's contribution to the First World War and the Battle of Beaumont-Hamel. Both the First World War Exhibition and The Rooms Site Courtyard area will serve as a perpetual monument to Newfoundland's contribution to the First World War, and will be dedicated by the Centennial Lead Donors on July 1, 2016 to all those who served overseas and on the home front.

We encourage those of you living here in Newfoundland or visiting to join us and other supporters to open this important monument and honour those who served Newfoundland and the British Empire.

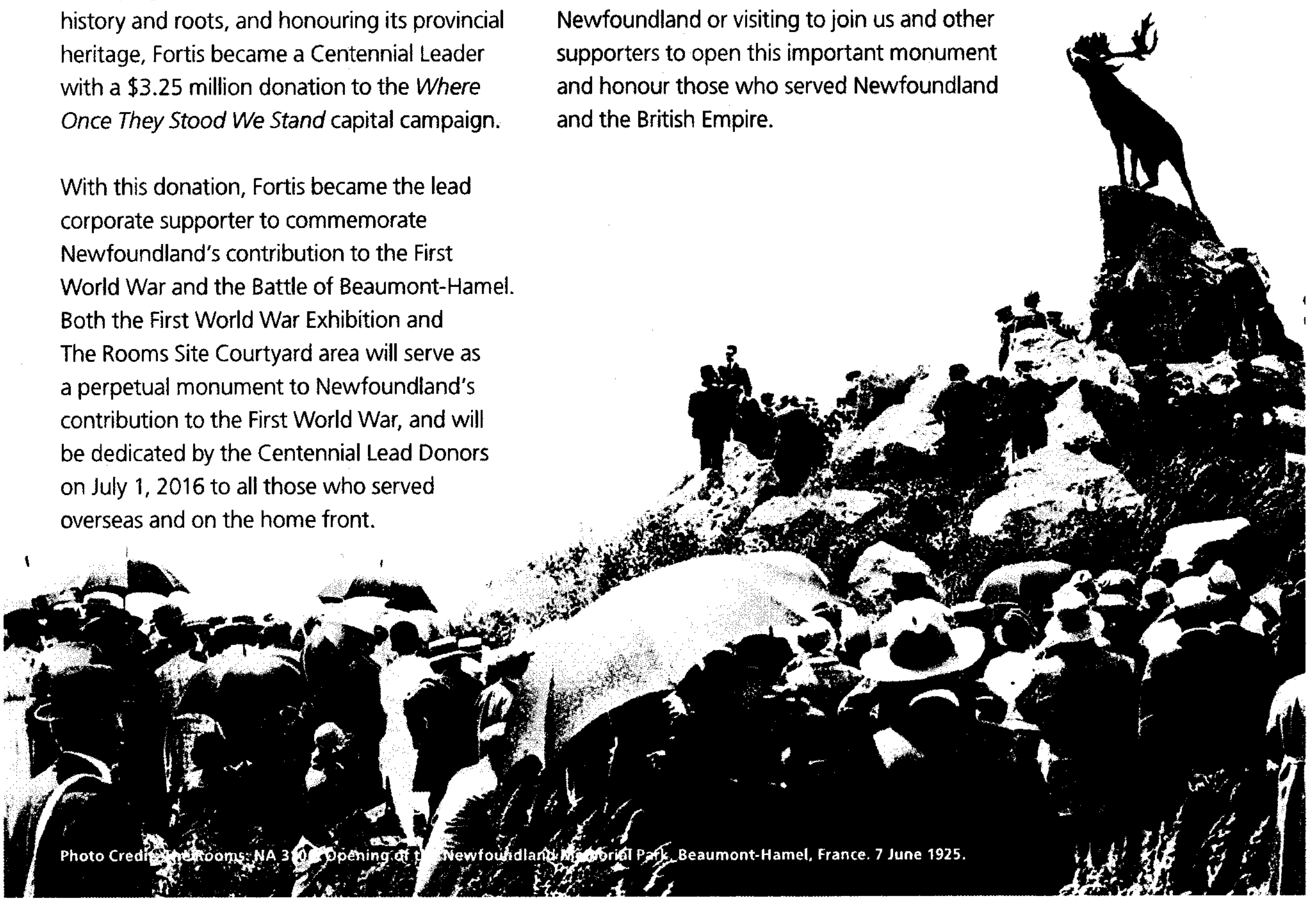


Photo Credit: The Rooms: NA 3[illegible] Opening of the Newfoundland Memorial Park, Beaumont-Hamel, France. 7 June 1925.

Management Discussion and Analysis

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Dated February 17, 2016

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2015. Financial information for 2015 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs based on information currently available. The forward-looking information in the MD&A includes, but is not limited to, statements related to the acquisition of ITC Holdings Corp. ("ITC"), the expected timing and conditions precedent to the closing of the acquisition of ITC, including shareholder approvals of both ITC and Fortis, regulatory approvals, governmental approvals and other customary closing conditions; the expectation that Fortis will borrow funds to satisfy its obligation to pay the cash portion of the purchase price and will issue securities to pay the balance of the purchase price; the assumption of ITC debt and expected maintenance of investment-grade credit ratings; the impact of the acquisition on the Corporation's earnings, midyear rate base, credit rating, estimated enterprise value and compound annual growth rate; the expectation that the acquisition of ITC will be accretive in the first full year following closing and that the acquisition will support the average annual dividend growth target of Fortis; the expectation that the Corporation will become a U.S. Securities and Exchange Commission registrant and have its common shares listed on the New York Stock Exchange in connection with the acquisition; the expectation that Fortis will identify one or more minority investors to invest in ITC; the annualized 2016 common share dividend; targeted annual dividend growth through 2020; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; the acquisition of a share of Aitken Creek Gas Storage facility, the expected timing, total expected consideration and conditions precedent to the closing of such acquisition, including regulatory approval; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the expectation that midyear rate base will increase from 2016 to 2020; the Corporation's forecast gross consolidated capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas ("LNG") facility expansion, the pipeline expansion to the Woodfibre LNG site, the development of a diesel power plant in Grand Cayman, the Residential Solar Program, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and *additional opportunities including electric transmission, LNG and renewable related infrastructure and generation; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2016 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated fixed-term debt maturities and repayments in 2016 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2016; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that economic conditions in Arizona will improve; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.*

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2016 include, but are not limited to: uncertainty regarding the completion of the acquisition of ITC including but not limited to the receipt of shareholder approvals of ITC and Fortis, the receipt of regulatory and other governmental approvals, the availability of financing sources at the desired time or at all, on cost-efficient or commercially reasonable terms and the satisfaction or waiver of certain other conditions to closing; uncertainty related to the realization of some or all of the expected benefits of the acquisition of ITC; uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; and risk associated with the impact of less favorable economic conditions on the Corporation's results of operations.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Karl Smith, *EVP, CFO, Fortis Inc.*

Fortis is a leader in the North American electric and gas utility business, with total assets of approximately $29 billion and fiscal 2015 revenue of $6.7 billion. The Corporation's asset mix is approximately 96% regulated (70% electric, 26% gas), with the remaining 4% comprised of long-term contracted hydroelectric operations. The Corporation's regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. In 2015 the Corporation's electricity distribution systems met a combined peak demand of 9,705 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,323 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) regulatory lag in the case of a historical test year. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, which are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014.

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 417,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 94,000 retail customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company. FEI is the largest distributor of natural gas in British Columbia, serving approximately 982,000 customers in more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 539,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 168,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"); the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 262,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 78,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity"). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 14,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility has been classified as held for sale.

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively.

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015. For further information, refer to the "Significant Items" section of this MD&A. Griffith was sold in March 2014.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE STRATEGY

The principal business of Fortis is the ownership and operation of regulated electric and gas utilities. The Corporation remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. Earnings per common share and total shareholder return are the primary measures of financial performance.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. The Corporation's standalone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions it well for future investment opportunities in existing and new franchise areas.

KEY TRENDS, RISKS AND OPPORTUNITIES

Pending Acquisition of ITC Holdings Corp.: On February 9, 2016, Fortis and ITC Holdings Corp. ("ITC") (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. For details on the Acquisition, including transaction details, strategic rationale and acquisition financing, refer to the "Subsequent Event" section of this MD&A, and for a discussion of risks associated with the Acquisition, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" section of this MD&A.

Electric Utility Industry Developments: The North American electric utility industry has changed significantly over the past several years. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. At the same time, the continued low interest rate environment and decrease in world oil and gas prices are having significant impacts on the North American economy. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

Government and regulatory policy in Canada and the United States is being directed at environmental protection and energy efficiency. The increasing availability of cleaner sources of power generation are driving new environmental regulation designed to eliminate or reduce dependence on traditional sources of electricity power generation, such as coal. The availability of cheaper, cleaner burning natural gas, as well as growing accessibility of renewable or alternative energy sources like solar are encouraging governments to deploy aggressive targets for the removal of high carbon emission sources of energy. Reaching these targets will require the shutdown of certain high carbon emission generating plants earlier than planned, which is an issue that utilities and regulators need to address. These environmental regulations are, however, expected to create additional investment opportunities in renewable power generation and related energy infrastructure. Fortis' regulated utilities are actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, is playing a significant role in the transformation of the utility industry. Although distributed generation customers remain connected to the electrical system and benefit from that connection, they avoid paying much of the fixed operating and maintenance costs because they can offset a portion of their volumetric energy usage with their own systems. This results in an increasing amount of utility costs that are ultimately shifted to other customers. The declining cost of certain types of distributed generation technologies, together with government subsidization, is encouraging increased adoption by customers. Not only does this expose the utility to declining revenue because of a decrease in energy sales, the rate structure serves to shift an increasing burden for these costs on those customers that do not have distributed generation, such as rooftop solar. Traditional rate designs have not been structured to ensure fairness among all customers, which is a focus for utilities and regulators. Fortis, through its subsidiaries, is working with its regulators to address these rate design issues for its customers.

Despite the challenges facing the utility industry, Fortis is well positioned to meet these headwinds and capitalize on any resulting opportunities. Its decentralized structure and customer focused business culture will support the efforts required to both meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to get out in front of these evolving challenges will be essential to meeting the industry challenges.

Natural Gas Opportunities: FortisBC Energy continues to pursue opportunities in British Columbia related to gas infrastructure. The combination of an abundant supply of natural gas, low costs for natural gas and supportive government policy are generating new interest for large industrial customers and niche liquefied natural gas ("LNG") producers to utilize FortisBC Energy's gas system.

In 2013 the Government of British Columbia issued an Order in Council announcing the exemption of FEI's Tilbury LNG facility expansion ("Tilbury Expansion") from regulatory review. The Tilbury Expansion is well underway and will increase LNG production and storage capabilities, and is expected to be in service around the end of 2016. Since this announcement, there has been considerable interest for LNG supply from the Pacific Northwest, Hawaii, Alaska and international markets. In 2014 the Government of British Columbia issued a second Order in Council amending directions to the regulator regarding the Tilbury Expansion. The revisions set out a number of requirements for the regulator, including the consideration of a further expansion of the Tilbury site that would include additional liquefaction.

Traditionally, the majority of natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas opportunities, additional capacity to connect to markets will have to be developed. FortisBC Energy continues to explore pipeline investment opportunities that include expansion of their existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on their Southern Crossing transmission pipeline. Specifically, FortisBC Energy is pursuing a potential pipeline expansion to the proposed Woodfibre LNG site in British Columbia. The Woodfibre LNG site is a former paper mill site located near Squamish, British Columbia. The Company has an opportunity to expand its gas pipeline and increase compression to deliver natural gas to this site.

For further information on the Corporation's natural gas investment opportunities, refer to the "Liquidity and Capital Resources – Additional Investment Opportunities" section of this MD&A.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's nine utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level.

Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

Central Hudson began operating under a new three-year rate order in mid-2015. In November 2015 TEP filed a general rate application ("GRA") with the Arizona Corporation Commission ("ACC") requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. The application also addresses rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. In May 2015 UNS Electric filed a similar GRA requesting new retail rates effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's application was similar to that of TEP.

The Corporation's regulatory calendar for its utilities in Canada continues to be extensive. Newfoundland Power recently filed a GRA for 2016 and FortisBC Energy, the benchmark utility in British Columbia, filed its application to review cost of capital for 2016. In Alberta, while the regulator issued decisions on outstanding generic cost of capital proceedings and capital tracker applications early in 2015, it has initiated a generic cost of capital proceeding for 2016 and 2017, which includes FortisAlberta.

For a further discussion of the nature of regulation and material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2015 was $16.4 billion. Over the five-year period through 2020, excluding the pending acquisition of ITC, the Corporation's capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%. Fortis expects this capital investment to support growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and rate base of its regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2015, almost 90% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $260 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $3.6 billion in credit facilities, of which approximately $2.4 billion was unused as at December 31, 2015. Based on current credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2016.

The Corporation has significant financing requirements associated with the pending acquisition of ITC. Refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

Dividend Increases: Dividends paid per common share increased to $1.40 in 2015. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter, or $1.50 on an annualized basis. This continues the Corporation's record of raising its annualized dividend to common shareholders for 42 consecutive years, the record for a public corporation in Canada.

Fortis also announced dividend guidance, targeting annual dividend per common share growth through 2020 of 6% based on a 2016 dividend of $1.50. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $9 billion five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

SIGNIFICANT ITEMS IN 2015

Pending Acquisition of Aitken Creek Gas Storage Facility: In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its share of the Aitken Creek Gas Storage Facility ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction.

Sale of Commercial Real Estate and Hotel Assets: In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $109 million, net of expenses. As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized an after-tax loss of approximately $8 million, which reflects an impairment loss and expenses associated with the sale transaction.

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy.

Sale of Non-Regulated Generation Assets in New York and Ontario: In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized an after-tax gain of approximately $27 million (US$22 million), net of expenses and foreign exchange impacts.

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $5 million.

Settlement of Belize Electricity Expropriation Matters: In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss.

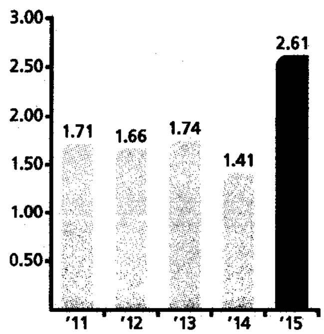
Management Discussion and Analysis

SUMMARY FINANCIAL HIGHLIGHTS

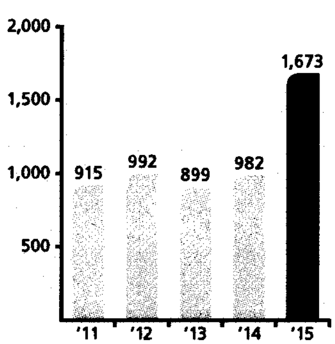
For the Years Ended December 31	2015	2014	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	728	317	411
Basic Earnings per Common Share *($)*	2.61	1.41	1.20
Diluted Earnings per Common Share *($)*	2.59	1.40	1.19
Weighted Average Number of Common Shares Outstanding *(millions)*	278.6	225.6	53.0
Cash Flow from Operating Activities *($ millions)*	1,673	982	691
Dividends Paid per Common Share *($)*	1.40	1.28	0.12
Dividend Payout Ratio *(%)*	53.6	90.8	(37.2)
Return on Average Book Common Shareholders' Equity *(%)* [(1)]	9.8	5.4	4.4
Total Assets *($ billions)*	28.8	26.2	2.6
Gross Capital Expenditures *($ billions)*	2.2	1.7	0.5
Public Preference Share Offering *($ billions)*	-	0.6	(0.6)
Convertible Debenture Offering *($ billions)*	-	1.8	(1.8)
Long-Term Debt Offerings *($ billions)*	1.0	1.2	(0.2)

[(1)] Return on average book common shareholders' equity is a non-US GAAP measure and is defined as net earnings attributable to common equity shareholders divided by the average of opening and closing consolidated shareholders' equity, excluding preference shares and non-controlling interests. Return on average book common shareholders' equity is referred to by users of the Corporation's consolidated financial statements in evaluating the results of operations.

Basic Earnings per Common Share *($)*



Cash Flow from Operating Activities *($ millions)*



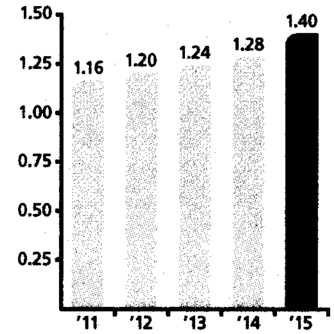
Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $728 million in 2015 compared to $317 million in 2014. On an adjusted basis, net earnings attributable to common equity shareholders for 2015 were $589 million, an increase of $195 million, or almost 50%, over 2014. Results for both years were impacted by non-recurring or adjusting items, which are detailed in the "Consolidated Results of Operations" section of this MD&A. The increase in adjusted net earnings attributable to common equity shareholders was driven by a full year's contribution from UNS Energy, which was acquired in mid-August 2014, earnings contribution from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar. Earnings growth was tempered by an increase in Corporate expenses and lower earnings contribution due to the sale of the commercial real estate and hotel assets.

Basic Earnings per Common Share: Basic earnings per common share were $2.61 in 2015 compared to $1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were $2.11 for 2015, an increase of $0.36 over 2014. The increase was driven by higher adjusted earnings per common share, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

Cash Flow from Operating Activities: Cash flow from operating activities was $1,673 million for 2015, an increase of $691 million, or 70%, over 2014. The increase was driven by higher cash earnings, mainly due to the factors noted above, and favourable changes in working capital.

Dividends: Dividends paid per common share increased to $1.40 in 2015, 9.0% higher than $1.28 in 2014. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter. The Corporation's dividend payout ratio was 53.6% in 2015 compared to 90.8% in 2014. On an adjusted basis, the dividend payout ratio was 66.4% in 2015 compared to 73.1% in 2014.

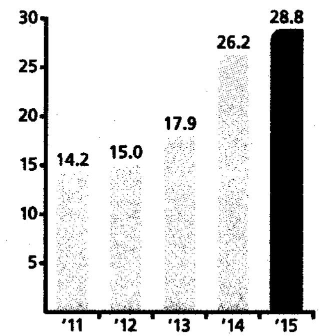
Dividends Paid per Common Share *($)*



Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity for 2015 was 9.8% compared to 5.4% for 2014. On an adjusted basis, the return on average book common shareholders' equity for 2015 was 7.9%, compared to 6.8% for 2014.

Total Assets: Total assets increased 9.9% to approximately $28.8 billion at the end of 2015 compared to approximately $26.2 billion at the end of 2014. The increase reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015.

Total Assets *($ billions)*
(as at December 31)



Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $2.2 billion in 2015 compared to $1.7 billion in 2014. The increase was driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: The Corporation's regulated utilities raised approximately $1 billion in long-term debt in 2015, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

Fortis completed the sale of $1.8 billion convertible debentures in 2014 to finance a portion of the acquisition of UNS Energy. In October 2014 approximately 58.2 million common shares of Fortis were issued on conversion of the debentures. In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were also used to finance a portion of the acquisition of UNS Energy. The Corporation and its regulated utilities raised approximately $1.2 billion in long-term debt in 2014.

For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	2015	2014	Variance
Revenue	6,727	5,401	1,326
Energy Supply Costs	2,561	2,197	364
Operating Expenses	1,864	1,493	371
Depreciation and Amortization	873	688	185
Other Income (Expenses), Net	187	(25)	212
Finance Charges	553	547	6
Income Tax Expense	223	66	157
Earnings From Continuing Operations	840	385	455
Earnings From Discontinued Operations, Net of Tax	-	5	(5)
Net Earnings	840	390	450
Net Earnings Attributable to:			
Non-Controlling Interests	35	11	24
Preference Equity Shareholders	77	62	15
Common Equity Shareholders	728	317	411
Net Earnings	840	390	450

Revenue

The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of UNS Energy and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs. The increase was partially offset by lower commodity costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of UNS Energy, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets, and lower Corporate retirement expenses.

Depreciation and Amortization

The increase in depreciation and amortization was primarily due to the acquisition of UNS Energy and continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income (Expenses), Net

The increase in other income, net of expenses, was driven by gains on the sale of commercial real estate and non-regulated generation assets in 2015, compared to acquisition-related expenses associated with UNS Energy in 2014. The increase was partially offset by a loss associated with the sale of hotel assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of UNS Energy, including interest expense on debt issued to complete the financing of the acquisition, and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense. The increase was partially offset by lower interest on convertible debentures. Approximately $72 million ($51 million after tax) in interest expense was recognized in 2014 associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. In October 2014 the convertible debentures were substantially all converted into common shares of the Corporation.

Income Tax Expense

The increase in income tax expense was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy and gains on the sale of commercial real estate and non-regulated generation assets in 2015, and a higher effective income tax rate, mainly due to the combined federal and state income tax rate at UNS Energy.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings Per Common Share

Net earnings attributable to common equity shareholders were impacted by a number of non-recurring or non-operating items. These items, referred to as adjusting items, are reconciled below and discussed in the segmented results of operations for the respective reporting segments. Management believes that adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share provide useful information to investors and shareholders as they provide increased transparency and predictive value. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation

Years Ended December 31 *($ millions, except for common share data)*	**2015**	2014	Variance
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411
Adjusting Items:			
FortisAlberta –			
Capital tracker revenue adjustment for 2013 and 2014	**(9)**	–	(9)
Non-Regulated – Fortis Generation –			
Gain on sale of generation assets	**(32)**	–	(32)
Non-Utility –			
Gain on sale of commercial real estate assets	**(109)**	–	(109)
Loss on sale of hotel assets	**8**	–	8
Earnings from discontinued operations	**–**	(5)	5
Corporate and Other –			
Foreign exchange gain	**(13)**	(8)	(5)
Loss on settlement of expropriation matters	**9**	–	9
Interest expense on convertible debentures	**–**	51	(51)
Acquisition-related expenses	**7**	39	(32)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**589**	394	195
Adjusted Basic Earnings Per Common Share *($)*	**2.11**	1.75	0.36

Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of $195 million at UNS Energy compared to $60 million for 2014. Earnings contribution of $22 million from the Waneta Expansion, which represents the Corporation's 51% controlling ownership interest, also contributed to the increase. Performance was driven by all of the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; a higher AFUDC at FortisBC Energy; and improved performance at Central Hudson under a new three-year rate order. Favourable foreign exchange impacts associated with US dollar-denominated earnings also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

Adjusted Basic Earnings Per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of UNS Energy, after considering the finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding, and contribution from the Waneta Expansion. Performance at all of the Corporation's other regulated utilities, as discussed above, and the impact of favourable foreign exchange also contributed to the increase. The increase was partially offset by an increase in Corporate expenses and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

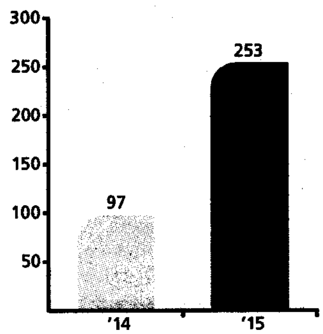
SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy	**195**	60	135
Central Hudson	**58**	37	21
	253	97	156
Regulated Gas Utility – Canadian			
FortisBC Energy	**140**	127	13
Regulated Electric Utilities – Canadian			
FortisAlberta	**138**	103	35
FortisBC Electric	**50**	46	4
Eastern Canadian	**62**	60	2
	250	209	41
Regulated Electric Utilities – Caribbean	**34**	27	7
Non-Regulated – Fortis Generation	**77**	20	57
Non-Regulated – Non-Utility	**114**	28	86
Corporate and Other	**(140)**	(191)	51
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A.

Regulated Electric & Gas Utilities – United States Earnings *($ millions)*



REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2015 earnings from regulated assets represented approximately 92% (2014 – 91%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses), excluding the gains on sale of non-core assets. Total regulated assets represented 96% of the Corporation's total assets as at December 31, 2015 (December 31, 2014 – 93%).

Regulated Electric & Gas Utilities – United States

Regulated Electric & Gas Utilities – United States earnings for 2015 were $253 million (2014 – $97 million), which represented approximately 37% (2014 – 21%) of the Corporation's total regulated earnings. Total segment assets were approximately $12.1 billion as at December 31, 2015 (December 31, 2014 – $9.9 billion), which represented approximately 44% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 40%).

UNS Energy

Financial Highlights [1]

Years Ended December 31	**2015**	2014
Average US:CAD Exchange Rate [2]	**1.28**	1.12
Electricity Sales *(gigawatt hours ("GWh"))*	**15,366**	5,646
Gas Volumes *(petajoules ("PJ"))*	**13**	5
Revenue *($ millions)*	**2,034**	684
Earnings *($ millions)*	**195**	60

[1] Financial results of UNS Energy are from August 15, 2014, the date of acquisition.

[2] The reporting currency of UNS Energy is the US dollar. The average US:CAD exchange rate for 2014 is from the date of acquisition.

Electricity Sales & Gas Volumes

Electricity sales were 15,366 gigawatt hours ("GWh") for 2015 compared to 14,560 GWh for the full year in 2014. The increase was primarily due to higher short-term wholesale electricity sales. The majority of short-term wholesale electricity sales is flowed through to customers and has no impact on earnings. Retail sales were comparable year over year.

Gas volumes of 13 petajoules ("PJ") for 2015 were comparable with the full year in 2014.

Revenue

Revenue was US$1,588 million for 2015 compared to US$1,560 million for the full year in 2014. The increase was primarily due to the flow through to customers of higher purchased power and fuel supply costs, higher transmission revenue, and higher wholesale electricity sales. On a Canadian dollar basis, revenue was also impacted by favourable foreign exchange.

Earnings

Earnings were US$152 million for 2015 compared to US$144 million for the full year in 2014, excluding the impact of acquisition-related expenses. The increase was primarily due to higher transmission revenue and a decrease in interest expense due to the expiry of leasing arrangements. The increase was partially offset by higher operating expenses. On a Canadian dollar basis, earnings were also impacted by favourable foreign exchange.

Central Hudson

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Average US:CAD Exchange Rate [1]	**1.28**	1.10	0.18
Electricity Sales *(GWh)*	**5,132**	5,075	57
Gas Volumes *(PJ)*	**24**	23	1
Revenue *($ millions)*	**880**	821	59
Earnings *($ millions)*	**58**	37	21

[1] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The increase in electricity sales was mainly due to higher average consumption as a result of warmer temperatures in the summer, which increased the use of air conditioning and other cooling equipment. Gas volumes for 2015 were comparable with last year.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

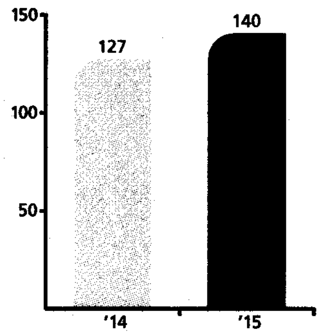
Revenue

The increase in revenue was driven by approximately $111 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. An increase in base electricity rates effective July 1, 2015 and the recovery from customers of previously deferred electricity costs also contributed to the increase in revenue. Additionally, revenue for the first half of 2015 was favourably impacted by energy efficiency incentives and higher gas revenue associated with a new gas delivery contract in late 2014. The increase was partially offset by the recovery from customers of lower commodity costs, which were mainly due to lower wholesale prices.

Earnings

The increase in earnings was primarily due to approximately $9 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, an increase in base electricity rates effective July 1, 2015, a new gas delivery contract implemented in late 2014, and energy efficiency incentives earned during the first half of 2015. The increase was partially offset by the impact of higher expenses during the two-year rate freeze period post acquisition, which ended on June 30, 2015.

Regulated Gas Utility – Canadian Earnings *($ millions)*



Regulated Gas Utility – Canadian

Regulated Gas Utility – Canadian earnings for 2015 were $140 million (2014 – $127 million), which represented approximately 21% of the Corporation's total regulated earnings (2014 – 28%). Total segment assets were approximately $6.0 billion as at December 31, 2015 (December 31, 2014 – $5.8 billion), which represented approximately 22% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 24%).

FortisBC Energy

Financial Highlights

Years Ended December 31	2015	2014	Variance
Gas Volumes *(PJ)*	**186**	195	(9)
Revenue *($ millions)*	**1,295**	1,435	(140)
Earnings *($ millions)*	**140**	127	13

Gas Volumes

The decrease in gas volumes was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas from those forecast to set customer gas rates do not materially affect earnings.

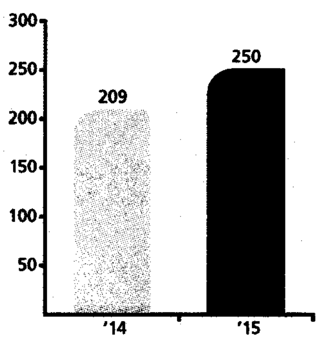
Revenue

The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers and lower gas volumes. The decrease was partially offset by higher regulatory flow-through deferral amounts.

Earnings

The increase in earnings was mainly due to higher AFUDC, regulatory flow-through deferral amounts and operating cost savings, net of the earnings sharing mechanism. The increase was partially offset by a decrease in the allowed ROE and equity component of capital structure as a result of the amalgamation of FEVI and FEWI with FEI, effective December 31, 2014. For further details on the amalgamation, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Regulated Electric Utilities – Canadian Earnings *($ millions)*



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2015 were $250 million (2014 – $209 million), which represented approximately 37% of the Corporation's total regulated earnings (2014 – 45%). Total segment assets were approximately $8.2 billion as at December 31, 2015 (December 31, 2014 – $7.7 billion), which represented approximately 30% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 32%).

FortisAlberta

Financial Highlights

Years Ended December 31	2015	2014	Variance
Energy Deliveries *(GWh)*	**17,132**	17,372	(240)
Revenue *($ millions)*	**563**	518	45
Earnings *($ millions)*	**138**	103	35

Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, partially offset by higher average consumption by farm and irrigation, residential and commercial customers. Lower levels of precipitation, particularly in the third quarter, and warmer temperatures had a favorable impact on energy deliveries to farm and irrigation customers. Higher energy deliveries to residential and commercial customers due to customer growth were partially offset by lower average consumption due to warmer temperatures.

Revenue

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The increase in revenue was primarily due to the operation of the PBR formula, including an increase in customer rates based on a combined inflation and productivity factor of 1.49%, higher capital tracker revenue, growth in the number of customers, and higher revenue related to flow-through costs to customers. Revenue was also favourably impacted by a $9 million capital tracker revenue adjustment recognized in 2015 associated with 2013 and 2014, as a result of regulatory decisions. For further details on regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Earnings

The increase in earnings was primarily due to rate base growth associated with capital expenditures, growth in the number of customers, and the impact of a technical update on depreciation and amortization. Also contributing to the increase in earnings was capital tracker revenue of approximately $9 million recognized in 2015 associated with 2013 and 2014, as discussed above.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**3,116**	3,179	(63)
Revenue *($ millions)*	**360**	334	26
Earnings *($ millions)*	**50**	46	4

Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption in the first and fourth quarters as a result of warmer temperatures.

Revenue

The increase in revenue was driven by increases in base electricity rates, mainly established to recover higher power purchase costs, and surplus capacity sales. Revenue was also favourably impacted by higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion. The increase was partially offset by lower electricity sales.

Earnings

The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

Eastern Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**8,403**	8,376	27
Revenue *($ millions)*	**1,033**	1,008	25
Earnings *($ millions)*	**62**	60	2

Electricity Sales

The increase in electricity sales was primarily due to customer growth in Newfoundland, as well as higher average consumption in PEI, mainly due to an increase in the number of customers using electricity for home heating. The increase was partially offset by lower electricity sales in Ontario, largely due to the loss of a commercial customer and lower average consumption by residential customers due to changes in temperatures.

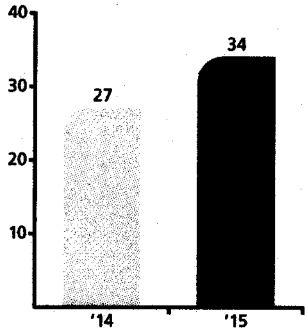
Revenue

The increase in revenue was mainly due to the flow through in customer electricity rates of overall higher energy supply costs and electricity sales growth.

Earnings

The increase in earnings was primarily due to electricity sales growth and lower operating costs, mainly due to restoration efforts at Newfoundland Power following the loss of energy supply from Newfoundland and Labrador Hydro ("Newfoundland Hydro") and related power interruptions in January 2014, partially offset by higher depreciation expense.

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2015 were $34 million (2014 – $27 million), which represented approximately 5% of the Corporation's total regulated earnings (2014 – 6%). Total segment assets were approximately $1.3 billion as at December 31, 2015 (December 31, 2014 – $1.1 billion), which represented approximately 4% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 4%).

Financial Highlights

Years Ended December 31	2015	2014	Variance
Average US:CAD Exchange Rate [1]	1.28	1.10	0.18
Electricity Sales *(GWh)*	802	771	31
Revenue *($ millions)*	321	321	–
Earnings *($ millions)*	34	27	7

[1] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales

The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures, which increased air conditioning load.

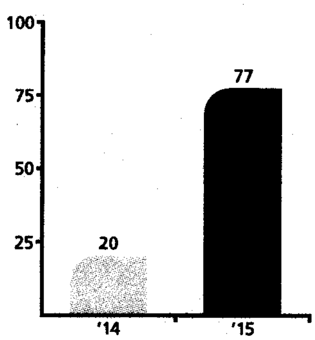
Revenue

Revenue was impacted by approximately $39 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, and electricity sales growth. The increase was largely offset by the flow through in customer electricity rates of lower fuel costs at Caribbean Utilities.

Earnings

The increase in earnings was due to approximately $5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, electricity sales growth and higher capitalized interest at Caribbean Utilities. The increase was partially offset by higher depreciation. Equity income from Belize Electricity from the date of settlement in August 2015 was less than $1 million.

Non-Regulated – Fortis Generation Earnings *($ millions)*



NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	2015	2014	Variance
Energy Sales *(GWh)*	844	407	437
Revenue *($ millions)*	107	38	69
Earnings *($ millions)*	77	20	57

Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in early April 2015 and reported energy sales of 517 GWh in 2015. The increase was partially offset by decreased production in Belize due to lower rainfall and in Upstate New York and Ontario due to the sale of generation assets in mid 2015, lower rainfall, and generating units taken out of service for repairs.

Revenue

The increase in revenue was driven by the Waneta Expansion, which recognized revenue of $70 million in 2015, and approximately $4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by decreased production in Belize, Upstate New York and Ontario.

Earnings

The increase in earnings was driven by the recognition of after-tax gains totalling approximately $32 million on the sale of generation assets in Upstate New York and Ontario in mid 2015, and earnings contribution of $22 million from the Waneta Expansion. Approximately $3 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and lower business development costs were partially offset by decreased production in Belize, Upstate New York and Ontario.

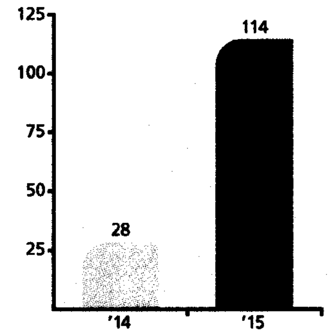
Non-Regulated – Non-Utility

Financial Highlights

Years Ended December 31

($ millions)	2015	2014	Variance
Revenue	171	249	(78)
Earnings	114	28	86

Non-Regulated – Non-Utility Earnings
($ millions)



Revenue

The decrease in revenue was primarily due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Earnings

The increase in earnings was driven by a net after-tax gain of approximately $101 million on the sale of commercial real estate and hotel assets. The increase was partially offset by lower earnings contribution from the commercial real estate and hotel assets as a result of the sale and $5 million in earnings in 2014 associated with Griffith from normal operations to the date of sale in March 2014.

Corporate and Other

Financial Highlights

Years Ended December 31

($ millions)	2015	2014	Variance
Revenue	24	31	(7)
Operating Expenses	26	38	(12)
Depreciation and Amortization	2	2	–
Other Income (Expenses), Net	(8)	(45)	37
Finance Charges	94	154	(60)
Income Tax Recovery	(43)	(79)	36
	(63)	(129)	66
Preference Share Dividends	77	62	15
Net Corporate and Other Expenses	(140)	(191)	51

Net Corporate and Other expenses were impacted by the following items.

(i) A foreign exchange gain of $13 million in 2015 compared to $8 million in 2014, associated with the Corporation's previous US-dollar denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income;
(ii) A loss of approximately $9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses;
(iii) Acquisition-related expenses of $10 million ($7 million after tax) in 2015 associated with the pending acquisition of ITC, which were included in other income;
(iv) Finance charges of $72 million ($51 million after tax) in 2014 associated with the convertible debentures issued to finance a portion of the acquisition of UNS Energy; and
(v) Other expenses of approximately $58 million ($39 million after tax) in 2014 related to the acquisition of UNS Energy.

Excluding the above-noted items, net Corporate and Other expenses were $137 million for 2015 compared to approximately $109 million for 2014. The increase in net Corporate and Other expenses was primarily due to higher preference share dividends and finance charges, and a decrease in revenue. The increase was partially offset by lower operating expenses.

The increase in preference share dividends and finance charges was primarily due to the acquisition of UNS Energy. Finance charges were also impacted by no longer capitalizing interest upon completion of the Waneta Expansion and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense.

The decrease in revenue was primarily due to a decrease in related-party interest income, mainly due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

The decrease in operating expenses was primarily due to lower retirement expenses. Retirement expenses of approximately $13 million ($11 million after tax) were recognized in 2014 compared to approximately $2 million ($1 million after tax) in 2015. The decrease in operating expenses was partially offset by a $3 million ($2 million after tax) corporate donation recognized in 2015.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated electric and gas utilities are summarized as follows.

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2014	2015	2016	Significant Features Future or Historical Test Year Used to Set Customer Rates
				ROE		
TEP	ACC	43.5	10.00	10.00	10.00	COS/ROE [1]
UNS Electric	ACC	52.6 [2]	9.50	9.50	9.50 [2]	ROEs established by the ACC
UNS Gas	ACC	50.8	9.75	9.75	9.75	Historical Test Year
Central Hudson	New York State Public Service Commission ("PSC")	48	10.00	10.00/ 9.00 [3]	9.00	COS/ROE Earnings sharing mechanism ROE established by the PSC Future Test Year
FEI	British Columbia Utilities Commission ("BCUC")	38.5 [2]	8.75	8.75	8.75 [2]	COS/ROE PBR mechanism for 2014 through 2019
FEVI	BCUC	41.5 [4]	9.25	n/a [4]	n/a [4]	ROEs established by the BCUC
FEWI	BCUC	41.5 [4]	9.50	n/a [4]	n/a [4]	2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisBC Electric	BCUC	40 [2]	9.15	9.15	9.15 [2]	COS/ROE PBR mechanism for 2014 through 2019 ROE established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisAlberta	Alberta Utilities Commission ("AUC")	40 [2]	8.30	8.30	8.30 [2]	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC 2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45 [2]	8.80 +/– 50 bps	8.80 +/– 50 bps	8.80 [2] +/– 50 bps	COS/ROE ROE established by the PUB Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40 [2]	9.75	9.75	9.35 [2]	COS/ROE ROE established by the *PEI Energy Accord* in 2014 and 2015. ROE in 2016 to be established by IRAC Future Test Year
FortisOntario	Ontario Energy Board	40	8.93 – 9.85	8.93 – 9.30	8.93 – 9.30	COS/ROE [5] Future test year and incentive regulation rate-setting mechanism
				ROA		
Caribbean Utilities	Electricity Regulatory Authority	N/A	7.00 – 9.00	7.25 – 9.25	6.75 – 8.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Historical Test Year
Fortis Turks and Caicos	Government of the Turks and Caicos Islands	N/A	15.00 – 17.50 [6]	15.00 – 17.50 [6]	15.00 – 17.50 [6]	COS/ROA Historical Test Year

[1] Additionally, allowed ROEs are adjusted for the fair value of rate base as required under the laws of the State of Arizona.
[2] Interim and subject to change pending the outcome of regulatory proceedings effective January 1, 2016 for FortisAlberta, FEI and FortisBC Electric; May 1, 2016 for UNS Electric; July 1, 2016 for Newfoundland Power; and March 1, 2016 for Maritime Electric.
[3] Allowed ROE of 10.0% with a 48% common equity component of capital structure to June 30, 2015. Allowed ROE of 9.00% with a 48% common equity component of capital structure effective July 1, 2015 through June 30, 2018.
[4] As approved by the BCUC, effective December 31, 2014, FEVI and FEWI were amalgamated with FEI and, as a result, the allowed ROE and common equity component of capital structure for 2015 reverted to those of FEI.
[5] Cornwall Electric is subject to a rate-setting mechanism under a Franchise Agreement with the City of Cornwall, based on a price cap with commodity cost flow through.
[6] Achieved ROAs at the utilities are significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base customer electricity rates.

Material Regulatory Decisions and Applications

The following summarizes the significant regulatory decisions and applications for the Corporation's regulated utilities for 2015.

UNS Energy

In November 2015 TEP, UNS Energy's largest utility, filed a GRA with the ACC requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. The key provisions of the rate request include: (i) a base retail rate increase of US$110 million, or 12.0%, compared with adjusted test year revenue; (ii) a 7.34% return on original cost rate base of US$2.1 billion; (iii) a common equity component of capital structure of approximately 50%; (iv) a cost of equity of 10.35% and an average cost of debt of 4.32%; and (v) rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. In May 2015 UNS Electric filed a GRA requesting new retail rates to be effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's GRA was similar to that of TEP. A decision on UNS Electric's application is expected in the third quarter of 2016 and TEP's application is expected in the fourth quarter of 2016.

Central Hudson

Three-Year Rate Order

In June 2015 the PSC issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US$225 million in energy infrastructure during the two-year delivery rate freeze period ended June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Rate Order includes capital investments of approximately US$490 million during the three-year period targeted at making the electric and gas systems stronger.

The approved Rate Order includes full cost recovery of electric and natural gas commodity costs and continuation of certain mechanisms, including revenue decoupling and earnings sharing mechanisms. In the approved earnings sharing mechanism, the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. In addition, the Rate Order includes a major storm reserve for electric operations and provides for continuation of recovery of various operating expenses, including environmental site investigation and remediation costs. To the extent that Central Hudson receives gas delivery revenue associated with a new contract implemented in late 2014, associated revenue is being used to mitigate future gas customer rate increases, effective July 1, 2015.

Reforming the Energy Vision

In 2014 the PSC issued an order instituting a proceeding to reform New York State's electricity industry and regulatory practices ("Reforming the Energy Vision"). The initiative seeks to further a number of policy objectives and seeks to determine the appropriate role of electric distribution utilities in furthering these objectives, as well as considering regulatory changes to better align utility interest with energy policy objectives. In 2015 Central Hudson continued to fully participate in this proceeding. The outcome of Reforming the Energy Vision cannot be determined at this time and it could impact the scope of regulated utilities in New York State.

FortisBC Energy and FortisBC Electric

Multi-Year PBR Plans

In September 2014 the BCUC issued its decisions on FEI and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2019. The approved PBR Plans incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

In May 2015 and June 2015, the BCUC issued its decisions on FEI and FortisBC Electric's 2015 rates in compliance with the PBR decisions issued in September 2014. The decisions approved 2015 midyear rate base of approximately $3,661 million and $1,249 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2015 of 0.7% and 4.2% over 2014 rates, respectively.

In December 2015 the BCUC issued its decisions on FEI and FortisBC Electric's 2016 rates. The decisions approved 2016 midyear rate base of approximately $3,693 million and $1,286 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2016 of 1.79% and 2.96% over 2015 rates, respectively.

Generic Cost of Capital Proceedings

A Generic Cost of Capital ("GCOC") Proceeding to establish the allowed ROE and capital structures for regulated utilities in British Columbia occurred from 2012 through 2014. FEI was designated as the benchmark utility and a BCUC decision established that the ROE for the benchmark utility would be set at 8.75% with a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. The GCOC Proceeding reaffirmed for FortisBC Electric a risk premium over the benchmark utility of 40 basis points, resulting in an allowed ROE of 9.15% effective January 1, 2013 through December 31, 2015, and a common equity component of capital structure at 40%.

The BCUC decision directed FEI to file an application to review the 2016 benchmark utility ROE and common equity component of capital structure. In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. As FEI is the benchmark utility, the review of the application could also have an impact on FortisBC Electric. A decision on the application is expected in the second quarter of 2016.

FortisAlberta

Generic Cost of Capital Proceedings

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

In April 2015 the AUC initiated a GCOC Proceeding to set the allowed ROE and capital structure for 2016 and 2017. While the AUC approved a request by utilities in Alberta to negotiate matters at issue in the GCOC Proceeding for 2016, a negotiated settlement was not reached and a 2016 and 2017 GCOC Proceeding commenced. A hearing is scheduled for June 2016 and a decision is expected before the end of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures.

In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

In May 2015 FortisAlberta filed an application with the AUC seeking: (i) capital tracker revenue of $72 million for 2016 and $90 million for 2017; (ii) a reduction of $5 million to the 2014 capital tracker revenue to reflect actual capital expenditures; and (iii) approval of additional revenue related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015, with a decision from the regulator expected in the first quarter of 2016.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

2016 Annual Rates Application

In December 2015 the regulator approved FortisAlberta's 2016 Annual Rates Application substantially as filed. The rates and riders, effective January 1, 2016, include an increase of approximately 4.6% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of $64 million, which is 90% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed in the capital tracker applications, as discussed previously; and (iii) $17 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed in the capital tracker compliance filing related to the 2015 capital tracker decision.

Utility Asset Disposition Matters

In previous decisions, the AUC made statements regarding cost responsibility for stranded assets and gains or losses related to extraordinary retirement of utility assets, which FortisAlberta and other Alberta utilities challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility service as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the *Electric Utilities Act* (Alberta). As a result, the utilities in Alberta had filed leave to appeal motions with the Court of Appeal of Alberta.

In September 2015 the Court of Appeal of Alberta issued a decision that dismissed the appeals of the utilities. The basis for the decision was that the AUC should be accorded deference for its conclusions in utility asset disposition matters. The decision by the Court of Appeal of Alberta has no immediate impact on FortisAlberta's financial position. However, the Company is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers. In November 2015 the utilities in Alberta filed a leave to appeal motion with the Supreme Court of Canada, the outcome and timing of which is unknown.

Eastern Canadian Electric Utilities

In October 2015 Newfoundland Power filed a 2016/2017 GRA with the PUB to set customer rates effective July 1, 2016. The Company is proposing an overall average increase in electricity rates of 3.1%. The GRA will include a full review of Newfoundland Power's costs, including cost of capital. The application is currently under review by the PUB. A public hearing is scheduled to begin at the end of the first quarter of 2016 and a decision on the application is expected by the end of the second quarter of 2016.

In October 2015 Maritime Electric filed a GRA with the IRAC to set customer rates effective March 1, 2016, on expiry of the *Prince Edward Island Energy Accord*. In January 2016 Maritime Electric and the Government of PEI entered into a 2016 General Rate Agreement covering the three-year period from March 1, 2016 through February 28, 2019. The agreement, which is subject to regulatory approval, is generally consistent with the GRA filed in October 2015, however, reflects an allowed ROE capped at 9.35% on a maximum average common equity component of capital structure of 40%. Under the agreement, the typical customer electricity cost increase will be limited to a maximum of 2.3% annually.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's regulated utilities.

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
TEP	GRA for 2017	November 2015	Fourth quarter of 2016
UNS Electric	GRA for 2016	May 2015	Third quarter of 2016
Central Hudson	Reforming the Energy Vision	Not applicable	To be determined
FEI	2016 Cost of Capital Application	October 2015	Second quarter of 2016
FortisAlberta	2016/2017 Capital Tracker Application	May 2015	First quarter of 2016
	2016/2017 GCOC Proceeding	Not applicable	Second half of 2016
Newfoundland Power	GRA for 2016/2017	October 2015	Second quarter of 2016

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014.

Significant Changes in the Consolidated Balance Sheets between December 31, 2015 and December 31, 2014

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Regulatory assets – current and long-term	117	The increase was mainly due to: (i) an increase in regulatory deferred income taxes, mainly at FortisAlberta; (ii) the impact of foreign exchange on the translation of US dollar-denominated regulatory assets; and (iii) the deferral of various other costs as permitted by the regulators. The above-noted increases were partially offset by a reduction in regulatory assets at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator, and a decrease in the deferral for employee future benefits.
Utility capital assets	2,416	The increase primarily related to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation and customer contributions.
Non-utility capital assets	(664)	The decrease was due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.
Goodwill	441	The increase was due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Short-term borrowings	181	The increase was mainly due to higher short-term borrowings at FortisBC Energy and FortisBC Electric, largely to finance utility capital expenditures.
Regulatory liabilities – current and long-term	193	The increase was mainly due to the impact of foreign exchange on the translation of US dollar-denominated regulatory liabilities and higher rate stabilization accounts at FortisBC Energy, partially offset by a reduction in regulatory liabilities at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator.
Long-term debt (including current portion)	732	The increase was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.
Capital lease and finance obligations (including current portion)	(190)	The decrease was mainly due to the purchase of an additional ownership interest in the Springerville Unit 1 generating facility and the Springerville coal handling facilities at UNS Energy following the expiry of lease arrangements.
Deferred income tax liabilities	424	The increase was primarily due to tax timing differences mainly related to capital expenditures at the regulated utilities and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	1,189	The increase primarily related to: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

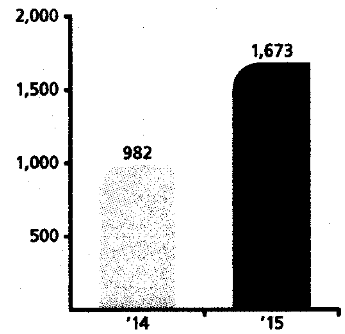
Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2015 compared to 2014, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
Cash, Beginning of Year	**230**	72	158
Cash Provided by (Used in):			
Operating Activities	**1,673**	982	691
Investing Activities	**(1,368)**	(4,199)	2,831
Financing Activities	**(346)**	3,361	(3,707)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**53**	14	39
Cash, End of Year	**242**	230	12

Cash Flow from Operating Activities *($ millions)*



Operating Activities: Cash flow from operating activities in 2015 was $691 million higher than in 2014. The increase was driven by higher cash earnings and favourable changes in working capital. The increase in cash earnings was driven by the acquisition of UNS Energy in August 2014. Earnings contribution from the Waneta Expansion and higher cash earnings at FortisAlberta also contributed to the increase. Favourable changes in working capital at FortisBC Energy and UNS Energy were partially offset by unfavourable changes at FortisAlberta.

Investing Activities: Cash used in investing activities in 2015 was $2,831 million lower than in 2014. The decrease was due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of $2,745 million. Also contributing to the decrease were proceeds received from the sale of commercial real estate assets in June 2015 for $430 million, hotel assets in October 2015 for $365 million, and generation assets in Upstate New York in June 2015 for $77 million (US$63 million), compared to proceeds of $105 million (US$95 million) on the sale of Griffith in March 2014. The decrease was partially offset by an increase in capital expenditures of $518 million, driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets.

Financing Activities: Cash provided by financing activities in 2015 was $3,707 million lower than in 2014. The decrease was primarily due to financing associated with the acquisition of UNS Energy in August 2014 and the repayment of credit facility borrowings in 2015 using proceeds from the sale of commercial real estate and hotel assets. The acquisition of UNS Energy was financed from proceeds of $1,800 million, or $1,725 million net of issue costs, from the issue of convertible debentures, proceeds from the issuance of preference shares and credit facility borrowings. In October 2014 substantially all of the convertible debentures were converted into 58.2 million common shares of Fortis.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net (repayments) borrowings under committed credit facilities for 2015 and 2014 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy (1)	**591**	–	591
Central Hudson (2)	**25**	33	(8)
FortisBC Energy (3)	**150**	–	150
FortisAlberta (4)	**149**	274	(125)
FortisBC Electric (5)	**–**	198	(198)
Newfoundland Power (6)	**75**	–	75
Caribbean Utilities (7)	**–**	57	(57)
Fortis Turks and Caicos (8)	**12**	92	(80)
Corporate (9)	**–**	539	(539)
Total	**1,002**	1,193	(191)

(1) In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured notes and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

(2) In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for other general corporate purposes.

(3) In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

(4) In September 2015 FortisAlberta issued 30-year $150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes. In September 2014 FortisAlberta issued $275 million senior unsecured debentures in a dual tranche of 10-year $150 million at 3.30% and 30-year $125 million at 4.11%. The net proceeds were used to repay maturing long-term debt, finance capital expenditures and for general corporate purposes.

(5) In October 2014 FortisBC Electric issued 30-year $200 million 4.00% senior unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

(6) In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(7) In November 2014 Caribbean Utilities issued a total of US$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds were used to finance capital expenditures.

(8) In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In December 2014 Fortis Turks and Caicos issued 15-year US$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

(9) In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity was approximately 9 years and the weighted average coupon rate was 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity was approximately 12 years and the weighted average coupon rate was 4.11%. Net proceeds were used to repay long-term debt and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy	**(449)**	–	(449)
Central Hudson	**–**	(24)	24
FortisBC Energy	**(92)**	(6)	(86)
FortisAlberta	**–**	(200)	200
FortisBC Electric	**–**	(140)	140
Newfoundland Power	**(6)**	(35)	29
Caribbean Utilities	**(17)**	(19)	2
Fortis Turks and Caicos	**(4)**	(4)	–
Fortis Properties	**(34)**	(22)	(12)
Corporate	**–**	(293)	293
Total	**(602)**	(743)	141

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy	**(199)**	61	(260)
FortisAlberta	**30**	3	27
FortisBC Electric	**–**	(54)	54
Newfoundland Power	**(47)**	65	(112)
Corporate	**(406)**	535	(941)
Total	**(622)**	610	(1,232)

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were used to repay a portion of credit facility borrowings used to initially finance a portion of the acquisition of UNS Energy.

Common share dividends paid in 2015 totalled $232 million, net of $156 million of dividends reinvested, compared to $194 million, net of $81 million of dividends reinvested, paid in 2014. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.40 in 2015 compared to $1.28 in 2014. The weighted average number of common shares outstanding was 278.6 million for 2015 compared to 225.6 million for 2014.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2015, are outlined in the following table.

Contractual Obligations

As at December 31, 2015 *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**11,240**	384	71	283	239	857	9,406
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Capital lease and finance obligations [1]	**2,478**	72	74	93	77	75	2,087
Renewable power purchase obligations [2]	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations [3]	**1,449**	366	253	222	153	131	324
Power purchase obligations [4]	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy [5]	**1,057**	146	141	105	102	82	481
Capital cost [6]	**488**	19	19	19	19	19	393
Operating lease obligations [7]	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements [8]	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities [9]	**147**	–	53	–	–	–	94
Employee future benefits funding contributions	**139**	49	12	8	9	9	52
Waneta Partnership promissory note	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other [10]	**71**	15	12	16	3	–	25
Total	**30,001**	1,989	1,476	1,552	1,318	1,885	21,781

[1] Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's capital lease obligations.

[2] TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

[3] Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

[4] Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy

In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric

Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario

Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric

Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson

Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$76 million in purchase commitments remaining as at December 31, 2015. During 2015, Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

(5) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million, which is not included in the previous table.

(6) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(8) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(9) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021.

(10) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit Plan obligations and asset retirement obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with the U.S. Federal Energy Regulatory Commission ("FERC") for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8 to the Corporation's 2015 Audited Consolidated Financial Statements.

Capital Structure

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 35% common equity, 65% debt and preferred equity, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

	2015		2014	
As at December 31	***($ millions)***	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**11,950**	**54.8**	11,239	56.4
Preference shares	**1,820**	**8.3**	1,820	9.1
Common shareholders' equity	**8,060**	**36.9**	6,871	34.5
Total [(2)]	**21,830**	**100.0**	19,930	100.0

[(1)] Includes long-term debt and capital lease and finance obligations, including current portions, and short-term borrowings, net of cash
[(2)] Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2015 was 53.7% debt, 8.5% preference shares and 37.8% common shareholders' equity (December 31, 2014 – 54.8% debt, 9.5% preference shares and 35.7% common shareholders' equity).

The improvement in the Corporation's capital structure was due to an increase in common shareholders' equity as a result of: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the year ended December 31, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans. The capital structure was also impacted by an increase in total debt due to the impact of foreign exchange on the translation of US dollar-denominated debt and new debt in support of energy infrastructure investment, partially offset by regular scheduled debt repayments and net repayments under committed credit facilities.

Credit Ratings

As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	**A– / Stable (long-term corporate and unsecured debt credit rating)**
DBRS	**A (low) / Stable (unsecured debt credit rating)**

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's long-term corporate credit rating at A–, revised its unsecured debt credit rating to BBB+ from A–, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's credit rating under review with negative implications.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $276 million in maintenance and repairs was expensed in 2015 compared to approximately $203 million in 2014. The increase was largely due to a full year of expense for UNS Energy in 2015.

Gross consolidated capital expenditures for 2015 were approximately $2.2 billion. A breakdown of these capital expenditures by segment and asset category for 2015 is provided in the following table.

Gross Consolidated Capital Expenditures [(1)]

Year Ended December 31, 2015

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** [(2)]	**Total**
Generation	321	1	–	–	3	9	107	**441**	**38**	**–**	**479**
Transmission	131	37	57	–	19	23	2	**269**	**–**	**–**	**269**
Distribution	135	102	134	358	38	121	16	**904**	**–**	**–**	**904**
Facilities, equipment, vehicles and other [(3)]	39	27	254	73	35	14	9	**451**	**–**	**28**	**479**
Information technology	43	14	15	21	8	8	3	**112**	**–**	**–**	**112**
Total	669	181	460	452	103	175	137	**2,177**	**38**	**28**	**2,243**

(1) Represents cash payments to construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.

(2) Includes capital expenditures of approximately $14 million at FAES, which is reported in the Corporate and Other segment

(3) Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $2,243 million for 2015 were $91 million higher than $2,152 million forecast for 2015, as disclosed in the MD&A for the year ended December 31, 2014. The increase was driven by higher capital spending at FortisBC Energy primarily due to the timing of payments associated with the Tilbury Expansion and at FortisAlberta primarily due to the purchase of two Rural Electrification Associations ("REAs") for approximately $21 million in 2015, and due to the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures. The increase was partially offset by lower-than-forecast capital spending at the Waneta Expansion, due to the timing of payments, and at FAES.

Gross consolidated capital expenditures for 2016 are expected to be approximately $1.9 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2016 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [1]

Year Ending December 31, 2016

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** [2]	**Total**
Generation	162	2	–	–	2	24	73	**263**	**15**	**–**	**278**
Transmission	66	30	84	–	21	19	6	**226**	**–**	**–**	**226**
Distribution	168	142	129	311	29	110	23	**912**	**–**	**–**	**912**
Facilities, equipment, vehicles and other [3]	40	25	118	109	16	9	20	**337**	**–**	**3**	**340**
Information technology	49	29	18	21	11	12	5	**145**	**–**	**–**	**145**
Total	485	228	349	441	79	174	127	**1,883**	**15**	**3**	**1,901**

[1] Represents forecast cash payments to construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC. Forecast capital expenditures for 2016 are based on a forecast exchange rate of US$1.00=CAD$1.38.

[2] Includes forecast capital expenditures of approximately $3 million at FAES, which is reported in the Corporate and Other segment

[3] Includes forecast capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2015 actual and 2016 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31 *(%)*	**Actual 2015**	Forecast 2016
Growth [1]	**40**	36
Sustaining [2]	**44**	48
Other [3]	**16**	16
Total	**100**	100

[1] Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

[2] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

[3] Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2016 through 2020, excluding the pending acquisition of ITC, gross consolidated capital expenditures are expected to be approximately $9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 40% at Regulated Electric & Gas Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utility; 5% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 35% to meet customer growth; 50% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 15% for facilities, equipment, vehicles, information technology and other assets.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base

($ billions)	**Actual 2015**	Forecast 2016
UNS Energy [1]	**4.1**	4.8
Central Hudson [1]	**1.4**	1.6
FortisBC Energy	**3.7**	3.7
FortisAlberta	**2.7**	3.0
FortisBC Electric	**1.3**	1.3
Eastern Canadian Electric Utilities	**1.6**	1.7
Regulated Electric Utilities – Caribbean [1]	**0.8**	0.9
Waneta Expansion	**0.8**	0.8
Total	**16.4**	17.8

[1] Actual midyear rate base for 2015 is based on the actual average exchange rate of US$1.00=CAD$1.28 and forecast midyear rate base for 2016 is based on a forecast exchange rate of US$1.00=CAD$1.38.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2015 and 2016 are summarized in the table below.

Significant Capital Projects (1)

($ millions) Company	Nature of Project	Pre-2015	Actual 2015	Forecast 2016	Forecast 2017–2020	Expected Year of Completion
UNS Energy (2)	Interest in Springerville Unit 1	23	57	–	–	2015
	Springerville Coal Handling Facilities Lease Buyout	–	91	–	–	2015
	Pinal Transmission Project	9	84	–	–	2015
	Residential Solar Program	–	1	22	90	Ongoing
Central Hudson (2)	Gas Main Replacement Program	7	19	29	135	Post-2020
FortisBC Energy	Tilbury LNG Facility Expansion (3)	145	181	105	15	2016
	Lower Mainland System Upgrade	4	11	50	362	2018
FortisAlberta	Pole-Management Program	159	41	42	94	Post-2020
Caribbean Utilities (2)	Generation Expansion	12	61	35	–	2016
Waneta Partnership	Waneta Expansion (4)	679	36	13	97	2015

(1) Represents utility capital asset and intangible asset expenditures, including both the capitalized interest and equity components of AFUDC, where applicable
(2) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.38 for 2016 through 2020
(3) Total project investment as at December 31, 2014 and 2015 includes approximately $43 million and $11 million, respectively, in non-cash capital accruals
(4) Includes the $72 million payment expected to be made in 2020 and excludes forecast capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

UNS Energy completed three significant capital investments in 2015. In January 2015, upon expiration of the Springerville Unit 1 lease, UNS Energy purchased an additional ownership interest in Springerville Unit 1 for US$46 million. This purchase increased the ownership interest to 49.5%. Additionally, upon expiration of the Springerville Coal Handling Facilities lease in April 2015, UNS Energy purchased an ownership interest in the coal-handling assets for US$72 million. The Pinal Transmission Project at UNS Energy was also completed in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt transmission line in Pinal County that will increase the Company's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

The Residential Solar Program at UNS Energy is a partnership with local solar companies for UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with approximately US$16 million expected to be spent in 2016.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US$20 million to expedite the replacement plan. Approximately US$15 million was spent on this program in 2015 and an additional US$21 million is expected to be spent in 2016. The majority of spending is expected post 2020.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion, at an estimated total project cost of $440 million, will include a second LNG tank and a new liquefier, both to be in service around the end of 2016. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility project from further regulatory review. Key construction activities in 2015 were focused on construction of the storage tank and liquefaction process areas. Total project costs to the end of 2015 were approximately $326 million.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply by reducing the number of single points of failure. The project has an estimated capital cost of $427 million, with approximately $50 million forecast to be spent in 2016, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2020 is expected to be approximately $336 million. Approximately $41 million was spent on this program in 2015, for a total of $200 million spent to date.

Caribbean Utilities was the successful bidder for new generation capacity and entered into a design-build contract agreement to cover the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. Approximately US$48 million was spent on the project in 2015, with approximately US$25 million forecast to be spent in 2016. The project cost is estimated to be US$85 million and the plant is expected to be commissioned in mid-2016.

Construction of the $900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project also included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. Fortis owns a 51% interest in the Waneta Partnership and operates and maintains the non-regulated investment. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table, includes capitalized interest by Fortis during construction, as well as other eligible capitalized expenses, and a $72 million payment expected to be made in 2020 related to accrued development costs previously incurred by CPC/CBT. The table excludes approximately $50 million of forecast capitalized interest of the minority partners in the Waneta Partnership.

Additional Investment Opportunities

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast and also exclude the acquisition of ITC.

FortisBC Energy is pursuing additional LNG infrastructure investment opportunities, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

The pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. The Woodfibre LNG plant has passed the British Columbia Environmental Assessment Office review and the Squamish First Nation approved an environmental certificate for the project in October 2015. These approvals are significant milestones; however, the project is pending a Federal Environmental Assessment. In addition, FortisBC Energy's pipeline expansion, at an estimated total project cost of up to $600 million, is also subject to various environmental approvals. A final investment decision by Woodfibre LNG is expected in 2016.

A further expansion of Tilbury is conditional upon having long-term contracts in place for the offtake of 70% of the additional liquefaction capacity, on average, for the first 15 years of operation. FortisBC Energy has a conditional agreement with Hawaiian Electric Company that would meet this requirement, subject to the regulatory approval process in Hawaii. The Corporation continues to have discussions with Hawaiian Electric Company, which is expected to be the primary offtaker, regarding the viability and scope of the project. Any resulting agreement would be subject to the approval of the Hawaii Public Utilities Commission.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to, the New York Transco, LLC at Central Hudson to address transmission constraints in New York; renewable energy alternatives at UNS Energy; Wataynikaneyap transmission line to connect remote First Nations communities at FortisOntario; further gas infrastructure opportunities at FortisBC Energy; and consolidation of Rural Electrification Associations at FortisAlberta.

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. For a discussion of the Corporation's cash flow requirements associated with the pending acquisition of ITC, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

In April 2015 FortisBC Energy filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $1 billion during the 25-month life of the shelf prospectus. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures under the base shelf prospectus.

In June 2015 Fortis injected US$180 million of equity into TEP. Proceeds were used to repay credit facility borrowings in June 2015 and the balance was used to redeem bonds in August 2015 and provide additional liquidity to TEP. This equity injection fulfilled one of the commitments made by Fortis in order to receive regulatory approval for the acquisition of UNS Energy, and increased TEP's common equity component of capital structure to almost 50%, which is comparable with other regulated utilities in Arizona.

In May 2015 Caribbean Utilities completed a rights offering in which it raised gross proceeds of US$32 million through the issue of 2.9 million common shares. Fortis invested US$23 million in approximately 2.2 million common shares of Caribbean Utilities. The net proceeds from the rights offering were used by Caribbean Utilities to finance capital expenditures.

In October 2015 FortisAlberta filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $500 million during the 25-month life of the shelf prospectus.

As at December 31, 2015, management expects consolidated fixed-term debt maturities and repayments to be $313 million in 2016 and to average approximately $260 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2015 and are expected to remain compliant in 2016.

Credit Facilities

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	Total as at December 31, 2015	Total as at December 31, 2014
Total credit facilities [1]	2,211	1,354	3,565	3,854
Credit facilities utilized:				
Short-term borrowings	(511)	–	(511)	(330)
Long-term debt (including current portion) [2]	(71)	(480)	(551)	(1,096)
Letters of credit outstanding	(68)	(36)	(104)	(192)
Credit facilities unused	1,561	838	2,399	2,236

[1] Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.

[2] As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million).

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other

Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $104 million as at December 31, 2015 (December 31, 2014 – $192 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Regulated utility assets comprised approximately 96% of total assets of Fortis as at December 31, 2015 (December 31, 2014 – 93%). Approximately 96% of the Corporation's operating revenue[(1)] was derived from regulated utility operations in 2015 (2014 – 95%), and approximately 92% of the Corporation's operating earnings[(1)], excluding the gains on sale of non-core assets, were derived from regulated utility operations in 2015 (2014 – 91%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting processes. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE, however, a utility is exposed to risks that inflationary increases may exceed the inflationary factor set by the regulator and that the utility may be unable to achieve productivity improvements. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, as a capital tracker where necessary.

Regulators approve the allowed ROEs and deemed capital structures of the utilities. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth. Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

Electricity and gas infrastructure investments require the approval of the regulatory authorities, either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

As an owner of an electricity distribution network under the *Electric Utilities Act (Alberta)*, FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

For additional information on the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

[(1)] Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

Risks Associated with the Pending Acquisition of ITC: ITC is a public company and its directors have fiduciary duties which may require them to consider competing offers to purchase the common stock of ITC as an alternative to the Acquisition. The agreement and plan of merger preserves the ability of the directors of ITC to accept a competing offer, in certain circumstances. Fortis may exercise its right to match such offer and, as a result, the purchase price could increase and other key transaction terms could change.

The closing of the acquisition of ITC, which is expected to occur in late 2016, is subject to normal commercial risks that the Acquisition will not close on the terms negotiated, or at all. Completion of the Acquisition remains subject to receipt of ITC and Fortis shareholder approvals, certain regulatory, state and federal approvals, and the satisfaction or waiver of other customary closing conditions contained in the agreement and plan of merger. The failure to obtain the required approvals or to satisfy or waive the conditions to closing may result in the termination of the agreement and plan of merger. Fortis intends to complete the Acquisition as soon as practicable after obtaining the required shareholder, regulatory and governmental approvals, and satisfying the other required closing conditions. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Acquisition and on the Corporation's business, financial condition or results of operations. If the closing of the acquisition of ITC does not take place as contemplated, the Corporation could suffer material adverse consequences. Failure to complete the Acquisition would, in certain circumstances, result in the Corporation being required to pay a termination fee of up to US$280 million and other potential costs.

Fortis expects that the Acquisition will provide benefits to the Corporation, including approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. There is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. Failure to realize the anticipated benefits of the acquisition of ITC may impact the financial performance of the Corporation, the price of its common shares and the ability of Fortis to continue to pay dividends on its common shares at rates consistent with the Corporation's dividend guidance, at current rates or at all.

Financing of the cash portion of the Acquisition is expected to be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. There can be no assurance that such financing sources will be available to Fortis at the desired time or at all, or on cost-efficient or commercially acceptable terms. As a result, there is no certainty that Fortis will reach a binding agreement with minority investors to complete the minority investment prior to closing of the Acquisition or at all. The Acquisition is not conditional upon Fortis securing one or more minority investors. Consummation of the Acquisition without completion of the contemplated minority investment could increase the consolidated indebtedness of the Corporation or result in the requirement for additional common equity and may have a negative impact on the Corporation's credit ratings and outlook and could result in additional financing costs and the failure to realize some, or all, of the expected benefits of the acquisition, including the extent to which the Acquisition is accretive. The Corporation obtained commitments for an aggregate of US$3.7 billion non-revolving term credit facilities. The commitments of the lenders to enter into these credit facilities is subject to certain customary conditions, which may result in such facilities becoming unavailable to Fortis in certain circumstances. If these credit facilities become unavailable, Fortis may not be able to complete the Acquisition.

While Fortis intends to become a U.S. Securities and Exchange Commission ("SEC") registrant and list its common shares on the New York Stock Exchange, there is no guarantee that it will be successful in this regard. If the Corporation is successful in this regard, it will be subject to increased regulatory compliance and may be subject to a greater risk of litigation.

The operations of ITC are conducted in US dollars and, following the Acquisition, the consolidated earnings and cash flows of Fortis will be impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. In particular, any decrease in the value of the US dollar relative to the Canadian dollar following the Acquisition could negatively impact the Corporation's net income as reported in Canadian dollars. Fortis may enter into forward foreign exchange contracts and utilize certain other derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective.

Fortis expects to incur a variety of costs in 2016 associated with completing the Acquisition. The majority of these costs will be non-recurring expenses related to financing and obtaining shareholder and regulatory approvals. Certain of these costs have already been incurred and other such costs will be incurred even if the Acquisition is ultimately not completed. Additional unanticipated acquisition-related costs may also be incurred in 2016.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and the effect it may have on allowed ROEs of the Corporation's regulated utilities. If interest rates continue to remain at historically low levels, allowed ROEs could decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which could have a negative effect on the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may cause a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. Central Hudson, FortisBC Energy and FortisBC Electric, however, have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. UNS Energy and Central Hudson use interest rate swaps and interest rate caps on variable-rate long-term debt to reduce risk associated with interest rates, as permitted by the regulators. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rates on, long-term debt are different from those forecast and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through interest costs to customers could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, almost 90% of the Corporation's consolidated long-term debt as at December 31, 2015 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2015.

Total Debt

As at December 31, 2015	($ millions)	(%)
Short-term borrowings	511	4.4
Utilized variable-rate credit facilities classified as long term	551	4.7
Variable-rate long-term debt (including current portion)	333	2.8
Fixed-rate long-term debt (including current portion)	10,284	88.1
Total	**11,679**	**100.0**

In 2015 the Corporation's regulated subsidiaries issued approximately $1 billion in long-term debt, all of which was at fixed interest rates ranging from 2.98% to 4.75%, with terms ranging from 10 to 30 years. The terms negotiated on new long-term debt demonstrate the ability of the Corporation and its utilities to raise long-term capital at attractive rates. Further information on the Corporation's consolidated long-term debt issuances is provided in the "Liquidity and Capital Resources" section of this MD&A.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2015, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions, leading to lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery. UNS Energy, Central Hudson and FortisBC Energy are exposed to various operational risks, associated with natural gas, such as: pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability.

The operation of UNS Energy's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of UNS Energy will continue to operate in accordance with expectations.

The operation of electricity T&D assets is also subject to risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. The FortisBC utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. UNS Energy, FortisBC Energy, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes.

The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material adverse effect on the financial position and results of operations of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and natural gas systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely distribute electricity and gas, which could have a material adverse effect on the operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts, in the Corporation's service territories influence energy sales. Declines in energy sales could adversely impact the respective utilities' results of operations, net earnings and cash flows.

The business of UNS Energy is concentrated in the State of Arizona. In recent years economic conditions in Arizona have contributed significantly to a reduction in retail customer growth and lower energy usage by the Company's residential, commercial and industrial customers. While it is expected that economic conditions in Arizona will improve in the future, if they do not or if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline.

FortisBC Energy is affected by the trend in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth in new multi-family housing starts continues to significantly outpace that of new single-family homes, which may temper growth in gas distribution volumes.

Alberta's economy is impacted by a number of factors, including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas. A general and extended decline in economic conditions in Alberta or in other jurisdictions where the Corporation's utilities operate would be expected to have the effect of reducing demand for electricity over time. The regulated nature of utility operations, including various mitigating measures approved by certain regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. Significantly reduced electricity demand in the Corporation's service areas could materially reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions could have a material adverse effect on the Corporation's results of operations, net earnings and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region has been impacted by challenging economic conditions over the past number of years. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand. Assets of Caribbean Regulated Electric Utilities comprise approximately 4% of the Corporation's total assets as at December 31, 2015.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or one of its larger subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, the regulatory environment in which the utilities operate and the nature and outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated fixed-term debt maturities in 2016 are expected to total $313 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing. The Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Activity in the global capital markets may impact the cost and timing of issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities could increase going forward. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2015 the following changes were made to debt credit ratings of the Corporation's utilities: (i) in February 2015 Moody's Investor Service ("Moody's") upgraded the debt credit ratings of UNS Energy to 'Baa1' from 'Baa2' and TEP, UNS Electric and UNS Gas to 'A3' from 'Baa1', and (ii) in July 2015 Fitch Ratings ("Fitch") downgraded Central Hudson's debt credit rating to 'A–' from 'A' and changed the rating outlook to stable from negative. Central Hudson's debt continues to be rated 'A' by S&P and 'A2' by Moody's, both with stable outlooks. In December 2015 DBRS confirmed FortisAlberta's debt credit rating of A(low) but revised its outlook to stable from positive. Also, in August 2015 Fitch confirmed TEP's credit rating of BBB+ but revised its outlook to positive from stable and in February 2016 Fitch withdrew its rating on TEP for commercial reasons at TEP's request. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P revised its outlook on TEP, Central Hudson, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues. For details related to environmental issues, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Information Technology and Cyber-Security Risks: As operators of critical energy infrastructure, the Corporation's utilities may face a heightened risk of cyber attacks. Information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

The Corporation's subsidiaries have security measures, policies and controls designed to protect and secure the integrity of its information technology systems, and safeguard the confidentiality of corporate and customer information; however, cyber-security threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's utilities' information technology systems are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information. If the breach is material in nature, it could adversely affect the financial performance of the Corporation, its reputation and standing with customers and regulators and expose it to claims of third-party damage. All of these factors could adversely affect the Corporation if not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Weather and Seasonality Risk: Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could materially impact the operations, financial condition and results of operations of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load.

At FortisBC Energy and the gas operations of UNS Energy and Central Hudson, weather has a significant impact on gas distribution volumes as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings associated with regulated gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power, to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

Natural gas and coal-fired generating plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to UNS Energy's generation facilities. Any material reduction in the water flow to UNS Energy's generation facilities would limit the ability of the Company to produce and market electricity from those respective facilities and could have a material adverse effect on the results of operations and financial position of the Corporation. Any change in regulations or the level of regulation respecting the use, treatment and discharge of water, or respecting the licensing of water rights in the jurisdictions where UNS Energy operates could result in a material adverse effect on the results of operations and financial position of the Company.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric. Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Company's entitlement to capacity and energy under the Canal Plant Agreement.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to the physical assets of utilities. Climate change, however, may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories. Although physical utility assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Central Hudson, Newfoundland Power and Maritime Electric, are subject to hurricane risk. Certain of the Corporation's utilities may also be subject to severe weather events, including ice, wind and snow storms. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost-recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. Central Hudson is authorized to request, and the PSC has typically approved, deferral account treatment for incremental storm restoration costs. To qualify for deferral, storm costs must meet certain criteria as stipulated by the PSC. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets in Belize are sensitive to rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Waneta Expansion's entitlement to capacity and energy under the Canal Plant Agreement.

Commodity Price Risk: UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market prices of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas, purchased power and coal serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into various price-risk management strategies to reduce exposure to commodity rates, including the use of derivative contracts that effectively fix the price of natural gas, power and electricity purchases. The absence of such hedging mechanism in the future could result in increased exposure to market price volatility.

Certain of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect FortisBC Energy, UNS Energy and Central Hudson, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Foreign Exchange Risk: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents, before considering the impact of the pending acquisition of ITC. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The above-noted utilities deal with credit quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2015 and do not expect any counterparties to fail to meet their obligations.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

Competitiveness of Natural Gas in British Columbia: In FortisBC Energy's service territory, natural gas primarily competes with electricity for space and hot water heating load. Recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis.

Government policy has also impacted the competitiveness of natural gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon-based energy sources or other energy sources.

There are other competitive challenges impacting the penetration of natural gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, FortisBC Energy has experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

In the future, if natural gas becomes less competitive due to pricing or other factors, the ability of FortisBC Energy to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of FortisBC Energy to fully recover COS in rates charged to customers.

Natural Gas, Fuel and Electricity Supply: FortisBC Energy is dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods, when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, FortisBC Energy is highly dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of FortisBC Energy could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The LNG storage facility on Vancouver Island helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from British Columbia. These include an increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia and the potential development of large-scale LNG facilities to export gas. British Columbia has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply at fair market prices.

The UNS Utilities are dependent on third parties to supply fuel, including natural gas and coal. Disruption of fuel supply could impair the ability of the Companies to deliver electricity or gas or generate electricity and could adversely affect operations. In addition, a loss of coal suppliers or the inability to renew existing coal or natural gas contracts at favorable terms could significantly affect the ability to serve customers and adversely affect the financial condition and the results of operations of the UNS Utilities.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for approximately 75% of its customers' energy requirements. The Corporation's utilities in the Caribbean are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled it from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these system supply issues and related power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. As well, the Government of Newfoundland and Labrador engaged consultants to complete an independent review of the current electricity system in the province.

Future changes in energy supply costs at Newfoundland Power, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales. The recovery of Muskrat Falls development costs are expected to materially increase customer electricity rates.

Power Purchase and Capacity Sale Contracts: FortisBC Electric's indirect customers are served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in extreme cases, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in customer rates.

Additionally, the Corporation's regulated electric utilities periodically enter into various power purchase contracts and resale contracts for excess capacity with third parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts. If the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity or not being able to secure additional capacity resale contracts. The utilities are also exposed to risk in the event of non-performance by counterparties to the various power purchase and resale contracts.

Employee Future Benefit Plan Performance and Funding Requirements: Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain of their employees. Approximately 63% of the Corporation's total employees are members of defined benefit pension plans and approximately 72% of employees are members of OPEB plans.

The employee future benefit plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net benefit cost. The primary assumptions utilized by management are the expected long-term rate of return on assets, the discount rate and the health care trend rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with employee future benefit plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

The projected benefit obligation and related net benefit cost can be affected by changes in the global financial and capital markets. There is no assurance that the employee future benefit plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the employee future benefit plan assets may result in material variations from the assumed long-term rates of return on the assets, which may cause material changes in future plan funding requirements from current estimates and future net benefit cost. Market-driven changes impacting the discount rates or the health care trend rate may also result in material changes in future plan funding requirements from current estimates and future net benefit cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process, as it affects the measurement of net benefit cost, future funding requirements and the projected benefit obligation.

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion in managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third-party owners with respect to the existing agreements for Springerville Unit 1. As a result of these disagreements and pending litigation, the third-party owners have and may continue to refuse to pay some or all of their pro rata share of Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments and Energy Efficiency: New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact various utilities' results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. Utilities are promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power, enable more efficient storage of energy, or reduce power consumption. These technologies include renewable energy, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales which could negatively impact the results of operations, net earnings and cash flows of utilities.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent environmental risks, as well as environmental laws and regulations, as discussed below.

Inherent Environmental Risks

The Corporation's electric and gas utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Inherent risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

Environmental Laws and Regulations

The Corporation's electric and gas utilities are subject to numerous federal, state and provincial environmental laws and regulations that may increase its cost of operations or expose it to environmental litigation and liabilities. Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Corporation's operations. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the Corporation. The utilities would request that additional costs resulting from environmental laws and regulations be recovered from customers in future rates. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies, and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

The management of greenhouse gas emissions is a specific environmental concern of the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state greenhouse gas laws, regulations and guidelines. In British Columbia, the Government of British Columbia's Energy Plan, *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. The utilities continue to assess and monitor the impact that the Government's Energy Plan and the *Clean Energy Act* may have on future operations.

In August 2015 the United States Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP") limiting carbon emissions from existing and new fossil fuelled power plants. The CPP establishes state-level carbon emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. UNS Energy is currently in the process of transitioning its generation resource mix, as appropriate, in order to reduce carbon emissions. The Company will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. UNS Energy is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. The Company cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, including the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. UNS Energy will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at the facilities. The Company has submitted comments on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. UNS Energy cannot predict the ultimate outcome of these matters.

The Company's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016 the United States Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP. UNS Energy will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. UNS Energy anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

If any of the coal-fired generation plants, or coal-handling facilities, from which UNS Energy obtains power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the Company could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating stations may force UNS Energy to incur higher costs for replacement capacity and energy. The Company may not be permitted recovery of these costs in customer rates.

In addition, early closures of certain generating units could require UNS Energy to redeem some or all tax-exempt bonds associated with the respective generating units. As at December 31, 2015, approximately 43% of UNS Energy's generating capacity was fuelled by coal.

Environmental laws and regulations have given rise to environmental liabilities at certain of the Corporation's utilities. TEP is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has an ownership interest and is obligated to pay similar costs at the coal mines that supply these generating stations. As at December 31, 2015, TEP has recognized approximately US$25 million in mine reclamation obligations, representing the present value of the estimated future liability. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs and timing of final reclamation at these sites are unknown and could be substantial. TEP currently recovers final mine reclamation costs through regulator-approved mechanisms as costs are paid to the coal suppliers.

Central Hudson is exposed to environmental contingencies associated with manufactured gas plants ("MGPs") that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid to late 1800s to the 1950s. The New York State Department of Environmental Conservation ("DEC") regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2015, Central Hudson has recognized approximately US$92 million in associated MGP environmental remediation liabilities. As approved by the PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates.

The Corporation believes that it and its subsidiaries are materially compliant with the environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. With the exception of the mine reclamation costs at TEP and the MGP remediation liabilities at Central Hudson, as noted above, as at December 31, 2015, there were no material environmental liabilities recognized in the Corporation's 2015 Audited Consolidated Financial Statements. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

Insurance Coverage Risk: The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' T&D assets is not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole, or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, lost revenue and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flows and financial position.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable, or that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Loss of Licences and Permits: The acquisition, ownership and operation of electric and gas utilities and assets require numerous licences, permits, agreements, orders, approvals and certificates ("Approvals") from various levels of government, government agencies and third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required Approvals. If there is a delay in obtaining any required Approvals, or if there is a failure to obtain or maintain any required Approvals or to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required Approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence, of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

Within certain portions of FortisAlberta's service territory, REAs have been granted by the AUC the right to provide electric distribution service to their eligible members. Members eligible to receive electric distribution service from an REA are those who meet the specific eligibility criteria defined in the integrated operating agreements between the Company and REA. In general, this eligibility criteria has limited the provision of service to customers whose land is used for agricultural activity or as a rural estate property. This historical arrangement has been challenged by some self-operating REAs that are seeking to expand their services to a broader range of customers within the service area that overlaps that of the Company. FortisAlberta is actively resisting these efforts on the part of these self-operated REAs, as it believes the legislative scheme in Alberta does not support this type of competition between the regulated utility and these small rural electricity cooperatives. There is a risk that the efforts of these self-operating REAs to expand their services to a broader range of customers could increase their ability to serve customers in competition with the Company.

The consequence to FortisAlberta of a municipality purchasing its distribution assets or an REA serving more customers in its service territory would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. A significant reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta.

Continued Reporting in Accordance with US GAAP: In January 2014 the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation and its reporting issuer subsidiaries in Canada to continue to prepare their financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become SEC registrants in order to continue reporting under US GAAP, or adopt IFRS. The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, the application of IFRS could result in volatility in the Corporation's earnings and earnings per common share as compared to those which would otherwise be recognized under US GAAP. In connection with the pending acquisition of ITC, Fortis expects to become a registrant with the SEC. As an SEC registrant, Fortis would be entitled under applicable Canadian laws to continue to prepare its consolidated financial statements in accordance with US GAAP.

Changes in Tax Legislation: The Corporation and its subsidiaries are subject to changes in tax legislation in Canada, the United States and other international jurisdictions.

Canadian Tax Legislation

During 2015 there were elections at the federal level and several provincial jurisdictions in Canada. A change in government can result in the passing of new tax legislation, including a change in rates of taxation. The new federal and provincial budgets are expected to be delivered in early 2016 and any resulting changes could have an impact on the Corporation and its Canadian subsidiaries. Any changes in tax legislation could affect the Corporation's results of operations, cash flows and financial position.

U.S. Tax Legislation

In 2015 the U.S. Congress enacted legislation approving the use of bonus depreciation through to 2019, subject to a phase out schedule reducing allowable rates to 50% in 2015 through 2017, 40% in 2018 and 30% in 2019. While this legislation provides greater certainty for planning purposes and reduces the cash tax burden of the Corporation's subsidiaries in the United States, any changes in this or other tax legislation in the United States could affect the Corporation's results of operations, cash flows and financial position.

International Tax Legislation

Fortis conducts business in certain tax-free jurisdictions, including certain countries in the Caribbean and Belize. Canada requires the governments of certain tax-free jurisdictions to enter a Tax Information Exchange Agreement ("TIEA"), which permits dividends paid from those jurisdictions to be exempt from tax when received in Canada. This legislation allows Fortis to receive a tax-free return of capital from the Caribbean. Certain legislation also provides a mechanism for the repayment of upstream loans that were previously used as a tax-deferred repatriation of earnings. The Corporation has approximately $79 million of upstream loans from its Caribbean subsidiaries, which are required to be repaid by August 2016. The Corporation expects to repay these loans, as required.

A TIEA has not yet been negotiated between Canada and Belize and there are no indications that Canada will conclude negotiations with the GOB in the near future. Until a TIEA is in place, active business earnings in Belize cannot be repatriated to Canada on a tax-free basis; however, the GOB has signed on to the Convention on Mutual Administrative Assistance in Tax Matter, which excludes Belize as a "non-qualifying country". As a result, the Corporation is not required to accrue tax on its active business income from Belize, whether or not repatriated to Canada.

In October 2015 the Organization for Economic Co-operation and Development ("OECD") released its final reports in connection with its action plan to address Base Erosion and Profit Sharing ("BEPS Action Plan"). The basis of the BEPS Action Plan is to identify and curb aggressive tax planning and practices, as well as monitor the international tax systems. Canada has not yet implemented the recommendations of the OECD report into tax treaties and domestic law; however, if it were to be enacted under Canadian tax legislation the Corporation would be required to assess the impacts and determine whether any changes to existing tax practices are required.

Access to First Nations' Lands: FortisBC Energy and FortisBC Electric provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of FortisBC Energy and FortisBC Electric is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as FortisBC Energy and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on FortisBC Energy and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult and accommodate First Nations, if necessary, and if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of FortisBC Energy and FortisBC Electric.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to the Company and, therefore, may have a material adverse effect on FortisAlberta.

Labour Relations Risk: The Corporation's subsidiaries employ members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with their labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in the future or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material adverse effect on the results of operations, cash flows and financial position of the utilities.

Human Resources Risk: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and in the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges to ensure the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective during 2015, are described as follows.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity: The Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations. The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period: The Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's 2015 Audited Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs: The Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014. Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes: The Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million, to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers: ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for US GAAP and IFRS that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis: ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments

Liability as at December 31	2015		2014	
($ millions)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	56	59	53	56
Long-term debt, including current portion	11,240	12,614	10,501	12,237

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value

As at December 31 *($ millions)*	Fair value hierarchy	2015	2014
Assets			
Energy contracts subject to regulatory deferral [(1) (2) (3)]	Levels 2/3	7	3
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	2	1
Available-for-sale investment [(4) (5)]	Level 1	33	–
Assets held for sale	Level 2	9	–
Other investments [(4)]	Level 1	12	5
Total gross assets		63	9
Less: Counterparty netting not offset on the balance sheet [(6)]		(6)	(3)
Total net assets		57	6
Liabilities			
Energy contracts subject to regulatory deferral [(1) (2) (7)]	Levels 1/2/3	78	72
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	–	1
Energy contracts – cash flow hedges [(2) (8)]	Level 3	–	1
Interest rate swaps – cash flow hedges [(8)]	Level 2	5	5
Total gross liabilities		83	79
Less: Counterparty netting not offset on the balance sheet [(6)]		(6)	(3)
Total net liabilities		77	76

(1) The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

(3) Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)

(4) Included in long-term other assets on the consolidated balance sheet

(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

(7) Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)

(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity (year)	Contracts (#)	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts *(PJ)*	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

As at December 31, 2015, Fortis recognized a total of $2,532 million in regulatory assets (December 31, 2014 – $2,415 million) and $1,638 million in regulatory liabilities (December 31, 2014 – $1,445 million).

For a further discussion of the nature of regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2015, the Corporation's consolidated capital assets and intangible assets were approximately $20.1 billion, or approximately 70%, of total consolidated assets compared to approximately $18.3 billion, or approximately 70%, of total consolidated assets as at December 31, 2014. Depreciation and amortization was $873 million for 2015 compared to $688 million for 2014.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2015 was $1,060 million, an increase of $109 million from $951 million as at December 31, 2014, mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated non-ARO removal cost liabilities.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation, amortization and removal cost rates, as applicable, are approved by the respective regulatory authority. The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates, as approved by the regulator.

Effective January 1, 2015, FortisAlberta's depreciation and amortization rates were changed as a result of a technical update to its last depreciation study, which was completed as of December 31, 2010. A technical update adjusts depreciation and amortization rates based on current capital asset balances, while retaining the depreciation parameters established in the last approved depreciation study. As a result, FortisAlberta's depreciation and amortization expense were reduced by approximately $7 million in 2015.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2015 or 2014.

As at December 31, 2015, consolidated goodwill totalled approximately $4.2 billion (December 31, 2014 – $3.7 billion). Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately $106 million as at December 31, 2015 (December 31, 2014 – $77 million).

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

No impairment provisions were required in either 2015 or 2014 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits:

Defined Benefit Pension Plans

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2016, is 6.17%, which is down from 6.25% used for 2015. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets. The defined benefit pension plan assets experienced total positive returns of approximately $30 million in 2015 compared to expected positive returns of $140 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, is 4.21%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015, of 4.00%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year, except as follows for UNS Energy. UNS Energy adopted the spot rate methodology for determining net pension cost for 2016.

There was a $26 million increase in consolidated defined benefit net pension cost for 2015 compared to 2014, mainly due to the acquisition of UNS Energy in August 2014, and foreign currency translation impacts. Any increases in defined benefit net pension cost at the regulated utilities for 2016 are expected to be recovered from customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2015 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2015

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [1]
Impact of increasing the rate of return assumption by 100 basis points	(24)	–
Impact of decreasing the rate of return assumption by 100 basis points	20	(44)
Impact of increasing the discount rate assumption by 100 basis points	(44)	(370)
Impact of decreasing the discount rate assumption by 100 basis points	51	469

[1] At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring net benefit pension cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2015, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $2,828 million (December 31, 2014 – $2,604 million) and consolidated plan assets of $2,466 million (December 31, 2014 – $2,216 million), for a consolidated funded status in a liability position of $362 million (December 31, 2014 – $388 million). During 2015, the Corporation recognized consolidated net pension benefit cost of $97 million (2014 – $71 million).

OPEB Plans

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plans at UNS Energy and Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at UNS Energy and Central Hudson experienced no returns in 2015 compared to expected positive returns of approximately $12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2015 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2015

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	7	51
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(5)	(43)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	9	85

Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2015, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $574 million (December 31, 2014 – $564 million) and consolidated plan assets of $181 million (December 31, 2014 – $154 million), for a consolidated funded status in a liability position of $393 million (December 31, 2014 – $410 million). During 2015, the Corporation recognized consolidated net OPEB benefit cost of $27 million (2014 – $21 million).

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2015 and 2014, with the exception of AROs recognized by UNS Energy, Central Hudson and FortisBC Electric.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits and interconnection facilities agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2015, the Corporation's total AROs were $49 million (December 31, 2014 – $37 million). UNS Energy's AROs were primarily associated with TEP's generation and photovoltaic assets; Central Hudson's AROs were primarily associated with asbestos remediation; and FortisBC Electric's AROs were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment. The total ARO liability as at December 31, 2015 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the companies' AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the companies' current assumptions. The AROs may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2015, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all of its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the electricity and gas sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments of electricity and gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2015, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $404 million (December 31, 2014 – $365 million) on consolidated revenue of $6,727 million for 2015 (2014 – $5,401 million). The increase in accrued unbilled revenue from December 31, 2014 was primarily due to the impact of foreign exchange on the translation of US dollar-denominated unbilled revenue accruals.

Capitalized Overhead: As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingencies.

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third-party owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the owner trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the *Federal Arbitration Act*. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As at December 31, 2015, TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Site Investigation and Remediation Program

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s, with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018.

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

RELATED-PARTY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related-party transactions for the years ended December 31, 2015 and 2014 are discussed below.

Upon completion of the Waneta Expansion in early April 2015, FortisBC Electric commenced purchasing capacity from the Waneta Expansion under terms of the 40-year WECA, as approved by the BCUC. Power purchased by FortisBC Electric from the Waneta Expansion in 2015 totalled approximately $30 million. In addition, the Waneta Expansion pays FortisBC Electric for management services associated with the generating station, which totalled approximately $7 million in 2015.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing. In addition, the Corporation provided long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. The majority of this long-term financing was repaid in 2015 as a result of the sale of commercial real estate and hotel assets. As at December 31, 2015, inter-segment loans outstanding totalled $48 million (December 31, 2014 – $402 million) and total interest charged in 2015 was $17 million (2014 – $27 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2015, 2014 and 2013.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2015**	2014	2013
Revenue	**6,727**	5,401	4,047
Net earnings	**840**	390	420
Net earnings attributable to common equity shareholders	**728**	317	353
Basic earnings per common share	**2.61**	1.41	1.74
Diluted earnings per common share	**2.59**	1.40	1.73
Total assets	**28,804**	26,233	17,908
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares	**1,820**	1,820	1,229
Common shareholders' equity	**8,060**	6,871	4,772
Dividends declared per common share	**1.43**	1.30	1.25
Dividends declared per First Preference Share, Series C [1]	**–**	–	0.4862
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G [2]	**0.9708**	0.9708	1.1416
Dividends declared per First Preference Share, Series H [3]	**0.7344**	1.0625	1.0625
Dividends declared per First Preference Share, Series I [3]	**0.3637**	–	–
Dividends declared per First Preference Share, Series J	**1.1875**	1.1875	1.1875
Dividends declared per First Preference Share, Series K [4]	**1.0000**	1.0000	0.6233
Dividends declared per First Preference Share, Series M [5]	**1.0250**	0.4613	–

(1) In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C.

(2) The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

(3) On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

(4) The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.

(5) The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2015/2014: Revenue increased $1,326 million, or 24.6%, from 2014 and net earnings attributable to common equity shareholders were $728 million, or $2.61 per common share, compared to $317 million, or $1.41 per common share, in 2014. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

2014/2013: Revenue increased $1,354 million, or 33.5%, from 2013. The increase in revenue was driven by the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. A higher commodity cost of natural gas charged to customers at FortisBC Energy, an increase in the base component of rates at most of the regulated utilities and higher electricity sales also contributed to the increase in revenue.

Net earnings attributable to common equity shareholders were $317 million in 2014 compared to $353 million in 2013. Results for both years were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Earnings for 2014 were reduced by $39 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy, compared to $34 million associated with the acquisition of Central Hudson in 2013. Interest expense of $51 million after tax, including the make-whole payment, associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy was recognized in 2014. In addition, earnings for 2013 were favourably impacted by an income tax recovery of $23 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, an extraordinary gain of $20 million related to the settlement of expropriation matters associated with the Exploits River Hydro Partnership, and the release of income tax provisions of approximately $7 million. An $8 million foreign exchange gain was recognized in 2014 compared to $6 million in 2013. Earnings for 2014 included $5 million associated with Griffith to the date of sale, and earnings for 2013 were reduced by $5 million associated with Griffith.

Excluding the above-noted impacts, net earnings attributable to common equity shareholders for 2014 were $394 million, an increase of $58 million from $336 million for 2013. The increase was driven by $60 million of earnings contribution at UNS Energy from the date of acquisition and the first full year of earnings contribution from Central Hudson, which was acquired in June 2013. Rate base growth and an increase in the number of customers at FortisAlberta and electricity sales growth at Caribbean Regulated Electric Utilities also contributed to the increase. The increase was partially offset by lower earnings at FortisBC Electric, primarily due to the impact of lower-than-expected finance charges in 2013 and higher Corporate and Other expenses. The increase in Corporate and Other expenses was primarily due to higher finance charges, largely due to the acquisitions of UNS Energy and Central Hudson, and higher operating expenses, partially offset by a higher income tax recovery and interest income.

The growth in total assets reflects the Corporation's acquisition of UNS Energy in August 2014 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of UNS Energy, including debt assumed on acquisition, and the financing of energy infrastructure investments.

Basic earnings per common share were $1.41 in 2014 compared to $1.74 in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, basic earnings per common share were $1.75 for 2014, an increase of $0.09 from $1.66 for 2013. The increase was driven by accretion associated with the acquisition of UNS Energy.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2015 and 2014.

Summary of Gas Volumes and Electricity and Energy Sales

Fourth Quarters Ended December 31 *(Unaudited)*	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy – Electricity Sales *(GWh)*	**3,562**	3,583	(21)
UNS Energy – Gas Volumes *(PJ)*	**4**	4	–
Central Hudson – Electricity Sales *(GWh)*	**1,160**	1,176	(16)
Central Hudson – Gas Volumes *(PJ)*	**5**	5	–
Regulated Gas Utility – Canadian			
FortisBC Energy *(PJ)*	**62**	59	3
Regulated Electric Utilities – Canadian			
FortisAlberta *(GWh)*	**4,188**	4,446	(258)
FortisBC Electric *(GWh)*	**836**	846	(10)
Eastern Canadian *(GWh))*	**2,189**	2,203	(14)
Regulated Electric Utilities – Caribbean *(GWh)*	**201**	187	14
Non-Regulated – Fortis Generation *(GWh)*	**122**	109	13

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Electricity and Energy Sales

The decrease in energy deliveries at FortisAlberta was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas. At most of the other regulated electric utilities, the decrease was mainly due to lower average consumption due to warmer temperatures, which reduced heating requirements. At the Regulated Electric Utilities – Caribbean, the impact of warmer temperatures increased electricity sales, due to higher air conditioning load. The overall decrease was partially offset by higher non-regulated energy sales, driven by the Waneta Expansion.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	**Revenue**			**Net Earnings**		
($ millions, except per share amounts)	**2015**	2014	Variance	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States						
UNS Energy	**482**	435	47	**26**	23	3
Central Hudson	**202**	186	16	**15**	4	11
	684	621	63	**41**	27	14
Regulated Gas Utility – Canadian						
FortisBC Energy	**411**	432	(21)	**65**	49	16
Regulated Electric Utilities – Canadian						
FortisAlberta	**140**	132	8	**29**	25	4
FortisBC Electric	**99**	90	9	**8**	12	(4)
Eastern Canadian Electric Utilities	**273**	266	7	**15**	14	1
	512	488	24	**52**	51	1
Regulated Electric Utilities – Caribbean	**82**	84	(2)	**9**	6	3
Non-Regulated – Fortis Generation	**30**	8	22	**11**	4	7
Non-Regulated – Non-Utility	**6**	62	(56)	**1**	7	(6)
Corporate and Other	**2**	7	(5)	**(44)**	(31)	(13)
Inter-Segment Eliminations	**(19)**	(9)	(10)	**–**	–	–
Total	**1,708**	1,693	15	**135**	113	22
Basic Earnings per Common Share *($)*				**0.48**	0.44	0.04

Revenue

The increase in revenue was mainly due to favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion, and an increase in base electricity rates at the Canadian Regulated Electric Utilities. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets.

Earnings

The increase in earnings was primarily due to: (i) favourable foreign exchange impacts; (ii) an increase in base electricity rates at Central Hudson effective July 1, 2015, combined with the impact of storm restoration and other non-recurring expenses recognized in the fourth quarter of 2014; (iii) earnings contribution of approximately $6 million from the Waneta Expansion; (iv) rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; and (v) a higher AFUDC at FortisBC Energy, partially offset by higher operating expenses. The timing of regulatory deferral mechanisms had a favourable impact on FortisBC Energy's earnings for the quarter and an unfavourable impact on FortisBC Electric. The increase in earnings was partially offset by lower earnings contribution due to the sale of commercial real estate and hotel assets and higher Corporate and Other expenses. Corporate and Other expenses included $7 million in acquisition-related expenses in the fourth quarter of 2015 and in the fourth quarter of 2014 included $4 million in interest expense associated with the convertible debentures and a $3 million foreign exchange gain. Excluding these items, the increase in Corporate and Other expenses was mainly due to a lower income tax recovery and lower related-party interest income.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2015**	2014	Variance
Cash, Beginning of Period	**347**	458	(111)
Cash Provided by (Used in):			
Operating Activities	**397**	334	63
Investing Activities	**(234)**	(829)	595
Financing Activities	**(280)**	257	(537)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**12**	10	2
Cash, End of Period	**242**	230	12

Cash flow from operating activities was $63 million higher quarter over quarter. The increase was primarily due to higher cash earnings at the Corporation's regulated utilities.

Cash used in investing activities was $595 million lower quarter over quarter. The decrease was mainly due to lower capital expenditures at the regulated utilities, largely due to UNS Energy's purchase of Gila River Unit 3 generation station in December 2014 for approximately $252 million (US$219 million), and proceeds received from the sale of hotel assets in October 2015 for $365 million.

Cash provided by financing activities was $537 million lower quarter over quarter. The decrease was primarily due to the repayment of credit facility borrowings in the fourth quarter of 2015 using proceeds from the sale of hotel assets. In addition, lower proceeds from long-term debt and lower credit facility borrowings were partially offset by lower repayments of long-term debt. In the fourth quarter of 2014, proceeds from the second installment of the convertible debentures were received, which were used to repay acquisition credit facilities used initially to finance a portion of the acquisition of UNS Energy.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2014 through December 31, 2015. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue ($ millions)	Net Earnings Attributable to Common Equity Shareholders ($ millions)	Earnings per Common Share Basic ($)	Earnings per Common Share Diluted ($)
December 31, 2015	1,708	135	0.48	0.48
September 30, 2015	1,566	151	0.54	0.54
June 30, 2015	1,538	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of sale transactions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand in different regions, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of FortisBC Energy are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2015/December 2014: Net earnings attributable to common equity shareholders were $135 million, or $0.48 per common share, for the fourth quarter of 2015 compared to earnings of $113 million, or $0.44 per common share, for the fourth quarter of 2014. A discussion of the variances in financial results for the fourth quarter of 2015 and the fourth quarter of 2014 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2015/September 2014: Net earnings attributable to common equity shareholders were $151 million, or $0.54 per common share, for the third quarter of 2015 compared to earnings of $14 million, or $0.06 per common share, for the third quarter of 2014. Earnings for the third quarter of 2015 were favourably impacted by a $5 million gain on the sale of non-regulated generation assets in Ontario and a $5 million positive adjustment associated with the sale of hotel assets, and were reduced by a $9 million loss on the settlement of expropriation matters related to the Corporation's investment in Belize Electricity. Earnings for the third quarter of 2014 were reduced by a total of $58 million due to acquisition-related expenses associated with UNS Energy. Excluding these items, the increase in earnings was driven by contribution of $97 million at UNS Energy compared to $37 million for the third quarter of 2014. Earnings contribution of $5 million from the Waneta Expansion also contributed to the increase. Performance was also driven by the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and customer growth at FortisAlberta; improved performance at Central Hudson; and favourable foreign exchange associated with US dollar-denominated earnings. Earnings at FortisBC Energy and FortisBC Electric were impacted by the timing of regulatory deferral mechanisms; however, FortisBC Energy's earnings were favourably impacted by lower operating expenses and higher AFUDC. The increase was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy.

June 2015/June 2014: Net earnings attributable to common equity shareholders were $244 million, or $0.88 per common share, for the second quarter of 2015 compared to earnings of $47 million, or $0.22 per common share, for the second quarter of 2014. The increase was driven by a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets. The increase was also due to earnings contribution of $52 million at UNS Energy and $12 million from the Waneta Expansion, representing the Corporation's 51% controlling ownership. Performance was also driven by the Corporation's regulated utilities, including rate base growth associated with capital expenditures, customer growth and a decrease in depreciation and amortization at FortisAlberta; increases at FortisBC Electric, largely due to timing of quarterly earnings compared to the same period last year, resulting from the impact of regulatory deferral mechanisms; and improved performance at Central Hudson. The increase was partially offset by a $5 million decrease in earnings at FortisBC Energy due to the timing of regulatory flow-through deferral amounts, and higher preference share dividends and finance charges in the Corporate and Other segment associated with the acquisition of UNS Energy.

March 2015/March 2014: Net earnings attributable to common equity shareholders were $198 million, or $0.72 per common share, for the first quarter of 2015 compared to earnings of $143 million, or $0.67 per common share, for the first quarter of 2014. The increase in earnings was driven by the Corporation's regulated utilities. UNS Energy contributed earnings of $20 million in the first quarter of 2015. FortisAlberta's earnings were favourably impacted by higher capital tracker revenue, including approximately $10 million associated with 2013 and 2014, and customer growth. Earnings at FortisBC Energy and FortisBC Electric were $9 million and $5 million, respectively, higher quarter over quarter, largely due to timing of quarterly earnings compared to the same period last year resulting from the impact of regulatory deferral mechanisms. Central Hudson and Eastern Canadian Regulated Electric Utilities also reported improved performance. The increase in earnings at the regulated utilities was partially offset by lower earnings at the Corporation's non-regulated subsidiaries, largely due to decreased production in Belize as a result of lower rainfall, costs at Fortis Properties associated with the strategic review, and approximately $5 million earnings contribution in the first quarter of 2014 from Griffith to the date of sale. Corporate and Other expenses were lower quarter over quarter, due to approximately $11 million in after-tax interest expense associated with the convertible debentures in the first quarter of 2014 and a higher foreign exchange gain, partially offset by higher preference share dividends and finance charges associated with the acquisition of UNS Energy.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2015 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2015 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2015, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

On February 9, 2016, Fortis and ITC entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin. ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the Acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott-Rodino Antitrust Improvements Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the Acquisition.

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance, and although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the Acquisition, Fortis will become a registrant with the SEC and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

OUTLOOK

Fortis is focused on closing the acquisition of ITC by the end of 2016. The Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix.

Substantially all of Fortis' assets are low-risk, regulated utilities and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one-third of total assets. Over the five-year period through 2020, excluding the acquisition of ITC, the Corporation's highly executable capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%.

On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition of ITC. Following the Acquisition, Fortis will be one of the top 15 North American public utilities ranked by enterprise value, with an estimated enterprise value of $42 billion. Additionally, ITC's midyear rate base, including construction work in progress, is expected to increase at a compound annual growth rate of approximately 7.5% through 2018, based on ITC's planned capital expenditure program.

Fortis continues to target 6% average annual dividend growth through 2020. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

Fortis expects long-term sustainable growth in rate base, assets and earnings resulting from strategic acquisitions and investment in its existing utility operations. The Corporation is also committed to identifying and executing on opportunities for incremental rate base and earnings growth through additional investments in existing service territories, and in new franchise areas.

OUTSTANDING SHARE DATA

As at February 16, 2016, the Corporation had issued and outstanding 281.9 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options and First Preference Shares, Series E were converted as at February 16, 2016 is as follows.

Conversion of Securities into Common Shares

As at February 16, 2016 *(Unaudited)*

Security	Number of Common Shares *(millions)*
Stock Options	**4.9**
First Preference Shares, Series E	**5.8**
Total	**10.7**

Additional information, including the Fortis 2015 Annual Information Form, Management Information Circular and Audited Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

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MANAGEMENT'S REPORT

The accompanying Annual Consolidated Financial Statements of Fortis Inc. have been prepared by management, who is responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2015 Annual Consolidated Financial Statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2015 Annual Consolidated Financial Statements and their report follows.

Barry Perry

Barry V. Perry
President and Chief Executive Officer, Fortis Inc.

Karl Smith

Karl W. Smith
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2015 and 2014, and the consolidated statements of earnings, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2015 and 2014, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP

Chartered Professional Accountants

St. John's, Canada
February 17, 2016

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	2015	2014
Current assets		*(Note 36)*
Cash and cash equivalents	$ 242	$ 230
Accounts receivable and other current assets *(Note 6)*	964	900
Prepaid expenses	68	59
Inventories *(Note 7)*	337	321
Regulatory assets *(Note 8)*	246	277
	1,857	1,787
Other assets *(Note 9)*	352	272
Regulatory assets *(Note 8)*	2,286	2,138
Utility capital assets *(Note 10)*	19,595	17,179
Non-utility capital assets *(Note 11)*	-	664
Intangible assets *(Note 12)*	541	461
Goodwill *(Note 13)*	4,173	3,732
	$ 28,804	$ 26,233
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 32)*	$ 511	$ 330
Accounts payable and other current liabilities *(Note 14)*	1,419	1,440
Regulatory liabilities *(Note 8)*	298	173
Current installments of long-term debt *(Note 15)*	384	525
Current installments of capital lease and finance obligations *(Note 16)*	26	208
	2,638	2,676
Other liabilities *(Note 17)*	1,152	1,141
Regulatory liabilities *(Note 8)*	1,340	1,272
Deferred income taxes *(Note 26)*	2,050	1,626
Long-term debt *(Note 15)*	10,784	9,911
Capital lease and finance obligations *(Note 16)*	487	495
	18,451	17,121
Shareholders' equity		
Common shares [1] *(Note 18)*	5,867	5,667
Preference shares *(Note 20)*	1,820	1,820
Additional paid-in capital	14	15
Accumulated other comprehensive income *(Note 21)*	791	129
Retained earnings	1,388	1,060
	9,880	8,691
Non-controlling interests *(Note 22)*	473	421
	10,353	9,112
	$ 28,804	$ 26,233

[1] No par value. Unlimited authorized shares; 281.6 million and 276.0 million issued and outstanding as at December 31, 2015 and 2014, respectively

Commitments *(Note 33)*
Contingencies *(Note 34)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	2015	2014
Revenue	$ 6,727	$ 5,401
Expenses		
Energy supply costs	2,561	2,197
Operating	1,864	1,493
Depreciation and amortization	873	688
	5,298	4,378
Operating income	1,429	1,023
Other income (expenses), net *(Note 24)*	187	(25)
Finance charges *(Note 25)*	553	547
Earnings before income taxes and discontinued operations	1,063	451
Income tax expense *(Note 26)*	223	66
Earnings from continuing operations	840	385
Earnings from discontinued operations, net of tax *(Note 28)*	–	5
Net earnings	$ 840	$ 390
Net earnings attributable to:		
Non-controlling interests	$ 35	$ 11
Preference equity shareholders	77	62
Common equity shareholders	728	317
	$ 840	$ 390
Earnings per common share from continuing operations *(Note 19)*		
Basic	$ 2.61	$ 1.39
Diluted	$ 2.59	$ 1.38
Earnings per common share *(Note 19)*		
Basic	$ 2.61	$ 1.41
Diluted	$ 2.59	$ 1.40

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	2015	2014
Net earnings	$ 840	$ 390
Other comprehensive income (loss)		
Unrealized foreign currency translation gains, net of hedging activities and tax *(Note 21)*	660	204
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax *(Note 21)*	2	–
Net change in fair value of cash flow hedges, net of tax *(Notes 21 and 31)*	1	1
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 21)*	–	1
Unrealized loss on available-for-sale investment, net of tax *(Notes 9, 21 and 31)*	(2)	–
Unrealized employee future benefits gains (losses), net of tax *(Notes 21 and 27)*	1	(5)
	662	201
Comprehensive income	$ 1,502	$ 591
Comprehensive income attributable to:		
Non-controlling interests	$ 35	$ 11
Preference equity shareholders	77	62
Common equity shareholders	1,390	518
	$ 1,502	$ 591

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2015**	2014
Operating activities		
Net earnings	**$ 840**	$ 390
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**785**	597
Amortization – intangible assets	**64**	60
Amortization – other	**24**	31
Deferred income tax expense *(Note 26)*	**164**	23
Accrued employee future benefits	**(19)**	25
Equity component of allowance for funds used during construction *(Note 24)*	**(23)**	(11)
Gain on sale of non-utility capital assets *(Note 24)*	**(131)**	–
Gain on sale of non-regulated generation assets *(Note 24)*	**(62)**	–
Other	**79**	71
Change in long-term regulatory assets and liabilities	**(89)**	(80)
Change in non-cash operating working capital *(Note 30)*	**41**	(124)
	1,673	982
Investing activities		
Change in other assets and other liabilities	**(36)**	(4)
Capital expenditures – utility capital assets	**(2,122)**	(1,617)
Capital expenditures – non-utility capital assets	**(9)**	(39)
Capital expenditures – intangible assets	**(112)**	(69)
Contributions in aid of construction	**59**	69
Purchase of assets held for sale *(Notes 6 and 16)*	**(32)**	–
Proceeds on sale of assets *(Notes 16 and 28)*	**922**	109
Business acquisitions, net of cash acquired *(Notes 9 and 29)*	**(38)**	(2,648)
	(1,368)	(4,199)
Financing activities		
Change in short-term borrowings	**148**	167
Proceeds from convertible debentures, net of issue costs *(Note 18)*	**–**	1,725
Proceeds from long-term debt, net of issue costs *(Note 15)*	**1,002**	1,193
Repayments of long-term debt and capital lease and finance obligations	**(602)**	(743)
Net (repayments) borrowings under committed credit facilities	**(622)**	610
Advances from non-controlling interests	**20**	38
Issue of common shares, net of costs and dividends reinvested *(Note 18)*	**40**	51
Issue of preference shares, net of costs *(Note 20)*	**–**	586
Dividends		
Common shares, net of dividends reinvested	**(232)**	(194)
Preference shares	**(77)**	(62)
Subsidiary dividends paid to non-controlling interests	**(23)**	(10)
	(346)	3,361
Effect of exchange rate changes on cash and cash equivalents	**53**	14
Change in cash and cash equivalents	**12**	158
Cash and cash equivalents, beginning of year	**230**	72
Cash and cash equivalents, end of year	**$ 242**	$ 230

Supplementary Information to Consolidated Statements of Cash Flows *(Note 30)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2015 and 2014 (in millions of Canadian dollars)	Common Shares	Preference Shares	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 18)	*(Note 20)*		*(Note 21)*		*(Note 22)*	
As at January 1, 2015	**$ 5,667**	**$ 1,820**	**$ 15**	**$ 129**	**$ 1,060**	**$ 421**	**$ 9,112**
Net earnings	**–**	**–**	**–**	**–**	**805**	**35**	**840**
Other comprehensive income	**–**	**–**	**–**	**662**	**–**	**–**	**662**
Common share issues	**200**	**–**	**(4)**	**–**	**–**	**–**	**196**
Stock-based compensation	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(23)**	**(23)**
Dividends declared on common shares ($1.43 per share)	**–**	**–**	**–**	**–**	**(400)**	**–**	**(400)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(77)**	**–**	**(77)**
As at December 31, 2015	**$ 5,867**	**$ 1,820**	**$ 14**	**$ 791**	**$ 1,388**	**$ 473**	**$ 10,353**
As at January 1, 2014	$ 3,783	$ 1,229	$ 17	$ (72)	$ 1,044	$ 375	$ 6,376
Net earnings	–	–	–	–	379	11	390
Other comprehensive income	–	–	–	201	–	–	201
Preference share issue	–	591	–	–	–	–	591
Common share issues	1,884	–	(5)	–	–	–	1,879
Stock-based compensation	–	–	3	–	–	–	3
Advances from non-controlling interests	–	–	–	–	–	38	38
Foreign currency translation impacts	–	–	–	–	–	7	7
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(10)	(10)
Dividends declared on common shares ($1.30 per share)	–	–	–	–	(301)	–	(301)
Dividends declared on preference shares	–	–	–	–	(62)	–	(62)
As at December 31, 2014	$ 5,667	$ 1,820	$ 15	$ 129	$ 1,060	$ 421	$ 9,112

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, which are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014 (Note 29).

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties.

   TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 megawatts ("MW"), including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

   UNS Gas is a regulated gas distribution utility, serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company (Note 2). FEI is the largest distributor of natural gas in British Columbia, serving more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"); the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

For the years ended December 31, 2015 and 2014

1. *DESCRIPTION OF THE BUSINESS (cont'd)*

Regulated Electric Utilities – Canadian (cont'd)

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities that provide electricity to certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility ("Walden") has been classified as held for sale (Note 6).

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively (Notes 24 and 28).

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015, and Griffith was sold in March 2014 (Note 28).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group") and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. NATURE OF REGULATION

The Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities is as follows.

UNS Energy
The UNS Utilities are regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by the U.S. Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). The UNS Utilities operate under COS regulation as administered by the ACC, which provides for the use of a historical test year in the establishment of retail electric and gas rates. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their COS and earn a reasonable rate of return on rate base, including an adjustment for the fair value of rate base as required under the laws of the State of Arizona.

TEP's allowed ROE is set at 10.0% on a capital structure of 43.5% common equity, effective from July 1, 2013. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.6% common equity, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

Central Hudson
Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). The Company is also subject to regulation by the North American Electric Reliability Corporation. Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates.

Central Hudson began operating under a three-year rate order issued by the PSC effective July 1, 2010 with an allowed ROE set at 10.0% on a deemed capital structure of 48% common equity. As approved by the PSC in June 2013, the original three-year rate order was extended for two years, through June 30, 2015, as part of the regulatory approval of the acquisition of Central Hudson by Fortis. In June 2015 the PSC issued a rate order for the Company covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. The new rate order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure.

Effective July 1, 2013, Central Hudson was also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE. In the new rate order effective July 1, 2015, the earnings sharing mechanism was continued, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer.

FortisBC Energy and FortisBC Electric
FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia). The Companies primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

2. *NATURE OF REGULATION (cont'd)*

FortisBC Energy and FortisBC Electric (cont'd)

In the first stage of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia, FEI was designated as the benchmark utility and a BCUC decision established that the allowed ROE for the benchmark utility would be set at 8.75% on a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. In March 2014 the BCUC issued its decision on the second stage of the GCOC Proceeding, setting the common equity component of capital structure for FEVI and FEWI at 41.5%, and reaffirming the common equity component of capital structure for FortisBC Electric at 40%, all effective January 1, 2013. The resulting allowed ROEs for FEVI, FEWI and FortisBC Electric were 9.25%, 9.50% and 9.15%, respectively, also effective January 1, 2013. Effective January 1, 2015, following the amalgamation of FEI, FEVI and FEWI, the ROE and common equity component of capital structure for the amalgamated FEI, was set to equal the benchmark utility, at 8.75% and 38.5%, respectively.

FEI and FortisBC Electric are subject to Multi-Year PBR Plans for 2014 through 2019. The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to PBR for a five-year term. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures. In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital tracker expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

Eastern Canadian Electric Utilities

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power operates under COS regulation with the use of a future test year in the establishment of rates. The PUB has set the allowed ROE at 8.80% and the common equity component of capital structure at 45% for 2013 through 2015.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which covers the period March 1, 2013 to February 29, 2016. Maritime Electric operates under COS regulation with the use of a future test year for the establishment of rates. IRAC set the allowed ROE at 9.75% on a targeted minimum capital structure of 40% common equity for 2014 and 2015.

In Ontario, Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Fourth-Generation Incentive Regulation Mechanism as prescribed by the OEB. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario. Canadian Niagara Power and Algoma Power use a future test year in the establishment of rates. Canadian Niagara Power's allowed ROE for distribution assets was set at 8.93% for 2014 and 2015 and the allowed ROE for transmission assets was set at 8.93% for 2014 and 9.30% for 2015, both on a deemed capital structure of 40% common equity. Algoma Power's allowed ROE was set at 9.85% for 2014 and 9.30% for 2015 on a deemed capital structure of 40% common equity. Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Regulated Electric Utilities – Caribbean

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. In November 2014 a new non-exclusive generation licence was issued for a term of 25 years, expiring in November 2039. The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2015 was in the range of 7.25% to 9.25%, compared to a range of 7.00% to 9.00% for 2014.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2015 calculated the Allowable Operating Profit to be $51 million (US$40 million) and the Cumulative Shortfall as at December 31, 2015 to be $274 million (US$198 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated utilities include specific accounting guidance for regulated operations, as outlined in Note 2, and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. All material intercompany transactions have been eliminated in the consolidated financial statements.

An evaluation of subsequent events through to February 17, 2016, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2015 (Note 35).

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and market value, unless evidence indicates that the weighted average cost, even in excess of market, will be recovered in future customer rates.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made. Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Should an impairment be identified, it will be recognized in the period in which such impairment is identified.

Available-for-Sale Assets

The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation. Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

Each of UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligations ("AROs") removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 8 *(xiv)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred. As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. FortisOntario, Fortis Turks and Caicos and Waneta Expansion recognize non-ARO removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets is recognized immediately in earnings.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 25) and the equity component of AFUDC is reported as other income (Note 24). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta, the cost of utility capital assets also includes Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

As approved by the regulator, FortisBC Energy has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FortisBC Energy increases both utility capital assets and long-term debt (Note 15).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets, with the exception of UNS Energy. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other utility capital assets in inventories until consumed. When put into service, the inventories are reclassified to utility capital assets (Note 7).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

Utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for regulated utility capital assets are approved by the respective regulator. Depreciation rates for 2015 ranged from 1.3% to 43.2% (2014 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2015 was 3.1% (2014 – 3.2%).

For the years ended December 31, 2015 and 2014

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Utility Capital Assets (cont'd)

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows:

	2015		2014	
(Years)	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	5–80	30	5–80	28
Gas	4–95	33	4–85	31
Transmission				
Electric	20–80	29	20–70	27
Gas	7–80	36	4–71	38
Generation	5–85	27	4–75	24
Other	3–70	8	3–70	8

Non-Utility Capital Assets

In 2015 the Corporation sold its commercial real estate and hotel assets, which included office buildings, shopping malls, hotels, land, construction in progress, and related equipment and tenant inducements (Note 28). Non-utility capital assets were recorded at cost less accumulated depreciation, where applicable, using the straight-line method of depreciation.

Maintenance and repairs were charged to earnings in the period incurred, while replacements and betterments which extended the useful lives were capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Intangible assets are comprised of computer software costs; land, transmission and water rights; and franchise fees. The cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at UNS Energy, FortisBC Energy, FortisBC Electric and the Waneta Partnership. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

In testing indefinite-lived intangible assets for impairment, the Corporation has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

Impairment testing for indefinite-lived intangible assets is carried out at the reporting unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer electricity and gas rates, as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and there were no impairment provisions required in either year. For its annual testing of impairment for indefinite-lived intangible assets, Fortis uses the approach for the annual testing for goodwill impairment as disclosed in this Note under "Goodwill".

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

Amortization rates for 2015 ranged from 1.0% to 50.0% (2014 – 1.0% to 50.0%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2015		2014	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**30–80**	**37**	30–75	32
Franchise fees and other	**10–104**	**15**	10–100	19

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets is recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no material impact on the consolidated financial statements as a result of regulated long-lived asset or non-regulated generation asset impairments for the years ended December 31, 2015 and 2014. Certain of the Corporation's non-utility hotel assets, all of which were sold in 2015, were subject to an impairment charge as a result of the carrying amount of the assets exceeding their fair value (Note 28).

Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer electricity and gas rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and no impairment provisions were required in either year.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, may also be performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of FortisBC Energy and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At FortisBC Energy and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at FortisBC Energy and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the projected benefit obligation, is recognized on the Corporation's consolidated balance sheet.

With the exception of UNS Energy, FortisAlberta and Maritime Electric, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*). As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made.

At UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis, FHI and Caribbean Utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

Other Post-Employment Benefits Plans

UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and the Corporation also offer other post-employment benefits ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of OPEB plans, measured as the difference between the fair value of the plan assets and the accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheet.

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of UNS Energy and FortisAlberta, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a component of other comprehensive income.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 23). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which, for the PSU and RSU Plans, is over the shorter of three years or the period to retirement eligibility. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2015 was $37.72 (December 31, 2014 – $38.96). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2015 was US$1.00=CAD$1.38 (December 31, 2014 – US$1.00=CAD$1.16). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.28 for 2015 (2014 – US$1.00=CAD$1.10).

The Corporation's approximate 33% equity investment in Belize Electricity is translated at the exchange rate in effect as at the balance sheet date. The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the investment is sold, substantially liquidated or evaluated for impairment in anticipation of disposal (Notes 9 and 24).

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income and the current period change is recorded in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Derivative Instruments and Hedging Activities

The Corporation and its subsidiaries use various physical and financial derivative instruments to meet forecast load and reserve requirements, to reduce exposure to fluctuations in commodity prices and foreign exchange rates, and to hedge interest rate risk exposure. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. As at December 31, 2015, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, electricity power purchase contracts, gas purchase contract premiums, long-term wholesale trading contracts, and interest rate swaps (Note 31).

All derivative instruments that do not meet the normal purchase or normal sale scope exception are recognized as assets or liabilities on the consolidated balance sheet and are measured at fair value. Changes in fair value are recognized in earnings unless the instruments qualify, and are designated, as an accounting or economic hedge.

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

For derivatives designated as hedging contracts, the Corporation's utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2015, the Corporation's hedging relationships primarily consisted of interest rate swaps and US dollar-denominated borrowings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and significant influence investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased a portion of the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of a portion of the foreign exchange risk related to its foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in other comprehensive income.

For derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates, as permitted by the respective regulators. Accordingly, the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(vii)*).

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. Valuation allowances are recognized against deferred tax assets when it is more likely than not that a portion of, or the entire amount of, the deferred income tax asset will not be realized. Deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Therefore, with the exception of certain deferred tax balances of FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable (Note 8 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs.

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 8 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $565 million as at December 31, 2015 (December 31, 2014 – $384 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical. Canada has entered into Tax Information Exchange Agreements ("TIEAs") with Bermuda, the Cayman Islands and the Turks and Caicos Islands. Consequently, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above, as no taxes are payable on these earnings. If a TIEA is entered into with Belize, earnings from the Corporation's operations in Belize would also be able to be repatriated to Canada on a tax-free basis. Negotiations between the Government of Canada and the GOB commenced in June 2010.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense. At FortisAlberta, investment tax credits are deducted from the related assets and are recognized as a reduction of income tax expense as the Company becomes taxable for rate-setting purposes.

For the years ended December 31, 2015 and 2014

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Sales Taxes

In the course of its operations, the Corporation's subsidiaries collect sales taxes from their customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

For regulatory reporting purposes, Central Hudson recognizes tax revenue collected on behalf of applicable government authorities on a gross basis. In 2015 approximately $19 million was included in both revenue and expenses (2014 – $22 million).

Revenue Recognition

Revenue from the sale of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority, and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

In certain circumstances, UNS Energy enters into purchased power and wholesale sales contracts that are not settled with energy. The net sales contracts and power purchase contracts are reflected at the net amount in revenue.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates (Note 8 *(xviii)*).

FortisBC Electric has entered into contracts to sell surplus capacity that may be available after it meets its load requirements. This revenue is recognized on an accrual basis at rates established in the sales contract.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Non-utility revenue, associated with commercial real estate and hotel assets that were sold in 2015, was recognized when services were provided or products were delivered to customers. Specifically, real estate revenue, derived from leasing retail and office space, was recognized in the month earned at rates in accordance with lease agreements. The leases were primarily of a net nature, with tenants paying basic rent plus a pro rata share of certain defined overhead expenses. Certain retail tenants paid additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants were recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases were recognized in earnings using the straight-line method over the term of the lease.

Asset Retirement Obligations

AROs, including conditional AROs, are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to utility capital assets (Note 17). The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities. As permitted by the respective regulator, at UNS Energy, Central Hudson and FortisBC Electric, changes in the obligations due to the passage of time are recognized as a regulatory asset using the effective interest method.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

New Accounting Policies

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
Effective January 1, 2015, the Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations (Note 28). The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period
Effective January 1, 2015, the Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
Effective October 1, 2015, the Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 36). Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes
Effective October 1, 2015, the Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes (Note 36).

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Use of Accounting Estimates

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Stock-Based Compensation, Income Taxes, Revenue Recognition and Asset Retirement Obligations, and in Notes 8, 23 and 34.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis

ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

5. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
	Electric & Gas			Gas		Electric								
Year Ended December 31, 2015 *($ in millions)*	UNS Energy	Central Hudson	Total	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Total	Caribbean Electric	Fortis Generation	Non-Utility	Corporate and Other	Inter-segment eliminations	Total
Revenue	2,034	880	2,914	1,295	563	360	1,033	3,251	321	107	171	24	(61)	6,727
Energy supply costs	820	315	1,135	498	–	116	673	1,287	169	1	–	–	(31)	2,561
Operating expenses	573	381	954	292	183	89	143	707	46	19	124	26	(12)	1,864
Depreciation and amortization	242	56	298	190	168	57	82	497	47	18	11	2	–	873
Operating income (loss)	399	128	527	315	212	98	135	760	59	69	36	(4)	(18)	1,429
Other income (expenses), net	5	8	13	11	3	–	2	16	2	56	109	(8)	(1)	187
Finance charges	98	38	136	134	78	39	56	307	14	3	18	94	(19)	553
Income tax expense (recovery)	111	40	151	51	(1)	9	19	78	–	24	13	(43)	–	223
Net earnings (loss)	195	58	253	141	138	50	62	391	47	98	114	(63)	–	840
Non-controlling interests	–	–	–	1	–	–	–	1	13	21	–	–	–	35
Preference share dividends	–	–	–	–	–	–	–	–	–	–	–	77	–	77
Net earnings (loss) attributable to common equity shareholders	195	58	253	140	138	50	62	390	34	77	114	(140)	–	728
Goodwill	1,912	624	2,536	913	227	235	67	1,442	195	–	–	–	–	4,173
Identifiable assets	6,977	2,601	9,578	5,116	3,592	1,872	2,219	12,799	1,084	1,025	–	352	(207)	24,631
Total assets	8,889	3,225	12,114	6,029	3,819	2,107	2,286	14,241	1,279	1,025	–	352	(207)	28,804
Gross capital expenditures	669	181	850	460	452	103	175	1,190	137	58	9	19	–	2,243
Year Ended December 31, 2014 *($ in millions)*														
Revenue	684	821	1,505	1,435	518	334	1,008	3,295	321	38	249	31	(38)	5,401
Energy supply costs	272	345	617	646	–	87	653	1,386	195	1	–	–	(2)	2,197
Operating expenses	209	337	546	287	176	90	143	696	39	10	172	38	(8)	1,493
Depreciation and amortization	80	49	129	190	164	59	79	492	38	5	22	2	–	688
Operating income (loss)	123	90	213	312	178	98	133	721	49	22	55	(9)	(28)	1,023
Other income (expenses), net	4	6	10	4	3	1	2	10	2	(1)	–	(45)	(1)	(25)
Finance charges	34	35	69	139	79	41	56	315	14	–	24	154	(29)	547
Income tax expense (recovery)	33	24	57	49	(1)	12	19	79	–	1	8	(79)	–	66
Net earnings (loss) from continuing operations	60	37	97	128	103	46	60	337	37	20	23	(129)	–	385
Earnings from discontinued operations, net of tax	–	–	–	–	–	–	–	–	–	–	5	–	–	5
Net earnings (loss)	60	37	97	128	103	46	60	337	37	20	28	(129)	–	390
Non-controlling interests	–	–	–	1	–	–	–	1	10	–	–	–	–	11
Preference share dividends	–	–	–	–	–	–	–	–	–	–	–	62	–	62
Net earnings (loss) attributable to common equity shareholders	60	37	97	127	103	46	60	336	27	20	28	(191)	–	317
Goodwill	1,603	523	2,126	913	227	235	67	1,442	164	–	–	–	–	3,732
Identifiable assets	5,648	2,123	7,771	4,846	3,234	1,803	2,163	12,046	924	961	696	543	(440)	22,501
Total assets	7,251	2,646	9,897	5,759	3,461	2,038	2,230	13,488	1,088	961	696	543	(440)	26,233
Gross capital expenditures	444	126	570	332	348	92	166	938	71	102	38	6	–	1,725

For the years ended December 31, 2015 and 2014

5. *SEGMENTED INFORMATION (cont'd)*

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions during the years ended December 31 were as follows.

Significant Related Party Inter-Segment Transactions

(in millions)	2015	2014
Sales from Fortis Generation to		
Regulated Electric Utilities – Canadian	$ 31	$ 2
Revenue from Regulated Electric Utilities – Canadian		
to Fortis Generation	7	–
Sales from Regulated Electric Utilities – Canadian to Non-Utility	4	6
Inter-segment finance charges on lending from:		
Fortis Generation to Eastern Canadian Electric Utilities	1	1
Corporate to Regulated Electric Utilities – Caribbean	–	5
Corporate to Non-Utility	17	22

The significant related party inter-segment asset balances as at December 31 were as follows.

Significant Related Party Inter-Segment Assets

(in millions)	2015	2014
Inter-segment borrowings from:		
Fortis Generation to Eastern Canadian Electric Utilities	$ 20	$ 20
Corporate to Regulated Electric Utilities – Canadian	48	–
Corporate to Non-Utility	–	402
Other inter-segment assets – Corporate to Regulated		
Electric & Gas Utilities – United States	108	–
Other inter-segment assets	31	18
Total inter-segment eliminations	$ 207	$ 440

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	2015	2014
Trade accounts receivable	$ 517	$ 479
Unbilled accounts receivable	404	365
Allowance for doubtful accounts	(66)	(31)
Income tax receivable	–	25
Assets held for sale	38	–
Other	71	62
	$ 964	$ 900

The increase in the allowance for doubtful accounts was primarily due to an increase in the reserve for uncollectible accounts at UNS Energy in relation to billings to third-party owners of Springerville Unit 1 for their pro-rata share of costs to operate the facility. Due to ongoing litigation and uncertainty with Springerville Unit 1 third-party owners, the accounts receivable balance of $32 million (US$23 million) as at December 31, 2015 associated with operating expenses has been fully reserved (Note 34).

Assets held for sale include utility capital assets of approximately $29 million (US$21 million) purchased by UNS Energy upon expiration of the Springerville Coal Handling Facilities lease in April 2015 (Note 16). UNS Energy has an agreement with a third party whereby they can purchase a 17.05% interest or continue to make payments to UNS Energy for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015.

Additionally, in December 2015 FortisBC Electric entered into an agreement to sell the non-regulated Walden hydroelectric power plant assets for a sale price of approximately $9 million (Note 31). The sale is expected to close in the first quarter of 2016. For the year ended December 31, 2015, earnings before taxes of less than $1 million were recognized (December 31, 2014 – less than $1 million) associated with Walden.

Other accounts receivable consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy and advances on coal purchases at UNS Energy. Other accounts receivable also included the fair value of derivative instruments (Note 31).

7. INVENTORIES

(in millions)	**2015**	2014
Materials and supplies	**$ 194**	$ 149
Gas and fuel in storage	**101**	134
Coal inventory	**42**	38
	$ 337	$ 321

Materials and supplies included approximately $152 million (December 31, 2014 – $118 million) at UNS Energy, and consisted of construction and repair materials for distribution, transmission and generation assets, as required by the regulator (Note 3).

8. REGULATORY ASSETS AND LIABILITIES

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2015**	2014	**Remaining recovery period** *(Years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 936**	$ 832	To be determined
Employee future benefits *(ii)*	**627**	680	Various
Deferred energy management costs *(iii)*	**145**	111	1–10
Manufactured gas plant ("MGP") site remediation deferral *(iv)*	**121**	123	To be determined
Rate stabilization accounts *(v)*	**119**	119	Various
Deferred lease costs *(vi)*	**90**	101	Various
Derivative instruments *(vii)*	**74**	69	Various
Deferred operating overhead costs *(viii)*	**66**	54	Various
Final mine reclamation and retiree health care costs *(ix)*	**39**	34	1–22
Deferred net losses on disposal of utility capital assets and intangible assets *(x)*	**33**	37	8
Springerville Unit 1 unamortized leasehold improvements *(xi)*	**30**	–	8
Property tax deferrals *(xii)*	**30**	29	1
Other regulatory assets *(xiii)*	**222**	226	Various
Total regulatory assets	**2,532**	2,415	
Less: current portion	**(246)**	(277)	1
Long-term regulatory assets	**$ 2,286**	$ 2,138	

For the years ended December 31, 2015 and 2014

8. *REGULATORY ASSETS AND LIABILITIES (cont'd)*

(in millions)	2015	2014	Remaining recovery period *(Years)*
Regulatory liabilities			
Non-ARO removal cost provision *(xiv)*	$ 1,060	$ 951	To be determined
Rate stabilization accounts *(v)*	212	142	Various
Electric and gas moderator account *(xv)*	88	–	To be determined
Renewable energy surcharge *(xvi)*	47	44	To be determined
Employee future benefits *(ii)*	44	58	Various
Customer and community benefits obligation *(xvii)*	32	55	To be determined
AESO charges deferral *(xviii)*	25	49	1–4
Other regulatory liabilities *(xix)*	130	146	Various
Total regulatory liabilities	1,638	1,445	
Less: current portion	(298)	(173)	1
Long-term regulatory liabilities	$ 1,340	$ 1,272	

Description of the Nature of Regulatory Assets and Liabilities

(i) Deferred Income Taxes

The Corporation's regulated utilities recognize deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity and gas rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*. The regulatory asset balances are expected to be recovered from customers in future rates when the income taxes become payable or receivable. As at December 31, 2015, $351 million (December 31, 2014 – $265 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 27). At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2015, regulatory assets of approximately $367 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $339 million). As at December 31, 2015, regulatory liabilities of approximately $36 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $55 million).

(iii) Deferred Energy Management Costs

FortisBC Energy, FortisBC Electric, Central Hudson and Newfoundland Power provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 1 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation. As at December 31, 2015, $25 million of UNS Energy's regulatory asset balance was not subject to a regulatory return (December 31, 2014 – $16 million).

(iv) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 14, 17 and 34). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(v) Rate Stabilization Accounts

Rate stabilization accounts associated with the Corporation's regulated electric and gas utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. Electric rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level and, at certain utilities, revenue decoupling mechanisms that minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Gas rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, and natural gas cost volatility.

As at December 31, 2015, approximately $49 million and $142 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2014 – approximately $105 million and $43 million, respectively).

As at December 31, 2015, regulatory assets of approximately $44 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $104 million). As at December 31, 2015, regulatory liabilities of approximately $76 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $42 million).

(vi) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2015 included $90 million (December 31, 2014 – $83 million) of deferred lease costs that are expected to be recovered from customers in future rates over the term of the lease. In 2015, of the $30 million (2014 – $30 million) of interest expense related to the capital lease obligations and the $6 million (2014 – $6 million) of depreciation expense related to the assets under capital lease, a total of $26 million (2014 – $26 million) was recognized in energy supply costs and $3 million (2014 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2014 – $7 million) deferred as a regulatory asset (Note 16).

The regulatory asset balance as at December 31, 2014 included $18 million of deferred lease costs at UNS Energy related to the remaining purchase commitments of Springerville Unit 1 and the Springerville Coal Handling Facility, of which both purchases occurred in 2015 (Note 16).

Deferred lease costs are not subject to a regulatory return.

(vii) Derivative Instruments

As approved by the respective regulatory authority, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings (Note 31). UNS Energy and Central Hudson's deferred regulatory asset balance totalling $57 million as at December 31, 2015 was not subject to a regulatory return (December 31, 2014 – $57 million).

(viii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets and intangible assets.

(ix) Final Mine Reclamation and Retiree Health Care Costs

Final mine reclamation and retiree health care costs are associated with TEP's jointly owned coal generating facilities at the San Juan, Four Corners and Navajo generating stations. TEP has the option to recognize its liability associated with final mine reclamation and retiree health care obligations at present or future value (Notes 17 and 34). TEP has elected to recognize these costs at future value and is permitted to fully recover these costs from customers through its rate stabilization accounts when the costs are paid. TEP expects to make continuous payments through 2037. These deferred costs are not subject to a regulatory return.

8. *REGULATORY ASSETS AND LIABILITIES (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(x) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, from 2010 through 2013 net losses on the retirement or disposal of utility capital assets and intangible assets at FortisBC Energy were recorded in a regulatory deferral account to be recovered from customers in future rates. The regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 10 years.

(xi) Springerville Unit 1 Unamortized Leasehold Improvements

Upon expiration of TEP's Springerville Unit 1 capital lease in January 2015, unamortized leasehold improvements were reclassified from utility capital assets to regulatory assets. The leasehold improvements represent investments made by TEP through the end of the lease term to ensure Springerville facilities continued providing safe, reliable service to TEP's customers. In its 2013 rate order, TEP received regulatory approval to amortize the leasehold improvements over a 10-year period. TEP continues to own an undivided 49.5% joint interest in Springerville Unit 1.

(xii) Property Tax Deferrals

Property taxes at UNS Energy and Central Hudson are deferred and are primarily collected from customers over a six-month to one-year period, as approved by the respective regulator. Property tax deferrals are not subject to a regulatory return.

(xiii) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $189 million (December 31, 2014 – $177 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $69 million (December 31, 2014 – $74 million) of the balance was not subject to a regulatory return.

(xiv) Non-ARO Removal Cost Provision

As required by the respective regulator, depreciation rates at UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xv) Electric and Gas Moderator Account

Under the terms of Central Hudson's three-year Rate Order issued in June 2015, certain of the Company's regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation. These electric and gas moderator accounts are not subject to a regulatory return.

(xvi) Renewable Energy Surcharge

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes and return on investments on certain company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"), which represent one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records the cost of the RECs as long-term other assets and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount (Note 9).

(xvii) Customer and Community Benefits Obligation

As approved by the respective regulator for UNS Energy and Central Hudson, Fortis committed to provide their customers and community with financial benefits that would have not been realized in the absence of the acquisitions. These commitments resulted in the recognition of regulatory liabilities to be used to mitigate future customer rate increase at the utilities. In 2014 these commitments for UNS Energy's customers included US$10 million in year one and US$5 million in years two through five to cover credits in retail customer rates. As a result, expenses of approximately $33 million (US$30 million) were recognized in 2014 related to the acquisition of UNS Energy for customer benefit obligations (Notes 24 and 29).

(xviii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2015, the regulatory liability primarily represented the over collection of the AESO charges deferral accounts for 2014 and 2015.

(xix) Other Regulatory Liabilities

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $120 million (December 31, 2014 – $140 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $68 million (December 31, 2014 – $76 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	2015	2014
Equity investment – Belize Electricity	$ 79	$ –
Supplemental Executive Retirement Plan assets	58	41
Deposit on pending business acquisition *(Note 29)*	38	–
Available-for-sale investment *(Notes 28 and 31)*	33	–
Deferred compensation plan assets *(Note 17)*	25	21
Renewable Energy Credits *(Note 8 (xvi))*	17	13
Long-term income tax receivable	13	13
Other investments	13	12
Other asset – Belize Electricity	–	116
Other	76	56
	$ 352	$ 272

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015 (Note 24).

UNS Energy and Central Hudson provide additional post-employment benefits through both a deferred compensation plan for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP"). Since both plans are considered non-qualified plans under the *Employee Retirement Income Security Act of 1974*, the assets are reported separately from the related liabilities (Note 17). The assets of the plans are held in trust and funded mostly through the use of trust-owned life insurance policies and mutual funds. A portion of the SERP assets is invested in corporate-owned life insurance policies. Amounts held in mutual and money market funds are recorded at fair value (Note 31).

In June 2015 the Corporation completed the sale of commercial real estate assets for gross proceeds of $430 million (Note 28). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The investment in trust units is recorded as an available-for-sale asset. The assets are measured at fair value based on quoted market prices and unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold (Notes 21 and 31).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets include the fair value of derivative instruments at UNS Energy and Central Hudson (Note 31).

10. UTILITY CAPITAL ASSETS

2015

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,245	$ (2,434)	$ 6,611
Gas	3,829	(1,021)	2,808
Transmission			
Electric	3,093	(997)	2,096
Gas	1,735	(531)	1,204
Generation	6,465	(2,241)	4,224
Other	2,429	(849)	1,580
Assets under construction	886	–	886
Land	186	–	186
	$ 27,868	$ (8,273)	$ 19,595

2014

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 8,102	$ (2,317)	$ 5,785
Gas	3,475	(920)	2,555
Transmission			
Electric	2,562	(859)	1,703
Gas	1,649	(491)	1,158
Generation	5,296	(2,189)	3,107
Other	2,158	(731)	1,427
Assets under construction	1,277	–	1,277
Land	167	–	167
	$ 24,686	$ (7,507)	$ 17,179

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

Construction of the Waneta Expansion was completed in April 2015. As at December 31, 2015, assets under construction are primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and other capital projects at the Corporation's regulated utilities.

The cost of utility capital assets under capital lease as at December 31, 2015 was $496 million (December 31, 2014 – $1,088 million) and related accumulated depreciation was $221 million (December 31, 2014 – $627 million). The decrease was primarily due to the purchase of certain utility capital assets at TEP in 2015 following the expiry of lease arrangements (Note 16).

Jointly Owned Facilities

As at December 31, 2015, UNS Energy's interests in jointly owned generating stations and transmission systems primarily consisted of the following:

2015

(in millions)	Ownership (%)	Cost	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0	$ 690	$ (347)	$ 343
Navajo Units 1, 2 and 3	7.5	207	(155)	52
Four Corners Units 4 and 5	7.0	154	(107)	47
Luna Energy Facility	33.3	75	(1)	74
Gila River Common Facilities	25.0	47	(14)	33
Springerville Unit 1 [(1)]	49.5	452	(240)	212
Springerville Coal Handling Facilities [(2)]	65.9	228	(90)	138
Transmission Facilities	Various	531	(238)	293
		$ 2,384	$ (1,192)	$ 1,192

[(1)] TEP is obligated to operate the unit for third-party owners under existing agreements. The third-party owners are obligated to compensate TEP for their pro rata share of expenses (Notes 16 and 34).
[(2)] TEP owns an additional 17.05% undivided interest in the Springerville Coal Handling Facilities, which is classified as assets held for sale (Notes 6 and 16).

UNS Energy holds an undivided interest in the above facilities and is entitled to its pro rata share of the utility capital assets. UNS Energy is proportionately liable for its share of operating costs and liabilities in respect of the jointly owned facilities.

11. NON-UTILITY CAPITAL ASSETS

In 2015 the Corporation sold its commercial real estate and hotel assets (Note 28). As a result, the Corporation did not hold any non-utility capital assets as at December 31, 2015.

2014

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Buildings	$ 599	$ (105)	$ 494
Equipment	145	(73)	72
Tenant inducements	35	(27)	8
Land	72	–	72
Assets under construction	18	–	18
	$ 869	$ (205)	$ 664

12. INTANGIBLE ASSETS

2015

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 685	$ (436)	$ 249
Land, transmission and water rights	328	(76)	252
Franchise fees and other	17	(13)	4
Assets under construction	36	–	36
	$ 1,066	$ (525)	$ 541

For the years ended December 31, 2015 and 2014

12. INTANGIBLE ASSETS (cont'd)

2014

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 573	$ (368)	$ 205
Land, transmission and water rights	258	(66)	192
Franchise fees and other	16	(12)	4
Assets under construction	60	–	60
	$ 907	$ (446)	$ 461

Included in the cost of land, transmission and water rights as at December 31, 2015 was $106 million (December 31, 2014 – $77 million) not subject to amortization.

Amortization expense related to intangible assets was $64 million for 2015 (2014 – $60 million). Amortization is estimated to average approximately $78 million annually for each of the next five years.

13. GOODWILL

(in millions)	2015	2014
Balance, beginning of year	$ 3,732	$ 2,075
Acquisition of UNS Energy *(Note 29)*	–	1,510
Sale of Griffith *(Note 28)*	–	(3)
Foreign currency translation impacts	441	150
Balance, end of year	$ 4,173	$ 3,732

Goodwill associated with the acquisitions of UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	2015	2014
Trade accounts payable	$ 574	$ 612
Gas and fuel cost payable	153	195
Employee compensation and benefits payable	137	134
Interest payable	127	128
Dividends payable	113	101
Accrued taxes other than income taxes	108	96
Fair value of derivative instruments *(Note 31)*	69	66
MGP site remediation *(Notes 8 (iv), 17 and 34)*	32	13
Defined benefit pension and OPEB plan liabilities *(Note 27)*	13	11
Other	93	84
	$ 1,419	$ 1,440

Accrued taxes other than income taxes primarily consisted of property taxes at UNS Energy and carbon tax at FortisBC Energy.

15. LONG-TERM DEBT

(in millions)	Maturity Date	2015	2014
Regulated Utilities			
UNS Energy			
Unsecured US Tax-Exempt Bonds –			
3.83% weighted average fixed and variable rate (2014 – 3.92%)	2020 – 2040	$ 848	$ 956
Unsecured US Fixed Rate Notes –			
4.26% weighted average fixed rate (2014 – 4.98%)	2021 – 2045	1,557	754
Secured US Fixed Rate Notes –			
5.38% weighted average fixed and variable rate (2014 – 5.38%)	2023 – 2026	–	151
Central Hudson			
Unsecured US Promissory Notes –			
4.30% weighted average fixed and variable rate (2014 – 4.31%)	2016 – 2042	728	587
FortisBC Energy			
Secured Purchase Money Mortgages –			
10.30% weighted average fixed rate (2014 – 10.71%)	2016	200	275
Unsecured Debentures –			
5.73% weighted average fixed rate (2014 – 5.95%)	2029 – 2045	1,770	1,620
Government loan	2016	5	10
FortisAlberta			
Unsecured Debentures –			
4.95% weighted average fixed rate (2014 – 5.01%)	2024 – 2052	1,684	1,534
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2014 – 8.80%)	2023	25	25
Unsecured Debentures –			
5.36% weighted average fixed rate (2014 – 5.36%)	2016 – 2050	660	660
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds –			
6.72% weighted average fixed rate (2014 – 7.08%)	2016 – 2045	553	484
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2014 – 7.18%)	2016 – 2061	167	167
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2014 – 6.11%)	2018 – 2041	104	104
Caribbean Electric			
Unsecured US Senior Loan Notes –			
4.89% weighted average fixed rate (2014 – 4.91%)	2016 – 2046	467	400
Non-Regulated – Non-Utility			
Secured First Mortgages and Senior Notes –			
7.46% weighted average fixed rate (2014 – 7.46%)	n/a	–	34
Corporate			
Unsecured US Senior Notes and Promissory Notes –			
4.43% weighted average fixed rate (2014 – 4.43%)	2019 – 2044	1,720	1,443
Unsecured Debentures –			
6.49% weighted average fixed rate (2014 – 6.49%)	2039	201	201
Long-term classification of credit facility borrowings *(Note 31)*		551	1,096
Total long-term debt *(Note 31)*		11,240	10,501
Less: Deferred financing costs *(Notes 3 and 36)*		(72)	(65)
Less: Current installments of long-term debt		(384)	(525)
		$ 10,784	$ 9,911

15. LONG-TERM DEBT (cont'd)

As noted in the previous table, certain long-term debt instruments issued by UNS Energy, FortisBC Energy, FortisBC Electric, Newfoundland Power, and Maritime Electric are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated. The purchase money mortgages of FortisBC Energy are secured equally and ratably by a first fixed and specific mortgage and charge on the Company's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $350 million.

UNS Energy entered into a four-year US$30 million variable rate term loan credit agreement and, at the same time, entered into a fixed-for-floating interest rate swap. Both the term loan and interest rate swap expired in 2015. The interest rate swap was designated as a cash flow hedge (Note 31).

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2015, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In January 2015 TEP redeemed at par US$130 million of fixed rate tax-exempt bonds that had an original maturity date of 2029. As at December 31, 2015, TEP had not remarketed the repurchase bonds.

In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures.

In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes.

In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured debentures and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt. Additionally, in August 2015 TEP redeemed at par US$79 million of variable rate tax-exempt bonds that had an original maturity date of 2022.

In September 2015 FortisAlberta issued 30-year $150 million 4.27% unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

Corporate

The unsecured debentures and US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries (in millions)	Corporate (in millions)	Total (in millions)
2016	$ 382	$ 2	$ 384
2017	69	2	71
2018	281	2	283
2019	112	127	239
2020	202	655	857
Thereafter	7,793	1,613	9,406
	$ 8,839	$ 2,401	$ 11,240

16. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

In 2014 and 2015, TEP purchased certain Springerville assets upon expiry of the lease arrangements, as detailed below. As at December 31, 2015, capital lease obligations at TEP consist of an undivided one-half interest in certain Springerville Common Facilities.

Springerville Unit 1 Capital Lease Purchases

In December 2014 and January 2015, upon expiration of the Springerville Unit 1 lease, TEP purchased an additional 35.4% ownership interest in the previously leased assets for US$20 million and US$46 million, respectively. As a result of the purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. Furthermore, TEP is obligated to operate the unit for the third-party owners under an existing agreement. The third-party owners are obligated to compensate TEP for their pro rata share of expenditures (Note 34).

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the Springerville Coal Handling Facilities lease, TEP purchased an 86.7% ownership interest in the previously leased coal handling assets for a total of US$120 million. In May 2015 TEP sold a 17.05% interest in the facilities to a third party for US$24 million and has an agreement with another third party to either purchase a 17.05% interest for US$24 million or to continue to make payments to TEP for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the associated assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015 (Note 6).

Springerville Common Facilities Leases

TEP is party to three Springerville Common Facilities leases, which have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025 (Note 33). Instead of extending the leases, TEP may exercise a fixed-price purchase provision of US$38 million in 2017 and US$68 million in 2021. TEP has agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

UNS Energy entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. As at December 31, 2015, interest on the lease debt is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2014 – 1.75%). The swap has the effect of fixing the interest rates on a portion of the amortizing principal balances of US$29 million (December 31, 2014 – US$33 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 31).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For the year ended December 31, 2015, in total $5 million (December 31, 2014 – $2 million) of interest expense on the Springerville capital lease obligations was recognized in finance charges and $3 million (December 31, 2014 – $3 million) and $8 million (December 31, 2014 – $7 million) of depreciation expense on the Springerville leased assets was recognized in energy supply costs and depreciation, respectively.

For the years ended December 31, 2015 and 2014

16. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA.

The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2015 was $26 million (2014 – $26 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 8 *(vi)*).

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2015 was $3 million (2014 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 8 *(vi)*).

Finance Obligations

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions at FEI have implicit interest at rates ranging from 6.82% to 8.66% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows FEI, at its option, to terminate the lease arrangements early, after 17 years. If the Company exercises this option, FEI would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time.

Repayment of Capital Lease and Finance Obligations

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2016	$ 68	$ 4	$ 72
2017	70	4	74
2018	61	32	93
2019	62	15	77
2020	73	2	75
Thereafter	2,049	38	2,087
	$ 2,383	$ 95	$ 2,478
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,965)
Total capital lease and finance obligations			513
Less: Current portion			(26)
			$ 487

17. OTHER LIABILITIES

(in millions)	2015	2014
OPEB plan liabilities *(Note 27)*	$ 385	$ 403
Defined benefit pension plan liabilities *(Note 27)*	368	390
MGP site remediation *(Notes 8 (iv), 14 and 34)*	96	109
Waneta Partnership promissory note *(Notes 31 and 33)*	56	53
Asset retirement obligations	49	37
Final mine reclamation and retiree health care liabilities *(Notes 8 (ix) and 34)*	39	34
Customer security deposits	38	26
Deferred compensation plan liabilities *(Note 9)*	25	21
DSU, PSU and RSU liabilities *(Note 23)*	20	17
Fair value of derivative instruments *(Note 31)*	13	13
Other	63	38
	$ 1,152	$ 1,141

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2015, its discounted net present value was $56 million (December 31, 2014 – $53 million). The promissory note was incurred by the Waneta Partnership on the acquisition of certain intangible assets and project design costs, from a company affiliated with CPC/CBT, associated with the construction of the Waneta Expansion. The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

As at December 31, 2015, UNS Energy, Central Hudson and FortisBC Electric recognized asset retirement obligations.

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

18. COMMON SHARES

Common shares issued during the year were as follows:

	2015		2014	
	Number of Shares *(in thousands)*	Amount *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	275,997	$ 5,667	213,165	$ 3,783
Conversion of Convertible Debentures	24	1	58,545	1,747
Dividend Reinvestment Plan	4,272	157	2,495	82
Consumer Share Purchase Plan	28	1	33	1
Employee Share Purchase Plan	356	13	384	12
Stock Option Plans	885	28	1,375	42
Balance, end of year	281,562	$ 5,867	275,997	$ 5,667

Convertible Debentures

To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts ("Convertible Debentures"). The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014 (the "Final Installment Date"). Prior to the Final Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make-whole payment, was recognized in 2014 (Note 25).

For the years ended December 31, 2015 and 2014

18. COMMON SHARES (cont'd)

Convertible Debentures (cont'd)

At the option of the holders, each Convertible Debenture was convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million common shares of Fortis were issued, representing conversion into common shares of more than 99% of the Convertible Debentures. As at December 31, 2015, a total of approximately 58.6 million common shares of Fortis were issued on the conversion of Convertible Debentures, for proceeds of $1.748 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy (Note 29).

19. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 278.6 million for 2015 and 225.6 million for 2014.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

2015	Net Earnings to Common Shareholders (in millions)			Weighted Average Number of Shares (millions)	EPS		
	Continuing Operations	Discontinued Operations	Total		Continuing Operations	Discontinued Operations	Total
Basic EPS	$ 728	$ –	$ 728	278.6	$ 2.61	$ –	$ 2.61
Effect of potential dilutive securities:							
Stock Options	–	–	–	0.7			
Preference Shares	10	–	10	5.4			
Diluted EPS	$ 738	$ –	$ 738	284.7	$ 2.59	$ –	$ 2.59

2014	Net Earnings to Common Shareholders (in millions)			Weighted Average Number of Shares (millions)	EPS		
	Continuing Operations	Discontinued Operations	Total		Continuing Operations	Discontinued Operations	Total
Basic EPS	$ 312	$ 5	$ 317	225.6	$ 1.39	$ 0.02	$ 1.41
Effect of potential dilutive securities:							
Stock Options	–	–	–	0.5			
Preference Shares	10	–	10	6.9			
	322	5	327	233.0			
Deduct anti-dilutive impacts:							
Preference Shares	(10)	–	(10)	(6.9)			
Diluted EPS	$ 312	$ 5	$ 317	226.1	$ 1.38	$ 0.02	$ 1.40

20. PREFERENCE SHARES

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2015**		2014	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount** *(in millions)*	Number of Shares	Amount *(in millions)*
Series E [1]	$ 1.2250	**7,993,500**	**$ 197**	7,993,500	$ 197
Series F [1]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [2]	$ 0.9708	**9,200,000**	**225**	9,200,000	225
Series H [2][3]	$ 0.6250	**7,024,846**	**172**	10,000,000	245
Series I [4]		**2,975,154**	**73**	–	–
Series J [1]	$ 1.1875	**8,000,000**	**196**	8,000,000	196
Series K [2]	$ 1.0000	**10,000,000**	**244**	10,000,000	244
Series M [2]	$ 1.0250	**24,000,000**	**591**	24,000,000	591
		74,193,500	**$ 1,820**	74,193,500	$ 1,820

[1] Cumulative Redeemable First Preference Shares
[2] Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares
[3] The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.
[4] Cumulative Redeemable Five-Year Floating Rate Preference Shares. The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

In September 2014 the Corporation issued 24 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M ("First Preference Shares, Series M") at a price of $25.00 per share for net after-tax proceeds of $591 million.

Holders of the First Preference Shares, Series E, Series F and Series J are each entitled to receive a fixed cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

The Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series E into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each First Preference Share, Series E may be converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G, Series H, Series K and Series M are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.9708, $0.6250, $1.0000 and $1.0250 per share per annum, respectively, for each year up to but excluding September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, and each five-year period thereafter, the holders of First Preference Shares, Series G, Series H, Series K and Series M, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G, Series H, Series K and Series M, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%, 1.45%, 2.05% and 2.48%, respectively.

20. PREFERENCE SHARES (cont'd)

On each First Preference Shares, Series H, Series K and Series M Conversion Date, the holders of First Preference Shares, Series H, Series K and Series M have the option to convert any or all of their First Preference Shares, Series H, Series K and Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series I, Series L and Series N, respectively. On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.

The holders of First Preference Shares, Series I are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation, for the five-year period beginning after June 1, 2015. The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%. The holders of First Preference Shares, Series L and Series N will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate of the First Preference Shares, Series L and Series N will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 2.05% and 2.48%, respectively.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

	2015		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains on net investments in foreign operations	**$ 273**	**$ 1,008**	**$ 1,281**
Losses on hedges of net investments in foreign operations	**(131)**	**(345)**	**(476)**
Income tax recovery	**2**	**(1)**	**1**
	144	**662**	**806**
Available-for-sale investment: *(Notes 9, 28 and 31)*			
Unrealized losses on available-for-sale investment	**–**	**(2)**	**(2)**
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	**1**	**2**	**3**
Income tax expense	**–**	**(1)**	**(1)**
	1	**1**	**2**
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	**(2)**	**1**	**(1)**
Unamortized net actuarial losses	**(20)**	**–**	**(20)**
Income tax recovery	**6**	**–**	**6**
	(16)	**1**	**(15)**
Accumulated other comprehensive income	**$ 129**	**$ 662**	**$ 791**

	2014		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation (losses) gains:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	$ (60)	$ 333	$ 273
Losses on hedges of net investments in foreign operations	–	(131)	(131)
Income tax recovery	–	2	2
	(60)	204	144
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	–	1	1
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(1)	1	–
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	(3)	1	(2)
Unamortized net actuarial losses	(9)	(11)	(20)
Income tax recovery	1	5	6
	(11)	(5)	(16)
Accumulated other comprehensive (loss) income	$ (72)	$ 201	$ 129

22. NON-CONTROLLING INTERESTS

(in millions)	2015	2014
Waneta Partnership	$ 335	$ 316
Caribbean Utilities	122	88
Mount Hayes Limited Partnership	10	11
Preference shares of Newfoundland Power	6	6
	$ 473	$ 421

23. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2015, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2002 and 2006 Plans. The 2002 and 2006 Plans will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 and 2006 Plans and all new options granted after 2011 are being made under the 2012 Plan. Directors are not eligible to receive grants of options under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

For the years ended December 31, 2015 and 2014

23. STOCK-BASED COMPENSATION PLANS (cont'd)

Stock Options (cont'd)

The following options were granted in 2015 and 2014. The fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2015	2014		
	March	August	June	February
Options granted (#)	667,244	12,216	23,584	925,172
Exercise price *($)* (1)	39.25	33.44	32.23	30.73
Grant date fair value *($)*	2.46	2.47	2.69	3.53
Assumptions:				
Dividend yield *(%)* (2)	3.6	3.8	3.8	3.8
Expected volatility *(%)* (3)	14.6	15.7	15.9	20.3
Risk-free interest rate *(%)* (4)	0.90	1.45	1.52	1.69
Weighted average expected life *(years)* (5)	5.5	5.5	5.5	5.5

(1) Five-day VWAP immediately preceding the date of grant
(2) Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options
(3) Based on historical experience over a period equal to the weighted average expected life of the options
(4) Government of Canada benchmark bond yield in effect at the date of grant that covers the weighted average expected life of the options
(5) Based on historical experience

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2015.

	Total Options		Non-vested Options (1)	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, January 1, 2015	4,705,935	$ 30.27	2,148,380	$ 3.84
Granted	667,244	$ 39.25	667,244	$ 2.46
Exercised	(885,242)	$ 27.55	n/a	n/a
Vested	n/a	n/a	(828,547)	$ 4.01
Cancelled/Forfeited	(71,483)	$ 33.16	(50,545)	$ 3.49
Options outstanding, December 31, 2015	4,416,454	$ 32.12	1,936,532	$ 3.30
Options vested, December 31, 2015 (2)	2,479,922	$ 30.22		

(1) As at December 31, 2015, there was $6 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
(2) As at December 31, 2015, the weighted average remaining term of vested options was four years with an aggregate intrinsic value of $18 million.

The following table summarizes additional 2015 and 2014 stock option information.

(in millions)	2015	2014
Stock option expense recognized	$ 3	$ 3
Stock options exercised:		
Cash received for exercise price	24	36
Intrinsic value realized by employees	10	12
Fair value of options that vested	3	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of DSUs	2015	2014
DSUs outstanding, beginning of year	176,124	203,172
Granted	28,737	29,279
Granted – notional dividends reinvested	7,037	8,526
DSUs paid out	(44,136)	(64,853)
DSUs outstanding, end of year	167,762	176,124

For the year ended December 31, 2015, expense of $1 million (2014 – $3 million) was recognized in earnings with respect to the DSU Plan.

In 2015, 44,136 DSUs were paid out to retired and deceased directors at a weighted average price of $37.58 per DSU for a total of approximately $2 million.

As at December 31, 2015, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $6 million (December 31, 2014 – $7 million), and is included in long-term other liabilities (Note 17).

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. As at December 31, 2015, the Corporation had the following PSU plans: the 2013 PSU Plan, the 2015 PSU Plan, and certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 150%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative compound annual growth rate in earnings per common share or, for certain subsidiaries, the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2015, the estimated payout percentages for the grants under the 2013 and 2015 PSU Plans range from 96% to 118%.

The following table summarizes information related to the PSUs for 2015 and 2014.

Number of PSUs	2015	2014
PSUs outstanding, beginning of year	481,700	257,419
Granted	276,381	261,737
Granted – notional dividends reinvested	25,687	17,691
PSUs paid out	(83,637)	(33,559)
PSUs cancelled/forfeited	(5,745)	(21,588)
PSUs outstanding, end of year	694,386	481,700

In January 2015, 68,759 PSUs were paid out to the former Chief Executive Officer ("CEO") of the Corporation at $38.90 per PSU, for a total of approximately $3 million. The payout was made in respect of the PSU grant made in March 2012 and the former CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors. As a result of the sale of commercial real estate and hotel assets, in October 2015, 14,878 PSUs were paid out to certain employees at a 100% payout percentage under the 2013 PSU Plan and the 2015 PSU Plan at $38.48 per PSU, for a total of approximately $1 million.

For the years ended December 31, 2015 and 2014

23. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans (cont'd)

For the year ended December 31, 2015, expense of approximately $12 million (2014 – $7 million) was recognized in earnings with respect to the PSU Plans and there was $9 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the aggregate intrinsic value of the outstanding PSUs was $28 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $19 million (December 31, 2014 – $10 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 14 and 17).

RSU Plans

In February 2015 the Corporation's Board of Directors approved the 2015 RSU Plan, effective January 1, 2015. The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	2015
Granted	59,462
Granted – notional dividends reinvested	2,150
RSUs cancelled/forfeited	(2,872)
RSUs outstanding, end of year	58,740

For the year ended December 31, 2015, expense of approximately $1 million was recognized in earnings with respect to the RSU Plan and there was approximately $1 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $1 million, and is included in long-term other liabilities (Note 17).

24. OTHER INCOME (EXPENSES), NET

(in millions)	2015	2014
Net gain on sale of commercial real estate and hotel assets *(Note 28)* (1)	$ 109	$ –
Gain on sale of non-regulated generation assets *(Note 28)* (2)	56	–
Equity component of AFUDC	23	11
Net foreign exchange gain	13	8
Interest income	8	13
Loss on settlement of expropriation matters *(Note 9)*	(9)	–
Acquisition-related expenses *(Notes 29 and 35)*	(10)	(25)
Acquisition-related customer and community benefits *(Notes 8 (xvii) and 29)*	–	(33)
Other	(3)	1
	$ 187	$ (25)

(1) Net of $23 million of expenses associated with the sale
(2) Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 9). As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015. Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity are recognized on the balance sheet in accumulated other comprehensive income.

The acquisition-related expenses and customer and community benefits in 2014 were associated with the acquisition of UNS Energy (Note 29).

25. FINANCE CHARGES

(in millions)	2015	2014
Interest – Long-term debt and capital lease and finance obligations	$ 572	$ 482
– Short-term borrowings	8	20
– Convertible Debentures *(Note 18)*	–	72
Debt component of AFUDC	(27)	(27)
	$ 553	$ 547

26. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	2015	2014
Gross deferred income tax assets		
Tax loss and credit carryforwards	$ 387	$ 376
Regulatory liabilities	210	186
Employee future benefits	116	108
Share issue and debt financing costs	13	20
Unrealized foreign exchange losses on long-term debt	65	17
Other	45	70
	836	777
Deferred income tax assets valuation allowance	(73)	(24)
Net deferred income tax assets	$ 763	$ 753
Gross deferred income tax liabilities		
Utility capital assets	$ (2,575)	$ (2,096)
Regulatory assets	(201)	(204)
Non-utility capital assets	–	(40)
Intangible assets	(37)	(39)
	(2,813)	(2,379)
Net deferred income tax liability	$ (2,050)	$ (1,626)

The deferred income tax asset associated with unrealized foreign exchange losses on long-term debt reflects $65 million of capital losses as at December 31, 2015 (December 31, 2014 – $17 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $65 million valuation allowance against the deferred income tax asset as at December 31, 2015 (December 31, 2014 – $17 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

For the years ended December 31, 2015 and 2014

26. *INCOME TAXES (cont'd)*

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2015 and 2014.

(in millions)	2015	2014
Total unrecognized tax benefits, beginning of year	$ 11	$ 3
Additions related to the current year	1	7
Adjustments related to prior years	1	1
Total unrecognized tax benefits, end of year	$ 13	$ 11

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2015. Fortis has not recognized interest expense in 2015 and 2014 related to unrecognized tax benefits.

The components of the income tax expense were as follows.

(in millions)	2015	2014
Canadian		
Current income taxes	$ 59	$ 43
Deferred income taxes	113	64
Less: regulatory adjustments	(100)	(67)
	13	(3)
Total Canadian	$ 72	$ 40
Foreign		
Deferred income taxes	151	26
Total Foreign	$ 151	$ 26
Income tax expense	$ 223	$ 66

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	2015	2014
Combined Canadian federal and provincial statutory income tax rate	27.5%	29.0%
Statutory income tax rate applied to earnings before income taxes	$ 292	$ 131
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	(7)	(23)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	(4)	(10)
Items capitalized for accounting purposes but expensed for income tax purposes	(39)	(26)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	(18)	–
Change in tax rates and legislation	13	–
Other	(14)	(6)
Income tax expense	$ 223	$ 66
Effective tax rate	21.0%	14.6%

In 2015 the Corporation's combined Canadian federal and provincial statutory income tax rate decreased from 29.0% to 27.5%. This change resulted from the inclusion of the Waneta Partnership's taxable income, which is taxable in the province of British Columbia at a lower provincial income tax rate, and increased income tax expense by approximately $3 million in 2015, through the re-measurement of deferred income tax assets. In addition, a change in New York State tax legislation in 2015 resulted in the need to include UNS Energy as part of the combined New York State tax return. As a result, existing deferred income tax balances were adjusted to reflect the effect of the change in the tax law, resulting in an increase in income tax expense of approximately $10 million in 2015.

As at December 31, 2015, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	Amount
Canadian		
Capital loss	n/a	$ 15
Non-capital loss	2025 – 2035	129
Other tax credits	2026 – 2035	2
		146
Unrecognized in the consolidated financial statements		(15)
		$ 131
Foreign		
Capital loss	2017	$ 12
Federal and state net operating loss	2031 – 2034	653
Other tax credits	2016 – 2035	69
Alternative minimum tax credits	n/a	64
		798
Unrecognized in the consolidated financial statements		(17)
		781
Total tax carryforwards		$ 912

As at December 31, 2015, the Corporation had approximately $912 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2014 – $1,093 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona and New York) and Canada (Federal and British Columbia). The Corporation's 2010 to 2015 taxation years are still open for audit in the Canadian jurisdictions and 2011 to 2015 taxation years are still open for audit in the United States jurisdictions. The Corporation is not currently under examination for income tax matters in any of these jurisdictions.

27. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans, and OPEB plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2012 for FortisBC Energy (plan covering non-unionized employees), FortisAlberta and Caribbean Utilities; December 31, 2013 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); as of December 31, 2014 for Newfoundland Power, FortisOntario, and the Corporation.

UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. Both UNS Energy and Central Hudson have met the minimum funding requirements.

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans for its members. The investment objective of the defined benefit pension and OPEB plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and defined benefit pension and OPEB expense for consolidated financial statement purposes.

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2015 Target Allocation**	**2015**	2014
Equities	**50**	**51**	49
Fixed income	**46**	**44**	46
Real estate	**4**	**4**	4
Cash and other	**–**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 31, were as follows.

Fair value of plan assets as at December 31, 2015

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 417**	**$ 922**	**$ –**	**$ 1,339**
Fixed income	**–**	**1,166**	**–**	**1,166**
Real estate	**–**	**14**	**97**	**111**
Private equities	**–**	**–**	**10**	**10**
Cash and other	**3**	**18**	**–**	**21**
	$ 420	**$ 2,120**	**$ 107**	**$ 2,647**

Fair value of plan assets as at December 31, 2014

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 352	$ 806	$ –	$ 1,158
Fixed income	23	1,069	–	1,092
Real estate	–	11	85	96
Private equities	–	–	8	8
Cash and other	6	10	–	16
	$ 381	$ 1,896	$ 93	$ 2,370

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2015 and 2014.

(in millions)	**2015**	2014
Balance, beginning of year	**$ 93**	$ 62
Assets assumed on acquisition	**–**	24
Actual return on plan assets held at end of year	**9**	6
Foreign currency translation impacts	**5**	–
Purchases, sales and settlements	**–**	1
Balance, end of year	**$ 107**	$ 93

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	2015	2014	2015	2014
Change in benefit obligation [1]				
Balance, beginning of year	$ 2,604	$ 1,724	$ 564	$ 417
Liabilities assumed on acquisition	–	403	–	83
Service costs	68	43	17	11
Employee contributions	17	17	1	1
Interest costs	109	90	23	21
Benefits paid	(118)	(101)	(21)	(15)
Actuarial (gains) losses	(102)	335	(50)	27
Past service credits/plan amendments	–	–	(10)	–
Foreign currency translation impacts	250	93	50	19
Balance, end of year [2]	$ 2,828	$ 2,604	$ 574	$ 564
Change in value of plan assets				
Balance, beginning of year	$ 2,216	$ 1,541	$ 154	$ 121
Assets assumed on acquisition	–	373	–	13
Actual return on plan assets	30	236	–	11
Benefits paid	(118)	(101)	(21)	(15)
Employee contributions	17	17	1	1
Employer contributions	99	70	17	11
Foreign currency translation impacts	222	80	30	12
Balance, end of year	$ 2,466	$ 2,216	$ 181	$ 154
Funded status	$ (362)	$ (388)	$ (393)	$ (410)

[1] Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans

[2] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,595 million as at December 31, 2015 (December 31, 2014 – $2,378 million).

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	2015	2014	2015	2014
Assets				
Defined benefit pension assets:				
Long-term other assets	$ 11	$ 6	$ –	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 14)*	5	4	–	–
Long-term other liabilities *(Note 17)*	368	390	–	–
OPEB plan liabilities:				
Current *(Note 14)*	–	–	8	7
Long-term other liabilities *(Note 17)*	–	–	385	403
Net liabilities	$ 362	$ 388	$ 393	$ 410

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows:

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Components of net benefit cost				
Service costs	**$ 68**	$ 43	**$ 17**	$ 11
Interest costs	**109**	90	**23**	21
Expected return on plan assets	**(140)**	(106)	**(12)**	(9)
Amortization of actuarial losses	**57**	32	**5**	3
Amortization of past service credits/plan amendments	**–**	(1)	**(5)**	(3)
Amortization of transitional obligation (asset)	**2**	2	**(7)**	(6)
Regulatory adjustments	**1**	11	**6**	4
Net benefit cost	**$ 97**	$ 71	**$ 27**	$ 21

The following tables provide the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2015 and 2014 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Unamortized net actuarial losses	**$ 16**	$ 16	**$ 4**	$ 4
Unamortized past service costs	**1**	–	**–**	2
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss *(Note 21)*	**$ 12**	$ 11	**$ 3**	$ 5
Net actuarial losses	**$ 513**	$ 513	**$ 41**	$ 95
Past service credits	**–**	–	**(33)**	(43)
Amount deferred due to actions of regulators	**23**	18	**39**	39
	$ 536	$ 531	**$ 47**	$ 91
Regulatory assets *(Note 8 (ii))*	**$ 536**	$ 531	**$ 91**	$ 149
Regulatory liabilities *(Note 8 (ii))*	**–**	–	**(44)**	(58)
Net regulatory assets	**$ 536**	$ 531	**$ 47**	$ 91

The following tables provide the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Current year net actuarial losses (gains)	**$ –**	$ 9	**$ (1)**	$ 3
Past service credits/plan amendments	**–**	–	**(1)**	(1)
Amortization of actuarial gains (losses)	**1**	(1)	**–**	–
Income tax recovery	**–**	(4)	**–**	(1)
Total recognized in comprehensive income	**$ 1**	$ 4	**$ (2)**	$ 1
Assets assumed on acquisition	**$ –**	$ 79	**$ –**	$ 6
Current year net actuarial losses (gains)	**8**	197	**(28)**	23
Past service credits/plan amendments	**–**	–	**(10)**	–
Amortization of actuarial losses	**(56)**	(31)	**(5)**	(5)
Amortization of past service costs	**(1)**	(1)	**(2)**	(3)
Foreign currency translation impacts	**49**	14	**(6)**	(4)
Regulatory adjustments	**5**	(37)	**7**	(1)
Total recognized in regulatory assets	**$ 5**	$ 221	**$ (44)**	$ 16

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2016 related to defined benefit pension plans.

Net actuarial losses of $47 million, past service credits of $1 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to defined benefit pension plans. Net actuarial losses of $3 million, past service credits of $1 million and regulatory adjustments of $5 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to OPEB plans.

Significant weighted average assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
(%)	**2015**	2014	**2015**	2014
Discount rate during the year	**4.00**	4.81	**3.95**	4.72
Discount rate as at December 31	**4.21**	4.00	**4.12**	3.95
Expected long-term rate of return on plan assets [1]	**6.25**	6.46	**6.95**	7.08
Rate of compensation increase	**3.48**	3.48	**–**	–
Health care cost trend increase as at December 31 [2]	**–**	–	**4.67**	4.67

[1] Developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

[2] The projected 2016 weighted average health care cost trend rate is 6.98% for OPEB plans and is assumed to decrease over the next 13 years by 2028 to the weighted average ultimate health care cost trend rate of 4.67% and remain at that level thereafter.

For 2015 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 51**	**$ (43)**
Increase (decrease) in service and interest costs	**5**	**(3)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	**Defined Benefit Pension Payments** *(in millions)*	**OPEB Payments** *(in millions)*
2016	$ 122	$ 24
2017	127	26
2018	131	27
2019	136	29
2020	141	30
2021 – 2025	796	173

Refer to Note 33 for expected defined benefit pension and OPEB plan funding contributions.

During 2015 the Corporation expensed $28 million (2014 – $21 million) related to defined contribution pension plans.

28. DISPOSITIONS AND DISCONTINUED OPERATIONS

Sale of Commercial Real Estate and Hotel Assets

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses (Note 24). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering (Notes 9 and 31).

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized a loss of approximately $20 million ($8 million after tax), which reflects an impairment loss and expenses associated with the sale transaction (Note 24).

28. DISPOSITIONS AND DISCONTINUED OPERATIONS (cont'd)

Sale of Commercial Real Estate and Hotel Assets (cont'd)

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy (Note 29), and for other general corporate purposes.

Earnings before taxes related to Fortis Properties of approximately $18 million were recognized in 2015, excluding the net gain on sale, compared to $31 million in 2014.

Sale of Non-Regulated Generation Assets in New York and Ontario

In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts (Note 24).

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) (Note 24).

Earnings before taxes of less than $1 million were recognized in 2015, excluding the gain on sale, compared to $3 million in 2014.

Sale of Griffith

In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The results of operations to the date of sale are presented as discontinued operations on the consolidated statements of earnings. As a result of the disposal, earnings from discontinued operations of $8 million ($5 million after tax) were recognized in the first quarter of 2014.

29. BUSINESS ACQUISITIONS

2015

Pending Acquisition of Aitken Creek Gas Storage Facility

In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its shares of the Aitken Creek Gas Storage Facility ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction, which is included in long-term other assets on the consolidated balance sheet (Note 9).

2014

UNS Energy

On August 15, 2014, Fortis acquired all of the outstanding common shares of UNS Energy for US$60.25 per common share in cash, for an aggregate purchase price of approximately US$4.5 billion, including the assumption of US$2.0 billion of debt on closing.

Financing of the net cash purchase price of approximately $2.7 billion (US$2.5 billion) is complete. Fortis completed the sale of $1.8 billion 4% Convertible Debentures. Proceeds from the first installment of approximately $599 million were received in January 2014. A significant portion of these cash proceeds were used to finance a portion of the UNS Energy acquisition. Proceeds from the final installment of approximately $1.2 billion were received on October 28, 2014 and were used to repay borrowings under acquisition credit facilities initially used to finance a portion of the UNS Energy acquisition. Substantially all of the Convertible Debentures have been converted into approximately 58.6 million common shares of Fortis (Note 18). In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million (Note 20). The net proceeds were also used to repay a portion of borrowings under the acquisition credit facilities. The remainder of the purchase price was financed through credit facility borrowings under a medium-term bridge facility and the Corporation's revolving credit facility (Note 32), which were subsequently repaid using net proceeds from the sale of commercial real estate and hotel assets (Note 28).

UNS Energy's operations are regulated by the ACC and FERC (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. No fair value adjustments, other than goodwill, were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at August 15, 2014, based on their fair values, using an exchange rate of US$1.00=CAD$1.0925.

(in millions)	**Total**
Purchase consideration	**$ 2,745**
Fair value assigned to net assets:	
Current assets	**539**
Long-term regulatory assets	**185**
Utility capital assets	**3,972**
Intangible assets	**116**
Other long-term assets	**108**
Current liabilities	**(458)**
Assumed long-term debt and capital lease and finance obligations (including current portion)	**(2,186)**
Long-term regulatory liabilities	**(341)**
Other long-term liabilities	**(797)**
	1,138
Cash and cash equivalents	**97**
Fair value of net assets acquired	**1,235**
Goodwill *(Note 13)*	**$ 1,510**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on August 15, 2014.

In 2014 acquisition-related expenses of approximately $25 million ($19 million after tax) were recognized in other income (expenses), net on the consolidated statement of earnings (Note 24). In addition, approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, in customer benefits offered to obtain regulatory approval of the acquisition were expensed in 2014 and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 8 *(xvii)* and 24).

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	**2015**	2014
Cash paid for:		
Interest	**$ 561**	$ 538
Income taxes	**109**	83
Change in non-cash operating working capital:		
Accounts receivable and other current assets	**$ 14**	$ 53
Prepaid expenses	**(1)**	2
Inventories	**15**	(11)
Regulatory assets – current portion	**57**	(16)
Accounts payable and other current liabilities	**(82)**	(123)
Regulatory liabilities – current portion	**38**	(29)
	$ 41	$ (124)
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 156**	$ 81
Conversion of Convertible Debentures into common shares *(Note 18)*	**1**	1,747
Additions to utility capital assets, non-utility capital assets, and intangible assets included in current and long-term liabilities	**187**	200
Contributions in aid of construction included in current assets	**4**	7
Exercise of stock options into common shares	**4**	5

31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

		As at December 31	
(in millions)	**Fair value hierarchy**	**2015**	2014
Assets			
Energy contracts subject to regulatory deferral [(1)(2)(3)]	Levels 2/3	**$ 7**	$ 3
Energy contracts not subject to regulatory deferral [(1)(2)]	Level 3	**2**	1
Available-for-sale investment *(Note 9)* [(4)(5)]	Level 1	**33**	–
Assets held for sale *(Note 6)*	Level 2	**9**	–
Other investments [(4)]	Level 1	**12**	5
Total gross assets		**63**	9
Less: Counterparty netting not offset on the balance sheet [(6)]		**(6)**	(3)
Total net assets		**$ 57**	$ 6
Liabilities			
Energy contracts subject to regulatory deferral [(1)(2)(7)]	Levels 1/2/3	**$ 78**	$ 72
Energy contracts not subject to regulatory deferral [(1)(2)]	Level 3	**–**	1
Energy contracts – cash flow hedges [(2)(8)]	Level 3	**–**	1
Interest rate swaps – cash flow hedges [(8)]	Level 2	**5**	5
Total gross liabilities		**83**	79
Less: Counterparty netting not offset on the balance sheet [(6)]		**(6)**	(3)
Total net liabilities		**$ 77**	$ 76

(1) The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.
(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.
(3) Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)
(4) Included in long-term other assets on the consolidated balance sheet
(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings (Notes 9 and 28).
(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.
(7) Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)
(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities (Note 8 *(vii)*).

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

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31. *FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)*

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (gigawatt hours *("GWh")*)	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts (petajoules *("PJ")*)	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows:

Asset (Liability)	As at December 31, 2015		December 31, 2014	
(in millions)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term other asset – Belize Electricity [(1)]	$ –	$ –	$ 116	$ n/a
Long-term debt, including current portion *(Note 15)* [(2)]	(11,240)	(12,614)	(10,501)	(12,237)
Waneta Partnership promissory note *(Note 17)*	(56)	(59)	(53)	(56)

[(1)] In August 2015 the Corporation settled expropriation matters with the GOB regarding the GOB's expropriation of Belize Electricity (Note 9).

[(2)] The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $551 million (December 31, 2014 – $1,096 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

32. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2015, FortisAlberta's gross credit risk exposure was approximately $116 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed corporate credit facility is used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at December 31, 2015, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $260 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2015**	Total as at December 31, 2014
Total credit facilities [1]	$ 2,211	$ 1,354	**$ 3,565**	$ 3,854
Credit facilities utilized:				
Short-term borrowings [2]	(511)	–	**(511)**	(330)
Long-term debt *(Note 15)* [3]	(71)	(480)	**(551)**	(1,096)
Letters of credit outstanding	(68)	(36)	**(104)**	(192)
Credit facilities unused	$ 1,561	$ 838	**$ 2,399**	$ 2,236

[1] Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.
[2] The weighted average interest rate on short-term borrowings was approximately 1.0% as at December 31, 2015 (December 31, 2014 – 1.3%).
[3] As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.5% as at December 31, 2015 (December 31, 2014 – 1.8%).

Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and 2014

32. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities
The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other
Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC Holdings Corp. ("ITC") (Note 35), S&P affirmed the Corporation's long-term corporate credit rating at A–, revised its unsecured debt rating to BBB+ from A–, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's credit rating under review with negative implications.

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Notes 15, 16 and 31).

Commodity Price Risk

UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity purchases. These derivative instruments are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates (Note 31).

33. COMMITMENTS

As at December 31, 2015, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 15 and 16, respectively, are as follows:

($ in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Renewable power purchase obligations (1)	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations (2)	**1,449**	366	253	222	153	131	324
Power purchase obligations (3)	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy (4)	**1,057**	146	141	105	102	82	481
Capital cost (5)	**488**	19	19	19	19	19	393
Operating lease obligations (6)	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements (7)	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities (8)	**147**	–	53	–	–	–	94
Defined benefit pension and OPEB funding contributions *(Note 27)*	**139**	49	12	8	9	9	52
Waneta Partnership promissory note *(Note 17)*	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other (9)	**71**	15	12	16	3	–	25
Total	**16,283**	1,533	1,331	1,176	1,002	953	10,288

33. COMMITMENTS (cont'd)

(1) TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

(2) Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

(3) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy
In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric
Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario
Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric
Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson
Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$76 million in purchase commitments remaining as at December 31, 2015. During 2015 Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

(4) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million.

(5) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(6) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(7) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(8) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021 (Note 16).

(9) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU Plan obligations and asset retirement obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Commitments table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8.

34. CONTINGENCIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingencies.

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third-party owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the owner trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the *Federal Arbitration Act*. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As at December 31, 2015, TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 million), and represents the present value of the estimated future liability (Note 17).

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset (Note 8 *(ix)*).

Central Hudson

Site Investigation and Remediation Program

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s, with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018 (Note 8 *(iv)*).

For the years ended December 31, 2015 and 2014

34. CONTINGENCIES (cont'd)

Central Hudson (cont'd)

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

35. SUBSEQUENT EVENT

On February 9, 2016, Fortis and ITC (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin. ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the Acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott-Rodino Antitrust Improvements Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the Acquisition.

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance and although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the Acquisition, Fortis will become a registrant with the U.S. Securities and Exchange Commission and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

36. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. As a result of the adoption of new accounting policies in 2015 (Note 3), the following changes to the Corporation's comparative financial statements were made:

(i) the reclassification of deferred financing costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 15); and

(ii) the presentation of all deferred income tax assets and liabilities as long term. This change in presentation resulted in the following reclassifications: (i) a decrease in current deferred income taxes assets of $158 million; (ii) a decrease in long-term deferred income tax assets of $62 million; (iii) a decrease in current deferred income tax liabilities of $9 million; and (iv) a decrease in long-term deferred income tax liabilities of $211 million on the consolidated balance sheet as at December 31, 2014 (Note 26). In addition, the Corporation also reclassified the associated regulatory deferred income taxes as long-term, resulting in the following reclassifications: (i) a decrease in current regulatory assets of $18 million; (ii) a decrease in long-term regulatory assets of $92 million; (iii) a decrease in current regulatory liabilities of $19 million; and (iv) a decrease in long-term regulatory liabilities of $91 million on the consolidated balance sheet as at December 31, 2014 (Note 8).

Historical Financial Summary

Statements of Earnings *(in $ millions)*	2015 [1]	2014 [1][2][3]	2013 [1][3]
Revenue	**6,727**	5,401	4,047
Energy supply costs and operating expenses	**4,425**	3,690	2,654
Depreciation and amortization	**873**	688	541
Other income (expenses), net	**187**	(25)	(31)
Finance charges	**553**	547	389
Income tax expense	**223**	66	32
Earnings from continuing operations	**840**	385	400
Earnings from discontinued operations, net of tax	**–**	5	–
Extraordinary gain, net of tax	**–**	–	20
Net earnings	**840**	390	420
Net earnings attributable to non-controlling interests	**35**	11	10
Net earnings attributable to preference equity shareholders	**77**	62	57
Net earnings attributable to common equity shareholders	**728**	317	353
Balance Sheets *(in $ millions)*			
Current assets	**1,857**	1,787	1,296
Goodwill	**4,173**	3,732	2,075
Other long-term assets	**2,638**	2,410	1,925
Utility capital assets, non-utility capital assets and intangible assets	**20,136**	18,304	12,612
Total assets	**28,804**	26,233	17,908
Current liabilities	**2,638**	2,676	2,084
Other long-term liabilities	**5,029**	4,534	3,024
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**18,451**	17,121	11,532
Shareholders' equity	**10,353**	9,112	6,376
Cash Flows *(in $ millions)*			
Operating activities	**1,673**	982	899
Investing activities	**(1,368)**	(4,199)	(2,164)
Financing activities, excluding dividends	**(14)**	3,627	1,434
Dividends, excluding dividends on preference shares classified as debt	**(332)**	(266)	(248)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**9.75**	5.45	8.06
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**54.8**	56.4	56.2
Preference shares (classified as debt and equity)	**8.3**	9.1	9.0
Common shareholders' equity	**36.9**	34.5	34.8
Interest Coverage *(x)*			
Debt	**2.7**	1.6	1.9
All fixed charges	**2.7**	1.6	1.9
Total gross capital expenditures *(in $ millions)*	**2,243**	1,725	1,175
Common share data			
Book value per share (year end) *($)*	**28.62**	24.89	22.38
Average common shares outstanding *(in millions)*	**278.6**	225.6	202.5
Basic earnings per common share *($)*	**2.61**	1.41	1.74
Dividends declared per common share *($)*	**1.43**	1.30	1.25
Dividends paid per common share *($)*	**1.40**	1.28	1.24
Dividend payout ratio *(%)*	**53.6**	90.8	71.3
Price earnings ratio *(x)*	**14.3**	27.6	17.5
Share trading summary (TSX)			
High price *($)*	**42.23**	40.83	35.14
Low price *($)*	**34.16**	29.78	29.51
Closing price *($)*	**37.41**	38.96	30.45
Volume *(in thousands)*	**172,038**	174,566	120,470

[1] Financial information for the years 2010 through 2015 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

[2] Certain 2014 comparative figures have been reclassified to comply with current period classifications.

[3] Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013.

Historical Financial Summary

2012 [1]	2011 [1]	2010 [1]	2009	2008	2007	2006
3,654	3,738	3,647	3,641	3,907	2,718	1,472
2,390	2,547	2,448	2,577	2,859	1,904	939
470	416	406	364	348	273	178
4	38	13	10	–	8	2
366	363	359	369	363	299	168
61	84	72	49	65	36	32
371	366	375	292	272	214	157
–	–	–	–	–	–	–
–	–	–	–	–	–	–
371	366	375	292	272	214	157
9	9	10	12	13	15	8
47	46	45	18	14	6	2
315	311	320	262	245	193	147
1,093	1,132	1,205	1,124	1,150	1,038	405
1,568	1,565	1,561	1,560	1,575	1,544	661
1,715	1,580	1,309	917	487	424	331
10,574	9,937	9,336	8,538	7,954	7,276	4,049
14,950	14,214	13,411	12,139	11,166	10,282	5,446
1,350	1,305	1,491	1,592	1,697	1,804	558
2,449	2,281	1,977	1,325	763	732	508
5,741	5,685	5,616	5,239	4,848	4,588	2,532
–	–	–	320	320	320	320
9,540	9,271	9,084	8,476	7,628	7,444	3,918
5,410	4,943	4,327	3,663	3,538	2,838	1,528
992	915	742	681	661	373	263
(1,096)	(1,115)	(980)	(1,045)	(852)	(2,033)	(634)
396	386	451	563	387	1,826	456
(225)	(206)	(189)	(176)	(191)	(146)	(77)
8.06	8.79	10.06	8.41	8.70	10.00	11.87
55.3	57.1	60.4	60.2	59.5	64.3	61.1
9.7	8.3	8.7	6.9	7.3	5.2	10.0
35.0	34.6	30.9	32.9	33.2	30.5	28.9
2.0	2.0	2.0	1.9	1.9	1.9	2.2
2.0	2.0	2.0	1.8	1.8	1.7	2.0
1,146	1,171	1,071	1,024	935	803	500
20.84	20.25	18.65	18.61	17.97	16.69	12.19
190.0	181.6	172.9	170.2	157.4	137.6	103.6
1.66	1.71	1.85	1.54	1.56	1.40	1.42
1.21	1.17	1.41	0.78	1.01	0.88	0.70
1.20	1.16	1.12	1.04	1.00	0.82	0.67
72.3	67.8	60.5	67.5	64.1	58.6	47.2
20.6	19.5	18.4	18.6	15.8	20.7	21.0
34.98	35.45	34.54	29.24	29.94	30.00	30.00
31.70	28.24	21.60	21.52	20.70	24.50	20.36
34.22	33.37	33.98	28.68	24.59	28.99	29.77
115,962	126,341	120,855	121,162	132,108	100,920	60,094

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 18, 2016	August 19, 2016
November 18, 2016	February 16, 2017

Dividend Payment Dates

June 1, 2016	September 1, 2016
December 1, 2016	March 1, 2017

Earnings Release Dates

May 3, 2016	July 29, 2016
November 4, 2016	February 16, 2017

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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Toronto, ON M5J 2Y1
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F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Thursday, May 5, 2016
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

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Fortis Inc. Executive

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President and Chief Executive Officer

Karl W. Smith
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President,
Corporate Services and Chief Human Resource Officer

Earl A. Ludlow
Executive Vice President,
Eastern Canadian and Caribbean Operations

David C. Bennett
Vice President, Chief Legal Officer and Corporate Secretary

Janet A. Craig
Vice President, Investor Relations

Karen J. Gosse
Vice President, Planning and Forecasting

Annette M. Iwasaki
Vice President, Talent Management

James D. Roberts
Vice President, Controller

James D. Spinney
Vice President, Treasurer

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David Sanders, Tucson, AZ
Christopher Valdez, Poughkeepsie, NY
Oscar Alonzo, San Ignacio, BZ
Doell Photography, Trail, BC
Shawn Talbot, Kelowna, BC
Ned Pratt, St. John's, NL

Design and Production:
Colour, St. John's, NL
colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

Board of Directors

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Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Tracey C. Ball ∗
Corporate Director
Edmonton, Alberta

Pierre J. Blouin ✱
Corporate Director
Ile Bizard, Quebec

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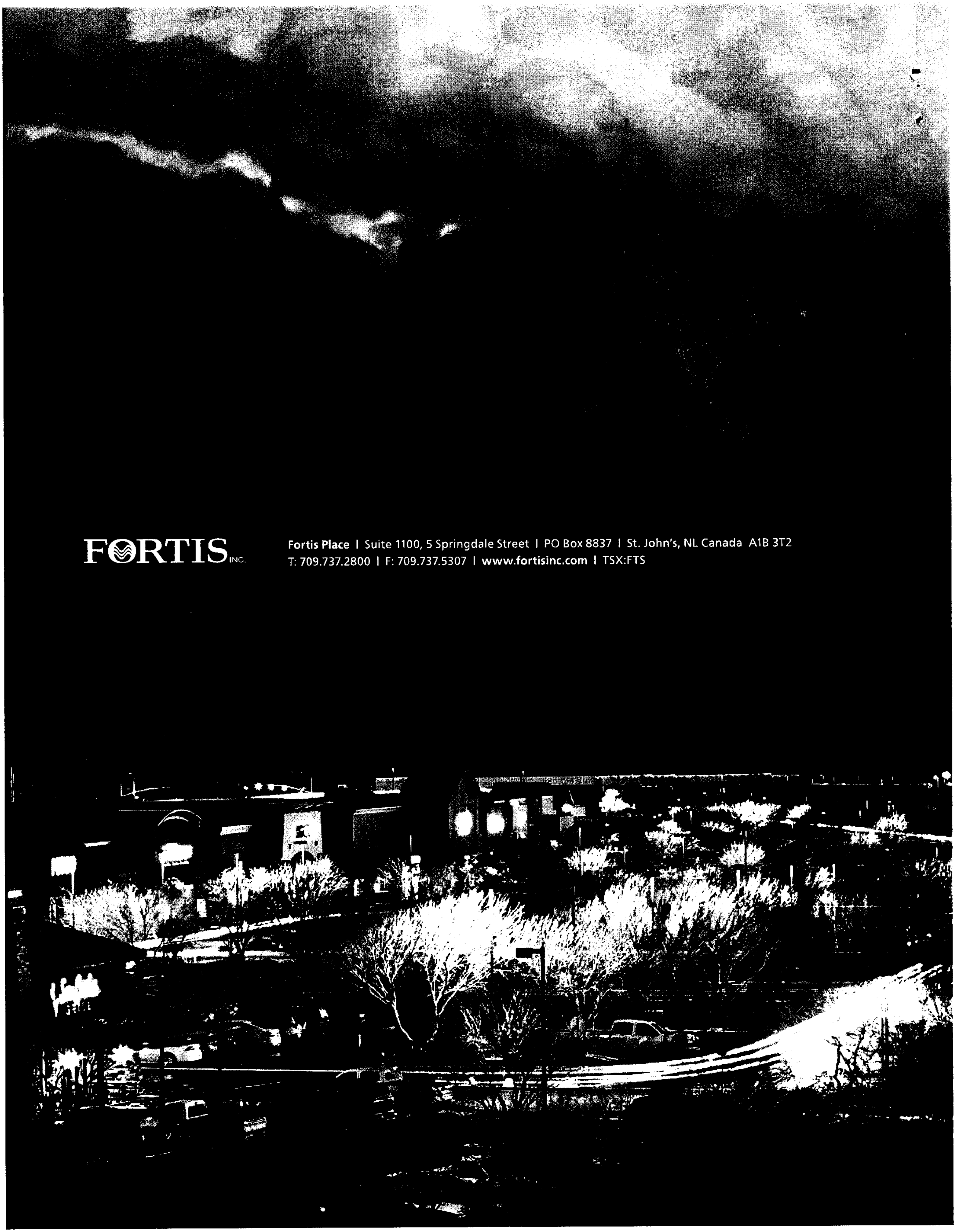
Ronald D. Munkley ✱ ★
Corporate Director
Mississauga, Ontario

Barry V. Perry
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

∗ Audit Committee
✱ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies, please visit www.fortisinc.com.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Utility Dive

How Tucson Electric Power's CEO wants to grow DERs in Arizona

As solar deployment spreads, TEP seeks rate design reforms and aims for a full suite of utility-owned DERs

By Gavin Bade | February 9, 2016

In the summer of 2014, Arizona's two largest utilities raised eyebrows throughout the power sector when they asked regulators for approval to begin installing rooftop solar.

Arizona Public Service (APS), the state's largest power provider with 1.2 million electricity customers, proposed to install 20 MW of solar (http://www.utilitydive.com/news/has-aps-invented-a-rooftop-solar-business-model-for-utilities/296019/) across rooftops of its service territory, crediting building owners for their roof space and building the arrays on the utility side of the meter. In December of that year, regulators approved a scaled-back 10 MW version of the proposal.

Tucson Electric Power (TEP), a smaller utility with just over 400,000 customers, proposed a more modest 3.5 MW program (http://www.utilitydive.com/news/tucson-electric-power-proposes-new-utility-owned-rooftop-solar-program/299840/) . After paying a $250 application fee, solar customers under TEP's program would be locked into a new, lower rate for 25 years. Regulators approved the program, authorizing TEP to install systems on about 600 rooftops, but only if it did so at cost parity with third party providers.

While the APS offering is akin to a "roof rental payment" for installing solar arrays on customers' buildings, the TEP solar option is closer to the offerings available from third party providers, which commonly include contracts that lock consumers into lower electricity rates based on the output of their systems.

At the outset, the TEP offering earned encouraging reviews from stakeholders (http://www.utilitydive.com/news/arizonas-utility-owned-solar-programs-the-new-business-models-utilities-a/348331/) in Arizona for its innovative approach to a utility-owned solar program. More than a year later, TEP CEO David Hutchens told Utility Dive that the program is so popular the utility is looking to expand it.

"It's already super-subscribed," Hutchens said. "[I]n 2015, we updated it, asked to do more, basically doubling the size of the program."

Utility Dive caught up with Hutchens after the Electric Light & Power conference in Orlando, Florida, the executives-only event that precedes DistribuTECH, the nation's largest power delivery conference. Hutchens discussed TEP's utility-owned rooftop solar offering, rate design changes in response to DER growth, and how his utility could offer a full suite of DERs in the future

Rate design changes

Located in the solar hotspot of Arizona, TEP is keen to increase the amount of renewable and distributed energy on its system, Hutchens told Utility Dive, but it also needs to "have the correct economic signals" so that it values each type of resource properly.

Part of identifying the correct economic signals will be lowering the remuneration rate for rooftop solar in the state, he said. Currently, customers with rooftop systems in Arizona are compensated for power they send back to the grid at the retail electricity rate, a common net metering rate in many states.

TEP would like to lower that rate. Last fall, the utility petitioned regulators to adjust the net metering credit (http://www.utilitydive.com/news/arizona-utility-tep-wants-to-add-solar-fee-reduce-net-metering-credit/408791/) down to the avoided cost for other solar generation — in other words, what it would pay for solar from a central station array. It also asked to raise fixed monthly charges from $10 to $20 and institute a residential demand charge for rooftop solar customers.

That request is pending, and a similar one (https://www.uesaz.com/news/updates/e-rates/) from TEP's sister company UniSource Energy Services is slated to have its first hearing on March 1, Hutchens said. The UES rate design case, despite the utility's size, attracted a lot of attention in the state.

"The biggest thing about that hearing is rate design and we've obviously attracted a lot of attention because it's the first rate design hearing in Arizona, even though it's this small little company that has 100,000 customers, we have 18 different intervenors in there," Hutchens said. "So everyone is coming in to talk about the rate design issue."

Solar installers sharply critiqued the TEP proposal (http://www.utilitydive.com/news/arizona-utility-tep-wants-to-add-solar-fee-reduce-net-metering-credit/408791/) when it was released in the fall. "These are discriminatory charges and discriminatory rates that make it uneconomical to go solar," a lawyer from The Alliance for Solar Choice, a solar lobbying group, said at the time.

But for Hutchens, the current rate structure is the one that's unfair. While solar customers are able to significantly reduce their utility bills with net metering credits, they also pay less back into the system for grid upkeep. Those costs, the utility argues, end up being shifted to non-solar customers, many of whom can ill afford increases in their electricity rates.

“We want to make sure that all of our customers get a fair shake,” Hutchens said, “and that is against some people's business models, which makes it a little bit of a tough conversation, but I think it's the right thing to do.”

“It's against the solar companies' business model, and from our perspective we want to make sure that the cost of service, the real cost of service, is reflected in our rates,” he added.

Which rates are ‘fair’ rates?

To better account for what it believes to be the value of distributed solar, TEP requested to lower the solar remuneration rate from the retail rate to its avoided cost for other solar generation.

While the utility could have asked to adjust the solar rate down to its avoided cost for all of its generation — not just solar — it decided that the solar avoided cost rate would be a more accurate valuation.

“We're not saying give us the three cents [per kWh] that the avoided cost would be for fossil fuels or gas, but we think it's right ... to say, 'This is a like product, so we'll be willing to pay you that same wholesale rate' because that's basically what it offsets from our perspective,” Hutchens said.

For TEP, there's little difference between the solar it gets from the community solar arrays deployed on its distribution system and the power it receives from net metered rooftop solar systems, he continued. But the latter costs the utility almost twice as much as the former.

“If you give us extra solar, we could have just bought that for 6 cents or 5.8 cents is what we filed. Why would we give you ten or twelve cents for it?” Hutchens said.

Solar installers commonly argue that rooftop arrays offer special benefits to the utility through enhanced reliability and reduced fossil fuel usage. Hutchens disagreed, arguing that on that count there's little difference between the two products as well.

“We're comparing it with ... the larger, community-scale stuff, which is half the cost, sitting right in our community. The only difference is it's not on a roof,” he said. “It’s on our distribution system, we can plan where to put it, we can control the output, so there's a lot of benefits there.”

The similarity between the community solar projects on its distribution system and rooftop arrays in its service area is a central reason why TEP did not try to reduce net metering rates further, Hutchens said.

“This is the same exact energy product,” he said. “The only difference is it's not on a roof. It's over here and costs half as much. That’s our argument.”

If TEP wins its rate case and remuneration rates are lowered, it could affect future utility-owned solar offerings from the company. When regulators approved the TEP rooftop solar pilot, they inserted a provision pushed by consumer advocates in the state that stipulated the utility must offer solar at price parity with third party providers. If the net metering rate is cut, TEP would also have to make its solar product less lucrative to customers.

“We would have to increase the amount that we charge those customers," Hutchens said. “Now what we do is we fix their bill. Well, we would have to fix it at a higher level.”

Basic cable vs. premium service

The motivation behind both moves — offering rooftop solar and reducing net metering rates — is to provide customers options, “but options that reflect the true economic realities of their decisions,” Hutchens said.

Hutchens drew an analogy to the cable industry. The utility provides its basic cable — the cheapest electricity available — and then customers can add on different “premium” options onto their package, such as solar, storage or an EV charger. Just as the costs for premium cable options like HBO or Cinemax aren’t shared across all cable customers, the premium power options would be paid for by the individual customers as well.

“We provide basic cable, and that's the cost of service, but things that cost more — we don't want other people paying for them,” Hutchens said. “We want you to pay for them because you find value in those products.”

“You don’t get to watch HBO if your neighbors paid for it, unless of course you splice into their line, but that’s the kind of model we want to see going forward,” he added. “Basic cable for everybody, keep that as low as we can, because we got a lot people who can't afford extras and that's really bothersome if we can't control the rates to those who are most at-risk in our community.”

While part of the push for lower remuneration rates and utility-owned solar is to address the cost shift, Hutchens said, TEP is also seeking to bring the cost of distributed generation to the utility more in line with renewables from community and central-station arrays.

“The other part is [rooftop solar] is twice as expensive,” he said. “So you peel the onion away and say, ‘What is the cost to society of these different options?' Let's pick the one that reduces the most carbon, reduces the most water usage, reduces the most environmental impact per dollar because that's what we should be doing as a society.”

Under that paradigm, Hutchens said the utility could be getting more renewables for its dollar than it currently receives under the net metering rates in Arizona.

“Wouldn't you love to have twice the renewables for the same costs? That's the story,” he said, expressing some frustration with the conversation over rooftop solar in his state. “It drives me crazy. It's like, how do you guys not get that?”

“It's like, 'Oh well my business model doesn't work,'” Hutchens said. “I know it doesn't work! But there are still people who would pay extra to have it on their roof because they're the same people who ... want the cool stuff. They want solar on their roof, they want storage in their garage, and they want to say, ‘Hey look man, I'm powered by the sun.’ But that isn't free.”

Helping DERs spread as a utility

The request to expand TEP’s utility-owned solar offering has been pushed off to a larger renewable energy standard docket that should go to hearings in the next few months, Hutchens said. “After that, it will be resolved and we hope to have a whole bunch more signed up.”

Beyond the rooftop solar program, Hutchens sees a role for TEP in owning and operating a whole suite of distributed resources, from solar to home storage and electric vehicle chargers — with the help of third party partners.

“That's the premium service model that I hope to get to, where we have that basic cable cost of service and then we work with partners to provide those other services,” he said, pointing to the ease of offering such products through the utility.

“Put it on your bill, we'll finance it. That's what we do. That's our function in life is financing energy infrastructure,” he said. “So why not put it all on our bill ... we'll work with Tesla and their battery, we'll work with any company that wants to put solar on the roof, we'll put all that stuff together [and] package it."

In just a few years, Hutchens envisions customers using his utility's website to choose from a variety of different DER service offerings.

"The dream, five years from now, is that you just go on our site and say, which of these services we got?" he said. "As long as that basic cable is still getting paid, to me, that is a great spot for a customer to be in."

Solar companies and other DER providers are wary of heavy utility involvement in the distributed energy space, since the utility's existing customer relationship and brand recognition could give them an advantage in offering such products. But Hutchens said he sees room for more collaboration in the industry.

"We can help them market it," he said. "Our customers don't want to get all confused trying to figure out whose product works with what. Let us do that."

By leveraging that established customer relationship, Hutchens expects that his utility can help DERs grow even faster in his service area than they are today.

"We've found that in the rooftop program. All these people wanted to sign up because they're like, 'Okay, we've got the big utility behind it ... we don't have to worry about signing this crazy complicated contract, we don't have to worry about whether they're going to be in business in five years, don't have to worry about maintenance, etc.," he said. "This is all taken care of by a name we know and we know we can call if we have a problem."

More renewables coming

Some of the early results of TEP's push to deploy more renewables will be on display in the utility's coming 2016 Integrated Resource Plan (IRP), set to be released in March.

The 2014 IRP envisioned a less carbon-intensive generation fleet than in the past, but still one that relied predominantly on fossil fuels. In 2028, it predicted TEP's fuel mix would be 43% coal and 36% gas, followed by 12% energy efficiency savings, 7% utility-scale renewables, and 3% DERs.

While Hutchens did not divulge many details about the coming IRP, he said it will be markedly different than the 2014 version.

"There's a lot of difference," he said. "There's a lot more renewables, a lot less coal and that's how we see our portfolio evolving."

Whatever the predictions are for the fuel mix in the coming IRP, it's likely that renewables will grow at an even faster rate, Hutchens added.

"We basically send out this straw man on March 1 and then we get into stakeholder groups, so you can bet the renewables that we come out with in that March 1 report will be the minimum that we'll see over time," he said. "Then we get into conversations, because new technology will only make that go up. It's not going to make it go down."

Correction: An earlier version of this post indicated that TEP's rate design case will go to hearings on March 1. That was incorrect. The rate design case for UES, its sister company, is scheduled to begin hearings on that day.

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Filed Under:

Solar & Renewables Distributed Energy

EXHIBIT
TASC 13
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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, 2015

OR

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

For the transition period from to .

Commission File Number 1-5924

TUCSON ELECTRIC POWER COMPANY
(Exact name of registrant as specified in its charter)

Arizona	**86-0062700**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

88 East Broadway Boulevard, Tucson, AZ 85701
(Address of principal executive offices)(Zip Code)

Registrant's telephone number, including area code: **(520) 571-4000**

Securities registered pursuant to Section 12(b) of the Exchange Act: **None**
Securities registered pursuant to Section 12(g) of the Exchange Act:

Common Stock, without par value
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

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 Securities Exchange Act of 1934 (Exchange Act).

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

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).

Yes ☒ No ☐

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

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

Large Accelerated Filer ☐ Accelerated Filer ☐ Non-accelerated Filer ☒ Smaller Reporting Company ☐

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

Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates: **None**

As of February 17, 2016, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis Inc.

Documents incorporated by reference: **None**

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DEFINITIONS

The abbreviations and acronyms used in the 2015 Form 10-K are defined below:

2010 Credit Agreement	The 2010 Credit Agreement consisted of a $200 million revolving credit and letter of credit facility together with an $82 million LOC facility to support tax-exempt bonds; terminated in October 2015 when replaced by the 2015 Credit Agreement
2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Covenants Agreement	A Lender Rate Mode Covenants Agreement between TEP and the purchaser of $100 million of unsecured tax-exempt bonds that were issued on behalf of TEP in November 2013 and sold in a private placement
2013 TEP Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
2014 Credit Agreement	The 2014 Credit Agreement consisted of a $130 million term loan commitment and a $70 million revolving credit commitment; terminated in June 2015
2015 Credit Agreement	The 2015 Credit Agreement provides for a $250 million revolving credit and letter of credit facility with a sublimit of $50 million; the credit agreement matures in 2020 and replaced the 2010 Credit Agreement
2015 TEP Rate Case	A pending general rate case filed with the ACC by TEP in November 2015 requesting new rates effective January 1, 2017
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base Rates	The portion of TEP's Retail Rates attributed to generation, transmission, distribution, and customer costs. Base Rates exclude authorized charges designed to recover specific costs that are passed through to customers including fuel and purchased power costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles in the United States
GBtu	Billion British thermal units
GWh	Gigawatt-hour(s)
Gila River Unit 3	Unit 3 of the Gila River Generating Station
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kV	Kilo-volt(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter of Credit
MW	Megawatt(s)
MWh	Megawatt-hour(s)

Navajo	Navajo Generating Station
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
ppb	Parts per billion

REC	Renewable Energy Credit
RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
Springerville Coal Handling Facilities	Coal handling facilities at Springerville used by all four Springerville units
Springerville Coal Handling Facilities Leases	Leases for coal handling facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by Springerville Units 1 and 2
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in Springerville Common Facilities
Springerville Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 2	Unit 2 of the Springerville Generating Station
Springerville Unit 3	Unit 3 of the Springerville Generating Station
Springerville Unit 4	Unit 4 of the Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
Third-Party Owners	Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
Tri-State	Tri-State Generation and Transmission Association, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy
UNS Energy	UNS Energy Corporation, the parent company of TEP, whose principal executive offices are located at 88 East Broadway Boulevard, Tucson, Arizona 85701
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. Tucson Electric Power Company (TEP) is including the following cautionary statements to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or for TEP in this Annual Report on Form 10-K. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance and underlying assumptions, and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as anticipates, believes, estimates, expects, intends, may, plans, predicts, projects, would, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, TEP disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report, except as may otherwise be required by the federal securities laws.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management's expectations, beliefs or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in: *Part I, Item 1A. Risk Factors; Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions; changes in, and compliance with, environmental laws, regulations, decisions and policies that could increase operating and capital costs, reduce generating facility output or accelerate generating facility retirements; regional economic and market conditions which could affect customer growth and energy usage; changes in energy consumption by retail customers; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; the inability to make additions to our existing high voltage transmission system; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in critical accounting estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; the ability to obtain coal from our suppliers; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

PART I

ITEM 1. BUSINESS

GENERAL

Tucson Electric Power Company (TEP) and its predecessor companies have served the greater Tucson metropolitan area for over 100 years. TEP was incorporated in the State of Arizona in 1963. TEP is a regulated electric utility company serving approximately 417,000 retail customers. TEP's service territory covers 1,155 square miles and includes a population of approximately one million people in Pima County, as well as parts of Cochise County. TEP's principal business operations include generating, transmitting, and distributing electricity to its retail customers. In addition to retail sales, TEP sells electricity, transmission, and ancillary services to other utilities, municipalities, and energy marketing companies on a wholesale basis. TEP is subject to comprehensive state and federal regulation. The regulated electric utility operation is TEP's only segment.

TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. In August 2014, UNS Energy was acquired by Fortis Inc. (Fortis) and became an indirect wholly owned subsidiary of Fortis, which is a leader in the North American electric and gas utility business.

REGULATED UTILITY OPERATIONS

TEP delivers electricity to retail customers in southern Arizona. TEP owns or has contracts for coal, natural gas, wind, solar, and landfill gas generation resources to provide electricity. This electricity, together with electricity purchased on the wholesale market, is delivered over transmission lines which are part of the Western Interconnection, a regional grid in the United States. The electricity is then transformed to lower voltages and delivered to customers through TEP's distribution system.

TEP operates under a certificate of public convenience and necessity as regulated by the Arizona Corporation Commission (ACC), under which TEP is obligated to provide electricity service to customers within its service territory. The ACC establishes retail rates on a cost-of-service basis, which are designed to allow TEP to recover its costs of providing services and an opportunity to earn a reasonable return on its investment.

CUSTOMERS

Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers over the last three years were as follows:

	2015		2014		2013	
Electric Sales - GWh						
Residential	3,724	28%	3,727	29%	3,867	30%
Commercial	2,124	15%	2,170	17%	2,187	17%
Industrial (Non-mining)	2,063	15%	2,098	16%	2,114	17%
Mining	1,109	8%	1,137	9%	1,079	9%
Other	33	—%	33	—%	32	—%
Total Electric Retail Sales	9,053	66%	9,165	71%	9,279	73%
Electric Wholesale Sales - Long-Term	750	5%	618	5%	605	5%
Electric Wholesale Sales - Short-Term	3,928	29%	3,082	24%	2,859	22%
Total Electric Sales	13,731	100%	12,865	100%	12,743	100%
Average Number of Retail Customers:						
Residential	376,439	90%	374,204	90%	370,925	90%
Commercial	38,253	9%	38,079	9%	37,783	9%
Industrial (Non-mining)	588	—%	604	—%	622	—%
Mining	4	—%	4	—%	4	—%
Other	1,857	1%	1,858	1%	1,843	1%
Total Retail Customers	417,141	100%	414,749	100%	411,177	100%

Retail Customers

TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases, and other governmental entities. TEP's retail sales are influenced by several factors, including economic conditions, seasonal weather patterns, Demand Side Management (DSM) initiatives and the increasing use of energy efficient products, and customer owned distributed generation.

Local, regional, and national economic factors impact the growth in the number of customers in TEP's service territory. In each of the past five years, TEP's average number of retail customers increased by less than 1%. TEP expects the number of retail customers to increase at a rate of approximately 1% in 2016 based on estimated population growth in its service territory.

TEP's retail sales volume in 2015 was approximately 9,053 gigawatt-hours (GWh), which is a decrease of 3% from 2011 levels. During the past five years, local economic conditions combined with state requirements to reduce retail sales through energy efficiency and distributed generation have resulted in lower sales volumes and lower use per customer.

Two of TEP's largest retail customers are in the copper mining industry. TEP's GWh sales to mining customers depend on a variety of factors including commodity prices, the electricity rate paid by mining customers, and the mines' development of their own electric generation resources. TEP's GWh sales to mining customers decreased by 2% in 2015 as a result of mining curtailments due to declining commodity prices. In 2016, TEP expects additional curtailments to certain mining customers based on announced plans and current commodity prices. TEP cannot predict how long the commodity prices will remain low or the impact prices will have on mining production.

See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations* for additional information regarding mining customers.

Wholesale Sales

TEP's electric utility operations include the wholesale marketing of electricity to other utilities and power marketers. Wholesale sales transactions are made on both a firm and interruptible basis. A firm contract requires TEP to supply power on demand (except under limited emergency circumstances), while an interruptible contract allows TEP to stop supplying power under defined conditions.

Generally, TEP commits to future sales based on expected generating capability, forward prices, and generation costs, using a diversified portfolio approach to provide a balance between long-term, mid-term, and spot energy sales. TEP's wholesale sales consist primarily of two types:

Long-Term Wholesale Sales

Long-term wholesale contracts cover periods of one year or greater. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. In 2015, TEP's primary long-term contracts were with Salt River Project Agriculture Improvement and Power District (SRP), Shell Energy North America (Shell), the Navajo Tribal Utility Authority (NTUA), and TRICO Electric Cooperative (TRICO). The SRP contract expires in May 2016, the Shell contract expires in December 2017, the NTUA contract expires in December 2022, and the TRICO contract expires in December 2024.

In November 2015, TEP entered into a long-term wholesale sales contract with Navopache Electric Cooperative (Navopache). Delivery of power begins January 1, 2017 and expires in December 2041.

Short-Term Wholesale Sales

Forward contracts commit TEP to sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one-month or three-month periods. TEP also engages in short-term sales by selling energy in the daily or hourly markets at fluctuating spot market prices and making other non-firm energy sales. The majority of our revenues from short-term wholesale sales offset fuel and purchased power costs and are passed through to TEP's retail customers. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices.

Competition

Retail Customers

TEP is the primary electric service provider to retail customers within its service territory and operates under a certificate of public convenience and necessity as regulated by the ACC. TEP is subject to competition from customer-sited distributed generation, energy efficiency, and other emerging technologies. TEP is experiencing increases in the levels of customer-sited solar arrays and the use of net energy metering, which allows self-generating retail customers to use their excess generation to offset a portion of their future electricity consumption at the full retail rate.

Wholesale Sales

The Federal Energy Regulatory Commission (FERC) regulates rates for wholesale power sales and transmission services. TEP's wholesale activity primarily consists of Short-Term Wholesale Sales to manage fuel and purchased power supplies to serve retail customer energy requirements and Long-Term Wholesale Sales to optimize generation capacity. As a result of its wholesale activity, TEP competes with other utilities, power marketers and independent power producers in the wholesale markets.

GENERATING FACILITIES

As of December 31, 2015 TEP owned 2,501 megawatts (MW) of nominal generating capacity, as set forth in the following table. Nominal capacity is based on unit design net output.

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	TEP's Share %	TEP's Share MW [1]
Springerville Station	1	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	2	Springerville, AZ	1990	Coal	406	TEP	100	406
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100	104
Sundt Station [2]	4	Tucson, AZ	1967	Gas	156	TEP	100	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	13	TEP	100	13
Ft. Huachuca Project		Ft. Huachuca, AZ	2014	Solar	17	TEP	100	17
Total TEP Capacity [3]								2,501

(1) Capacity measured in direct current (DC).

(2) Sundt Station Unit 4 is a multi-fuel generating facility that can be operated on either coal or natural gas as a primary fuel source. In August 2015, TEP exhausted its existing coal supply at Sundt Station Unit 4 and plans to continue operating Sundt Station Unit 4 with natural gas as a primary fuel source. The table above reflects the nominal generating capacity assuming the unit is fueled by natural gas. Refer to *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Environmental Matters* of this Form 10-K for additional information related to environmental matters impacting Unit 4 of the H. Wilson Sundt Generating Station (Sundt).

(3) Excludes 913 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.

Springerville Generating Station

TEP has a 49.5% ownership interest in Unit 1 of the Springerville Generating Station (Springerville Unit 1) and operates the remaining interests in Springerville Unit 1 on behalf of third parties, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). The Owner Trustees and Co-Trustees are responsible for their share of operating and capital costs for the facility. See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Third-Party Owners.

Unit 2 of the Springerville Generating Station (Springerville Unit 2) is owned by San Carlos Resources, Inc., a wholly-owned subsidiary of TEP.

TEP's other interests in the Springerville Generating Station (Springerville) include: (i) 49.5% undivided interest in certain common facilities used by Springerville Unit 1; and (ii) an 83% ownership interest in the Springerville Coal Handling Facilities.

Springerville Common Facilities Leases

The leveraged lease arrangements relating to a 50% undivided interest in certain Springerville Common Facilities (Springerville Common Facilities Leases) used by Springerville Unit 2, which expire in 2017 and 2021, have fair market value renewal options as well as fixed-price purchase options. The fixed prices to acquire the leased interests in the Springerville Common Facilities are $38 million in 2017 and $68 million in 2021.

See Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources* for additional information regarding the capital leases.

Springerville Units 3 and 4

Springerville Units 3 and 4 are each approximately 400 MW coal-fired generating facilities that are operated, but not owned by TEP. These facilities are located at the same site as Springerville Units 1 and 2. The lessee of Springerville Unit 3 and the owner of Springerville Unit 4 compensate TEP for operating the facilities and pay an allocated portion of the fixed costs related to the Springerville common facilities and Coal Handling Facilities.

Sundt Generating Station

Sundt and the internal combustion turbines located in Tucson are designated as must-run generation facilities. Must-run generation units are required to run in certain circumstances to maintain distribution system reliability and to meet local load requirements.

Renewable Energy Resources

The ACC's Renewable Energy Standard (RES) requires TEP, and other affected utilities, to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. TEP plans to meet this requirement through a combination of owned resources and Power Purchase Agreements (PPAs). See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and *Rates and Regulations* below for additional information regarding RES.

Owned Renewable Resources

As of December 31, 2015, TEP owned 46 MW of photovoltaic (PV) solar generating capacity. In 2016, TEP plans to complete an additional solar project adding 5 MW of PV solar generating capacity. The solar generating facilities are located on properties held under easements and leases. In December 2015, TEP also acquired a 5 MW concentrated solar project which does not increase capacity but displaces the equivalent amount of steam produced by burning fossil fuel.

Renewable Power Purchase Agreements

As of December 31, 2015, TEP has renewable PPAs for 175 MW of capacity measured in direct current (DC) from solar resources, 80 MW of capacity measured in alternating current (AC) from wind resources and 4 MW of capacity measured in AC from a landfill gas generation plant. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future period.

Power Purchases

TEP purchases power from other utilities and power marketers. TEP may enter into contracts to purchase: (i) energy under long-term contracts to serve retail load and long-term wholesale contracts; (ii) capacity or energy during periods of planned outages or for peak summer load conditions; and (iii) energy for resale to certain wholesale customers under load and resource management agreements.

TEP typically uses generation from its gas-fired units, supplemented by power purchases, to meet the summer peak demands of its retail customers. Some of these power purchases are price-indexed to natural gas. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure with fixed price contracts for a maximum of three years. TEP also purchases energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages, or when doing so is more economical than generating its own energy.

TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities. These relationships allow TEP to call upon other utilities during emergencies, such as plant outages and system disturbances, and reduce the amount of reserves TEP is required to carry.

PEAK DEMAND AND FUTURE RESOURCES

Peak Demand

(in MW)	2015	2014	2013	2012	2011
Retail Customers	2,222	2,218	2,230	2,290	2,334
Firm Sales to Other Utilities	638	673	484	286	322
Coincident Peak Demand (A)	2,860	2,891	2,714	2,576	2,656
Total Generating Resources	2,452	2,240	2,240	2,267	2,262
Other Resources (1)	913	932	775	683	1,009
Total TEP Resources (B)	3,365	3,172	3,015	2,950	3,271
Total Margin (B) – (A)	505	281	301	374	615
Reserve Margin (% of Coincident Peak Demand)	18%	10%	11%	15%	23%

(1) Other Resources include firm power purchases and interruptible retail and wholesale loads.

The chart above shows the relationship over a five-year period between peak demand and energy resources. Total margin is the difference between total energy resources and coincident peak demand, and the reserve margin is the ratio of margin to coincident peak demand. The reserve margin in 2015 was in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of North American Reliability Corporation (NERC).

Peak demand occurs during the summer months due to the cooling requirements of retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions, and other factors. Retail peak demand has primarily declined over the five-year period due to weak economic conditions and the implementation of energy efficiency programs and distributed generation.

Forecasted retail peak demand for 2016 is 2,109 MW compared with actual peak demand of 2,222 MW in 2015. TEP's 2016 estimated retail peak demand is based on weather patterns observed over a 10-year period and other factors, including estimates of customer usage and planned curtailment of mining customers. TEP believes existing generation capacity and PPAs are sufficient to meet expected demand in 2016 and established reserve margin criteria.

Future Resources

At December 31, 2015, approximately 49% of TEP's generating capacity was fueled by coal. Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal generation while still meeting its peak load requirements. In August 2015, TEP exhausted its existing coal supply at Unit 4 of the H. Wilson Sundt Generating Station (Sundt Unit 4). TEP expects to continue operating Sundt Unit 4 on natural gas as a primary fuel source.

See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations* for additional information regarding TEP's generating facilities.

FUEL SUPPLY

Fuel and Purchased Power Summary

Resource information is provided below:

	Average Cost per kWh (cents per kWh)			Percentage of Total kWh Resources		
	2015	2014	2013	2015	2014	2013
Coal	2.44	2.50	2.66	60%	68%	75%
Gas	3.35	4.99	4.57	19%	9%	8%
Purchased Power	4.05	4.79	4.83	21%	23%	17%
All Sources	3.31	3.64	3.54	100%	100%	100%

Coal

The coal used for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona and New Mexico. The table below provides information on the existing coal contracts that supply our generating stations. The average cost of coal per million metric British thermal unit (MMBtu), including transportation, was $2.34 in 2015, $2.43 in 2014, and $2.57 in 2013.

Station	Coal Supplier	2015 Coal Consumption (tons in 000s)	Contract Expiration	Avg. Sulfur Content	Coal Obtained From
Springerville [(1)]	Peabody CoalSales	2,676	2020	1.0%	Lee Ranch Mine/El Segundo Mine
Four Corners [(2)]	BHP Billiton	378	2031	0.7%	Navajo Mine
San Juan [(3)]	San Juan Coal Co.	1,079	2022	0.8%	San Juan Mine
Navajo	Peabody CoalSales	510	2019	0.6%	Kayenta Mine

(1) Peabody has a pending sale of the Lee Ranch Mine/El Segundo Mine to Bowie Resources Partners.

(2) Beginning in July 2016 through June 2031, the coal for Four Corners will be purchased from the Navajo Transitional Energy Company (NTEC). NTEC purchased the mine located near Four Corners from BHP Billiton and will begin overseeing the mine operation in 2016.

(3) BHP Billiton sold San Juan Coal Co. to Westmoreland Coal Company, effective January 31, 2016.

TEP Operated Generating Facilities

The coal supplies for Springerville Units 1 and 2 are transported approximately 200 miles by railroad from northwestern New Mexico. TEP expects coal reserves to be sufficient to supply the estimated requirements for Springerville Units 1 and 2 for their estimated remaining lives.

TEP no longer uses coal as a primary fuel source for Sundt Unit 4.

Coal Generating Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generating facilities at the Four Corners Generating Station (Four Corners), the Navajo Generating Station (Navajo), and the San Juan Generating Station (San Juan). Four Corners, which is operated by Arizona Public Service Company (APS), and San Juan, which is operated by Public Service Company of New Mexico (PNM), are mine-mouth generating stations located adjacent to the coal reserves. Navajo, which is operated by SRP, obtains its coal supply from the nearby Kayenta coal mine and receives deliveries on a dedicated electric rail delivery system. Effective January 31, 2016, Westmoreland Coal Company purchased San Juan Coal Company (SJCC) from BHP Billiton and has also agreed to a new coal supply agreement extending through June 30, 2022. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining lives of the stations.

Natural Gas Supply

TEP uses generation from its facilities fueled by natural gas, in addition to energy from its coal-fired facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. The average cost of natural gas per MMBtu, including transportation, was $3.49 in 2015, $5.17 in 2014, and $4.55 in 2013.

TEP purchases capacity from El Paso Natural Gas (EPNG) for transportation from the San Juan and Permian Basins to its Sundt plant under firm transportation agreements. TEP also purchases firm gas transportation for Gila River Unit 3 from EPNG and Transwestern Pipeline Co., and for Luna Generating Station (Luna) from EPNG. TEP purchases gas from Southwest Gas Corporation under a retail tariff for North Loop's 94 MW of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie, a 75 MW internal combustion turbine.

TRANSMISSION AND DISTRIBUTION

TEP's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. TEP's transmission system, together with contractual rights on other transmission systems, enables TEP to integrate and access generation resources to meet its customer load requirements. TEP's transmission and distribution systems included approximately 2,170 miles of transmission lines, and 7,557 miles of distribution lines as of December 31, 2015.

In 2015, TEP completed construction and placed into service a 500-Kilo-volt (kV) transmission line extending from the Pinal Central substation to TEP's Tortolita substation northwest of Tucson. The transmission line was built to provide additional transmission capacity from the Palo Verde area into TEP's northern service territory.

RATES AND REGULATION

The ACC and the FERC each regulate portions of the utility accounting practices and rates of TEP. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of debt, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2015 Rate Case

In November 2015, TEP filed a general rate case with the ACC requesting a Base Rate increase of $110 million and various rate design changes. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this From 10-K and *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations* for key provisions regarding the 2015 Rate Case.

Purchased Power and Fuel Adjustment Clause

The Purchased Power and Fuel Adjustment Clause (PPFAC) allows TEP to recover its fuel, transmission, and purchased power costs, including demand charges, and the costs of contracts for hedging fuel and purchased power costs for its retail customers. The PPFAC consists of a forward component and a true-up component.

The true-up component reconciles any over/under collected amounts from the preceding 12-month period and is credited to or recovered from customers in the subsequent year.

TEP's PPFAC also includes the recovery of the following costs and/or credits: lime costs used to control sulfur dioxide (SO_2) emissions at Springerville; sulfur credits received from TEP's coal suppliers; broker fees; revenues from short-term wholesale sales; and all of the proceeds from the sale of SO_2 allowances.

At December 31, 2015, TEP had over-collected fuel and purchased power costs by $18 million.

Renewable Energy Standards and Tariff

The ACC's RES requires TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge until such costs are reflected in TEP's Base Rates. The associated lost revenues attributable to meeting distributed generation targets will be partially recovered through the Lost Fixed Cost Recovery Mechanism (LFCR). See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

In July 2015, TEP submitted its application for the 2016 RES implementation plan that includes a budget of $57 million, which will be partially offset by applying approximately $9 million of previously recovered carryover funds. TEP proposed to recover $48 million through the RES surcharge. The budget will fund the following: the above market cost of renewable energy purchases; previously awarded performance-based incentives for customer installed distributed generation; depreciation and a return on TEP's investments in company-owned solar projects; and various other program costs. TEP expects to receive a decision on the application in the first half 2016. TEP expects to recognize approximately $9 million of revenue in 2016 as a return on company-owned solar projects.

The percentage of retail kilowatt-hour (kWh) sales attributable to the 2015 RES renewable energy requirement was 8.6%, exceeding the overall 2015 requirement of 5.0%. TEP expects to meet the 2016 RES renewable energy requirement of 6.0% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation Renewable Energy Credits (REC), which are used to demonstrate compliance with the distributed generation requirement, TEP has requested a waiver of the RES distributed generation requirements in its 2016 RES implementation plan.

Energy Efficiency Standards

In 2010, the ACC approved new Energy Efficiency Standards (EE Standards) designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the EE Standards, TEP's cumulative annual energy savings are approximately 9.3% of retail kWh sales in 2015. Compliance with the EE Standards is determined through the ACC's review of the company's annual energy efficiency implementation plan.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan. Under the 2016 plan, TEP has been approved to recover approximately $14 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward Arizona's EE Standards and the associated lost revenue will be partially recovered through the LFCR. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

ENVIRONMENTAL MATTERS

The EPA regulates the amount of SO_2, nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. TEP expects to recover the cost of environmental compliance from its ratepayers.

National Ambient Air Quality Standards

In October 2015, the EPA released the final rule for the 8-hour Ozone NAAQS or Ozone Standard. The EPA lowered the standard from 75 parts per billion (ppb) to 70ppb. If Pima County does not meet the standard, the county will be designated as a "non-attainment" area and will need to develop a plan to bring the air-shed into compliance. A "non-attainment" designation may slow economic growth in the region and impact our ability to site new local generation.

Implementation of the rule is scheduled as follows:

- States' recommendation of area designations (attainment, non-attainment, or unclassified) by October 2016.
- EPA's response to states' designation recommendation by June 2017.
- EPA's finalization of area designations by October 2017, based on 2014-2016 air quality data.

Effluent Limitation Guidelines

In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines setting technology standards and limitations for steam electric power plant discharges. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. TEP is evaluating the effects of this rule on its facilities including Navajo, San Juan, and Four Corners. Since the majority of TEP's facilities are zero discharge, TEP does not anticipate a significant financial impact.

TEP believes it is in material compliance with applicable laws and regulations. Refer to *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Environmental Laws and Regulations* of this Form 10-K for additional information related to environmental laws and regulations impacting TEP's liquidity and capital resources and *Liquidity and Capital Resources* for TEP's forecasted environmental-related capital expenditures.

EMPLOYEES

At December 31, 2015, TEP had 1,478 employees, of which approximately 688 were represented by the International Brotherhood of Electrical Workers (IBEW) Local No. 1116. A new collective bargaining agreement between the IBEW and TEP was entered into in January 2016 and expires in January 2019.

SEC REPORTS AVAILABLE ON TEP'S WEBSITE

TEP makes available its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practical after we electronically file or furnish them to the Securities and Exchange Commission (SEC). These reports are available free of charge through TEP's website address at www.tep.com/about/investors/.

UNS Energy's code of ethics, which applies to the Board of Directors and all officers and employees of UNS Energy and its subsidiaries, including TEP, and any amendments or any waivers made to the code of ethics, is also available on TEP's website at www.tep.com/about/investors/.

TEP is providing the address of TEP's website solely for the information of investors and does not intend the address to be an active link. Information contained at TEP's website is not part of, or incorporated by reference into, any report or other filing filed with the SEC by TEP.

ITEM 1A. RISK FACTORS

The business and financial results of TEP are subject to a number of risks and uncertainties, including those set forth below. These risks and uncertainties fall primarily into five major categories: revenues, regulatory, environmental, financial, and operational.

REVENUES

National and local economic conditions can negatively affect the results of operations, net income, and cash flows at TEP.

Economic conditions have contributed significantly to a reduction in TEP's retail customer growth and lower energy usage by the company's residential, commercial, and industrial customers. As a result of weak economic conditions, TEP's average retail customer base grew by less than 1% in each year from 2011 through 2015 compared with average increases of approximately 1% in each year from 2005 to 2009. TEP estimates that a 1% change in annual retail sales could impact pre-tax net income and pre-tax cash flows by approximately $6 million.

New technological developments and compliance with the ACC's EE Standards and RES will continue to have a significant impact on retail sales, which could negatively impact TEP's results of operations, net income, and cash flows.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-owned generation, and appliances, equipment, and control systems. Continued development and use of these technologies and compliance with the ACC's EE Standards could further impact the results of operations, net income, and cash flows of TEP.

The revenues, results of operations, and cash flows of TEP are seasonal, and are subject to weather conditions and customer usage patterns, which are beyond the company's control.

TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during the summer. Conversely, TEP's first quarter net income is typically limited by relatively mild winter weather in its retail service territory. Cool summers or warm winters may reduce customer usage, adversely affecting operating revenues, cash flows, and net income by reducing sales.

TEP is dependent on a small segment of large customers for future revenues. A reduction in the electricity sales to these customers would negatively affect our results of operations, net income, and cash flows.

TEP sells electricity to mines, military installations, and other large industrial customers. In 2015, 35% of TEP's retail kWh sales were to 592 industrial and mining customers. Retail sales volumes and revenues from these customer classes could decline as a result of, among other things: global, national, and local economic conditions; curtailments of customer operations due to declines in commodity prices; decisions by the federal government to close military bases; the effects of energy efficiency and distributed generation; or the decision by customers to self-generate all or a portion of their energy needs. A reduction in retail kWh sales to TEP's large customers would negatively affect our results of operations, net income, and cash flows.

REGULATORY

TEP is subject to regulation by the ACC, which sets the company's Retail Rates and oversees many aspects of its business in ways that could negatively affect the company's results of operations, net income, and cash flows.

The ACC is a constitutionally created body composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms. As a result, the composition of the commission, and therefore its policies, are subject to change every two years.

TEP's Retail Rates consist of Base Rates and various rate adjustors that allow for timely recovery of certain costs between rate cases. The ACC is charged with setting Retail Rates that allow TEP to recover its costs of service and an opportunity to earn a reasonable rate of return. In setting TEP's Retail Rates, the ACC could disallow the recovery of costs or not provide for the timely recovery of costs. The decisions made by the ACC on such matters impact the net income and cash flows of TEP.

Changes in federal energy regulation may negatively affect the results of operations, net income, and cash flows of TEP.

TEP is subject to the impact of comprehensive and changing governmental regulation at the federal level that continues to change the structure of the electric and gas utility industries and the ways in which these industries are regulated. TEP is subject to regulation by the FERC. The FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of the FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

ENVIRONMENTAL

TEP is subject to numerous environmental laws and regulations that may increase its cost of operations or expose it to environmentally-related litigation and liabilities. Many of these regulations could have a significant impact on TEP due to its reliance on coal as its primary fuel for electric generation.

Numerous federal, state, and local environmental laws and regulations affect present and future operations. Those laws and regulations include rules regarding air emissions, water use, wastewater discharges, solid waste, hazardous waste, and management of coal combustion residuals.

These laws and regulations can contribute to higher capital, operating, and other costs, particularly with regard to enforcement efforts focused on existing power plants and new compliance standards related to new and existing power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations, and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable laws and regulations may result in litigation, and the imposition of fines, penalties, and a requirement by regulatory authorities for costly equipment upgrades.

Existing environmental laws and regulations may be revised and new environmental laws and regulations may be adopted or become applicable to our facilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on our results of operations, particularly if those costs are not fully recoverable from our customers. TEP's obligation to comply with the EPA's Best Available Retrofit Technology (BART) determinations as a participant in the San Juan, Four Corners, and Navajo plants, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to meet their obligations and willingness to continue their participation in these plants. TEP cannot predict the ultimate outcome of these matters.

TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has a minority interest and is obligated to pay similar costs at the mines that supply these generating stations. While TEP has recorded the portion of its costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial.

Federal regulations limiting greenhouse gas emissions require a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.

In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan requires CO_2 emission reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. TEP is unable to determine how the final CPP rule will impact its facilities until the plans are developed and approved by the EPA.

Early closure of TEP's coal-fired generation plants resulting from environmental regulations could result in TEP recognizing impairments in respect of such plants and increased cost of operations if recovery of our remaining investments in such plants and the costs associated with such early closures were not permitted through rates charged to customers.

TEP's coal-fired generating stations may be required to be closed before the end of their useful lives in response to recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation plants, or coal handling facilities, from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize an impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any of such generating stations may force TEP to incur higher costs for replacement capacity and energy. TEP may not be permitted full recovery of these costs in the rates it charges its customers. As of December 31, 2015, approximately 49% of TEP's generating capacity is fueled by coal.

FINANCIAL

The Third-Party Owners of Springerville Unit 1 have and may continue to refuse to pay some, or all, of their pro-rata share of the costs and expenses associated with Springerville Unit 1.

TEP owns 49.5% of Springerville Unit 1 and two separate third-parties own the remaining 50.5%. Starting in January 2015, TEP is obligated to operate Springerville Unit 1 for these Third-Party Owners under existing agreements. TEP and the Third-Party Owners disagree on several key aspects of these agreements, including the allocation of Springerville Unit 1 operating and maintenance expenses, capital improvement costs, and transmission rights. In addition, since late 2014 the Third-Party Owners have filed separate complaints at the FERC, in New York State court, and with the American Arbitration Association that include allegations that TEP violated certain provisions of the governing agreements in relation to TEP's operation of Springerville Unit 1. Because of these disagreements and the pending litigation, the Third-Party Owners have and may continue to refuse to pay some or all of their pro-rata share of such Springerville Unit 1 costs and expenses. As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016. The Third-Party Owners' share of estimated 2016 operations and maintenance costs for Springerville Unit 1 is approximately $27 million and their share of estimated 2016 capital expenditures is approximately $9 million.

Volatility or disruptions in the financial markets, or unanticipated financing needs, could: increase our financing costs; limit our access to the credit markets; affect our ability to comply with financial covenants in our debt agreements; and increase our pension funding obligations. Such outcomes may adversely affect our liquidity and our ability to carry out our financial strategy.

We rely on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. Market disruptions such as those experienced in 2008 and 2009 in the United States and abroad may increase our cost of borrowing or adversely affect our ability to access sources of liquidity needed to finance our operations and satisfy our obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties we do business with, unprecedented volatility in the markets where our outstanding securities trade, and general economic downturns in our utility service territories. If we are unable to access credit at competitive rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our short-term obligations, and execute our financial strategy could be adversely affected.

- Changing market conditions could negatively affect the market value of assets held in our pension and other retiree plans and may increase the amount and accelerate the timing of required future funding contributions.

Plant closings or changes in power flows into our service territory could require us to redeem or defease some or all of the tax-exempt bonds issued for our benefit. This could result in increased financing costs.

TEP has financed a substantial portion of utility plant assets with the proceeds of pollution control revenue bonds and industrial development revenue bonds issued by governmental authorities. Interest on these bonds is, subject to certain exceptions, excluded from gross income for federal tax purposes. This tax-exempt status is based, in part, on continued use of the assets for pollution control purposes or the local furnishing of energy within TEP's two-county retail service area.

As of December 31, 2015, there were outstanding approximately $309 million aggregate principal amount of tax-exempt bonds that financed pollution control facilities at TEP's generating units. Should certain of TEP's generating units be retired and dismantled prior to the stated maturity dates of the related tax-exempt bonds, it is possible that some or all of the bonds financing such facilities would be subject to mandatory early redemption by TEP. Of the total amount outstanding, $37 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $272 million principal amount of the bonds have early redemption dates or final maturities ranging from 2019 to 2022.

In addition, as of December 31, 2015, there were outstanding approximately $307 million aggregate principal amount of tax-exempt bonds that financed local furnishing facilities. Depending on changes that may occur to the regional generation mix in the desert southwest, to the regional bulk transmission network, or to the demand for retail energy in TEP's local service area, it is possible that TEP would no longer qualify as a local furnisher of energy within the meaning of the Internal Revenue Code. In recent years, reductions in retail demand in the winter months have made it increasingly difficult for TEP to continue to qualify as a local furnisher of electricity. If TEP could no longer qualify as a local furnisher of energy, all of TEP's tax-exempt local furnishing bonds would be subject to mandatory early redemption by TEP or defeasance to the earliest possible redemption date. Of the total tax-exempt local furnishing bonds outstanding, $100 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $207 million principal amount of the bonds have early redemption dates ranging from 2020 to 2023.

TEP's net income and cash flows can be adversely affected by rising interest rates.

At December 31, 2015, TEP had $137 million of tax-exempt variable rate debt obligations. The interest rates are set weekly or monthly. The average weekly interest rates (including Letters of Credit (LOCs) and remarketing fees) ranged from 0.93% - 1.42% in 2015. The average monthly interest rates ranged from 0.79% - 0.87%. A 100 basis point increase in the average interest rates on this debt over a twelve-month period would increase TEP's interest expense by approximately $1 million.

TEP is also subject to risk resulting from changes in the interest rate on its borrowings under the 2015 Credit Agreement. Such borrowings may be made on a spread over London Interbank Offer Rate (LIBOR) or an Alternate Base Rate.

If short-term interest rates rise, the resulting increase in the cost of variable rate borrowings would negatively impact our results of operations, net income, and cash flows. Likewise, if capital market conditions result in higher long-term interest rates, TEP's borrowing costs would increase on any new long-term debt needed to finance capital expenditures or to refinance existing long-term debt.

OPERATIONAL

The operation of electric generating stations, and transmission and distribution systems, involves risks that could result in reduced generating capability or unplanned outages that could adversely affect TEP's results of operations, net income, and cash flows.

The operation of electric generating stations, and transmission and distribution systems, involves certain risks, including equipment breakdown or failure, fires, weather, and other hazards, interruption of fuel supply, and lower than expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of our business. If TEP's generating stations and transmission and distribution systems operate below expectations, TEP's operating results could be adversely affected and/or TEP's capital spending could be increased.

TEP receives power from certain generating facilities that are jointly owned and operated by third parties. Therefore, TEP may not have the ability to affect the management or operations at such facilities which could adversely affect TEP's results of operations, net income, and cash flows.

Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities. As a result of this reliance on other operators, TEP may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed in the face of requirements relating to environmental compliance which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP.

We may be subject to physical attacks.

As operators of critical energy infrastructure, we may face a heightened risk of physical attacks on our electric systems. Our electric generation, transmission, and distribution assets and systems are geographically dispersed and are often in rural or unpopulated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks.

If, despite our security measures, a significant physical attack occurred, we could have our operations disrupted, property damaged, experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

We may be subject to cyber attacks.

We may face a heightened risk of cyber attacks. Our information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. Our operations technology systems have direct control over certain aspects of the electric system and, in addition, our utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business.

If, despite our security measures, a significant cyber breach occurred, we could have our operations disrupted, property damaged, and customer information stolen; experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Transmission facilities owned by TEP and by third parties are located in Arizona and New Mexico and transmit the output from TEP's electric generating stations at Four Corners, Navajo, San Juan, Springerville, Gila River, and Luna to the Tucson area for use by TEP's retail customers. The transmission system is interconnected at various points in Arizona and New Mexico with other regional utilities. See *Part I, Item 1. Business, General* for additional information regarding the transmission facilities.

TEP's electric generating stations (except as noted below), administrative headquarters, warehouses and service centers are located on land owned by TEP. The electric distribution and transmission facilities owned by TEP are located:

- on property owned by TEP;
- under or over streets, alleys, highways, and other places in the public domain, as well as in national forests and state lands, under franchises, easements, or other rights which are generally subject to termination;
- under or over private property as a result of easements obtained primarily from the record holder of title; or
- over American Indian reservations under grant of easement by the Secretary of the Interior or lease by American Indian tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or liens existing at the time the easements were acquired.

Springerville is located on property held by TEP under a term patent with the State of Arizona. TEP, under separate sale and leaseback arrangements, leases a 50% undivided interest in the Springerville Common Facilities (which do not include land).

Four Corners and Navajo are located on properties held under easements from the United States and under leases from the Navajo Nation. TEP, individually and in conjunction with PNM in connection with San Juan, has acquired land rights, easements and leases for the plant, transmission lines and a water diversion facility located on land owned by the Navajo

Nation. TEP also has acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo located on reservation lands of the Zuni, Navajo, and Tohono O'odham Nations. TEP, in conjunction with PNM and Samchully Power & Utilities 1 LLC, holds an undivided ownership interest in the property on which Luna is located.

TEP's rights under these various easements and leases may be subject to defects such as:

- possible conflicting grants or encumbrances due to the absence of, or inadequacies in, the recording laws or record systems of the Bureau of Indian Affairs (BIA) and the American Indian tribes;
- possible inability of TEP to legally enforce its rights against adverse claimants and the American Indian tribes without Congressional consent; or
- failure or inability of the American Indian tribes to protect TEP's interests in the easements and leases from disruption by the U.S. Congress, Secretary of the Interior, or other adverse claimants.

These possible defects have not interfered, and are not expected to materially interfere, with TEP's interest in and operation of its facilities.

Under separate ground lease agreements, TEP leased parcels of land for the following photovoltaic facilities:

- The Solar Zone of the University of Arizona Tech Park in Pima County, Arizona; and
- Bright Tucson Community Solar Blocks in Pima County, Arizona.

In December 2014, TEP placed in service an additional photovoltaic facility in Cochise County, Arizona, for which TEP entered into a 30-year easement agreement. The easement is to facilitate the operations of a solar photovoltaic renewable energy generation system on behalf of the Department of the Army, located at Fort Huachuca in Cochise County.

See *Item 1. Business, General* for additional information regarding generating facilities.

ITEM 3. LEGAL PROCEEDINGS

Springerville Unit 1 Proceedings

Upon the termination of the Springerville Unit 1 Leases on January 1, 2015, 50.5% of Springerville Unit 1, or 195 MW of capacity, continued to be owned by third parties, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). TEP is not obligated to purchase any of the Third-Party Owners' Springerville Unit 1 power.

Commencing on January 1, 2015, with the termination of the leases, TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. In 2014, TEP and the Third-Party Owners engaged in discussions regarding the post-lease operation of Springerville Unit 1 and related cost sharing arrangements, but did not reach agreement on several key points.

In November 2014, the Springerville Unit 1 Third-Party Owners filed a complaint (FERC Action) against TEP at the FERC alleging that TEP had not agreed to wheel power and energy for the Third-Party Owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the Third-Party Owners and for the cost specified by the Third-Party Owners. The Third-Party Owners requested an order from the FERC requiring such wheeling of the Third-Party Owners' energy from their Springerville Unit 1 interests beginning in January 2015 to the Palo Verde switchyard and for the price specified by the Third-Party Owners. In February 2015, the FERC issued an order denying the Third-Party Owners complaint. In March 2015, the Third-Party Owners filed a request for rehearing in the FERC Action, which the FERC denied in October 2015. In December 2015, the Third-Party Owners appealed the FERC's order denying the Third-Party Owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015, TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

On December 19, 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged, and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners' claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015, the Third-Party Owners filed a motion for summary judgment on their claim that TEP has failed to pay certain of the Third-Party Owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent a notice to TEP that alleged that TEP had defaulted under the Third-Party Owners' leases. The notices demanded that TEP pay liquidated damages totaling approximately $71 million. In letters to the Owner Trustees, TEP denied the allegations in the notices.

In April 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners' fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. The arbitration hearing is scheduled for July 2016.

In November 2015, TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming the Owner Trustee and Co-Trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015, the Owner Trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners and to vigorously pursue the claims it has asserted against the Owner Trustees and Co-Trustees.

TEP and the Third-Party Owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations* for additional information regarding Springerville Unit 1.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

TEP's common stock is wholly-owned by UNS Energy and is not listed for trading on any stock exchange.

Dividends

TEP paid dividends to UNS Energy of $50 million in 2015 and $40 million in 2014 and 2013.

TEP can pay dividends if it maintains compliance with its 2015 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement which all contain substantially the same financial covenants. At December 31, 2015, TEP was in compliance with the terms of all financial covenants and agreements.

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP's dividend payments were still restricted as the 50 percent of total capital threshold had not yet been reached.

ITEM 6. SELECTED FINANCIAL DATA

(in thousands)	2015	2014	2013	2012	2011
Income Statement Data					
Operating Revenues	**$ 1,306,544**	$ 1,269,901	$ 1,196,690	$ 1,161,660	$ 1,156,386
Net Income	**127,794**	102,338	101,342	65,470	85,334
Balance Sheet Data					
Total Utility Plant, Net	**$ 3,558,229**	$ 3,425,190	$ 2,944,455	$ 2,750,421	$ 2,650,652
Total Assets (1)	**4,249,478**	4,119,830	3,490,085	3,413,638	3,247,647
Long-Term Debt, Net (1)	**$ 1,451,720**	$ 1,361,828	$ 1,213,367	$ 1,213,246	$ 1,072,037
Non-Current Capital Lease Obligations	**55,324**	69,438	131,370	262,138	352,720
Cash Flow Data					
Net Cash Flows From Operating Activities	**$ 364,934**	$ 313,663	$ 346,191	$ 267,919	$ 268,294
Net Cash Flows From Investing Activities	**(502,891)**	(517,638)	(259,662)	(227,881)	(312,011)
Net Cash Flows From Financing Activities	**119,471**	252,810	(140,937)	11,987	51,452
Other Data					
Ratio of Earnings to Fixed Charges (2)	**3.74**	2.56	2.67	2.10	2.40

(1) Total Assets and Long-term Debt, Net were adjusted to reflect the reclassifications made as a result of the recently adopted accounting pronouncements. See Note 1 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding recently adopted accounting pronouncements.

(2) For purposes of this computation, earnings are defined as pre-tax earnings from continuing operations before minority interest, or income/loss from equity method investments, plus interest expense and amortization of debt discount and expense related to indebtedness. Fixed charges are interest expense, including amortization of debt discount, interest on operating lease payments, and expense on indebtedness, including capital lease obligations.

See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* for additional information.

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

Management's Discussion and Analysis explains the results of operations, the general financial condition, and the outlook for TEP. It includes the following:

- outlook and strategies;
- operating results during 2015 compared with the same periods of 2014, and 2014 compared with 2013;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

Management's Discussion and Analysis includes financial information prepared in accordance with Generally Accepted Accounting Principles in the United States of America (GAAP), as well as certain non-GAAP financial measures. The non-GAAP financial measures should be viewed as a supplement to, and not a substitute for, financial measures presented in accordance with GAAP. Non-GAAP financial measures as presented herein may not be comparable to similarly titled measures used by other companies.

Management's Discussion and Analysis should be read in conjunction with Item 6 of this Form 10-K and the Consolidated Financial Statements and Notes in Item 8 of this Form 10-K. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see *Forward-Looking Information* at the front of this report and *Part I, Item 1A. Risk Factors* for additional information.

References in this report to "we" and "our" are to TEP.

OUTLOOK AND STRATEGIES

TEP's financial prospects and outlook are affected by many factors including: global, national, regional, and local economic conditions; volatility in the financial markets; environmental laws and regulations; and other regulatory factors. Our plans and strategies include the following:

- Achieving a constructive outcome in our pending rate case proceeding that provides TEP recovery of its full cost of service and an opportunity to earn an appropriate return on its rate base investments, updated rates to provide more accurate price signals and a more equitable allocation of costs to TEP's customers, and enables TEP to continue to provide safe and reliable service.
- Continuing to focus on our long-term generation resource strategy, including shifting from coal to natural gas, renewables, and energy efficiency while providing rate stability for our customers, mitigating environmental impacts, complying with regulatory requirements, leveraging our existing utility infrastructure, and maintaining financial strength.
- Developing strategic responses to new environmental regulations and potential new legislation, including new carbon emission standards to reduce greenhouse gas emissions from existing power plants. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that protect the financial stability of our utility business and the interests of our customers.
- Strengthening the underlying financial condition of TEP by achieving constructive regulatory outcomes, strengthening our capital structure, sustaining our credit ratings, and promoting economic development in our service territory.
- Focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing

customer service, and maintaining a strong community presence.

2015 Operational and Financial Highlights

The year ended December 31, 2015 included the following notable items:

- In January 2015, TEP purchased an additional 24.8% undivided ownership interest in Springerville Unit 1, bringing its total ownership interest to 49.5%;
- In January 2015, TEP purchased existing unsecured tax-exempt industrial development revenue bonds in the amount of $130 million using funds borrowed from the term loan portion of the 2014 Credit Agreement;
- In February 2015, TEP issued and sold $300 million of unsecured notes;
- In April 2015, TEP purchased an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities, and in May 2015, TEP sold a 17.05% undivided ownership interest in the Springerville Coal Handling Facilities to SRP;
- In June 2015, TEP terminated the 2014 Credit Agreement;
- In June 2015, TEP received an equity contribution of $180 million from UNS Energy;
- In October 2015, TEP entered into a new unsecured credit agreement (2015 Credit Agreement) that provides for a $250 million revolving credit and letter of credit (LOC) facility. The new credit agreement matures in 2020 and replaces the 2010 Credit Agreement;
- In November 2015, TEP filed a general rate case with the ACC that requests, among other things, a Base Rate increase of $110 million. The application also requests that new rates become effective no later than January 1, 2017; and
- In December 2015, TEP completed construction and placed into service a 500-kV transmission line extending from the Pinal Central substation to TEP's Tortolita substation northwest of Tucson.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations for the years ended December 31, 2015, 2014 and 2013. The significant items affecting net income are presented on an after-tax basis.

2015 compared with 2014

TEP reported net income of $128 million in 2015 compared with $102 million in 2014. The increase of $26 million, or 25%, was primarily due to:

- $16 million in lower O&M resulting primarily from acquisition related costs and outages at Springerville Units 1 and 2 that were incurred in 2014, partially offset by higher O&M related to Gila River, labor costs, and outside services;
- $6 million in higher transmission revenue resulting primarily from an increase in sales volume on favorably priced contracts; and
- $4 million in lower interest expense primarily due to a reduction in the balance of capital lease obligations.

2014 compared with 2013

TEP reported net income of $102 million in 2014 compared with $101 million in 2013. The increase of $1 million, or 1%, was primarily due to:

- $25 million in higher revenues including a non-fuel Base Rate increase that was effective on July 1, 2013, an increase in LFCR revenues, higher long-term wholesale revenues due in part to an increase in the average market price and higher transmission revenue; and

- $7 million in lower interest expense, primarily due to a reduction in the balance of capital lease obligations.

The increase was partially offset by:

- $22 million in higher O&M for acquisition related costs, higher generating plant maintenance expense, and increased rent expense associated with the Navajo lease amendment;

- $5 million in higher income taxes primarily generated by a non-recurring $11 million tax benefit recorded in June 2013 to recover previously recorded income tax expense as a result of the 2013 TEP Rate Order. This amount is partially offset by a $2 million increase in the valuation allowance in 2013 and a $3 million increase in investment tax credits recorded in 2014. See Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes; and
- $4 million in higher depreciation and amortization expenses, resulting primarily from an increase in asset base in the current year.

Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data during 2015, 2014 and 2013:

	Year Ended 2015	Year Ended 2014	Increase (Decrease) Percent(1)	Year Ended 2013	Increase (Decrease) Percent(1)
Electric Retail Sales (kWh in millions)					
Residential	3,724	3,727	(0.1)%	3,867	(3.6)%
Commercial	2,124	2,170	(2.1)%	2,187	(0.8)%
Industrial	2,063	2,098	(1.7)%	2,114	(0.8)%
Mining	1,109	1,137	(2.5)%	1,079	5.4 %
Public Authorities	33	33	— %	32	3.1 %
Total Electric Retail Sales	9,053	9,165	(1.2)%	9,279	(1.2)%
Retail Margin Revenues (in millions)					
Residential	$ 281	$ 280	0.4 %	$ 271	3.3 %
Commercial	185	188	(1.6)%	181	3.9 %
Industrial	103	104	(1.0)%	97	7.2 %
Mining	38	38	— %	34	11.8 %
Public Authorities	2	2	— %	2	— %
Total by Customer Class	609	612	(0.5)%	585	4.6 %
LFCR Revenues	12	11	9.1 %	2	*
DSM Performance Bonus	3	2	50.0 %	1	100.0 %
Other Retail Margin Revenues	5	1	*	—	*
Total Retail Margin Revenues (Non-GAAP) (1)	629	626	0.5 %	588	6.5 %
Fuel and Purchased Power Revenues	344	303	13.5 %	300	1.0 %
DSM and RES Surcharge Revenues	49	41	19.5 %	46	(10.9)%
Total Retail Revenues (GAAP)	$ 1,022	$ 970	5.4 %	$ 934	3.9 %
Average Retail Margin Rate (Cents / kWh) (2)					
Residential	7.55	7.51	0.5 %	7.02	7.0 %
Commercial	8.71	8.66	0.6 %	8.28	4.6 %
Industrial	4.99	4.96	0.6 %	4.61	7.6 %
Mining	3.43	3.34	2.7 %	3.14	6.4 %
Public Authorities	5.61	6.06	(7.4)%	5.56	9.0 %
Total Average Margin Rate by Customer Class	6.73	6.68	0.7 %	6.30	6.0 %
Total Average Retail Margin Rate (3)	6.95	6.80	2.2 %	6.31	7.8 %
Average Fuel and Purchased Power Rate	3.80	3.31	14.8 %	3.24	2.2 %
Average DSM and RES Rate	0.54	0.48	12.5 %	0.52	(7.7)%
Total Average Retail Rate	11.29	10.59	6.6 %	10.07	5.2 %
Weather Data					
Cooling Degree Days					
Year Ended December 31,	1,576	1,557	1.2 %	1,631	(4.5)%
10-Year Average	1,520	1,515	*	1,491	*

Heating Degree Days					
Year Ended December 31,	1,072	930	15.3 %	1,449	(35.8)%
10-Year Average	1,317	1,335	*	1,404	*

* Not meaningful

(1) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are

directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales, LFCR Revenues, DSM Performance Bonus, and certain other retail margin revenues available to cover the non-fuel operating expenses of our core utility business.

(2) Calculated on un-rounded data and may not correspond exactly to data shown in table.

(3) Total Average Retail Margins Rates include revenues related to LFCR Revenues, DSM Performance Bonus, and Other Retail Margin Revenues included in the Total Retail Margin Revenues.

Retail Revenues were higher in 2015 compared with 2014 primarily due to the increase in the PPFAC rate and higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to higher LFCR revenues, DSM Performance Bonus, and Other Retail Margin Revenues related to adjustor mechanisms.

Retail Revenues were higher in 2014 compared with 2013 primarily due to higher Retail Margin Revenues and increased LFCR revenues. The increase in Retail Margin Revenues resulted from a non-fuel Base Rate increase effective July 1, 2013. These increases were partially offset by lower sales volume due to milder weather.

Wholesale Sales and Transmission Revenues

	Year Ended December 31,		
(in millions)	2015	2014	2013
Long-Term Wholesale Revenues	$ 36	$ 28	$ 26
Transmission Revenues	27	16	15
Short-Term Wholesale Revenues	104	114	92
Total Electric Wholesale Sales	$ 167	$ 158	$ 133

Long-Term Wholesale Revenues increased by $8 million, or 29%, in 2015 compared with 2014 primarily due to new wholesale agreements partially offset by unfavorable wholesale market prices. Transmission Revenues increased by $11 million, or 69%, in 2015 compared with 2014 primarily due to a new long-term transmission agreement with UNS Electric related to Gila River and contract renewals resulting in favorable pricing.

Long-Term Wholesale Revenues increased by $2 million, or 8%, in 2014 compared with 2013 primarily due to favorable market prices for wholesale power. There were no significant changes in transmission revenues in 2014 compared to 2013.

The majority of revenues from short-term wholesale sales are related to ACC jurisdictional assets and are credited against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

	Year Ended December 31,		
(in millions)	2015	2014	2013
Springerville Units 3 and 4 Revenue (1)	$ 91	$ 112	$ 102
Other Revenue	27	29	28
Total Other Revenue	$ 118	$ 141	$ 130

(1) Represents revenues and reimbursements from Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, to TEP related to the operation of these plants.

In addition to reimbursements related to Springerville Units 3 and 4, TEP's other revenues include inter-company revenues from its affiliates, UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy, (UNS Gas) and UNS Electric, for corporate services provided by TEP, and miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees. See Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding related party transactions.

There were no significant changes in Other Revenue in 2015 compared with 2014, as well as no significant changes in Other Revenue in 2014 compared with 2013.

Operating Expenses

Generating Output and Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources for 2015, 2014, and 2013 are detailed below:

	Generation and Purchased Power (kWh)			Fuel and Purchased Power Expense		
(in millions)	2015	2014	2013	2015	2014	2013
Coal-Fired Generation	8,584	9,271	10,254	$ 209	$ 232	$ 273
Gas-Fired Generation	2,723	1,210	1,007	91	60	46
Utility Owned Renewable Generation	65	48	38	—	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4 (1)	—	—	—	5	5	7
Total Generation	11,372	10,529	11,299	305	297	326
Total Purchased Power	3,079	3,195	2,329	125	153	112
Transmission and Other PPFAC Recoverable Costs	—	—	—	25	18	12
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	—	40	(11)	(12)
Total Generation and Purchased Power	14,451	13,724	13,628	$ 495	$ 457	$ 438
Less Line Losses and Company Use	(719)	(859)	(885)			
Total Energy Sold	13,732	12,865	12,743			

(1) Springerville Unit 3 and 4 Fuel Expense is reimbursed by Tri-State and SRP.

Fuel and Purchased Power Expense increased by $38 million, or 8%, in 2015 compared with 2014 primarily due to an increase in the PPFAC charge and additional generation and transmission costs associated with Gila River Unit 3. The increase was partially offset by favorable purchased power costs (see table below) and decreased coal generation at Springerville Unit 1 as a result of the lease expiration in January 2015.

Fuel and Purchased Power Expense increased by $19 million, or 4%, in 2014 compared with 2013 primarily due to the increase in purchased power volumes resulting from outages at Springerville and Sundt generating stations in 2014. The increase was partially offset by a decrease in generation expense as a result of the outages.

See the table below for information on the average fuel cost of generated and purchased kWh:

(cents per kWh)	2015	2014	2013
Coal	2.44	2.50	2.66
Gas	3.35	4.99	4.57
Purchased Power	4.05	4.79	4.83
All Sources	3.31	3.64	3.54

Operations and Maintenance Expense

The table below summarizes the items included in Operations and Maintenance (O&M) expense:

(in millions)	2015	2014	2013
Reimbursed Expenses - Springerville Units 3 and 4 (1)	$ 65	$ 84	$ 70
Reimbursed Expenses - Customer Funded Renewable Energy and DSM Programs (2)	25	23	26
Other Operating and Maintenance Expense (3)	255	272	239

Total Operations and Maintenance Expense	$ 345	$ 379	$ 335

(1) Expenses related to Springerville Units 3 and 4 are reimbursed with corresponding amounts recorded in other revenue.

(2) These expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

(3) The Third-Party Owners' share of expenses related to Springerville Unit 1 is included in Other Operating and Maintenance Expense.

Operating and Maintenance expenses decreased by $34 million, or 9%, in 2015 compared with 2014. Springerville Units 3 and 4 expenses, which are reimbursed by third party owners, decreased primarily due to outages incurred in 2014. Other Operating and Maintenance Expense decreased primarily due to acquisition related costs and outages at Springerville Units 1 and 2 that occurred in 2014, partially offset by higher O&M related to Gila River, labor costs and outside services.

Operating and Maintenance expenses increased by $44 million, or 13%, in 2014 compared with 2013. Springerville Units 3 and 4 expenses, which are reimbursed by third party owners, increased primarily due to outages incurred in 2014. Other Operating and Maintenance Expense increased primarily due to acquisition related costs and outages at Springerville Units 1 and 2 that occurred in 2014.

FACTORS AFFECTING RESULTS OF OPERATIONS

2015 Rate Case

In November 2015, TEP filed a general rate case with the ACC to: (i) update and improve its rate design and tariffs to provide more accurate price signals and a more equitable allocation of its fixed costs to its customers; (ii) provide TEP with an opportunity to recover its full cost of service, including an appropriate return on its rate base investments; and (iii) enable TEP to continue to provide safe and reliable service. The rate application is based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

The key provisions of the rate case include:

- a Base Rate increase of $110 million, or 12%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion;
- a capital structure for rate making purposes of approximately 50% common equity and 50% long-term debt;
- a cost of equity of 10.35% and an average cost of debt of 4.32%;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of San Juan Unit 2 and the Sundt Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Springerville Unit 1 that is available to TEP for dispatch to serve retail customer needs and to recover the related operating costs through the PPFAC; and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

TEP cannot predict the outcome of this proceeding or whether its rate request will be adopted by the ACC in whole or in part.

Generating Resources

At December 31, 2015, approximately 49% of TEP's generating capacity was fueled by coal. Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal generation.

In August 2015, TEP exhausted its existing coal supply at Unit 4 of the H. Wilson Sundt Generating Station (Sundt Unit 4). Currently, TEP is operating Sundt Unit 4 on natural gas as a primary fuel source.

TEP's ability to further reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- The impact of the Clean Power Plan on current coal-fired generating facilities; and
- The ability to resolve Springerville Unit 1 legal proceedings relating to the Third-Party Owners.

See *Part I, Item 1. Business, General* for additional information regarding TEP's generating facilities.

Springerville Unit 1

TEP leased Unit 1 of the Springerville Generating Station and an undivided one-half interest in certain Springerville Common Facilities (collectively Springerville Unit 1) under seven separate lease agreements (Springerville Unit 1 Leases) that were accounted for as capital leases. The leases expired in January 2015. At that time, TEP purchased a leased interest comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million. Following this purchase, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity.

The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, is owned by Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). TEP is not obligated to purchase any of the Third-Party Owners' generating output. TEP is obligated to operate the unit for the Third-Party Owners. Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses for the unit. TEP estimates the Third-Party Owners' share of 2016 operations and maintenance expense will be $27 million and their estimated share of 2016 capital expenditures will be $9 million.

In April 2015, TEP filed a demand for arbitration seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expense and capital expenditures for Springerville Unit 1. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and *Part I, Item 3. Legal Proceedings* for additional information regarding the legal proceedings relating to the Third-Party Owners.

Potential Plant Retirements

TEP's 2014 Integrated Resource Plan (IRP), which was acknowledged by the ACC in April 2015, reflected plans to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) by 2018. TEP's 2014 IRP included retiring certain coal-fired generating facilities at San Juan Generating Station (San Juan) and coal handling facilities at the H. Wilson Sundt Generating Station (Sundt) earlier than their current estimated useful lives. These facilities currently do not have the requisite emission control equipment to meet proposed Environmental Protection Agency (EPA) regulations. TEP plans to seek regulatory recovery for amounts that would not otherwise be recovered if and when any assets are retired. TEP plans to file a preliminary IRP in March 2016 and is required to file its next IRP by April 2017.

See *Part I, Item 1. Business, Environmental Matters* for additional information regarding the impact of environmental matters on plant operations.

Springerville Coal Handling Facilities Capital Lease Purchase

TEP previously leased interests in the coal handling facilities at the Springerville Generating Station (Springerville Coal Handling Facilities) under two separate lease agreements (Springerville Coal Handling Facilities Leases). The lease agreements had an initial term that expired in April 2015 and provided TEP the option to renew the leases or to purchase the leased interests at the aggregate fixed price of $120 million. In April 2015, TEP exercised its option to purchase the facilities.

Upon the expiration of the lease term, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities bringing TEP's total ownership interest to 100%. With the completion of the purchase, SRP was obligated to buy a 17.05% undivided interest in the Springerville Coal Handling Facilities from TEP for approximately $24 million. This transaction was completed in May 2015. Tri-State, is obligated to either: 1) buy a 17.05% undivided interest in the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option.

Sales to Mining Customers

TEP's largest mining customer is taking initial steps to curtail production in 2016 due to the decline in commodity prices. TEP cannot predict the extent to which this customer will curtail production, how long commodity prices will remain low, or the total impact the prices will have on mining production in the future. At December 31, 2015, mining customers made up 8% of TEP's total electric sales.

The proposed Rosemont Copper Mine near Tucson, Arizona is in the permitting stage. If the Rosemont Copper Mine is constructed and reaches full production, it will become TEP's largest retail customer with an estimated load of approximately 85 to 120 MW.

Interest Rates

See *Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk* for information regarding interest rate risks and its impact on earnings.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

Cash flows may vary during the year, with cash flows from operations typically the lowest in the first quarter and highest in the third quarter due to TEP's summer peaking load. As a result of the varied seasonal cash flow, we will use, as needed, our revolving credit facility to assist in funding business activities. We believe that we have sufficient liquidity under our revolving credit facilities to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements.

Available Liquidity

(in millions)	As of December 31, 2015	
Cash and Cash Equivalents	$	56
Amount Available under Revolving Credit Facility (1)		250
Total Liquidity	$	306

(1) TEP's revolving credit facility, which matures in 2020, provides for a $250 million revolving credit commitment with a LOC sublimit of $50 million.

Future Liquidity Requirements

We expect to meet all of our financial obligations and other anticipated cash outflows for the foreseeable future. These obligations and anticipated cash outflows include, but are not limited to, dividend payments, debt maturities, and obligations included in the *Contractual Obligations* and forecasted *Capital Expenditures* tables below.

See *Part III, Item 7A. Quantitative and Qualitative Disclosures about Market Risk* for additional information regarding TEP's market risks and Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding TEP's financing arrangements.

Summary of Cash Flow

The table below presents net cash provided by (used for) operating, investing and financing activities:

	Year Ended		Increase (Decrease)	Year Ended	Increase (Decrease)
(in millions)	2015	2014	Percent	2013	Percent
Operating Activities	$ 365	$ 314	16.2 %	$ 346	(9.2)%
Investing Activities	(503)	(518)	(2.9)%	(260)	99.2 %
Financing Activities	120	253	(52.6)%	(141)	279.4 %
Net Increase (Decrease) in Cash	(18)	49	(136.7)%	(55)	189.1 %
Cash, Beginning of Year	74	25	196.0 %	80	(68.8)%
Cash, End of Year	$ 56	$ 74	(24.3)%	$ 25	196.0 %

Cash Flows for both 2015 and 2014 included unusually large capital expenditures. These capital requirements were met with a combination of equity contributions from UNS Energy and long-term borrowings as discussed in *Financing Activities* below.

In 2015, we issued long-term debt and used the proceeds to repay revolving and term loans under our credit agreements and pay a portion of the purchase price for interests in the Springerville Coal Handling Facilities. In addition, we received an equity contribution from UNS Energy and used the proceeds to repay the outstanding balances under our revolving credit facilities and redeem long-term variable rate tax-exempt bonds which were called for redemption in June 2015.

In 2014, we received an equity contribution from UNS Energy and used the proceeds to pay for the purchase of both Gila River Unit 3 and Springerville Unit 1 leased assets.

Operating Activities

2015 compared with 2014

In 2015, net cash flows from operating activities increased by $51 million compared to 2014 primarily due to:

- $39 million of higher cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid driven primarily by an increase in the average PPFAC rate; and
- $34 million in lower cash paid for acquisition-related costs and incentive compensation primarily due to the 2014 acquisition.

The increase in net cash flows from operating activities was partially offset by $16 million of higher cash paid for pension and retiree funding.

2014 compared with 2013

In 2014, net cash flows from operating activities decreased by $32 million compared to 2013 primarily due to:

- $27 million of higher cash paid for acquisition-related costs and incentive compensation primarily due to the 2014 acquisition; and
- $6 million of higher cash paid for capital lease interest.

Investing Activities

2015 compared with 2014

In 2015, net cash flows used for investing activities decreased by $15 million compared with 2014 primarily due to:

- $164 million purchase, in December 2014, of a 75% interest in Gila River Unit 3; and
- $20 million purchase, in December 2014, of a 10.6% interest in Springerville Unit 1.

The decrease in net cash flows used for investing activities was partially offset by:

- $120 million purchase, in April 2015, of an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities partially offset by $24 million of cash received for the sale, in May 2015, of a 17.05% undivided ownership interest in the Springerville Coal Handling Facilities to SRP;
- $46 million purchase, in January 2015, of an additional 24.8% undivided ownership interest in Springerville Unit 1 increasing our total ownership interest to 49.5%;
- $11 million in lower cash receipts for contributions in aid of construction received; and
- $10 million of higher capital expenditures to fund system reinforcement through replacements and betterments.

2014 compared with 2013

In 2014, net cash flows used for investing activities increased by $258 million compared with 2013 primarily due to:

- $164 million purchase, in December 2014, of a 75% interest in Gila River Unit 3;

- $71 million of higher capital expenditures to fund the construction of new solar projects and improvements to our generating facilities; and
- $20 million purchase, in December 2014, of a 10.6% interest in Springerville Unit 1.

Financing Activities

2015 compared with 2014

In 2015, net cash flows from financing activities decreased by $133 million compared with 2014 primarily due to:

- $209 million in higher cash payments due to the purchase of $130 million in fixed rate tax-exempt long-term debt in January 2015, and the retirement of $79 million in variable rate tax-exempt bonds in August 2015;
- $170 million in lower proceeds borrowed and higher repayments under TEP's revolving credit facilities;
- $45 million in lower cash proceeds from UNS Energy's equity contributions; and
- $10 million in higher cash dividend payments.

The decrease in net cash flows from financing activities was partially offset by:

- $152 million in lower cash payments due to the expiration of capital lease obligations in 2015; and
- $150 million in higher cash proceeds from the issuance of long-term debt, in February 2015.

2014 compared with 2013

In 2014, net cash flows from financing activities increased by $394 million compared with 2013 primarily due to:

- $225 million in higher cash proceeds from UNS Energy's equity contributions made to complete the purchases for interest in Gila River Unit 3 and Springerville Unit 1;
- $149 million in higher cash proceeds from the issuance of long-term debt; and
- $85 million in higher cash borrowings (net of repayments) under TEP's revolving credit facilities.

The increase in net cash flows from financing activities was partially offset by $66 million in higher cash payments of capital lease obligations.

External Sources of Liquidity

Short-Term Investments

TEP's short-term investment policy governs the investment of excess cash balances. We regularly review and update this policy in response to market conditions. At December 31, 2015, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facilities

We have access to working capital through a revolving credit agreement with lenders. The 2015 Credit Agreement provides for a $250 million revolving credit commitment and LOC facility, due in October 2020. The LOC sublimit is $50 million. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. No amounts were drawn under the 2015 Credit Agreement at December 31, 2015.

In June 2015, the 2014 Credit Agreement was terminated. In October 2015, the 2010 Credit Agreement was terminated.

For details on TEP's credit facilities see Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Debt Financing

We use debt financing to lower our overall cost of capital. We are exposed to adverse changes in interest rates to the extent that we rely on variable rate financing. Our cost of capital is also affected by our credit ratings

In April 2015, we filed a financing application with the ACC. The application requests extending and expanding the existing financing authority to TEP by: (i) extending authority from December 2016 to December 2020; (ii) increasing the outstanding long-term debt limitation from $1.7 billion to $2.2 billion; (iii) allowing parent equity contributions of up to $400 million; and (iv) extending current interest rate hedging authority. The ACC issued an order granting such authority in January 2016.

As discussed in *Part I, Item 1A. Risk Factors* of this Form 10-K, we may need to redeem or defease certain tax-exempt bonds outstanding. To the extent that is required, we would need to issue new taxable debt or enter into a new bank financing.

We have no new financing planned for 2016. TEP has, from time to time, refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, TEP may refinance other debt issuances or make additional debt repurchases in the future. For details on changes to or maturities on long-term debt, see Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Debt Restrictive Covenants

The 2015 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain pricing based on TEP's credit ratings. A change in TEP's credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments. Also, under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. At December 31, 2015, TEP was in compliance with these covenants.

TEP conducts its wholesale marketing and risk management activities under certain master agreements whereby TEP may be required to post credit enhancements in the form of cash or a LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, a change in TEP's credit ratings, or if there has been a material change in TEP's creditworthiness. As of December 31, 2015, TEP had posted less than $1 million in LOCs for credit enhancement with wholesale counterparties.

We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.

Credit Ratings

Our credit ratings affect our access to capital markets and supplemental bank financing. At December 31, 2015, TEP's credit ratings for senior unsecured debt were A3 from Moody's and BBB+ from both Standard & Poor's and Fitch. As of February 2016, at TEP's request for commercial reasons, Fitch withdrew its rating on TEP.

TEP's credit ratings are dependent on a number of factors, both quantitative and qualitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell, or hold TEP securities. Each rating should be evaluated independently of any other ratings.

Dividends

TEP declared and paid $50 million in dividends to UNS Energy in 2015 and $40 million in 2014 and 2013.

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP had not yet reached the 50 percent of total capital and was therefore still restricted by the condition contained in the ACC's approval order.

Capital Expenditures

TEP's routine capital expenditures include funds used for system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. In 2015, total capital expenditures of $500 million, included the purchase of an undivided ownership interest in Springerville Unit 1 and the remaining ownership interest in the Springerville Coal Handling facilities. In 2014, total capital expenditures of $507 million, included the purchase of interest in Gila River Unit 3 and an undivided ownership interest in Springerville Unit 1. Construction for a new 500-kilovolt (kV) transmission line in Pinal County that began in December 2014 and concluded in late 2015, totaled $79 million.

With the exception of 2017, we expect capital requirements to remain stable from 2016 through 2020. TEP's forecasted capital expenditures are summarized below:

(in millions)	2016	2017	2018	2019	2020
Generation Facilities:					
Environmental Compliance	$ 39	$ 27	$ 11	$ 2	$ 2
Renewable Energy	27	27	27	27	27
Springerville Common Lease Purchase	—	38	—	—	—
Other Generation Facilities	34	82	31	36	39
Total Generation Facilities	100	174	69	65	68
Transmission and Distribution	122	112	159	154	163
General and Other (1)	52	46	56	57	54
Total Capital Expenditures	$ 274	$ 332	$ 284	$ 276	$ 285

(1) General and Other primarily includes cost for information technology as well as fleet, facilities and communication equipment.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors. We expect to pay for forecasted capital expenditures with cash on hand, internally generated funds, and short-term revolver borrowings.

Contractual Obligations

The following chart displays TEP's contractual obligations by maturity and by type of obligation as of December 31, 2015:

		Payments Due by Period			
(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt					
Principal (1)	$ 1,466	$ —	$ 100	$ 117	$ 1,249
Interest (2)	769	59	120	116	474
Capital Lease Obligations (3)	77	17	30	30	—
Operating Leases: (4)					
Land Easements and Rights-of-Way	82	1	2	2	77
Operating Leases Other	9	1	2	2	4
Purchase Obligations:					
Fuel, Including Transportation (5)(6)	580	78	125	90	287
Purchased Power	28	28	—	—	—
Transmission	38	6	12	7	13
Renewable Purchase Power Agreements (7)(8)	1,054	61	122	121	750
RES Performance-Based Incentives (9)	107	8	16	16	67
Acquisition of Springerville Common Facilities (10)	106	—	38	—	68
Other Long-Term Liabilities: (11) (12)					
Restricted and Performance-Based Stock Units	2	—	2	—	—
Pension & Other Post Retirement Obligations (13)	77	16	11	13	37
Total Contractual Obligations	$ 4,395	$ 275	$ 580	$ 514	$ 3,026

(1) $37 million of TEP's variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of

such bond in 2019 as though the LOC terminates without replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate IDRBs, which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in 2018. Total long-term debt is not reduced by $11 million of related unamortized debt issuance costs or $3 million of unamortized original issue discount.

(2) Excludes interest on revolving credit facilities and includes interest on TEP's 2013 tax-exempt IDRBs through the end of the current five-year term.

(3) Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP began reimbursing TEP for various operating costs related to the common facilities on an ongoing basis. The common facilities included assets leased by TEP under the Springerville Common and Springerville Coal Handling Facilities Leases. Upon expiration of the Springerville Coal Handling Lease in April 2015, TEP purchased the interests in those assets. SRP then purchased an undivided interest in those coal handling assets from TEP. Tri-State and SRP each continue to reimburse TEP for their shares of common assets owned or leased by TEP. TEP was reimbursed for $11 million of operation costs in 2015, and absent a purchase of an interest in the coal handling facilities by Tri-State, will be reimbursed $10 million of operation costs in 2016. Capital Lease Obligations do not reflect any reduction associated with this reimbursement. Our capital lease obligation balances decline over time as scheduled capital lease payments are made by TEP.

(4) TEP's operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates.

(5) Contemporaneously with the sale of SJCC's stock in January 2016, the existing coal sale agreement terminated and a new Coal Supply Agreement (CSA) became effective. The new CSA is between SJCC and PNM and continues through June 30, 2022. TEP is not a party to the new CSA, but has minimum purchase obligations under restructured ownership agreements at San Juan. Estimated future payments, not included in the table above, are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

(6) Excludes TEP's liability for final environmental reclamation at the coal mines which supply the Navajo, San Juan and Four Corners generating stations as the timing of payment has not been determined. See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding TEP's share of reclamation costs.

(7) TEP enters into long-term renewable power purchase agreements which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries.

(8) In February 2016, a facility achieved commercial operation status. The related contract expires in 2036. Estimated future payments, not included in the table above, are $3 million in each of 2016 through 2020 and $43 million through the end of the contract.

(9) TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding TEP's RES tariff.

(10) The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. Instead of extending the leases, TEP may exercise its fixed-price purchase options.

(11) Excludes asset retirement obligations of $33 million expected to occur through 2066.

(12) Excludes unrecognized tax benefits of $5 million. At this time we are unable to make a reasonably reliable estimate of the timing of payments in individual years in connection with these tax liabilities.

(13) These obligations represent TEP's expected contributions to pension plans in 2016, expected benefit payments for its unfunded Supplemental Executive Retirement Plan (SERP), and expected retiree benefit costs to cover medical and life insurance claims as determined by the plans' actuaries. Due to the significant impact that returns on plan assets and changes in discount rates might have on payment obligation amounts, other contributions are excluded beyond 2016.

We expect to pay for forecasted capital expenditures with cash on hand, internally generated funds, and short-term revolver borrowings.

Off Balance Sheet Arrangements

Other than the unrecorded contractual obligations in the table above, we do not have any arrangements or relationships with entities that are not consolidated into the financial statements.

Income Tax Position

Prior year tax legislation and the Consolidated Appropriations Act of 2016, include provisions that make qualified property placed in service between 2010 and 2019 eligible for bonus depreciation for tax purposes. In addition, the IRS issued new guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions are an acceleration of tax benefits TEP otherwise would have received over 20 years and have created net operating loss carryforwards that can be used to offset future taxable income. As a result, TEP did not pay any federal or state income taxes in 2015 and does not expect to make any payments until 2020.

Environmental Matters

The EPA regulates the amount of sulfur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Complying with these changes may reduce operating efficiency. TEP capitalized $33 million in 2015, $11 million in 2014, and $5 million in 2013 in costs to comply with environmental rules and regulations. In addition, we recorded O&M expenses of $6 million in 2015, $5 million in 2014, and $8 million in 2013. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

In February 2012, the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. Based on the EPA's final Mercury and Air Toxics Standards (MATS) rules, additional emission control equipment would have been required by April 2015. TEP, as operator of the Springerville and Sundt generating stations, and the operators of Navajo and Four Corners received extensions until April 2016 to comply with the MATS rules.

In June 2015, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision in Michigan v. EPA to uphold the MATS rules requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider "cost" before determining that MATS was "appropriate and necessary." The D.C. Circuit Court of Appeals remanded the rules to the EPA for further consideration.

At this time, despite the U.S. Supreme Court ruling, the MATS rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of our facilities. Additionally, Arizona has an Arizona-specific mercury rule in place that will become effective and applicable to our Arizona facilities in the event the Federal rule is struck down. Our compliance strategy is intended to ensure compliance with both the Federal and the State rule, as applicable.

TEP's share of the estimated mercury emission control costs to comply with the MATS rules includes the following:

(in millions)	Navajo	Springerville(1)
Capital Expenditures	$ 1	$ 5
Annual O&M Expenses	$ 1	$ 1
Compliance Year	2016	2016

(1) Total capital expenditures and annual O&M expenses represent amounts for Springerville Units 1 and 2, with estimated costs split equally between the two units. In January 2015, TEP completed the purchase of 24.8% of Springerville Unit 1, bringing its total ownership interest to 49.5%. With the completion of the purchase, the Third-Party Owners are responsible for 50.5% of environmental costs attributable to Springerville Unit 1. TEP will continue to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

TEP expects no additional capital expenditures or O&M expenses will be incurred to comply with the MATS rules at Four Corners, Sundt, and San Juan Generating Stations.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as BART for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rule calls for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on land leased from the Navajo Nation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants.

In the western U.S., Regional Haze BART determinations have focused on controls for NO_x, often resulting in a requirement to install Selective Catalytic Reduction (SCR). Complying with the BART rule, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. The BART provisions do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s, after the time frame as designated by the rules. Other provisions of the

Regional Haze Rules requiring further emission reductions are not likely to impact Springerville operations until after 2018. TEP cannot predict the ultimate outcome of these matters.

TEP's estimated NO_x emissions control costs involved in meeting these rules are:

(in millions)	Navajo	San Juan	Four Corners	Sundt
Capital Expenditures	$ 28	$ 12	$ 44	$ 12
Annual O&M Expenses	$ 1	$ 1	$ 2	$ 6
Compliance Year	2030	2016	2018	2017

Navajo

In August 2014, the EPA published a final Federal Implementation Plan (FIP) which provides that one unit at Navajo will be shut down by 2020, SCR (or the equivalent) will be installed on the remaining two units by 2030, and conventional coal-fired generation will cease by December 2044. The final BART rule includes options that accommodate potential ownership changes at the plant. The plant has until December 2019 to notify the EPA of how it will comply with the FIP.

San Juan

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of Selective Non-Catalytic Reduction (SNCR) on Units 1 and 4 by February 2016. TEP owns 50% of Units 1 and 2 at San Juan. The SIP approval references a New Source Review permit issued by the New Mexico Environment Department in November 2013 which, among other things, calls for balanced draft upgrades on San Juan Unit 1 to reduce particulate matter emissions. PNM, the operator of San Juan, is currently installing SNCR. Balanced draft modifications to San Juan Unit 1were completed in June 2015. TEP's share of the balanced draft upgrades was approximately $22 million. In December 2015, PNM obtained New Mexico Public Regulation Commission approval to shut down Units 2 and 3 at San Juan.

At December 31, 2015, the net book value of TEP's share in San Juan Unit 2, including construction work in progress, was $104 million. Consistent with the 2013 Rate Order, TEP has requested authorization from the ACC to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case.

Four Corners

In December 2013, APS, on behalf of the co-owners of Four Corners, notified the EPA that they have chosen an alternative BART compliance strategy; as a result, APS closed Units 1, 2, and 3 in December 2013 and agreed to the installation of SCR on Units 4 and 5 by July 2018. TEP owns 7% of Four Corners Units 4 and 5.

Sundt

In June 2014, the EPA issued a final rule that would require TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Unit 4 of the H. Wilson Sundt Generating Station (Sundt) continues to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under the rule, TEP is required to notify the EPA of its decision by March 2017.

At December 31, 2015, the net book value of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. The estimated NO_x emissions control costs in the table above will not be expended if Sundt's coal handling facilities are retired early.

<u>Greenhouse Gas Regulation</u>

In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets CO_2 emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the

EPA by September 2016. States that receive an extension must submit a final completed plan to the EPA by September 2018. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP has submitted comments on the proposed Federal Plan impacting our facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. TEP cannot predict the ultimate outcome of these matters.

TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016, the Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP rule. TEP will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. TEP anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

<u>Coal Combustion Residuals Regulation</u>

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville Generating Station (Springerville) ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP's share of the cost at Springerville is estimated to be $2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be $5 million at Four Corners, $3 million at Navajo, and less than $1 million at San Juan, the majority of which are expected to be capital expenditures.

See *Capital Expenditures* above for TEP's actual and forecasted environmental-related cost.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with GAAP requires management to apply accounting policies and to make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements and related notes. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional information on TEP's other significant accounting policies can be found in Note 1 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for Regulated Operations

We account for our regulated electric operations based on accounting standards that allow the actions of our regulators, the ACC and the FERC, to be reflected in our financial statements. Regulator actions may cause us to capitalize certain costs that would otherwise be included as an expense, or in Accumulated Other Comprehensive Income (AOCI), in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. We evaluate regulatory assets and liabilities each period and believe future recovery or settlement is probable. Our assessment includes consideration of recent rate orders, historical regulatory treatment of similar costs, and changes in the regulatory and political environment. If management's assessment is ultimately different than actual regulatory outcomes, the impact on our results of operation, financial position, and future cash flows could be material.

At December 31, 2015, regulatory liabilities net of regulatory assets totaled $96 million at TEP. There are no current or expected proposals or changes in the regulatory environment that impact our ability to apply accounting guidance for regulated operations. If we conclude, in a future period, that our operations no longer meet the criteria in this guidance, we would reflect our regulatory pension assets in AOCI and recognize the impact of other regulatory assets and liabilities in the income statement, both of which would be material to our financial statements. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory matters.

Accounting for Asset Retirement Obligations

We are required to record the fair value of a liability for a legal obligation to retire a long-lived tangible asset in the period in which the liability is incurred. This includes obligations resulting from conditional future events. We incur legal obligations as a result of environmental regulations imposed by State and Federal regulators, contractual agreements and other factors. To estimate the liability, management must use significant judgment and assumptions in: determining whether a legal obligation exists to remove assets; estimating the probability of a future event for a conditional obligation; estimating the fair value of the cost of removal; estimating when final removal will occur; and estimating the credit-adjusted risk-free interest rates to be used to discount the future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations. TEP defers costs associated with the majority of its legal AROs as regulatory assets because these costs are included in depreciation rates approved for recovery by the ACC. Deferred costs are amortized over the life of the underlying asset.

TEP identified legal obligations to retire generation plant assets specified in land leases for its jointly-owned Navajo and Four Corners Generating Stations. The land on which these stations reside is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at expiration of the leases. TEP also has certain environmental obligations at the Luna, San Juan, Sundt and Springerville Generating Stations. TEP estimates that its share of the AROs to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt, Gila River and Springerville environmental obligations will be approximately $157 million at the retirement dates. Additionally, TEP entered into ground lease agreements with certain land owners for the installation of photovoltaic (PV) assets. The provisions of the PV ground leases require TEP to remove the PV facilities upon expiration of the leases. TEP's ARO related to the PV assets is estimated to be approximately $30 million at the retirement dates. No other legal obligations to retire generation plant assets were identified.

TEP has various transmission and distribution lines that operate under leases and rights-of-way that contain end dates and may contain site restoration clauses. TEP operates transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As such, there are no AROs for these assets.

The total net present value of TEP's ARO liability was $32 million at December 31, 2015. ARO liabilities are reported in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. See Note 3 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding AROs.

Additionally, the authorized depreciation rates for TEP include a component designed to accrue the future costs of retiring assets for which no legal obligations exist. The accumulated balances at December 31, 2015 represent non-legal asset retirement obligation accruals, less actual removal costs incurred, net of salvage proceeds realized, and are included in Regulatory and Other Liabilities, Regulatory Liabilities on the Consolidated Balance Sheets. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Pension and Other Retiree Benefit Plan Assumptions

TEP records plan assets, obligations, and expenses related to pension and other retiree benefit plans based on actuarial valuations, which include key assumptions on discount rates, expected returns on plan assets, compensation increases, and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally recorded or amortized over future periods. We believe that the assumptions used in recording obligations are reasonable based on prior experience, market conditions, and the advice of plan actuaries. Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K discusses the assumptions used in the calculation of pension plan and other retiree plan obligations.

TEP is required to recognize the underfunded status of its defined benefit pension and other retiree plans as a liability. The underfunded status is the difference between the fair value of the plans assets and the projected benefit obligation for pension plans or accumulated retiree benefit obligation for other retiree benefit plans. As the funded status, discount rates, and actuarial facts change, the liability will vary significantly in future years. TEP records the underfunded amount for its pension and other retiree obligations as a liability and a regulatory asset to reflect expected recovery of pension and other retiree obligations through the rates charged to retail customers.

At December 31, 2015, TEP discounted its future pension plan obligations at rates between 4.5% and 4.6% and its other retiree plan obligations at a rate of 4.2%. The discount rate for future pension plan and other retiree plan obligations is determined annually based on the rates currently available on high-quality, non-callable, long-term bonds. The discount rate is based on a corporate yield curve using an average yield between the 60th and 90th percentile of AA-graded U.S. corporate bonds with future cash flows that match the timing and amount of expected future benefit payments. For TEP's pension plans, a 25-basis point change in the discount rate would increase or decrease the Projected Benefit Obligation (PBO) by approximately $15 million and the plan expense by $1 million. For TEP's other retiree benefit plan, a 25-basis point change in the discount rate would increase or decrease the Accumulated Postretirement Benefit Obligation (APBO) by approximately $2 million.

We measured service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. As discussed in Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, at the end of 2015, we changed our approach to determine the service and interest cost components of pension and other postretirement benefit expense for future years. For 2016, we elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plan's liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. The use of this approach reduces 2016 service and interest cost by $4 million with a corresponding increase to regulatory assets. This change does not affect the measurement of our plan obligations nor the funded status of our plans.

TEP calculates the market-related value of pension plan assets using the fair value of the assets on the measurement date. TEP assumed that its pension plans' assets would generate a long-term rate of return of 7% at December 31, 2015. In establishing its assumption as to the expected return on assets, TEP reviews the asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the pension's actuary that includes both historical performance analysis and forward-looking views of the financial markets. Pension expense decreases as the expected rate of return on assets increases. A 25-basis point change in the expected return on assets would impact pension expense in 2015 by $1 million.

TEP adopted the RP-2014 mortality table projected with improvement scale MP-2015 with 15 year convergence and 0.75% long term rate to measure December 31, 2015 pension obligations, whereas RP-2000 mortality table with Scale BB was utilized for the December 31, 2014 measurement.

TEP used a current year health care cost trend rate of 7.6% in valuing its retiree benefit obligation at December 31, 2015. This rate reflects both market conditions and historical experience. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage point change in assumed health care cost trend rates would increase the retiree benefit obligation by approximately $6 million and decrease the retiree benefit obligation by approximately $5 million. In addition, a one-percentage point change in assumed health care cost trend rates would change the related 2016 plan expense by approximately $1 million.

In 2016, TEP will incur pension costs of approximately $11 million and other retiree benefit costs of approximately $5 million. TEP expects to charge approximately $13 million of these costs to O&M expense, and $3 million to capital. TEP expects to make pension plan contributions of $10 million in 2016. In 2009, TEP established a VEBA trust to fund its other retiree benefit plan. In 2016, TEP expects to make benefit payments to retirees under the retiree benefit plan of approximately $5 million and contributions to the VEBA trust of approximately $1 million, net of distributions.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

TEP enters into forward contracts to purchase or sell capacity or energy at contract prices over a given period of time, typically for one month, three months, or one year, within established limits to meet forecasted load requirements or to take advantage of favorable market opportunities. In general, TEP enters into forward purchase contracts when market conditions provide the opportunity to purchase energy for its load at prices that are below the marginal cost of its supply resources or to supplement its own resources (e.g., during plant outages and summer peaking periods). TEP enters into forward sales contracts when it forecasts that it will have excess supply and the market price of energy exceeds its marginal cost. TEP enters into forward gas commodity price swap agreements to lock in fixed prices on a portion of forecasted gas purchases and to hedge the price risk associated with forward PPAs that are indexed to natural gas prices.

For all commodity derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the Consolidated Balance Sheets and measure those instruments at fair value. Unrealized gains and losses on commodity derivative contracts entered into for retail customer load are recorded as either a regulatory asset or regulatory liability on the balance sheet based on our ability to recover the costs of hedging activities entered into to mitigate energy price risk for retail customers. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets through the PPFAC mechanism.

- The market prices used to determine fair values for TEP's derivative instruments at December 31, 2015, are estimated based on various factors including broker quotes, exchange prices, over the counter prices, and time value.

TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standardized agreement, which allows for the netting of current period exposures to and from a single counterparty.

Interest Rate Swaps

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates tied to LIBOR on the Springerville Common Facilities Lease. As of December 31, 2015, approximately $29 million of variable rate lease debt for the Springerville Common Facilities Lease had been hedged through an interest rate swap agreement through January 2020.

Revenue Recognition

TEP's retail revenues, which are recognized in the period that electricity is delivered and consumed by customers, include unbilled revenue based on an estimate of kWh delivered at the end of each period. Unbilled revenues are dependent upon a number of factors that require management's judgment including estimates of retail sales and customer usage patterns. The unbilled revenue is estimated by comparing the estimated kWh delivered to the kWh billed to our retail customers. The excess of estimated kWh delivered over kWh billed is then allocated to the retail customer classes based on estimated usage by each customer class. We then record revenue for each customer class based on the various Retail Rates for each customer class. Due to the seasonal fluctuations of TEP's actual load, the unbilled revenue amount increases during the spring and summer and decreases during the fall and winter. A provision for uncollectible accounts, associated with retail revenues, is recorded as a component of O&M expense.

Plant Asset Depreciable Lives

TEP has significant investments in electric generation assets and electric transmission and distribution assets. We calculate depreciation expense based on our estimate of the useful lives of our plant assets and expected net removal costs. The useful lives of plant assets are further detailed in Note 3 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Changes to depreciation estimates resulting from a change of estimated service life or removal costs could have a significant impact on the amount of depreciation expense recorded in the income statement. The ACC approves depreciation rates for all generation and distribution assets. Depreciation rates for such assets cannot be changed without the ACC's approval. TEP's transmission assets are subject to the jurisdiction of the FERC. See Note 1 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding depreciation rates.

Income Taxes

Due to the differences between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. We account for this difference by recording deferred income tax assets and liabilities using the effective income tax rate at our balance sheet date. Income tax liabilities are allocated to TEP based on TEP's taxable income and deductions as reported in the FortisUS, Inc. consolidated tax return.

A valuation allowance is established against deferred tax assets for which management believes it is more likely than not that the deferred asset will not be realized. In making this judgment, management evaluates all available evidence and gives more weight to objective verifiable evidence. At December 31, 2015, TEP had a $4 million valuation allowance. See Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements affecting TEP, refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

TEP's primary market risks include fluctuations in interest rates, returns on marketable securities, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. We enter into interest rate swaps and financing transactions to manage changes in interest rates. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms.

See *Forward-Looking Information* for additional information.

Risk Management Committee

We have a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to the wholesale energy marketing and power procurement activities of TEP. Our Risk Management Committee, which meets on a quarterly basis and as needed, consists of officers from the finance, accounting, legal, wholesale marketing, and generation operations departments of TEP. To limit TEP's exposure to commodity price risk, the Risk Management Committee sets trading and hedging policies and limits, which are reviewed frequently to respond to constantly changing market conditions. To limit TEP's exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

Interest Rate Risk

<u>Long-Term Debt</u>

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations. TEP had $137 million in tax-exempt variable rate debt outstanding at December 31, 2015. The outstanding debt included one series of bonds for which interest rates are reset weekly and one series of bonds for which interest rates are reset monthly. The weighted average weekly rate (including LOC fees and remarketing fees) was 1.24% in 2015 and 1.46% in 2014. The average weekly interest rate ranged from 0.93% - 1.42% in 2015 and 1.40% - 1.75% in 2014. The monthly rate is based on a percentage of an index equal to one-month LIBOR plus a credit spread. The average monthly rate was 0.81% in 2015 and 0.87% in 2014. The monthly rate ranged from 0.79% - 0.87% in 2015 and 0.85% - 0.95% in 2014.

Although short-term interest rates were low and stable in 2015 and 2014, TEP may still be subject to volatility in its tax-exempt variable rate debt. A 100 basis point increase in average interest rates on this debt, over a twelve month period, would result in a decrease in TEP's pre-tax net income of approximately $1 million.

TEP can manage its exposure to variable interest rate risk by entering into interest rate swaps and financing transactions to rebalance its mix of variable rate and fixed rate long-term debt. TEP has a fixed-for-floating interest rate swap in place to hedge floating interest rate risk associated with a portion of its Springerville Common Facilities lease debt. The notional amount of the swap is $29 million at December 31, 2015. The notional amount of lease debt that was unhedged as of December 31, 2015 was $13 million. TEP did not have any other interest rate swaps at December 31, 2015.

<u>Interest Rate Swap</u>

To adjust the value of TEP's interest rate swap, classified as a cash flow hedge, to fair value in Other Comprehensive Income (Loss), TEP recorded the following net unrealized gains:

(in millions)	2015	2014	2013
Net Unrealized Gains	$ 1	$ 2	$ 4

<u>Revolving Credit Facilities</u>

TEP is subject to interest rate risk resulting from changes in interest rates on borrowings under its credit agreements. The interest paid on borrowings is variable. Revolving credit borrowings may be made on the basis of a spread over LIBOR or an Alternate Base Rate. As a result, TEP may experience significant volatility in the rates paid on LIBOR borrowings under its revolving credit facilities.

Marketable Securities Risk

The majority of TEP's pension plan assets, as well as assets associated with other employee benefit obligations, are investments in equity and debt securities. These investments are exposed to price fluctuations in equity markets and changes in interest rates. Of the assets held for employee benefit obligations, the pension plan assets comprise the largest portion. The pension plan assets will help fund defined retirement benefits for substantially all of our employees. Declines in the values of these assets could increase required employer contributions, which would adversely affect cash flows. Declines in values could also increase the reported pension expense, adversely affecting TEP's results of operations.

Commodity Price Risk

TEP is exposed to commodity price risk primarily relating to changes in the market price of electricity, natural gas, and coal. This risk is mitigated through hedging practices and a PPFAC mechanism which fully recovers the actual retail fuel and purchased power costs incurred on a timely basis from TEP's retail customers. The PPFAC mechanism has a forward component and a true-up component. The forward component of the PPFAC rate is based on forecasted fuel and purchased power costs. The true-up component reconciles actual fuel and purchased power costs with the amounts collected in the prior year and any amounts under/over-collected will be collected from/credited to customers. If the actual price of power is higher than the forecasted PPFAC rate, TEP's operating cash flows are reduced by the price difference until the subsequent 12-month period when the true-up component is adjusted to allow the recovery of this difference.

Purchases and Sales of Energy

To manage its exposure to energy price risk, TEP enters into forward contracts to buy or sell energy at a specified price and future delivery period. Generally, TEP commits to future sales based on expected excess generating capability, forward prices and generation costs, using a diversified market approach to provide a balance between long-term, mid-term, and spot energy sales. TEP generally enters into forward purchases during its summer peaking period to ensure it can meet its load and reserve requirements, and account for other contracts and resource contingencies. TEP also enters into limited forward purchases and sales to optimize its resource portfolio and take advantage of geographical differences in price. These positions are managed on both a volumetric and dollar basis and are closely monitored using risk management policies and procedures overseen by the Risk Management Committee. For example, the risk management policies provide that TEP should not take a short physical position in the third quarter and must have owned generation backing up all physical forward sales positions at the time the sale is made. TEP's risk management policies also place limits on the duration of transactions in both gas and power.

TEP enters into some forward contracts considered to be normal purchases and sales of electric energy and are therefore not accounted for as derivatives. TEP records revenues on its "normal sales" and expenses on its "normal purchases" in the period in which the energy is delivered. TEP also enters into forward contracts that are not considered to be "normal purchases and sales" and therefore are accounted for as derivatives. When TEP has derivative forward contracts, it marks them to market using actively quoted prices obtained from brokers for power traded over-the-counter at Palo Verde and at other southwestern U.S. trading hubs. TEP believes that these broker quotations used to calculate the mark-to-market values represent accurate measures of the fair values of TEP's positions because of the short-term nature of TEP's positions, as limited by risk management policies, and the liquidity in the short-term market.

Long-Term Wholesale Sales

TEP has several long-term wholesale agreements for the sale of energy. Sales under some of these agreements are based on indexed energy prices. Changes in the price of power affect TEP's revenue and income from these agreements.

Natural Gas

TEP is also subject to commodity price risk from changes in the price of natural gas. In addition to energy from its coal-fired facilities, TEP typically uses power purchases, supplemented by generation from its gas-fired units to meet the summer peak demands of its retail customers and to meet local reliability needs. Some of these purchased power contracts are indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel, gas-indexed power purchases, and spot market purchases with various instruments up to three years in advance. TEP purchases its remaining gas fuel and power needs in the spot and short-term markets.

As required by fair value accounting rules, for the year ended December 31, 2015, TEP considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted.

To adjust the value of its commodity derivatives to fair value, TEP adjusted regulatory assets or regulatory liabilities as follows:

(in millions)	2015	2014	2013
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ 6	$ (18)	$ —

The table below displays the valuation methodologies and maturities of TEP's power and gas derivative contracts by source of fair value:

	Unrealized Gain (Loss) of TEP's Hedging Activities			
	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
(in millions)	December 31, 2015			
Prices Actively Quoted	$ (7)	$ (1)	$ (2)	$ (10)
Prices Based on Models and Other Valuation Methods	(1)	—	—	(1)
Total	$ (8)	$ (1)	$ (2)	$ (11)

Sensitivity Analysis of Derivatives

TEP uses sensitivity analysis to measure the impact of favorable and unfavorable changes in market prices on the fair value of its derivative forward contracts. TEP records unrealized gains and losses as either a regulatory asset or regulatory liability. As contracts settle, the unrealized gains and losses are reversed and realized gains or losses are recorded to the PPFAC. For TEP's non-cash flow power hedges, a 10% change in the market price of power would affect unrealized positions reported as a regulatory asset or regulatory liability by approximately $1 million; for gas swaps and collar contracts, a 10% change in the market price of energy would affect unrealized positions reported as a regulatory asset or liability by approximately $3 million.

Coal

TEP is subject to commodity price risk from changes in the price of coal used to fuel its coal-fired generating plants. This risk is mitigated through the use of long term coal supply agreements with limited price volatility.

TEP's coal supply contract for Springerville Units 1 and 2 expires in 2020, at which time a new coal purchase agreement will be negotiated. TEP expects coal reserves from the Lee Ranch - El Segundo mine, which supplies Springerville Units 1 and 2 to be sufficient to supply the estimated requirements for the units presently estimated remaining lives. The current coal price is determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling.

TEP participates in jointly-owned generating facilities at Four Corners, Navajo, and San Juan, where coal supplies are received under contracts administered by the operating agents. The coal contracts at Four Corners and Navajo expire in 2031 and 2019, respectively. The new coal supply contract with Westmoreland for San Juan, effective January 31, 2016, expires in 2022. At December 31, 2015, TEP had contracts to purchase coal for use at the jointly-owned facilities and expected its estimated average annual cost for the next three years to be $51 million and $22 million thereafter through 2031. Contemporaneous with the new San Juan coal supply contract in January 2016, additional estimated minimum purchase obligations are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources* and Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Credit Risk

TEP is exposed to credit risk in its energy-related marketing activities related to potential non-performance by counterparties. We manage the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using standard agreements which allow for the netting of current period exposures to and from a single counterparty. We calculate counterparty credit exposure by adding any outstanding receivable (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts. If exposure exceeds credit limits or contractual collateral thresholds, we may request that a counterparty provide credit enhancement in the form of cash collateral or an LOC.

TEP has entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through three years. As of December 31, 2015, the credit exposure to TEP from financial institution counterparties was less than $1 million.

As of December 31, 2015, TEP's total credit exposure related to its wholesale marketing and gas hedging activities was approximately $10 million. TEP did not have any exposure to non-investment grade counterparties.

At December 31, 2015, TEP posted no cash collateral and less than $1 million in LOCs as credit enhancements with its counterparties, and did not hold any collateral from its counterparties.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

TEP's management is responsible for establishing and maintaining adequate internal control over financial reporting. 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.

Management assessed the effectiveness of TEP's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the 2013 COSO Internal Control – Integrated Framework.

Based on management's assessment using those criteria, management has concluded that, as of December 31, 2015, TEP's internal control over financial reporting was effective.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Tucson Electric Power Company:

We have audited the accompanying consolidated balance sheets of Tucson Electric Power Company as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in stockholder's equity and cash flows for each of the two years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provided a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tucson Electric Power Company at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Ernst & Young LLP

Calgary, Canada

February 18, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of Tucson Electric Power Company

In our opinion, the consolidated statements of income, comprehensive income, changes in stockholder's equity and cash flows for the year ended December 31, 2013 present fairly, in all material respects, the results of operations and cash flows of Tucson Electric Power Company and its subsidiaries for the year ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Phoenix, Arizona

February 25, 2014, except for the effects of the revision discussed in Note 1 (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company's 2014 annual report on Form 10-K, as to which the date is August 14, 2014

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Amounts in thousands)

	Year Ended December 31,		
	2015	**2014**	**2013**
Operating Revenues			
Electric Retail Sales	**$ 1,021,543**	$ 970,145	$ 934,357
Electric Wholesale Sales	**167,020**	158,323	132,500
Other Revenues	**117,981**	141,433	129,833
Total Operating Revenues	**1,306,544**	1,269,901	1,196,690
Operating Expenses			
Fuel	**305,559**	297,537	325,903
Purchased Power	**124,764**	152,922	112,452
Transmission and Other PPFAC Recoverable Costs	**24,798**	18,179	12,233
Increase (Decrease) to Reflect PPFAC Recovery Treatment	**39,787**	(11,194)	(12,458)
Total Fuel and Purchased Power	**494,908**	457,444	438,130
Operations and Maintenance	**345,356**	378,877	335,321
Depreciation	**138,093**	126,520	118,076
Amortization	**19,261**	28,567	31,294
Taxes Other Than Income Taxes	**49,623**	47,805	43,498
Total Operating Expenses	**1,047,241**	1,039,213	966,319
Operating Income	**259,303**	230,688	230,371
Other Income (Deductions)			
Interest Income	**93**	208	120
Other Income	**6,647**	8,598	5,770
Other Expense	**(2,833)**	(12,735)	(10,715)
Appreciation (Depreciation) in Value of Investments	**(142)**	1,371	2,833
Total Other Income (Deductions)	**3,765**	(2,558)	(1,992)
Interest Expense			
Long-Term Debt	**61,159**	60,577	56,378
Capital Leases	**3,994**	10,249	25,140
Other Interest Expense	**1,134**	810	87
Interest Capitalized	**(2,732)**	(3,755)	(2,554)
Total Interest Expense	**63,555**	67,881	79,051
Income Before Income Taxes	**199,513**	160,249	149,328
Income Tax Expense	**71,719**	57,911	47,986
Net Income	**$ 127,794**	$ 102,338	$ 101,342

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

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Amounts in thousands)

	Year Ended December 31,		
	2015	**2014**	**2013**
Comprehensive Income			
Net Income	**$ 127,794**	$ 102,338	$ 101,342
Other Comprehensive Income (Loss)			
Net Changes in Fair Value of Cash Flow Hedges:			
Net of Income Tax (Expense) Benefit of ($821), ($1,140), and ($1,793)	**1,261**	1,675	2,738
Supplemental Executive Retirement Plan Adjustments:			
Net of Income Tax (Expense) Benefit of ($63), $1,068, and ($572)	**101**	(1,725)	916
Total Other Comprehensive Income (Loss), Net of Tax	**1,362**	(50)	3,654
Total Comprehensive Income	**$ 129,156**	$ 102,288	$ 104,996

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

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Amounts in thousands)

	Year Ended December 31,		
	2015	**2014**	**2013**
Cash Flows from Operating Activities			
Net Income	**$ 127,794**	$ 102,338	$ 101,342
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities:			
Depreciation Expense	**138,093**	126,520	118,076
Amortization Expense	**19,261**	28,567	31,294
Amortization of Debt Issuance Costs	**3,043**	2,626	2,452
Provision for Springerville Unit 1 - Third-Party Owners Unrealized Revenue	**22,627**	—	—
Use of Renewable Energy Credits for Compliance	**19,731**	17,818	15,990
Deferred Income Taxes	**72,026**	59,024	58,100
Pension and Retiree Expense	**18,588**	13,648	19,878
Pension and Retiree Funding	**(30,682)**	(14,388)	(27,636)
Allowance for Equity Funds Used During Construction	**(5,352)**	(6,677)	(4,526)
LFCR and DSM Revenues	**(14,646)**	(12,937)	(2,575)
Increase (Decrease) to Reflect PPFAC Recovery Treatment	**39,787**	(11,194)	(12,458)
Fortis Acquisition Direct Customer Benefit	—	18,870	—
Change in Current Assets and Current Liabilities:			
Accounts Receivable	**(25,690)**	(14,261)	824
Materials, Supplies, and Fuel Inventory	**(8,758)**	666	16,145
Accounts Payable	**(23,149)**	10,712	334
Regulatory Liabilities	**(2,977)**	8,388	3,331
Other, Net	**15,238**	(16,057)	25,620
Net Cash Flows—Operating Activities	**364,934**	313,663	346,191
Cash Flows from Investing Activities			
Capital Expenditures	**(333,841)**	(323,524)	(252,848)
Purchase of Gila River Unit 3	—	(163,938)	—
Purchase of Springerville Coal Handling Facilities Lease Assets	**(120,312)**	—	—
Purchase of Springerville Unit 1 Lease Assets	**(45,753)**	(19,608)	—
Proceeds from Sale of Springerville Coal Handling Facilities	**23,656**	—	—
Purchase of Intangibles - Renewable Energy Credits	**(29,184)**	(28,334)	(23,280)
Return of Investments in Springerville Lease Debt	—	—	9,104
Contributions in Aid of Construction	**4,517**	15,903	3,959
Other, Net	**(1,974)**	1,863	3,403
Net Cash Flows—Investing Activities	**(502,891)**	(517,638)	(259,662)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	**148,000**	275,000	78,000
Repayments of Borrowings Under Revolving Credit Facilities	**(233,000)**	(190,000)	(78,000)
Proceeds from Borrowings Under Term Loan	**130,000**	—	—
Repayments of Borrowings Under Term Loan	**(130,000)**	—	—

Proceeds from Issuance of Long-Term Debt	**299,019**	149,168	—
Repayments of Long-Term Debt	**(208,600)**	—	—
Dividends Paid to Parent	**(50,000)**	(40,000)	(40,000)
Payments of Capital Lease Obligations	**(13,464)**	(165,145)	(99,621)
Payment of Debt Issue/Retirement Costs	**(3,942)**	(1,856)	(1,865)
Contribution from Parent	**180,000**	225,000	—
Other, Net	**1,458**	643	549
Net Cash Flows—Financing Activities	**119,471**	252,810	(140,937)
Net Increase (Decrease) in Cash and Cash Equivalents	**(18,486)**	48,835	(54,408)
Cash and Cash Equivalents, Beginning of Period	**74,170**	25,335	79,743
Cash and Cash Equivalents, End of Period	**$ 55,684**	$ 74,170	$ 25,335

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

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31,	
	2015	**2014**
ASSETS		
Utility Plant		
Plant in Service	**$ 5,618,435**	$ 5,175,148
Utility Plant Under Capital Leases	**131,705**	667,157
Construction Work in Progress	**102,028**	109,070
Total Utility Plant	**5,852,168**	5,951,375
Less Accumulated Depreciation and Amortization	**(2,194,301)**	(2,052,216)
Less Accumulated Amortization of Capital Lease Assets	**(99,638)**	(473,969)
Total Utility Plant, Net	**3,558,229**	3,425,190
Investments and Other Property	**39,569**	37,599
Current Assets		
Cash and Cash Equivalents	**55,684**	74,170
Accounts Receivable, Net	**136,682**	131,799
Fuel Inventory	**34,600**	36,368
Materials and Supplies	**94,003**	86,750
Regulatory Assets	**51,841**	69,383
Derivative Instruments	**1,808**	1,633
Assets Held for Sale, Net	**21,550**	—
Other	**25,904**	21,010
Total Current Assets	**422,072**	421,113
Regulatory and Other Assets		
Regulatory Assets	**212,312**	223,192
Derivative Instruments	**430**	300
Other	**16,866**	12,436
Total Regulatory and Other Assets	**229,608**	235,928
Total Assets	**$ 4,249,478**	$ 4,119,830

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

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31,	
	2015	**2014**
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000,000 Shares Authorized, 32,139,434 Shares Outstanding at December 31, 2015 and 2014)	**$ 1,296,539**	$ 1,116,539
Capital Stock Expense	**(6,357)**	(6,357)
Accumulated Earnings	**189,317**	111,523
Accumulated Other Comprehensive Loss	**(4,564)**	(5,926)
Total Common Stock Equity	**1,474,935**	1,215,779
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding at December 31, 2015 and 2014)	**—**	—
Capital Lease Obligations	**55,324**	69,438
Long-Term Debt, Net	**1,451,720**	1,361,828
Total Capitalization	**2,981,979**	2,647,045
Current Liabilities		
Current Obligations Under Capital Leases	**14,114**	173,822
Borrowings Under Revolving Credit Facilities	**—**	85,000
Accounts Payable	**86,274**	113,413
Accrued Taxes Other than Income Taxes	**37,577**	36,110
Accrued Employee Expenses	**27,718**	15,679
Accrued Interest	**14,246**	21,021
Regulatory Liabilities	**53,077**	38,847
Customer Deposits	**20,349**	20,339
Derivative Instruments	**12,174**	18,874
Other	**7,533**	9,673
Total Current Liabilities	**273,062**	532,778
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	**468,024**	389,540
Regulatory Liabilities	**307,286**	321,186
Pension and Other Postretirement Benefits	**120,336**	138,319
Derivative Instruments	**4,067**	6,288
Other	**94,724**	84,674
Total Regulatory and Other Liabilities	**994,437**	940,007
Commitments and Contingencies		
Total Capitalization and Other Liabilities	**$ 4,249,478**	$ 4,119,830

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

(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY
(Amounts in thousands)

	Common Stock	Capital Stock Expense	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances at December 31, 2012	**$ 888,971**	**$ (6,357)**	**$ (12,157)**	**$ (9,530)**	**$ 860,927**
Net Income			101,342		101,342
Other Comprehensive Income (Loss), Net of Tax				3,654	3,654
Dividends Declared to Parent			(40,000)		(40,000)
Balances at December 31, 2013	**888,971**	**(6,357)**	**49,185**	**(5,876)**	**925,923**
Net Income			102,338		102,338
Other Comprehensive Income (Loss), Net of Tax				(50)	(50)
Dividends Declared to Parent			(40,000)		(40,000)
Contribution from Parent	225,000				225,000
Other	2,568				2,568
Balances at December 31, 2014	**1,116,539**	**(6,357)**	**111,523**	**(5,926)**	**1,215,779**
Net Income			127,794		127,794
Other Comprehensive Income (Loss), Net of Tax				1,362	1,362
Dividends Declared to Parent			(50,000)		(50,000)
Contribution from Parent	180,000				180,000
Balances at December 31, 2015	**$1,296,539**	**$ (6,357)**	**$ 189,317**	**$ (4,564)**	**$1,474,935**

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

Tucson Electric Power Company (TEP) is a regulated utility that generates, transmits, and distributes electricity to approximately 417,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis).

References in these notes to "we" and "our" are to TEP.

FORTIS ACQUISITION OF UNS ENERGY

UNS Energy, the parent of TEP, was acquired by Fortis for $60.25 per share of UNS Energy common stock in cash, effective August 15, 2014. The Arizona Corporation Commission's (ACC) approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling approximately $19 million over five years: $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital; and
- Fortis making an equity investment of at least $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the UNS Energy acquisition, Fortis exceeded the investment requirement by contributing $287 million to UNS Energy through December 31, 2014. UNS Energy then contributed $225 million to TEP.

As a result of the acquisition being completed, TEP recorded approximately $15 million, through August 2014, as its allocated share of acquisition-related expenses, in addition to the customer bill credits discussed above. Acquisition-related expenses, reported in Operations and Maintenance and Other Expense, include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards. See Note 9 for additional information regarding share-based compensation.

BASIS OF PRESENTATION

TEP's consolidated financial statements and disclosures are presented in accordance with Generally Accepted Accounting Principles (GAAP) in the United States which includes specific accounting guidance for regulated operations. See Note 2 for additional information regarding regulatory matters. The consolidated financial statements include the accounts of TEP and its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined and intercompany balances and transactions are eliminated. TEP jointly owns several generating stations and transmission facilities with non-affiliated entities. TEP's proportionate share of jointly owned facilities is recorded as Utility Plant on the Consolidated Balance Sheets, and our proportionate share of the operating costs associated with these facilities is included on the consolidated statements of income. See Note 3 for additional information regarding Utility Plant.

TEP did not reflect the impacts of acquisition accounting in its financial statements. All adjustments of assets and liabilities to fair value and the resultant goodwill associated with the acquisition were recorded by FortisUS Inc., a wholly owned subsidiary of Fortis.

Certain amounts from prior periods have been reclassified to conform to the current year presentation. Most notably, in 2014, TEP elected to change its method of reporting cash flows from the direct to the indirect method to conform to Fortis' presentation election.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2015, we adopted accounting guidance that:

- limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. The adoption of this guidance did not have any impact on our disclosures, financial condition, results of operations, or cash flows as we did not have any activities that required application of this accounting guidance.
- requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, rather than as deferred charges. The adoption of this standard resulted in reclassification of

debt issuance costs from Other Current Assets and Other Assets to Long-Term Debt on the Consolidated Balance Sheets. TEP will continue to account for debt issuance costs related to line-of-credit arrangements as an asset. TEP reclassified $11 million at December 31, 2014 from Other Current Assets and Other Assets to Long-Term Debt to conform to the current year presentation.

- simplifies the presentation of deferred taxes by requiring deferred tax assets and liabilities to be classified as noncurrent on the balance sheet. The adoption of this standard resulted in a reclassification of deferred income taxes from Deferred Income Taxes - Current Assets to Deferred Income Taxes - Regulatory and Other Liabilities. TEP reclassified $102 million at December 31, 2014 from Deferred Income Taxes - Current Assets to Deferred Income Taxes - Regulatory and Other Liabilities to conform to the current year presentation.

USE OF ACCOUNTING ESTIMATES

Management uses estimates and assumptions when preparing financial statements under GAAP. These estimates and assumptions affect:

- assets and liabilities on our balance sheets at the dates of the financial statements;
- our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- our revenues and expenses in our income statements during the periods presented.

Because these estimates involve judgments based upon our evaluation of relevant facts and circumstances, actual results may differ from the estimates.

ACCOUNTING FOR REGULATED OPERATIONS

We apply accounting standards that recognize the economic effects of rate regulation. As a result, we capitalize certain costs that would be recorded as expense or in Accumulated Other Comprehensive Income (AOCI) by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in the rates charged to retail customers or to wholesale customers through transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or amounts that are expected to be returned to customers through future rate reductions.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process. We evaluate regulatory assets each period and believe recovery is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings or AOCI. See Note 2 for additional information regarding regulatory matters.

TEP applies regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise's costs of providing service; and
- Rates are set at levels that will recover the entity's costs and can be charged to and collected from customers.

CASH AND CASH EQUIVALENTS

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

RESTRICTED CASH

Cash balances that are restricted regarding withdrawal or usage based on contractual or regulatory considerations are reported in Investments and Other Property on the balance sheets. Restricted cash was $4 million at December 31, 2015 and $2 million at December 31, 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ALLOWANCE FOR DOUBTFUL ACCOUNTS

We record an Allowance for Doubtful Accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales, and economic conditions. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible. The change in the balance of the Allowance for Doubtful Accounts in our Consolidated Balance Sheets is summarized as follows:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Beginning of Period	$ 5	$ 5	$ 5
Increases:			
Charged to Operating Revenues	23	—	—
Charged to Operating Expenses	2	2	2
Write-offs	(3)	(2)	(2)
End of Period	$ 27	$ 5	$ 5

The Allowance for Doubtful Accounts increased in 2015 due to Third-Party Owners' claims at Springerville Unit 1. See Note 7 for additional information regarding the Third-Party Owners' claims.

INVENTORY

We value materials, supplies, and fuel inventory 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 in retail rates. We capitalize handling and procurement costs (such as labor, overhead costs, and transportation costs) as part of the cost of the inventory. Materials and Supplies consist of generation, transmission, and distribution construction and repair materials.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at original cost. Original cost includes materials and labor, contractor services, construction overhead (when applicable), and an Allowance for Funds Used During Construction (AFUDC), less contributions in aid of construction.

We record the cost of repairs and maintenance, including planned major overhauls, to Operations and Maintenance (O&M) expense in the income statement as costs are incurred.

When a unit of regulated property is retired, we reduce accumulated depreciation by the original cost plus removal costs less any salvage value. There is no income statement impact.

AFUDC and Capitalized Interest

AFUDC reflects the cost of debt and equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts are capitalized and amortized through depreciation expense as a recoverable cost in Retail Rates. The capitalized interest that relates to debt is recorded as a reduction in Interest Expense in the income statement. The capitalized cost for equity funds is recorded as Other Income in the income statement.

The average AFUDC rates on regulated construction expenditures are included in the table below:

	2015	2014	2013
Average AFUDC Rates	6.12%	7.30%	7.38%

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 3 for additional information regarding Utility Plant. The ACC approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Below are the summarized average annual depreciation rates for all utility plant:

	2015	2014	2013
Average Annual Depreciation Rates	2.83%	2.99%	3.16%

Utility Plant Under Capital Leases

TEP finances the facilities at Springerville used in common with Springerville Unit 1 and Unit 2 (Springerville Common Facilities) with capital leases. The capital lease expense incurred consists of Amortization Expense and Interest Expense—Capital Leases. See Note 3 for additional information regarding Utility Plant and Note 6 for additional information related to the lease terms.

Computer Software Costs

We capitalize costs incurred to purchase and develop internal use computer software and amortize those costs over the estimated economic life of the product. If the software is no longer useful, we immediately charge capitalized computer software costs to expense.

ASSET RETIREMENT OBLIGATIONS

TEP has identified legal Asset Retirement Obligations (AROs) related to the retirement of certain generation assets. Additionally, TEP incurred AROs related to its photovoltaic assets as a result of entering into various ground leases or easement agreements. We record a liability for a legal ARO in the period in which it is incurred if it can be reasonably estimated. When a new obligation is recorded, we capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. We record the increase in the liability due to the passage of time by recognizing accretion expense in O&M expense and depreciate the capitalized cost over the useful life of the related asset or, when applicable, the terms of the lease subject to ARO requirements. TEP defers costs associated with the majority of its legal AROs as regulatory assets based on the ACC's approval of these costs in TEP's depreciation rates.

Depreciation rates also include a component for estimated future removal costs that have not been identified as legal obligations. We recover those amounts in the rates charged to retail customers and have recorded an obligation for estimated costs of removal as regulatory liabilities.

EVALUATION OF ASSETS FOR IMPAIRMENT

We evaluate long-lived assets and investments for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If expected future cash flows (without discounting) are less than the carrying value of the asset, an impairment loss is recognized if the impairment is other-than-temporary and the loss is not recoverable through rates.

DEFERRED FINANCING COSTS

We defer the costs to issue debt and amortize such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. Deferred debt issuance costs are presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs.

TEP accounts for debt issuance costs related to line-of-credit arrangements as an asset.

We defer and amortize the gains and losses on reacquired debt associated with regulated operations to interest expense over the remaining life of the original debt.

OPERATING REVENUES

We recognize revenues related to the sale of energy when services or commodities are delivered to customers. The billing of electric sales to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period. At the end of the month, amounts of energy delivered since the last meter reading are estimated and the corresponding unbilled revenue is calculated using average customer Retail Rates.

For purchased power and wholesale sales contracts that are settled financially, TEP nets the sales contracts with the purchase power contracts and reflects the net amount as Electric Wholesale Sales.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP recognizes monthly management fees in Other Revenues as the operator of Springerville Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP). Additionally, Other Revenues include reimbursements from Tri-State and SRP for various operating expenses at Springerville and for the use of the Springerville Common Facilities and the Springerville Coal Handling Facilities. The offsetting expenses are recorded in the respective line items of the income statements based on the nature of services provided. As the operating agent for Tri-State and SRP, TEP may earn performance incentives based on unit availability which are recognized in Other Revenues in the period earned.

The ACC has authorized mechanisms for Lost Fixed Cost Recovery (LFCR) related to kilowatt-hour (kWh) sales lost due to Energy Efficiency Standards (EE Standards) and distributed generation. We recognize revenues in the period that verifiable energy savings occur. Revenue recognition related to the LFCR creates a regulatory asset until such time as the revenue is collected.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

We recover actual fuel, purchased power and transmission costs to provide electric service to retail customers through base fuel rates and a Purchased Power and Fuel Adjustment Clause (PPFAC); the ACC periodically adjusts the PPFAC rate at which TEP recovers these costs. The difference between costs recovered through rates and actual fuel, purchased power, transmission, and other approved costs to provide retail electric service is deferred. Cost over-recoveries are deferred as regulatory liabilities and cost under-recoveries are deferred as regulatory assets. See Note 2 for additional information regarding regulatory matters.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS

The ACC's Renewable Energy Standard (RES) requires TEP to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. TEP must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out this plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes, and a return on investments in company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates.

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's EE Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs. The EE Standards require increasing annual targeted retail kWh savings equal to 22% by 2020.

Any RES or DSM surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in the financial statements as a regulatory asset or liability. TEP recognizes RES and DSM surcharge revenue in Electric Retail Sales in amounts necessary to offset recognized qualifying expenditures.

RENEWABLE ENERGY CREDITS

The ACC measures compliance with the RES requirements through Renewable Energy Credits (RECs). A REC represents one kWh generated from renewable resources. When TEP purchases renewable energy, the premium paid above the market cost of conventional power equals the REC cost recoverable through the RES surcharge. As described above, the market cost of conventional power is recoverable through the PPFAC.

When RECs are purchased, TEP records the cost of the RECs (an indefinite-lived intangible asset) as Other Assets, and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, TEP recognizes Purchased Power expense and Other Revenues in an equal amount. See Note 2 for additional information regarding regulatory matters.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than for financial statement presentation purposes. Temporary differences are accounted for by recording deferred income tax assets and liabilities on our balance sheets. These assets and liabilities are recorded using enacted income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. We reduce deferred tax assets by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized.

Tax benefits are recognized when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest expense accruals relating to income tax obligations are recorded in Other Interest Expense.

Prior to 1990, TEP flowed through to ratepayers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory Assets include income taxes recoverable through future rates, which reflects the future revenues due to TEP from ratepayers as these tax benefits reverse. See Note 2 for additional information regarding regulatory matters.

We account for federal energy credits generated prior to 2012 using the grant accounting model. The credit is treated as deferred revenue, which is recognized over the depreciable life of the underlying asset. The deferred tax benefit of the credit is treated as a reduction to income tax expense in the year the credit arises. Federal energy credits generated since 2012 are deferred as Regulatory Liabilities – Noncurrent and amortized as a reduction in Income Tax Expense over the tax life of the underlying asset. Income Tax Expense attributable to the reduction in tax basis is accounted for in the year the federal energy credit is generated and is deferred as regulatory assets. All other federal and state income tax credits are treated as a reduction to Income Tax Expense in the year the credit arises.

Income tax liabilities are allocated to TEP based on its taxable income as reported in the FortisUS Inc. consolidated tax return.

TAXES OTHER THAN INCOME TAXES

We act as conduits or collection agents for sales taxes, utility taxes, franchise fees, and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable to governmental agencies on the balance sheet for these taxes and assessments. These amounts are not reflected in the income statements.

FAIR VALUE

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange, and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange. See Note 11 for additional information regarding fair value.

DERIVATIVE INSTRUMENTS

We use various physical and financial derivative instruments, including forward contracts, financial swaps, and call and put options, to meet forecasted load and reserve requirements, to reduce our exposure to energy commodity price volatility and to hedge our interest rate risk exposure. For all derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the Consolidated Balance Sheets and measure those instruments at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not recorded at fair value and settled amounts are recognized as cost of fuel, energy and capacity on the Consolidated Statements of Income.

For our derivatives designated as hedging contracts, we formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. Also, we formally document hedging activity by transaction type and risk management strategy.

For our derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. See Note 11 for additional information regarding derivative instruments.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

PENSION AND OTHER RETIREE BENEFITS

We sponsor noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. We also provide limited health care and life insurance benefits for retirees.

We recognize the underfunded status of our defined benefit pension plans as a liability on our balance sheet. The underfunded status is measured as the difference between the fair value of the pension plans' assets and the projected benefit obligation for the pension plans. We recognize a regulatory asset to the extent these future costs are probable of recovery in the rates charged to retail customers and expect to recover these costs over the estimated service lives of employees.

Additionally, we maintain a Supplemental Executive Retirement Plan (SERP) for senior management. Changes in SERP benefit obligations are recognized as a component of AOCI.

Pension and other retiree benefit expenses are determined by actuarial valuations based on assumptions that we evaluate annually. See Note 8 for additional information regarding the employee benefit plans.

NOTE 2. REGULATORY MATTERS

The ACC and the FERC each regulate portions of TEP's utility accounting practices and rates. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2015 RATE CASE

In November 2015, TEP filed a general rate case with the ACC based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

The key provisions of TEP's general rate case include:

- a Base Rate increase of $110 million, or 12%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of the San Juan Generating Station (San Juan) Unit 2 and the H. Wilson Sundt Generating Station (Sundt) Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Unit 1 of the Springerville Generating Station (Springerville Unit 1) that is available to TEP for dispatch to serve retail customers' needs and to recover the related operating costs through the PPFAC; and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

TEP cannot predict the outcome of this proceeding or whether its rate request will be adopted by the ACC in whole or in part.

COST RECOVERY MECHANISMS

TEP has received regulatory decisions that allow for more timely recovery of certain costs through the recovery mechanisms described below.

Purchased Power and Fuel Adjustment Clause

TEP's PPFAC rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which attempts to recover or refund the difference between forecasted fuel costs and those embedded in the current PPFAC and fuel rates; and (ii) a true-up component that reconciles the difference between actual costs and those recovered in the preceding 12-month period. The PPFAC bank balance was over-collected by $18 million at December 31, 2015 and under-collected by $19 million at December 31, 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The PPFAC rates during the periods reported were as follows:

Period	Cents per kWh
April 2015 through March 2016	0.68
October 2014 through March 2015 (1)	0.50
May 2014 through September 2014 (1)	0.10
July 2013 through April 2014 (2)	(0.14)
January 2013 through June 2013	0.77

(1) The ACC approved a two-step increase to shift a higher level of recovery into the winter season.

(2) The effective date of the 2012 PPFAC rate reduction was deferred to coincide with the effective date of the 2013 Rate Order.

San Juan Mine Fire Insurance Proceeds

In September 2011, a fire at the underground mine providing coal to San Juan caused interruptions to mining operations and resulted in increased fuel costs. The 2013 Rate Order required TEP to defer incremental fuel costs of $10 million from recovery under the PPFAC pending final resolution of an insurance claim by the San Juan Coal Company (SJCC) and distribution of insurance proceeds to San Juan participants. TEP received insurance proceeds of $1 million in 2015 and $8 million in 2014. The insurance proceeds offset the deferred fuel costs and are included in the Statements of Cash Flows as an operating activity. The remaining $1 million of unreimbursed fuel costs will be recovered through the PPFAC, in accordance with the 2013 Rate Order.

Renewable Energy Standards

The ACC's RES requires TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP's Base Rates. The associated lost revenues attributable to meeting distributed generation targets will be partially recovered through the LFCR.

In July 2015, TEP submitted its application for the 2016 RES implementation plan that includes a budget of $57 million, which will be partially offset by applying approximately $9 million of previously recovered carryover funds. TEP proposed to recover $48 million through the RES surcharge. The budget will fund the following: (i) the above market cost of renewable energy purchases; (ii) previously awarded performance-based incentives for customer installed distributed generation; (iii) depreciation and a return on TEP's investments in company-owned solar projects; and (iv) various other program costs. TEP expects to receive a decision on the application in the first half of 2016. TEP expects to recognize approximately $9 million of revenue in 2016 as a return on company-owned solar projects.

TEP met the overall 2015 RES renewable energy requirement of 5% of retail Kilowatt-hour (kWh) sales and expects to meet the 2016 requirement of 6% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation REC, which are used to demonstrate compliance with the distributed generation requirement, the company has requested a waiver of the RES distributed generation requirements in its 2016 RES implementation plan.

Energy Efficiency Standards

In 2010, the ACC approved new EE Standards designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the EE Standards, TEP's cumulative annual energy savings are approximately 9.3% of 2015 retail kWh sales. TEP's compliance with the EE Standards is governed by the ACC's approval of its annual implementation plan.

The EE Standards provide for a DSM surcharge for regulated utilities to recover the costs to implement DSM programs as well as an annual performance incentive. TEP recorded $3 million in 2015, $2 million in 2014, and less than $1 million in 2013 related to performance. The performance incentive is recorded in the first quarter of the year and is included in Electric Retail Sales on the Consolidated Statements of Income.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan. Under the 2016 plan, TEP has been approved to recover approximately $14 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward Arizona's EE Standard and the associated lost revenue will be partially recovered through the LFCR.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism provides recovery of certain non-fuel costs that would go unrecovered due to lost retail kWh sales as a result of implementing ACC approved energy efficiency programs and distributed generation targets. TEP records a regulatory asset and recognizes LFCR revenues when the amounts are verifiable, regardless of when the lost retail kWh sales occur. For recovery of the LFCR regulatory asset, TEP is required to file an annual LFCR adjustment request with the ACC for the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of TEP's total retail revenues.

TEP recorded a regulatory asset and recognized LFCR revenues of $12 million in 2015, $11 million in 2014, and $2 million in 2013 related to reductions in retail kWh sales for the prior years. LFCR revenues are included in Electric Retail Sales on the Consolidated Statements of Income.

Appellate Review of Rate Decisions

In a 2015 appellate challenge to two ACC rate decisions regarding a water company, the Arizona Court of Appeals considered the question of how the ACC should determine a utility's "fair value", as specified in the Arizona Constitution, in connection with authorizing recovery of costs through rate adjustors outside of a rate case. The Court reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. In February 2016, the Arizona Supreme Court granted the ACC's request for review of this decision. If the Supreme Court upholds the decision without modification, certain TEP rate adjustors may be negatively affected which could have a significant impact on TEP's ability to recover certain costs between rate cases. TEP filed a brief in support of the ACC's petition to the Supreme Court for review of the Court of Appeals' decision, but cannot predict the outcome of this matter.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

REGULATORY ASSETS AND LIABILITIES

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. With the exception of interest earned on under-recovered PPFAC costs and the ECA, we do not earn a return on regulatory assets. Regulatory liabilities represent items that we either expect to pay to customers through billing reductions in future periods or plan to use for the purpose for which they were collected from customers. Regulatory assets and liabilities recorded on the Consolidated Balance Sheets are summarized below:

	December 31,	
(in millions)	2015	2014
Regulatory Assets		
Pension and Other Retiree Benefits (Note 8)	$ 120	$ 126
Final Mine Reclamation and Retiree Health Care Costs (1)	28	29
Income Taxes Recoverable through Future Rates (2)	26	31
Property Tax Deferrals (3)	21	21
Springerville Unit 1 Leasehold Improvements - Third Party Owners (4)	21	—
LFCR and DSM	16	12
Derivatives (Note 11)	12	18
PPFAC	—	19
Springerville Purchase Deferrals (5)	—	16
Other Regulatory Assets	20	20
Total Regulatory Assets	264	292
Less Current Portion	52	69
Total Non-Current Regulatory Assets	$ 212	$ 223
Regulatory Liabilities		
Net Cost of Removal for Interim Retirements (6)	$ 264	$ 265
Deferred Investment Tax Credits (7)	32	41
RES	25	28
PPFAC	18	—
Other Regulatory Liabilities	21	26
Total Regulatory Liabilities	360	360
Less Current Portion	53	39
Total Non-Current Regulatory Liabilities	$ 307	$ 321

(1) Final Mine Reclamation and Retiree Health Care Costs represent costs associated with TEP's jointly-owned facilities at San Juan, Four Corners, and Navajo. TEP has the option to recognize its liability associated with final reclamation and retiree health care obligations at present or future value. TEP has elected to recognize these costs at future value and is permitted to fully recover these costs through the PPFAC when paid. TEP expects to make continuous payments through 2037.

(2) Income Taxes Recoverable through Future Rates are amortized over the life of the assets. See Note 1 and Note 12 for additional information regarding income taxes.

(3) Property taxes are recorded as a regulatory asset based on historical ratemaking treatment allowing regulated utilities to recover property taxes on a pay-as-you-go or cash basis. TEP records a liability to reflect the accrual for financial reporting purposes and an offsetting regulatory asset to reflect recovery for regulatory purposes. This asset is fully recovered in rates with a recovery period of approximately six months.

(4) Upon expiration of Springerville Unit 1 capital leases in January 2015, TEP recorded a regulatory asset for unamortized leasehold improvement costs that relate to third-party ownership interests. These leasehold improvements, previously recorded in Plant in Service on the Consolidated Balance Sheets, represent investments TEP made through the end of the lease term to ensure that the Springerville Unit 1 facilities continued providing safe, reliable service to TEP's customers. In the 2013 Rate Order, TEP received ACC authorization to recover Springerville Unit 1 leasehold improvement costs over a 10-year amortization period.

(5) TEP deferred the increase in lease interest expense relating to the purchase commitments for Springerville Unit 1 and the Springerville Coal Handling Facilities to a regulatory asset because TEP believes the full purchase price is recoverable in rate base. See Note 6 for additional information regarding the Springerville leases.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for transmission, distribution, generation plant, and general and intangible plant which are not yet expended.

(7) Accumulated Deferred Investment Tax Credit (ITC) represents federal energy credits generated after 2011 that are amortized over the tax life of the underlying asset.

IMPACTS OF REGULATORY ACCOUNTING

If we determine that we no longer meet the criteria for continued application of regulatory accounting, we would be required to write off our regulatory assets and liabilities related to those operations not meeting the regulatory accounting requirements. Discontinuation of regulatory accounting could have a material impact on our financial statements.

NOTE 3. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by major class:

	December 31,	
(in millions)	2015	2014
Plant in Service		
Electric Generation Plant	$ 2,612	$ 2,388
Electric Transmission Plant	1,008	890
Electric Distribution Plant	1,456	1,398
General Plant	358	338
Intangible Plant - Software Costs (1) (2)	172	149
Intangible Plant - Transmission Rights and Other	7	8
Electric Plant Held for Future Use	5	4
Total Plant in Service	$ 5,618	$ 5,175
Utility Plant under Capital Leases (3)	$ 132	$ 667

(1) Unamortized computer software costs were $45 million and $31 million as of December 31, 2015 and 2014, respectively.

(2) The amortization of computer software costs was $14 million in 2015, $17 million in 2014, and $14 million in 2013.

(3) TEP purchased certain Springerville facilities leased interests in 2015 and 2014. See Note 6 for additional information regarding the Springerville leases.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Utility Plant under Capital Leases

All utility plant under capital leases is used in generation operations and amortized over the primary lease term. See Note 6 for additional information regarding capital leases. At December 31, 2015, the utility plant under capital leases represents an undivided one-half interest in certain Springerville Common Facilities. The following table shows the amount of lease expense incurred for generation-related capital leases:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Lease Expense			
Interest Expense – Included in:			
Capital Leases	$ 4	$ 10	$ 25
Operating Expenses – Fuel	—	1	2
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	2	6	5
Operating Expenses – Amortization	6	16	15
Total Lease Expense	$ 12	$ 33	$ 47

Utility plant depreciation rates and approximate average remaining service lives based on the most recent depreciation studies available for the major classes of Utility Plant in Service at December 31, 2015, were as follows:

	Annual Depreciation Rate (1)	Average Remaining Life in Years
Electric Generation Plant	3.31%	22
Electric Transmission Plant	1.48%	32
Electric Distribution Plant	2.08%	35
General Plant	5.48%	11
Intangible Plant (2)	Various	Various

(1) The depreciation rates represent a composite of the depreciation rates of assets within each major class of utility plant.

(2) The majority of TEP's investment in intangible plant represents computer software. Computer software is being amortized over its expected useful life of three to five years for smaller application software and average remaining life of three to eight years for large enterprise software.

GILA RIVER ACQUISITION

In December 2014, TEP and UNS Electric, Inc. (UNS Electric) acquired Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 megawatts (MW) located in Gila Bend, Arizona, from a subsidiary of Entegra Power Group LLC. TEP purchased a 75% undivided interest in Gila River Unit 3 (413 MW) for $164 million, and UNS Electric purchased the remaining 25% undivided interest.

TEP's purchase of Gila River Unit 3 was intended to replace the reduction of 195 MW of output from Springerville Unit 1 and the 170 MW of capacity expected to be retired at San Juan in 2017.

The transaction was accounted for using the acquisition method of accounting which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the assets acquired and liabilities assumed as of the acquisition date:

(in millions)	
Utility Plant, Net	$ 163

Materials and Supplies		2
ARO Obligation Assumed [(1)]		(1)
Total Purchase Price	$	164

(1) The ARO obligation was recorded at net present value in Regulatory and Other Liabilities - Other on TEP's Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

JOINTLY-OWNED FACILITIES

In addition to Gila River Unit 3, at December 31, 2015, TEP was a participant in the following jointly-owned generating stations and transmission systems:

(in millions)	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0%	$ 486	$ 12	$ 251	$ 247
Navajo Units 1, 2, and 3	7.5%	148	2	112	38
Four Corners Units 4 and 5	7.0%	102	9	77	34
Luna Energy Facility	33.3%	54	—	—	54
Gila River Unit 3	75.0%	198	2	56	144
Gila River Common Facilities	18.8%	25	—	7	18
Springerville Unit 1 (1)	49.5%	319	8	174	153
Springerville Coal Handling Facility (2)	65.9%	164	1	65	100
Transmission Facilities	Various	383	1	172	212
Total		$ 1,879	$ 35	$ 914	$ 1,000

(1) TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. The Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses. See Note 6 for additional information regarding the purchase of leased interest. See Note 7 for additional information regarding Springerville Unit 1.

(2) TEP owns an additional 17.05% undivided interest in the Springerville Coal Handling Facilities classified as Assets Held for Sale on the Consolidated Balance Sheets. See Note 6 for additional information regarding the Springerville Coal Handling Facilities lease interests.

As participants in these jointly-owned facilities, we are responsible for our share of operating and capital costs for the above facilities. We account for our share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

RETIREMENTS

San Juan

In October 2014, the EPA published a final rule approving a State Implementation Plan (SIP) covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017. TEP is a participant in San Juan Unit 2. Given the closure of two units and the desire of certain participants to exit their ownership in San Juan, PNM and the other participants, including TEP, negotiated restructured ownership agreements which became effective upon the sale of San Juan Coal Company's (SJCC) stock in January 2016. As a condition of the New Mexico Public Regulatory Commission's (NMPRC) approval of the early retirement of San Juan Units 2 and 3, PNM is required to make a filing with the NMPRC in 2018 to demonstrate the ongoing economic viability of San Juan beyond 2022. Under the new restructured ownership agreements, TEP and the other remaining participants have the option to exit their remaining ownership interest in San Juan as of June 30, 2022.

At December 31, 2015, the net book value of TEP's share in San Juan Unit 2, including construction work in progress, was $104 million. Consistent with the 2013 Rate Order, TEP has requested authorization from the ACC to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. See Note 2 for additional information regarding the 2015 Rate Case.

Sundt

In June 2014, the EPA issued a final rule that would require TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continues to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under the rule, TEP is required to notify the EPA of its decision by March 2017.

At December 31, 2015, the net book value of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. See Note 2 for additional information regarding the 2015 Rate Case.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and photovoltaic assets and is included in Regulatory and Other Liabilities on the Consolidated Balance Sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2015	2014
Beginning of Period	$ 28	$ 22
Liabilities Incurred	4	5
Accretion Expense or Regulatory Deferral	1	1
Revisions to the Present Value of Estimated Cash Flows [1]	(1)	—
End of Period	$ 32	$ 28

(1) Primarily related to changes in expected cost estimates, in conjunction with changes of asset retirement dates of generating facilities.

NOTE 4. ACCOUNTS RECEIVABLE

The following table presents the components of Accounts Receivable, Net on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2015	2014
Customer	$ 79	$ 78
Due from Affiliates (Note 5)	7	5
Unbilled	39	37
Other	39	17
Allowance for Doubtful Accounts [1]	(27)	(5)
Accounts Receivable, Net	$ 137	$ 132

(1) The Allowance for Doubtful Accounts increased in 2015 due to the Third-Party Owners' claims at Springerville Unit 1. See Note 7 for additional information regarding the Third-Party Owners' claims.

NOTE 5. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with Fortis, UNS Energy and its affiliated subsidiaries including Unisource Energy Services, Inc. (UES), UNS Electric, UNS Gas, Inc. (UNS Gas) and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy affiliates). These transactions include the sale and purchase of power and transmission services, common cost allocations, and the provision of corporate and other labor related services.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the components of related party balances included in Accounts Receivable, Net and Accounts Payable on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2015	2014
Receivables from Related Parties		
UNS Electric	$ 6	$ 4
UNS Gas	1	1
Total Due from Related Parties	$ 7	$ 5
Payables to Related Parties		
SES	$ 2	$ 2
UNS Electric	2	1
UNS Energy	2	—
Total Due to Related Parties	$ 6	$ 3

The following table presents the components of related party transactions included on the Consolidated Statements of Income:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Wholesale Sales - TEP to UNS Electric (1)	$ 8	$ 4	$ 1
Wholesale Sales - UNS Electric to TEP (1)	1	4	2
Control Area Services - TEP to UNS Electric (2)	2	3	4
Common Costs - TEP to UNS Energy Affiliates (3)	12	13	12
Supplemental Workforce - SES to TEP (4)	16	16	16
Corporate Services - UNS Energy to TEP (5)	7	14	5
Corporate Services - UNS Energy Affiliates to TEP (6)	1	1	1

(1) TEP and UNS Electric sell power and transmission services to each other at prevailing market prices.

(2) TEP charges UNS Electric for control area services under a FERC-approved Control Area Services Agreement.

(3) Common costs (information systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. The method of allocation is deemed reasonable by management and is reviewed by the ACC as part of the rate case process.

(4) SES provides supplemental workforce and meter-reading services to TEP based on related party service agreements. The charges are based on cost of services performed and deemed reasonable by management.

(5) Costs for corporate services at UNS Energy include Fortis management fees, legal fees, and audit fees which are allocated to its subsidiaries using the Massachusetts Formula, an industry accepted method of allocating common costs to affiliated entities. TEP's allocation is approximately 81% of UNS Energy's allocated costs. In 2015, these costs included approximately $5 million in Fortis management fees, which began in January 2015 following the August 2014 acquisition. In 2014, these costs included approximately $12 million in acquisition-related costs (excluding TEP allocated labor related charges).

(6) Costs for corporate services (e.g., finance, accounting, tax, legal, and information technology) and other labor services for UNS Energy Affiliates are directly assigned to the benefiting entity at a fully burdened cost when possible.

CONTRIBUTION FROM PARENT

In June 2015, UNS Energy made an equity contribution to TEP of $180 million. TEP used proceeds from the equity contribution to repay the outstanding balances under TEP's revolving credit facilities. The remaining balance of the proceeds was used to redeem bonds in August 2015 and to provide additional liquidity to TEP. See Note 6 for additional information regarding the August 2015 bond redemption. TEP received contributions of $225 million from UNS Energy in 2014 and no contributions in 2013.

DIVIDEND PAID

TEP declared and paid $50 million in dividends to UNS Energy in 2015 and $40 million in 2014 and 2013.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP had not reached the 50 percent of total capital and was therefore still restricted by the condition contained in the ACC's approval order.

NOTE 6. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

LONG-TERM DEBT

Long-term debt matures more than one year from the date of the financial statements. The following table presents the components of Long-Term Debt on the Consolidated Balance Sheets:

(dollars in millions)			December 31,	
Debt (1)	Interest Rate	Maturity Date (3)	2015	2014
Notes				
2011 Notes	5.15%	2021	$ 250	$ 250
2012 Notes	3.85%	2023	150	150
2014 Notes	5.00%	2044	150	150
2015 Notes	3.05%	2025	300	—
Tax Exempt Local Furnishings Bonds				
1982 Pima A Irvington Project	Reset Weekly (2)	2022	—	39
1982 Pima A TEP Projects	Reset Weekly (2)	2022	—	40
2008 Pima B	5.75%	2029	—	130
2010 Pima A	5.25%	2040	100	100
2012 Pima A	4.50%	2030	16	16
2013 Pima A	4.00%	2029	91	91
2013 Apache A	Reset Monthly (2)	2032	100	100
Tax Exempt Pollution Control Bonds				
2009 Pima A	4.95%	2020	80	80
2009 Coconino A	5.13%	2032	15	15
2010 Coconino A	Reset Weekly (2)	2032	37	37
2012 Apache A	4.50%	2030	177	177
Total Long-Term Debt			1,466	1,375
Less Unamortized Discount and Debt Issuance Costs			14	13
Total Long-Term Debt, Net			$ 1,452	$ 1,362

(1) As of December 31, 2015, all of TEP's debt is unsecured, with the exception of the 2010 Coconino A variable rate bonds, which are backed by a LOC.

(2) For variable rate debt for which rates are reset weekly, the weighted average rate (including LOC fees and remarketing fees) was 1.24% in 2015 and 1.46% in 2014. The average weekly interest rate ranged from 0.93% - 1.42% in 2015 and 1.40% - 1.75% during 2014. For variable rate debt for which rates are reset monthly, the rate is based on a percentage of an index equal to one-month London Interbank Offered Rate (LIBOR) plus a credit spread. The average monthly rate was 0.81% in 2015 and 0.87% in 2014. The

monthly interest rate ranged from 0.79% - 0.87% in 2015 and 0.85% - 0.95% in 2014.

(3) The 2010 Coconino A variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. The 2013 Apache A variable rate bonds are subject to mandatory tender for purchase in 2018.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEBT ISSUANCES AND REDEMPTIONS

Fixed Rate Debt

In February 2015, TEP issued and sold $300 million aggregate principal amount of senior unsecured notes. TEP may redeem the notes prior to December 2024, with a make-whole premium plus accrued interest. On or after December 2024, TEP may redeem the notes at par plus accrued interest.

In January 2015, TEP purchased $130 million aggregate principal amount of unsecured tax exempt Industrial Development Revenue Bonds (IDRBs) issued in June 2008 by the Industrial Development Authority (IDA) of Pima County, Arizona for the benefit of TEP. The multi-modal bonds mature in September 2029. At December 31, 2015, TEP had not remarketed the repurchased bonds and as a result the bonds were not recorded in Long-Term Debt on the Consolidated Balance Sheets.

In March 2014, TEP issued and sold $150 million of unsecured notes. TEP may redeem the notes prior to September 2043, with a make-whole premium plus accrued interest. After September 2043, TEP may redeem the notes at par plus accrued interest.

Variable Rate Debt

In August 2015, TEP redeemed two series of variable rate tax-exempt bonds at par with an aggregate principal amount of $79 million prior to maturity. In September 2015, TEP terminated the associated LOCs issued under a revolving credit facility.

In September 2014, TEP's interest rate swap entered into in August 2009 expired. The interest rate swap had the economic effect of converting $50 million of variable rate bonds to a fixed rate of 2.40% from September 2009 to September 2014.

CREDIT AGREEMENTS

In October 2015, TEP entered into an unsecured credit agreement (2015 Credit Agreement) replacing the 2010 Credit Agreement. The 2015 Credit Agreement provides for a $250 million revolving credit commitment and LOC facility. The LOC sublimit is $50 million. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. All amounts outstanding under the facility will be due in October 2020, the termination date. The 2015 Credit Agreement allows for two one-year extensions of the facility if certain conditions are satisfied.

Interest rates and fees under the 2015 Credit Agreement are based on a pricing grid tied to TEP's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.00% for Eurodollar loans or Alternate Base Rate with no spread for Alternate Base Rate loans.

At December 31, 2015, TEP had no borrowings outstanding included in Current Liabilities on the Consolidated Balance Sheets. As of February 17, 2016, there was $250 million available under the 2015 Credit Agreement's revolving credit and LOC facilities.

In 2015, TEP terminated both the 2010 and 2014 Credit Agreements. The amended 2010 Credit Agreement provided for a $200 million revolving credit commitment and LOCs supporting variable-rate, tax-exempt bonds, with an expiration date of November 2016. The 2014 Credit Agreement, entered into in December 2014, provided for a $130 million term loan commitment and a $70 million revolving credit commitment, with an expiration date of November 2015. At December 31, 2014, TEP had $85 million in total borrowings outstanding under these agreements which were included in Current Liabilities on the Consolidated Balance Sheets.

2010 REIMBURSEMENT AGREEMENT

In December 2010, a $37 million LOC was issued to support certain variable rate tax-exempt bonds pursuant to the 2010 Reimbursement Agreement. The LOC had an expiration date of December 2014. In February 2014, the LOC was amended to extend the expiration date from 2014 to 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 0.75% per annum based on TEP's current credit ratings.

COVENANT COMPLIANCE

Certain of our credit and long-term debt agreements contain restrictive covenants, including restrictions on additional indebtedness, liens to secure indebtedness, mergers, sales of assets, transactions with affiliates, and restricted payments. At December 31, 2015, we were in compliance with the terms of our long-term debt, 2015 Credit Agreement, 2013 Covenants Agreement, and 2010 Reimbursement Agreement.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CAPITAL LEASE OBLIGATIONS

The following table details Capital Lease Obligation on TEP's Consolidated Balance Sheets:

(in millions)	December 31, 2015	December 31, 2014
Springerville Unit 1	$ —	$ 43
Springerville Coal Handling Facilities	—	117
Springerville Common Facilities	69	83
Total Capital Lease Obligations	69	243
Less Current Obligations Under Capital Leases	14	174
Total Capital Lease Obligations, Net	$ 55	$ 69

Springerville Unit 1 Capital Lease Purchases

In December 2014, TEP purchased a 10.6% leased interest in Springerville Unit 1 representing 41 MW of capacity for the appraised value of $20 million. In January 2015, upon expiration of the lease term, TEP purchased leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million, the appraised value. Upon purchase of the leased interests, TEP reduced Capital Lease Obligations on the Consolidated Balance Sheets for the purchase price.

With the completion of the purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. The Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses. See Note 7 for more information regarding claims relating to Springerville Unit 1.

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the lease, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million, bringing its total ownership of the assets to 100%. Upon purchase of the leased interest, TEP reduced Capital Lease Obligations on the Consolidated Balance Sheets for the purchase price.

In May 2015, SRP, the owner of Springerville Unit 4, purchased from TEP a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million.

Tri-State, the lessee of Springerville Unit 3, is obligated to either: (i) buy a 17.05% undivided interest in the facilities for approximately $24 million; or (ii) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option. At December 31, 2015, Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities is classified as Assets Held for Sale on the Consolidated Balance Sheets.

Springerville Common Facilities Leases

The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. TEP may also exercise a fixed-price purchase provision. The fixed prices for the acquisition of the interests in the common facilities are $38 million in 2017 and $68 million in 2021.

TEP entered into agreements with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that contain the following conditions if the Common Facilities Leases are not renewed:

- TEP will exercise the purchase options under these contracts;

- SRP will be obligated to buy a portion of these facilities; and
- Tri-State will be obligated to either: (i) buy a portion of these facilities; or (ii) continue making payments to TEP for the use of these facilities.

TEP entered into an interest rate swap in 2006 that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. The swap has the effect of fixing the benchmark LIBOR rate on a portion of the amortizing principal balance. The swap matures in January 2020 with interest on the lease debt payable at a swapped rate of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5.77% plus an applicable margin per the lease agreement. The lease debt outstanding at December 31, 2015 consisted of a notional amount of $29 million on which interest was fixed by the swap and a notional amount of $13 million of debt that was not hedged. The applicable margin was 1.88% and 1.75% at December 31, 2015 and 2014, respectively.

TEP recorded the interest rate swap as a cash flow hedge for financial reporting purposes. See Note 11 for additional information.

DEBT MATURITIES

Long-term debt, including revolving credit facilities classified as long-term, and capital lease obligations mature on the following dates:

(in millions)	Long-Term Debt Maturities [1]	Capital Lease Obligations	Total [2]
2016	$ —	$ 15	$ 15
2017	—	16	16
2018	100	11	111
2019	37	11	48
2020	80	18	98
Total 2016 - 2020	217	71	288
Thereafter	1,249	—	1,249
Less: Imputed Interest	—	(2)	(2)
Total	$ 1,466	$ 69	$ 1,535

(1) $37 million of TEP's variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in 2019 as though the LOC terminates without replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate IDRBs, which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in 2018.

(2) Total long-term debt is not reduced by $11 million of related unamortized debt issuance costs and $3 million of unamortized original issue discount.

NOTE 7. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2015, TEP had the following firm, non-cancellable, minimum purchase obligations and operating leases:

(in millions)	2016	2017	2018	2019	2020	Thereafter	Total
Fuel, Including Transportation	$ 78	$ 76	$ 49	$ 49	$ 41	$ 287	$ 580
Purchased Power	28	—	—	—	—	—	28
Transmission	6	6	6	4	3	13	38
Renewable Power Purchase Agreements	61	61	61	61	60	750	1,054
RES Performance-Based Incentives	8	8	8	8	8	67	107
Operating Leases:							
Land Easements and Rights-of-Way	1	1	1	1	1	77	82
Operating Leases Other	1	1	1	1	1	4	9

Total Purchase Commitments	$ 183	$ 153	$ 126	$ 124	$ 114	$ 1,198	$ 1,898

Fuel, Including Transportation

TEP has long-term contracts for the purchase and delivery of coal with various expiration dates through 2031. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these contracts include a price adjustment clause that will affect the future cost. TEP expects to spend more than the minimum purchase obligations to meet its fuel requirements. TEP's fuel costs are recoverable from customers through the PPFAC.

Contemporaneously with the sale of SJCC's stock in January 2016, the existing coal sale agreement terminated and a new Coal Supply Agreement (CSA) became effective. The new CSA is between SJCC and PNM and continues through June 30, 2022. TEP is not a party to the new CSA, but has minimum purchase obligations under restructured ownership agreements at San Juan. Estimated future payments, not included in the table above, are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2016 and 2040.

Purchased Power and Transmission

TEP has agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts and expire in 2016. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected market prices as of December 31, 2015.

TEP has agreements with other utilities to provide transmission services over lines that are part of the Western Interconnection, a regional grid in the United States. These contracts expire in various years between 2018 and 2028.

TEP's purchased power and transmission costs are recoverable from customers through the PPFAC mechanism.

Renewable Power Purchase Agreements and RES Performance-Based Incentives

TEP enters into long-term renewable power purchase agreements which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. These contracts expire in various years between 2030 and 2035.

In February 2016, a facility achieved commercial operation status. The related contract expires in 2036. Estimated future payments, not included in the table above, are $3 million in each of 2016 through 2020 and $43 million through the end of the contract.

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff.

See Note 2 for additional information regarding TEP's RES tariff.

Operating Leases

Our operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates. TEP's operating lease expense totaled $3 million in 2015 and 2014 and $2 million in 2013.

CONTINGENCIES

Navajo Generating Station Lease Extension

Navajo Generating Station (Navajo) is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in Navajo, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the Department of the Interior, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo. In 2015, TEP recorded additional estimated lease expense of approximately $1 million with the expectation that the lease amendment will become effective. TEP's Consolidated Balance Sheets reflect a total liability related

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to the lease amendment of $3 million and $2 million at December 31, 2015 and 2014, respectively, recorded in Regulatory and Other Liabilities—Other.

Claims Related to Springerville Generating Station Unit 1

In November 2014, the Springerville Unit 1 Third-Party Owners filed a complaint (FERC Action) against TEP at the FERC alleging that TEP had not agreed to wheel power and energy for the Third-Party Owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the Third-Party Owners and for the cost specified by the Third-Party Owners. The Third-Party Owners requested an order from the FERC requiring such wheeling of the Third-Party Owners' energy from their Springerville Unit 1 interests beginning in January 2015 to the Palo Verde switchyard and for the price specified by the Third-Party Owners. In February 2015, the FERC issued an order denying the Third-Party Owners complaint. In March 2015, the Third-Party Owners filed a request for rehearing in the FERC Action, which the FERC denied in October 2015. In December 2015, the Third-Party Owners appealed the FERC's order denying the Third-Party Owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015, TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

On December 19, 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged, and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners' claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015, the Third-Party Owners filed a motion for summary judgment on their claim that TEP has failed to pay certain of the Third-Party Owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent notices to TEP that alleged that TEP had defaulted under the Third-Party Owners' leases. The notices demanded that TEP pay liquidated damages totaling approximately $71 million. In letters to the Owner Trustees, TEP denied the allegations in the notices.

In April 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners' fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. The arbitration hearing is scheduled for July 2016.

In November 2015, TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming the Owner Trustee and Co-Trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015, the Owner Trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. TEP intends to vigorously

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

defend itself against the claims asserted by the Third-Party Owners and to vigorously pursue the claims it has asserted against the Third-Party Owners.

TEP and the Third-Party Owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Claims Related to San Juan Generating Station

In August 2013, the Bureau of Land Management (BLM) proposed regulations that, among other things, redefine the term "underground mine" to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately $5 million of which TEP's proportionate share would approximate $1 million. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot predict the final outcome of the BLM's proposed regulations.

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court of Colorado against the Office of Surface Mining (OSM) challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by OSM. Of the fifteen claims for relief in the WEG Petition, two concern SJCC's San Juan mine. WEG's allegations concerning the San Juan mine arise from OSM administrative actions in 2008. WEG alleges various National Environmental Policy Act (NEPA) violations against OSM, including, but not limited to, OSM's alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG's petition seeks various forms of relief, including a finding that the federal defendants violated NEPA by approving the mine plans, voiding, reversing, and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with NEPA has been demonstrated, and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. The parties have requested the court to stay this matter until April 2016, in furtherance of settlement negotiations. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the U.S. District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs sought to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. In June 2015, APS, the operator of Four Corners, announced a settlement with the Environmental Protection Agency (EPA) for outstanding environmental issues related to New Source Review provisions under the Clean Air Act. The settlement calls for environmental upgrades including Selective Catalytic Reduction (SCR) upgrades already planned for under the Regional Haze regulation, environmental mitigation projects, and civil penalties. A consent decree reflecting terms of the settlement was entered by the court in August 2015, effectively closing the case. TEP's share of the additional capital, excluding the SCR upgrades, is approximately $2 million over the three year period it will take to construct the upgrades. TEP's share of the annual O&M expenses is approximately $1 million. In addition, TEP recorded less than $1 million for its share of the one-time charges for environmental mitigation projects and civil penalties.

In May 2013, the New Mexico Taxation and Revenue Department (NMTRD) issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. TEP's share of the assessment is $1 million based on our ownership percentage. In December 2013, the coal supplier and Four Corners' operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

resulting liabilities. In June 2015, the U.S. District Court ruled in favor of the Four Corners' participants. NMTRD filed an appeal of the decision in August 2015. TEP cannot predict the final outcome or timing of resolution of these claims.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP's share of reclamation costs at all three mines is expected to be $43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The reclamation liability recorded was $25 million and $22 million at December 31, 2015 and 2014, respectively.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP's PPFAC allows us to pass through final reclamation costs, as a component of fuel cost, to retail customers. Therefore, TEP classifies these costs as a regulatory asset by increasing the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements and recovers the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

Discontinued Transmission Project

TEP and UNS Electric had initiated a project to jointly construct a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. At this time, TEP and UNS Electric will not proceed with the project based on the cost of the proposed 345-kilo-volt (kV) line, the difficulty in reaching agreement with the United States Forest Service on a path for the line, and concurrence by the ACC that recent transmission additions by TEP and UNS Electric support elimination of this project. TEP and UNS Electric plan to maintain the Certificate of Environmental Compatibility (CEC) previously granted by the ACC for this project in contemplation of using the route to serve future customers and to address reliability needs. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from the FERC before seeking rate recovery from the ACC. In 2012, TEP wrote off $5 million of the capitalized costs and recorded a regulatory asset of $5 million for the balance deemed probable of recovery in TEP's next FERC rate case.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and the Luna Energy Facility (Luna). The participants in each of the generating stations, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generating capacity of the defaulting participant. As of December 31, 2015, there have been no such payment defaults under any of the participation agreements. The Navajo participation agreement expires in 2019, San Juan in 2022, Four Corners in 2041, and Luna in 2046.

NOTE 8. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

TEP has three noncontributory, defined benefit pension plans. Benefits are based on years of service and average compensation. Two of the plans are for substantially all employees. We fund those plans by contributing at least the minimum amount required under the Internal Revenue Service (IRS) regulations. We also maintain a Supplemental Executive Retirement Plan (SERP) for executive management.

OTHER RETIREE BENEFIT PLANS

TEP provides limited health care and life insurance benefits for retirees. Active TEP employees may become eligible for these benefits if they reach retirement age while working for TEP or an affiliate.

(1) In 2016, TEP expects to contribute $10 million to the pension plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides the components of TEP's regulatory assets and accumulated other comprehensive loss that have not been recognized as components of net periodic benefit cost as of the dates presented:

	Pension Benefits		Other Retiree Benefits	
	Year Ended December 31,			
(in millions)	2015	2014	2015	2014
Net Loss	$ 117	$ 118	$ 6	$ 11
Prior Service Cost (Benefit)	3	4	(1)	(2)

The accumulated benefit obligation aggregated for all pension plans is $355 million and $365 million at December 31, 2015 and 2014, respectively.

All three of our pension plans had accumulated benefit obligations in excess of plan assets at December 31, 2014. As a result of increases in discount rates and employer contributions, two of our plans had accumulated benefit obligations in excess of plan assets at December 31, 2015. The following table includes information for pension plans with accumulated benefit obligations in excess of pension plan assets:

	December 31,	
(in millions)	2015	2014
Accumulated Benefit Obligation	$ 188	$ 365
Fair Value of Plan Assets	169	335

Net periodic benefit plan cost includes the following components:

	Pension Benefits			Other Retiree Benefits		
	Year Ended December 31,					
(in millions)	2015	2014	2013	2015	2014	2013
Service Cost	$ 12	$ 10	$ 11	$ 4	$ 4	$ 3
Interest Cost	17	16	14	3	3	3
Expected Return on Plan Assets	(23)	(21)	(19)	(1)	(1)	(1)
Actuarial Loss Amortization	7	3	8	—	—	—
Net Periodic Benefit Cost	$ 13	$ 8	$ 14	$ 6	$ 6	$ 5

Approximately 20% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in income.

We measured service and interest costs for pension and other postretirement benefits utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. At the end of 2015, we changed our approach to determine the service and interest cost components of pension and other postretirement benefit expense. We elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows beginning in 2016. TEP believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of our plan obligations nor the funded status. We accounted for this change as a change in accounting estimate, and accordingly, have accounted for it on a prospective basis.

The changes in plan assets and benefit obligations recognized as regulatory assets or in AOCI are as follows:

Pension Benefits	
Regulatory Asset	AOCI

(in millions)	2015	2014	2013	2015	2014	2013
Current Year Actuarial (Gain) Loss	$ 5	$ 49	$ (42)	$ —	$ 3	$ (1)
Amortization of Actuarial Gain (Loss)	(7)	(3)	(8)	—	—	—
Total Recognized (Gain) Loss	$ (2)	$ 46	$ (50)	$ —	$ 3	$ (1)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Other Retiree Benefits Regulatory Asset		
(in millions)	2015	2014	2013
Current Year Actuarial (Gain) Loss	$ (4)	$ 5	$ (6)

For all pension plans, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. We expect to amortize an estimated $7 million net loss from pension regulatory assets and an estimated $1 million in prior service credit from other retiree benefit plan regulatory assets into net periodic benefit cost in 2016.

The following table includes the weighted average assumptions used to determine benefit obligations:

	Pension Benefits		Other Retiree Benefits	
	2015	2014	2015	2014
Discount Rate	4.5-4.6%	4.1-4.2%	4.2%	3.9%
Rate of Compensation Increase	3.0%	3.0%	N/A	N/A

The following table includes the weighted average assumptions used to determine net periodic benefit costs:

	Pension Benefits			Other Retiree Benefits		
	2015	2014	2013	2015	2014	2013
Discount Rate	4.1%-4.2%	5.0%-5.1%	4.1%-4.1%	3.9%	4.7%	3.8%
Rate of Compensation Increase	3.0%	3.0%	3.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets.

We use a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a "best-estimate" range over 20 years from the 25th percentile to the 75th percentile. The model, used as a guideline for selecting the overall rate-of-return-on-assets assumption, is based on forward looking return expectations only. The above method is used for all asset classes.

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost. The following table includes the assumed health care cost trend rates:

	December 31,	
	2015	2014
Next Year	7.6%	6.7%
Ultimate Rate Assumed	4.5%	4.5%
Year Ultimate Rate is Reached	2036	2027

Assumed health care cost trend rates significantly affect the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects on the December 31, 2015 amounts:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on Total Service and Interest Cost Components	$ 1	$ 1
Effect on Retiree Benefit Obligation	6	5

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

PENSION PLAN AND OTHER RETIREE BENEFIT ASSETS

Pension Assets

We calculate the fair value of plan assets on December 31, the measurement date. Pension plan asset allocations, by asset category, on the measurement date were as follows:

	2015	2014
Asset Category		
Equity Securities	49%	48%
Fixed Income Securities	41%	43%
Real Estate	8%	7%
Other	2%	2%
Total	100%	100%

The following table sets forth the fair value measurements of pension plan assets by level within the fair value hierarchy:

(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	December 31, 2015			
Asset Category				
Cash Equivalents	$ 1	$ —	$ —	$ 1
Equity Securities:				
United States Large Cap	—	81	—	81
United States Small Cap	—	17	—	17
Non-United States	—	67	—	67
Fixed Income	—	137	—	137
Real Estate	—	8	18	26
Private Equity	—	—	7	7
Total	$ 1	$ 310	$ 25	$ 336

(in millions)				
	December 31, 2014			
Asset Category				
Cash Equivalents	$ 1	$ —	$ —	$ 1
Equity Securities:				
United States Large Cap	—	82	—	82
United States Small Cap	—	17	—	17
Non-United States	—	61	—	61
Fixed Income	—	143	—	143
Real Estate	—	8	16	24
Private Equity	—	—	7	7
Total	$ 1	$ 311	$ 23	$ 335

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, United States bond funds, and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Level 3 real estate investments were valued using a real estate index value. The real estate index value was developed based on appraisals comprising 100% of real estate assets tracked by the index.

Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth a reconciliation of changes in the fair value of pension assets classified as Level 3 in the fair value hierarchy. There were no transfers in or out of Level 3.

(in millions)	Private Equity	Real Estate	Total
Beginning Balance at January 1, 2014	$ 7	$ 14	$ 21
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Ending Balance at December 31, 2014	7	16	23
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Ending Balance at December 31, 2015	$ 7	$ 18	$ 25

Pension Plan Investments

Investment Goals

Asset allocation is the principal method for achieving each pension plan's investment objectives while maintaining appropriate levels of risk. We consider the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding are reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the pension plans. We expect to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

We recognize the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. We also recognize some risk must be assumed to achieve a pension plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: plan status, plan sponsor financial status and profitability, plan features, and workforce characteristics. We have determined that the pension plans can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. TEP tracks each pension plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the pension plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges may also be used for defensive purposes.

Relationship between Plan Assets and Benefit Obligations

The overall health of each plan will be monitored by comparing the value of plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the fair value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of plan data, but will be no less frequent than annually via actuarial valuation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Target Allocation Percentages

The current target allocation percentages for the major asset categories of the plan as of December 31, 2015 follow. Each plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	TEP Plans	VEBA Trust
Cash/Treasury Bills	—%	2%
Equity Securities:		
United States Large Cap	24%	39%
United States Small Cap	5%	5%
Non-United States Developed	15%	7%
Non-United States Emerging	5%	9%
Fixed Income	42%	38%
Real Estate	8%	—%
Private Equity	1%	—%
Total	100%	100%

Pension Fund Descriptions

For each type of asset category selected by the Pension Committee, our investment consultant assembles a group of third-party fund managers and allocates a portion of the total investment to each fund manager. In the case of the private equity fund, our investment consultant directs investments to a private equity manager that invests in third-parties' funds.

Other Retiree Benefit Assets

As of December 31, 2015, the fair value of VEBA trust assets was $13 million, of which $5 million were fixed income investments and $8 million were equities. As of December 31, 2014, the fair value of VEBA trust assets was $12 million, of which $4 million were fixed income investments and $8 million were equities. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the defined benefit pension plans and other retiree benefit plan, which reflect future service, as appropriate.

(in millions)	2016	2017	2018	2019	2020	2021-2025
Pension Benefits	$ 17	$ 18	$ 19	$ 21	$ 22	$ 125
Other Retiree Benefits	5	5	5	6	6	33

DEFINED CONTRIBUTION PLAN

We offer a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account. We match part of a participant's contributions to the plan. TEP made matching contributions to the plan of $5 million in 2015, 2014, and 2013.

NOTE 9. SHARE-BASED COMPENSATION

2011 STOCK AND INCENTIVE PLAN

The Fortis acquisition of UNS Energy in 2014 resulted in accelerated vesting and expense recognition of all outstanding nonvested UNS Energy share-based awards issued under the UNS Energy 2011 Omnibus Stock and Incentive Plan (2011 Plan). The outstanding non-vested awards would otherwise have been recognized over remaining vesting periods through February 2017. TEP recognized approximately $2 million of expense in 2014 due to the accelerated vesting of the awards. TEP recorded total share-based compensation expense of $5 million for the year ended December 31, 2014 and $3 million for the year ended December 31, 2013. In August 2014, UNS Energy settled all outstanding share-based compensation awards related to the 2011 Plan in cash.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2015 SHARE UNIT PLAN

The Human Resources and Governance Committee (Committee) of UNS Energy, approved and UNS Energy's Board of Directors ratified the 2015 Share Unit Plan (Plan) effective as of January 1, 2015. Under the Plan, key employees, including executive officers of UNS Energy and its subsidiaries, may be granted long-term incentive awards of performance-based share units (PSUs) and time-based restricted share units (RSUs) annually. Each PSU and RSU granted will be valued based on one share of Fortis common stock converted to U.S. dollars. Fortis common stock is traded on the Toronto Stock Exchange. TEP's share of the obligation and expense as a subsidiary of UNS Energy is allocated based on the Massachusetts Formula.

UNS Energy awarded 47,776 PSUs and 23,888 RSUs in 2015 that are payable on the third anniversary of the grant date. The awards are classified as liability awards based on the cash settlement feature. Liability awards are measured at their fair value at the end of each reporting period and will fluctuate based on the price of Fortis common stock as well as the level of achievement of the financial performance criteria. At December 31, 2015, TEP's allocated share of probable payout is $2 million.

TEP's allocated portion of the compensation expense is recognized in Operations and Maintenance on the Consolidated Statements of Income. Compensation expense associated with unvested PSUs and RSUs is recognized on a straight-line basis over the minimum required service period in an amount equal to the fair value on the measurement date or each reporting period. TEP recorded $1 million for the year ended December 31, 2015 based on its share of UNS Energy's compensation expense.

NOTE 10. SUPPLEMENTAL CASH FLOW INFORMATION

CASH TRANSACTIONS

	Year Ended December 31,		
(in millions)	2015	2014	2013
Interest, Net of Amounts Capitalized	$ 65	$ 83	$ 53
Income Taxes	—	—	—

NON-CASH TRANSACTIONS

Other significant non-cash investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Accrued Capital Expenditures	$ 28	$ 29	$ 24
Net Cost of Removal of Interim Retirements (1)	1	12	25
Commitment to Purchase Capital Lease Interests	—	109	55
Capital Lease Obligations (2)	—	1	9
Proceeds from Issuance of Long-Term Debt Deposited in Trust	—	—	191
Asset Retirement Obligations (3)	3	4	8

(1) The non-cash net cost of removal of interim retirements represents an accrual for future asset retirement obligations that does not impact earnings.

(2) The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments.

(3) The non-cash additions to asset retirement obligations and related capitalized assets represent a revision of estimated asset retirement cost due to changes in timing and amount of the expected future asset retirement obligations.

NOTE 11. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

We categorize our financial instruments into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

indirectly. Level 3 inputs are unobservable and supported by little or no market activity. Transfers between levels are recorded at the end of a reporting period. There were no transfers between levels in the periods presented.

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, TEP's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

(in millions)	Level 1	Level 2	Level 3	Total
	December 31, 2015			
Assets				
Cash Equivalents[1]	$ 33	$ —	$ —	$ 33
Restricted Cash[1]	4	—	—	4
Energy Derivative Contracts - Regulatory Recovery[2]	—	1	—	1
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	1	1
Total Assets	37	1	1	39
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(10)	(3)	(13)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(13)	(3)	(16)
Net Total Assets (Liabilities)	$ 37	$ (12)	$ (2)	$ 23
(in millions)	December 31, 2014			
Assets				
Cash Equivalents[1]	$ 15	$ —	$ —	$ 15
Restricted Cash[1]	2	—	—	2
Energy Derivative Contracts - Regulatory Recovery[2]	—	—	2	2
Total Assets	17	—	2	19
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(9)	(9)	(18)
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	(1)	(1)
Energy Derivative Contracts - Cash Flow Hedge[2]	—	—	(1)	(1)
Interest Rate Swap[3]	—	(5)	—	(5)
Total Liabilities	—	(14)	(11)	(25)
Net Total Assets (Liabilities)	$ 17	$ (14)	$ (9)	$ (6)

(1) Cash Equivalents and Restricted Cash represent amounts held in money market funds and certificates of deposit valued at cost, including interest, which approximates fair market value. Cash Equivalents are included in Cash and Cash Equivalents on the Consolidated Balance Sheets. Restricted Cash is included in Investments and Other Property on the Consolidated Balance Sheets.

(2) Energy Contracts include gas swap agreements (Level 2), power options (Level 2), gas options (Level 3), forward power purchase and sales contracts (Level 3) entered into to reduce exposure to energy price risk, and, at December 31, 2014 a power sale option (Level 3). These contracts are included in Derivative Instruments on the Consolidated Balance Sheets. The valuation techniques are described below.

(3) The Interest Rate Swap is valued using an income valuation approach based on the 6-month LIBOR and is included in Derivative Instruments on the Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All energy derivative contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We present derivatives on a gross basis on the balance sheet. The tables below presents the potential offset of counterparty netting and cash collateral.

	Gross Amount Recognized on the Balance Sheets	Gross Amount Not Offset on the Balance Sheets		Net Amount
		Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	
(in millions)	December 31, 2015			
Derivative Assets				
Energy Derivative Contracts	$ 2	$ 1	$ —	$ 1
Derivative Liabilities				
Energy Derivative Contracts	(13)	(1)	—	(12)
Interest Rate Swap	(3)	—	—	(3)
(in millions)	December 31, 2014			
Derivative Assets				
Energy Derivative Contracts	$ 2	$ 2	$ —	$ —
Derivative Liabilities				
Energy Derivative Contracts	(20)	(2)	—	(18)
Interest Rate Swap	(5)	—	—	(5)

DERIVATIVE INSTRUMENTS

We enter into various derivative and non-derivative contracts to reduce our exposure to energy price risk associated with our gas and purchased power requirements. The objectives for entering into such contracts include: creating price stability; meeting load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC.

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability or use quoted prices in an inactive market, we categorize the instrument in Level 2. We categorize derivatives in Level 3 when we use an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices we obtain quotes from brokers, major market participants, exchanges, or industry publications and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms such as non-standard time blocks and non-standard delivery points. In these cases, we apply adjustments based on historical price curve relationships, transmission, and line losses.

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves.

The December 31, 2014 valuation of our power sale option was a function of observable market variables, regional power and gas prices, as well as the ratio between the two, which represents the prevailing market heat rate.

We also consider the impact of counterparty credit risk using current and historical default and recovery rates, as well as our own credit risk using credit default swap data.

The inputs and our assessments of the significance of a particular input to the fair value measurements require judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. We review the assumptions underlying our price curves monthly.

Cash Flow Hedges

We can enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. We have an interest rate swap agreement that expires January 2020. We also had a power purchase swap to hedge the cash flow risk associated with

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

a long-term power supply agreement which expired in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $1 million. The realized losses from our cash flow hedges are shown in the following table:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Capital Lease Interest Expense	$ 2	$ 2	$ 2
Long-Term Debt Interest Expense	—	1	1
Purchased Power	1	1	1

As of December 31, 2015, the total notional amount of our interest rate swap was $29 million.

Energy Derivative Contracts - Regulatory Recovery

We record unrealized gains and losses on energy purchase contracts that are recoverable through the PPFAC on the balance sheet as a regulatory asset or a regulatory liability rather than reporting the transaction in the income statement or in the statement of other comprehensive income, as shown in following table:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ 6	$ (18)	$ —

Energy Derivative Contracts - No Regulatory Recovery

Forward contracts with long-term wholesale customers do not qualify for regulatory recovery. For these contracts that qualify as derivatives, we record unrealized gains and losses in the income statement, unless and until a normal purchase or normal sale election is made. In February 2015, TEP made a normal sale election for a three-year sales option contract entered into in December 2014. In June 2015, TEP entered into long-term power trading contracts that qualify as derivatives but do not qualify for regulatory recovery. The unrealized gains and losses on the long-term power trading contracts are recorded in the income statement, and 10% of any gains will be shared with ratepayers through the PPFAC, as realized.

Derivative Volumes

At December 31, 2015, we have energy contracts that will settle through the fourth quarter of 2018. The volumes associated with our energy contracts were as follows:

	December 31,	
	2015	2014
Power Contracts GWh	1,752	2,604
Gas Contracts GBtu	17,214	19,932

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Level 3 Fair Value Measurements

The following table provides quantitative information regarding significant unobservable inputs in TEP's Level 3 fair value measurements:

(in millions)	Valuation Approach	Fair Value of Assets	Fair Value of Liabilities	Unobservable Inputs	Range of Unobservable Input	
	December 31, 2015					
Forward Power Contracts	Market approach	$ 1	$ (2)	Market price per MWh	$ 19.20	$ 31.35
Gas Option Contracts	Option model	—	(1)	Market price per MMbtu	$ 2.17	$ 2.69
				Gas volatility	31.0%	58.3%
Level 3 Energy Contracts		$ 1	$ (3)			
(in millions)	December 31, 2014					
Forward Power Contracts	Market approach	$ 1	$ (6)	Market price per MWh	$ 22.35	$ 39.05
Power Sale Option	Market approach	1	(1)	Market price per MWh	$ 27.75	$ 44.94
				Market price per MMbtu	$ 2.88	$ 4.02
Gas Option Contracts	Option model	—	(4)	Market price per MMbtu	$ 2.72	$ 3.26
				Gas volatility	30.8%	53.3%
Level 3 Energy Contracts		$ 2	$ (11)			

Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude of the change and the direction of the change for each input. The impact of changes to fair value, including changes from unobservable inputs, are subject to recovery or refund through the PPFAC mechanism and are reported on the balance sheet as a regulatory asset or regulatory liability, or as a component of other comprehensive income, rather than in the income statement.

The following table presents a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

(in millions)	Year Ended December 31, 2015	2014
Beginning of Period	$ (9)	$ (2)
Gains (Losses) Recorded to:[1]		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	(8)
Electric Wholesale Sales	3	—
Settlements	8	1
End of Period	$ (2)	$ (9)

(1) Includes gains (losses) attributable to the change in unrealized gains/(losses) relating to assets (liabilities) still held at the end of the

period of \$(1) million and \$(8) million for the years ended December 31, 2015, and 2014, respectively.

CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. We enter into contracts for the physical delivery of energy and gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and subsequent measurement at fair value.

We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

limits; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we would have to provide certain credit enhancements in the form of cash or LOCs to fully collateralize our exposure to these counterparties.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

Material adverse changes could trigger credit risk-related contingent features. At December 31, 2015, the value of all derivative instruments in net liability positions under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $20 million, compared with $27 million at December 31, 2014. At December 31, 2015, TEP had less than $1 million of LOCs as credit enhancements with its counterparties. If the credit risk-related contingent features were triggered on December 31, 2015, TEP would have been required to post an additional $20 million of collateral of which $8 million relates to outstanding net payable balances for settled positions.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- Borrowings under revolving credit facilities approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, we use quoted market prices, when available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The following table includes the face value and estimated fair value of our long-term debt:

	Fair Value Hierarchy	Face Value		Fair Value	
		December 31,			
(in millions)		2015	2014	2015	2014
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$ 1,466	$ 1,375	$ 1,529	$ 1,457

NOTE 12. INCOME TAXES

Income tax expense differs from the amount of income tax determined by applying the United States statutory federal income tax rate of 35% to pre-tax income due to the following:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Federal Income Tax Expense at Statutory Rate	$ 70	$ 56	$ 52
State Income Tax Expense, Net of Federal Deduction	8	7	7
Federal/State Tax Credits	(8)	(5)	(2)

Allowance for Equity Funds Used During Construction	(1)	(2)	(1)
Deferred Tax Asset Valuation Allowance	1	—	2
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	—	—	(11)
Other	2	2	1
Total Federal and State Income Tax Expense	$ 72	$ 58	$ 48

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset

Renewable energy assets are eligible for investment tax credits. We reduce the income tax basis of those qualifying assets by half of the related investment tax credit. Historically, the difference between the income tax basis of the assets and the book basis under GAAP was recorded as a deferred tax liability with an offsetting charge to income tax expense in the year the qualifying asset was placed in service. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

Income tax expense included in the income statements consists of the following:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Current Tax Expense (Benefit)			
Federal	$ —	$ (1)	$ (8)
State	—	—	(2)
Total Current Tax Expense (Benefit)	—	(1)	(10)
Deferred Tax Expense (Benefit)			
Federal	66	54	47
Federal Investment Tax Credits	(6)	(4)	(1)
State	12	9	12
Total Deferred Tax Expense (Benefit)	72	59	58
Total Federal and State Income Tax Expense	$ 72	$ 58	$ 48

The significant components of deferred income tax assets and liabilities consist of the following:

	December 31,	
(in millions)	2015	2014
Gross Deferred Income Tax Assets		
Capital Lease Obligations	$ 27	$ 96
Net Operating Loss Carryforwards	156	187
Customer Advances and Contributions in Aid of Construction	20	19
Alternative Minimum Tax Credit	24	24
Accrued Postretirement Benefits	23	23
Emission Allowance Inventory	9	10
Investment Tax Credit Carryforward	32	31
Other	53	54
Total Gross Deferred Income Tax Assets	344	444
Deferred Tax Assets Valuation Allowance	(4)	(2)
Gross Deferred Income Tax Liabilities		
Plant, Net	(750)	(699)
Capital Lease Assets, Net	(12)	(74)
Pensions	(27)	(27)
PPFAC	—	(8)
Other	(19)	(24)

Total Gross Deferred Income Tax Liabilities	(808)	(832)
Net Deferred Income Tax Liabilities	$ (468)	$ (390)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP has recorded a $4 million valuation allowance against credit and loss carryforward deferred tax assets at December 31, 2015 and a $2 million valuation allowance against credit carryforward deferred tax assets at December 31, 2014. Management believes TEP will not produce sufficient taxable income to use all credit and loss carryforwards before they expire.

As of December 31, 2015, TEP had the following carryforward amounts:

(in millions)	Amount	Expiring Year
Federal Net Operating Loss	$ 430	2031-34
State Net Operating Loss	114	2016-34
State Credits	10	2016-30
Alternative Minimum Tax Credit	24	None
Investment Tax Credits	32	2032-35

Uncertain Tax Positions

A reconciliation of the beginning and ending balances of unrecognized tax benefits follows:

	December 31,	
(in millions)	2015	2014
Beginning of Period	$ 4	$ 2
Additions Based on Tax Positions Taken in the Current Year	1	2
End of Period	$ 5	$ 4

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million at December 31, 2015 and would not reduce income tax expense at December 31, 2014.

TEP recorded no interest expense during 2015 and 2014 related to uncertain tax positions. In addition, TEP had no interest payable and no penalties accrued at December 31, 2015 and 2014.

TEP has been audited by the IRS through tax year 2010. TEP is not currently under audit by any federal or state tax agencies. The balance in unrecognized tax benefits could change in the next 12 months as a result of IRS audits, but we are unable to determine the amount of change.

NOTE 13. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

We consider the applicability and impact of all Accounting Standards Updates. Updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on our consolidated financial position, results of operations, or disclosures.

Revenue from Contracts with Customers

In May 2014, the FASB issued an accounting standards update that will eliminate the transaction and industry-specific revenue recognition guidance under current U.S. GAAP and replace it with a principles based approach for determining revenue recognition. The revenue standard requires entities to apply the guidance retrospectively or recognize the cumulative effect of initially applying the guidance as an adjustment to the opening balance of retained earnings supplemented by additional disclosures. In July 2015, the FASB voted to defer the effective date of the revenue recognition standard by one year. We are required to adopt the new guidance for annual and interim periods beginning January 1, 2018.

Retail sales of electricity based on regulator-approved tariff rates represent TEP's primary source of revenue. While it is expected that tariff-based sales to regulated customers are within the scope of the new standard, this question is being reviewed by the AICPA Financial Reporting Executive Committee. TEP is in the process of assessing its performance obligations in its wholesale contracts and identifying other contracts with customers.

Classification and Measurement of Financial Instruments

In January 2016, the FASB amended the guidance on the classification and measurement of financial instruments. Most notably, the new accounting standard update requires the following:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

- all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and
- financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category and form of financial asset.

TEP is required to adopt the new guidance for annual and interim periods beginning January 1, 2018. TEP is evaluating the impact to our financial statements and disclosures.

NOTE 14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial information is unaudited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature. Peak sales periods for TEP generally occur during the summer. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	2015			
Operating Revenue	$ 273	$ 340	$ 409	$ 284
Operating Income	28	74	120	36
Net Income	9	38	69	12
(in millions)				
	2014			
Operating Revenue	$ 256	$ 322	$ 387	$ 305
Operating Income	32	80	85	34
Net Income	9	39	40	15

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

TEP's Chief Executive Officer and Chief Financial Officer supervised and participated in TEP's evaluation of its disclosure controls and procedures as such term is defined under Rule 13a – 15(e) or Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this report. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in TEP's periodic reports filed or submitted under the Exchange Act, is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by TEP in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, TEP's Chief Executive Officer and Chief Financial Officer concluded that TEP's disclosure controls and procedures are effective.

While TEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting, there has been no change in TEP's internal control over financial reporting during 2015 that has materially affected, or is reasonably likely to materially affect, TEP's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

All of the members of the TEP Board of Directors are executive officers and employees of TEP, a wholly owned subsidiary of UNS Energy.

The directors of TEP are elected annually by TEP's sole shareholder, UNS Energy, acting at the direction of the Board of Directors of UNS Energy.

The names and information concerning the members of the TEP Board of Directors are set forth below:

Name	Age	Served As Director Since	Business Experience
David G. Hutchens	49	2011	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995. Mr. Hutchens' extensive experience in the electric and gas utility business and his position as President and Chief Executive Officer provide him with intimate knowledge of TEP's operations and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.
Kevin P. Larson	59	2009	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer. Mr. Larson is also a Chartered Financial Analyst. Mr. Larson's extensive experience in the electric and gas utility business and his position as Senior Vice President and Chief Financial Officer provide him with intimate knowledge of TEP's financial affairs and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.
Todd. C. Hixon	49	2015	Mr. Hixon has served as Vice President and General Counsel of TEP since May 2011. Mr. Hixon joined TEP's legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel. Mr. Hixon's extensive experience in utility legal and regulatory matters and his position as Vice President and General Counsel provide him with intimate knowledge of TEP's legal and regulatory affairs and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.

Executive Officers

Executive Officers, who are elected annually by TEP's Board of Directors, acting at the direction of the Board of Directors of UNS Energy, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
David G. Hutchens	49	President and Chief Executive Officer	2007
Kevin P. Larson	59	Senior Vice President and Chief Financial Officer	1997
Kentton C. Grant	57	Vice President and Treasurer	2007
Susan M. Gray	43	Vice President, T&D Operations and Engineering	2015
Todd C. Hixon	49	Vice President and General Counsel	2011
Karen G. Kissinger	61	Vice President and Chief Compliance Officer	1991
Mark C. Mansfield	60	Vice President, Energy Resources	2012
Frank P. Marino	51	Vice President and Controller	2013
Thomas A. McKenna	67	Vice President, Energy Delivery	2007
Catherine E. Ries	56	Vice President, Customer and Human Resources	2007
Mary Jo Smith	58	Vice President, Public Policy	2015
Herlinda H. Kennedy	54	Corporate Secretary	2006

David G. Hutchens	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995.
Kevin P. Larson	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.
Kentton C. Grant	Mr. Grant was elected Treasurer in 2010 and has served as Vice President of TEP since January 2007. Mr. Grant joined TEP in 1995.
Susan Gray	Ms. Gray has served as Vice President of T&D Operations and Engineering since 2015. Ms. Gray joined TEP in 1994 as a student engineer, and has served in a variety of capacities since then, most recently serving as Senior Director of T&D.
Todd C. Hixon	Mr. Hixon has served as Vice President and General Counsel of TEP since May 2011. Mr. Hixon joined TEP's legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel.
Karen G. Kissinger	Ms. Kissinger has served as Vice President and Chief Compliance Officer of TEP since August 2013. Ms. Kissinger served as Vice President, Controller, and Chief Compliance Officer from 2001 to 2013. Ms. Kissinger joined TEP as Vice President and Controller in January 1991.
Mark C. Mansfield	Mr. Mansfield has served as Vice President, Energy Resources since 2012. He joined the company in 2008 as Senior Director of Generation.
Frank P. Marino	Mr. Marino has served as Vice President and Controller of TEP since August 2013. Mr. Marino joined TEP as Assistant Controller in January 2013. Prior to joining TEP, he served in various roles at the AES Corporation, a global power company. In 2012 he served as AES' Vice President for Business Demand and Outsourcing Management, and from 2007-2011 he served as Chief Financial Officer for two different business units.
Thomas A. McKenna	Mr. McKenna has served as Vice President, Energy Delivery since August 2013. Mr. McKenna was named Vice President, Engineering in January 2007. Mr. McKenna joined an affiliate of TEP in 1998. Mr. McKenna is retiring from TEP on May 1, 2016.
Catherine E. Ries	Ms. Ries has served as Vice President, Customer and Human Resources since August 2015. Prior to that she served as Vice President of Human Resources and Information Technology, since May 2011. Ms. Ries joined TEP as Vice President of Human Resources in June 2007.
Mary Jo Smith	Ms. Smith has served as Vice President of Public Policy since 2015. Ms. Smith joined TEP as Director of Investor Relations in 2003 and most recently served as Senior Director of Regulatory Services and Corporate Communications.
Herlinda H. Kennedy	Ms. Kennedy has served as Corporate Secretary of TEP since September 2006. Ms. Kennedy joined TEP in 1980 and was named assistant Corporate Secretary in 1999.

Code of Ethics

See *Part I, Item 1. Business, SEC Reports Available on TEP's Website.*

Audit and Risk Committee of the UNS Energy Board

The Audit and Risk Committee of the Board of Directors of UNS Energy was established for the purpose of overseeing the accounting and financial reporting process and audits of the financial statements of UNS Energy and its consolidated subsidiaries, including TEP.

The Audit and Risk Committee reviews current and projected financial results of operations, selects an independent registered public accounting firm to audit UNS Energy's and TEP's financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations and transmits its recommendations to the UNS Energy Board of Directors. The Audit and Risk Committee of UNS Energy reviews UNS Energy's and TEP's accounting and internal control procedures with the internal audit department from time to time, makes recommendations to the board of UNS Energy for any changes deemed necessary in such procedures and performs such other functions as delegated by the UNS Energy Board of Directors.

The following UNS Energy directors are members of the Audit and Risk Committee of UNS Energy's Board of Directors:

- Ramiro G. Peru, Chair
- Robert A. Elliott

- James P. Laurito
- Gregory A. Pivirotto
- Joaquin Ruiz

All Audit and Risk Committee members possess the level of financial literacy and accounting or related financial management expertise required by New York Stock Exchange (NYSE) rules. UNS Energy's Board of Directors has determined that, while each member of the Audit and Risk Committee has accounting and/or related financial management expertise, Mr. Ramiro Peru is an "audit committee financial expert" as that term is defined by applicable SEC regulations.

Human Resources and Governance Committee of the UNS Energy Board

TEP is a wholly owned subsidiary of UNS Energy. As described in *Part III, Item 11 Executive Compensation* below, the TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. Instead, the UNS Energy Board of Directors' Human Resources and Governance Committee makes compensation-related decisions, including the approval of the compensation plan described in *Part III, Item 11 Executive Compensation.*

The following UNS Energy directors are members of the Human Resources and Governance Committee of UNS Energy's Board of Directors:

- Louise L. Francesconi, Chair
- Lawrence J. Aldrich
- Robert A. Elliott
- Barry Perry

UNS Energy Directors

Due to the role of the Audit and Risk Committee and the Human Resources and Governance Committee of the UNS Energy Board of Directors described above, the following information is included with respect to the members of the UNS Energy Board of Directors (other than with respect to Mr. Hutchens, who is also a member of the Board of Directors of UNS Energy):

Name	Age	Served as Director Since	Business Experience
Lawrence J. Aldrich	63	2000	Partner, Newport Board Group, since 2014; Chairman and Executive Director, Arizona Business Coalition on Health, since 2011; President and Chief Executive Officer of University Physicians Healthcare (UPH), a healthcare organization, from 2009 to 2010; Senior Vice President/Corporate Operations and General Counsel for UPH from 2007 to 2008; President of Aldrich Capital Company, an acquisition, management and consulting firm, since 2007; Chief Operating Officer of The Critical Path Institute, a non-profit medical research company focusing in drug development, from 2005 to 2007. Mr. Aldrich's extensive experience in the areas of public relations/advertising, finance, legal, human resources, marketing, engineering, operations, government/regulatory, information technology, insurance/health care, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

Robert A. Elliott	60	2003	President and owner of Elliott Accounting, an accounting, tax, management and investment advisory services firm, since 1983; Chair of AAA of Arizona, a regional automotive and travel club, since 2014 and Director since 2007; Director and Corporate Secretary of Southern Arizona Community Bank, a banking institution, from 1998 to 2010; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona from 1998 to 2009; Chairman of the Board of the Tucson Airport Authority, an airport operator/manager, from January 2006 to January 2007; President and Chairman of the Board of the National Basketball Retired Players Association from 2011-2013; Director of University of Arizona Foundation, a philanthropic organization, since 2011. Mr. Elliott's extensive experience in the areas of accounting, audit, banking and corporate tax, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Louise L. Francesconi	63	2008	President of Raytheon Missile Systems, a defense electronics corporation, from 1997 until her retirement in 2008; Director of Stryker Corporation, a medical technology company, since July 2006; Chairman of the Board of Trustees for TMC Healthcare, a hospital, since 1999; Director of Global Solar Energy, Inc., a manufacturer of solar panels and other solar-related products, from 2008 to 2011. Ms. Francesconi's extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, engineering, operations, audit, government/regulatory, information technology and insurance/healthcare, and her significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
James P. Laurito	59	2014	President and CEO of Central Hudson Gas & Electric Company since November 1, 2014. Mr. Laurito joined Central Hudson as President in November 2009. Prior to that, he served as President of both New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation from 2003 until 2009. Mr. Laurito's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Barry Perry	51	2014	President and CEO of Fortis since December 31, 2014. Prior to his current position at Fortis, Mr. Perry served as Vice President, Finance and CFO of Fortis since 2004. Mr. Perry joined the Fortis organization in 2000 as VP, Finance and CFO of Newfoundland Power. Previously, he held the position of VP, Treasurer with a global forest products company and Corporate Controller with a large crude oil refinery. Mr. Perry's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Ramiro G. Peru	60	2008	Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation, a mining corporation, from 2004 until his retirement in 2007; Senior Vice President and Chief Financial Officer of Phelps Dodge Corporation from 1999 to 2004; Director of Anthem, Inc. (formerly WellPoint, Inc.), a health benefits company, since 2004; Board of Directors, Fiesta Bowl, since 2012; Director of SM Energy Company, 2014 - 2015. Mr. Peru's extensive experience in the areas of accounting, corporate

communications, finance, legal, human resources/benefits, audit, government/regulatory, corporate tax, information technology, insurance/health care and environmental contributes to the diverse knowledge, skills and qualifications of the UNS Energy Board.

Gregory A. Pivirotto	63	2008	President, Chief Executive Officer and Director of University Medical Center Corporation, in Tucson, from 1994 until his retirement in 2010; Adjunct Professor at the University of Arizona College of Law since 2013; certified public accountant since 1978; Director of Arizona Hospital & Healthcare Association, a trade association providing advocacy, education and service to hospitals and other healthcare organizations, from 1997 to 2005; Director of Tucson Airport Authority, an airport operator/manager, from 2008 to January 2014; Member of the Advisory Board of Harris Bank Arizona from 2010 to 2013; Director of the Donor Network of Arizona from 1993 to 2006 and since 2012. Mr. Pivirotto's extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, operations, audit, government/regulatory, banking, corporate tax, information technology and insurance/healthcare, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Joaquin Ruiz	64	2005	Professor of Geosciences, University of Arizona, an educational institution, since 1983; Dean, College of Science, University of Arizona, since 2000; Executive Dean of the University of Arizona College of Letters, Arts and Science since 2009 and Vice President for Strategy and Innovation since 2012. Mr. Ruiz's extensive experience in the areas of renewables and environmental, public relations/advertising, human resources/benefits, operations, government/regulatory, information technology, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

This section describes TEP's overall executive compensation policies and practices and specifically analyzes the total compensation for the following executive officers, referred to as the Named Executives:

- David G. Hutchens, President and Chief Executive Officer;
- Kevin P. Larson, Senior Vice President and Chief Financial Officer;
- Karen G. Kissinger, Vice President and Chief Compliance Officer;
- Todd C. Hixon, Vice President and General Counsel; and
- Kentton C. Grant, Vice President and Treasurer

COMPENSATION PHILOSOPHY

Compensation Committee

TEP is a wholly owned subsidiary of UNS Energy (itself a wholly owned, indirect subsidiary of Fortis). The TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. The same individuals serve as executive officers of both UNS Energy and TEP. The UNS Energy Board of Directors Human Resources and Governance Committee makes all compensation decisions for all such executive officers, including the design of the 2015 executive compensation program, and also approves this disclosure, among other responsibilities. Any references to a Compensation Committee in this section refer to the UNS Energy Human Resources and Governance Committee.

TEP Compensation as a Component of UNS Energy Total Compensation

The Compensation Committee designs its programs to compensate UNS Energy executive officers for services to UNS Energy and all UNS Energy subsidiaries, including TEP. The amounts shown in this section represent the Named Executives' compensation allocated to TEP and its subsidiaries only, which, in 2015 amounts to 80.90% of the Named Executives total compensation for service provided to UNS Energy and its subsidiaries. The percentage allocated to TEP is obtained using the Massachusetts formula, an industry-wide accepted method of allocating common costs to affiliated entities based on an equal weighting of payroll costs, plant/tangible assets and total revenues. References to the Company refer to UNS Energy and include all UNS Energy subsidiaries. The Performance Enhancement Plan (PEP) includes target goals attributable to TEP, UNS Electric, and UNS Gas.

Objectives of the Compensation Program

The Compensation Committee has established a balanced total compensation program that ensures that a significant part of executive officer compensation is performance-based. Corporate goals are designed to focus executive officers and all non-union employees on successful execution of the Company's strategy and annual operating plan.

The Company's executive officer compensation policies and decisions have the following objectives:

1. Attracting, motivating and retaining highly-skilled executives;
2. Linking the payment of compensation to the achievement of critical short- and long-term financial and strategic objectives; providing safe, reliable and economically available electric and gas service; and aligning performance objectives of management with those of its other employees by using similar performance measures for both groups;
3. Balancing risk and reward to align the interests of management with those of the Company's stakeholders and encouraging management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximizing the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and

5. Encouraging management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance "best practices."

Summary of 2015 Executive Officer Compensation Program

Compensation Component	Key Features	Purpose
Base Salary	Increases considered on an annual basis to remain near the median of the Company's peer group (as described in *Elements of Compensation - Base Salary,* below) Intended to constitute a sufficient component of total compensation to discourage inappropriate risk-taking	Provide a fixed amount of cash compensation to the Company's Named Executives
Short-term Incentive Compensation (Performance Enhancement Program or PEP)	Incentive plans are structured identically for executive and non-executive employees and across business units/functions, uniting all non-union employees in the achievement of common goals All incentive plans are capped at 150% of target, protecting against the possibility that executives would try to maximize bonuses by taking short-term actions not supportive of long-term objectives. Must achieve at least the threshold level of net income to receive payment above 50% of target for other performance measures; this cap limits non-financial goal payout if the financial goals are not met	Motivate and reward achieving or exceeding the Company's short-term performance goals, reinforcing pay-for-performance Focus entire Company on key customer, operational and financial objectives
Long-Term Incentive Compensation (LTI or equity- based compensation)	LTI compensation is delivered in a combination of performance share units (PSUs) and restricted share units (RSUs) Ultimate value earned from the LTI program is based on both absolute and relative shareholder value and longer-term operating performance PSUs represent 67% of the target award with 50% of the shares earned based on achievement of cumulative net income goals and 50% of the shares earned based on achievement of Fortis's TSR relative to an industry peer group over a three-year period RSUs represent 33% of the target awards, and cliff vest on the 3rd anniversary of grant	Opportunities for ownership and financial reward in support of the Company's longer-term financial goals and stock price growth; also supports retention objective Provide a link between compensation and long-term shareholder interests as reflected in changes in Fortis stock price

The Compensation Committee considers decisions regarding each component of pay in the context of each executive officer's total compensation. For example, if the Compensation Committee increases an executive officer's base salary, it also considers the resultant impact on short- and long-term performance-based incentive compensation and compares total compensation levels to competitive practice. See *Compensation Analysis,* below. The Compensation Committee does not directly consider the value of previous equity awards in setting current year total compensation opportunities, but does review the value of outstanding equity awards to assess the degree to which such awards support the Company's performance motivation, retention, and shareholder alignment objectives.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following sections highlight how the above objectives are reflected in the Company's compensation program.

Attracting, Retaining and Motivating Executives

To attract, retain and motivate highly-skilled employees, the Company provides the Named Executives with compensation packages that are competitive with those offered by other electric and gas utility companies of comparable size and complexity and/or electric and gas utility companies thought to be competitors for executives.

The Compensation Committee generally targets total direct compensation for the Named Executives to be, on average, at the median of selected comparable companies identified below under the *Compensation Analysis* section. Under this approach, newly promoted executives and those new to their role may be placed below the median to reflect their limited experience and evolving skill set. Similarly, executives with longer tenure and therefore an above-market skill set, or those executives who are sustained high performers over time and are most critical to the Company's long-term success, may be placed above the median. The Company believes that this strategy enables it to successfully hire, motivate and retain talented executives while ensuring a reasonable overall compensation cost structure relative to its peers.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this section.

Linking Compensation to Performance

The Company's compensation program seeks to link the actual compensation earned by the Named Executives to their performance and that of the Company and Fortis. To ensure that the executive officers are held accountable for achieving the Company's financial, operational and strategic objectives and for creating Fortis shareholder value, the Company believes that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs comprise approximately 45% to 70% of the total direct compensation opportunity for the Named Executives. Of the performance-based compensation, approximately 30-50% is short-term and 50-70% is long-term. Placing a greater emphasis on long-term performance-based compensation encourages executive officers to focus on the long-term impact of their actions. Non-variable compensation, such as benefits and perquisites, is de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Balancing Risk and Reward to Align the Interests of the Company's Named Executives with Stakeholders

The Company's compensation program seeks to align the interests of the Named Executives with those of the Company's key stakeholders, including Fortis shareholders, customers, the community and employees. The Company uses the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for employees and improving financial performance by linking their short-term cash incentive compensation to achievement of these objectives. The Company uses an equity-based compensation component of its compensation package to align the interests of the Named Executives with those of the Fortis shareholders. The Company's compensation strategy mitigates risk by emphasizing long-term compensation and financial performance measures correlated with shareholder value. UNS Energy believes that equity-based compensation, together with the three-year vesting of share-based awards, result in compensation programs that do not encourage excessive risk-taking by management relating to the Company's business and operations, and increase executive officer accountability in the performance of the Company. In addition, the Compensation Committee has the ability to reduce short-term incentive compensation award payouts, in its sole discretion, based upon factors other than Company performance measures. In considering the design alternatives, the Compensation Committee continually evaluates the potential for unintended consequences of its compensation program.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for the Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives.

Adhering to Corporate Governance "Best Practices"

The Compensation Committee continually seeks to evaluate the executive officer compensation program in light of corporate governance "best practices." For example, the short-term and long-term incentive compensation programs include a clawback provision, and the Change in Control Agreements do not contain an excise tax gross-up provision, all of which are discussed in more detail below.

The Compensation Committee also reviews tally sheets and wealth accumulation analyses, which are designed to assist the Compensation Committee in evaluating the reasonableness of the compensation provided to Named Executives.

Compensation Analysis

To provide a foundation for the executive officer compensation program, the Company periodically benchmarks its Named Executives' compensation levels and practices against a peer group of companies intended to represent the Company's competitors for business and talent. The peer group, which is reviewed periodically and approved by the Compensation Committee, includes the 12 utility companies named below that are comparable to UNS Energy in size, as measured by annual revenues and market capitalization (the Peer Group). As of November 2013, the date when the most recent benchmarking analysis was performed, UNS Energy's revenues and number of employees approximate the median of the Peer Group; total assets and market capitalization were between the 25th percentile and the median; net income is below the 25th percentile.

2015 Peer Group

ALLETE, Inc.	NorthWestern Corp.
Avista Corp.	NV Energy, Inc.
Cleco Corp.	PNM Resources Inc.
El Paso Electric Co.	Portland General Electric Co.
Great Plains Energy, Inc.	UIL Holdings Corp.
IDACORP Inc.	Westar Energy Inc.

ELEMENTS OF COMPENSATION

Base Salary

The Company uses base salary to provide each Named Executive a set amount of money during the year with the expectation that he or she will perform his or her responsibilities to the best of his or her ability and in the best interests of the Company. The Company believes that competitive base salaries are necessary to attract and retain executives critical to achieving its business goals. In general, Named Executives' base salaries are targeted to the median of the Peer Group described above. However, individual salaries can and do vary from the Peer Group median data based on such factors as: (i) the competitive environment for Named Executives; and (ii) incumbent responsibilities, experience, skills and performance relative to similarly situated executive officers within the Company. Named Executives' salaries range from below the 25th percentile to the median of the Peer Group at the time the last benchmarking review was conducted.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base salary increases for Named Executives other than the CEO, the Compensation Committee also considers the CEO's recommendations.

In February 2015, the Compensation Committee approved 2% base salary increases for the Named Executives, which were consistent with salary increases as a percent of salary for other non-union Company employees. Base salary as a percentage of total compensation for the Named Executives ranged from approximately 30-55% of target total direct compensation. Additional information is provided in the *Summary Compensation Table* below.

Short-Term Incentive Compensation (Cash Awards)

The Company's short-term incentive compensation consists of cash awards under the Performance Enhancement Plan ("PEP"), which links a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance.

Each year, before the end of the first quarter, the Compensation Committee establishes performance objectives that must be met in whole or in part before the Company pays PEP awards. The key performance objectives are tailored to drive behavior that supports the Company's strategy of delivering safe, reliable service and value to customers and a fair return to shareholders over time. The Compensation Committee generally attempts to align the target opportunity for each Named Executive, stated as a percentage of base salary, with the median rate for equivalent positions at the Peer Group companies. In 2015, the target short -term incentive opportunity for the Named Executives ranged from 40% to 80% of base salary.

depending upon the Named Executive's responsibilities (i.e., the greater the responsibility, the more pay at risk). The Company's Named Executives' target incentive opportunities as a percent of base salary were near the Peer Group median at the time the last benchmarking review was conducted. As described more fully below, the actual amounts paid depend on the achievement of specified performance objectives and could range from 50% of the target award upon achievement of threshold performance to 150% of the target award upon achievement of exceptional performance.

Financial and Operating Performance Objectives-2015

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2015, the objectives were: (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment. The Compensation Committee selected the goals and individual weightings for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence. This use of balanced financial and operational metrics encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders.

The program design includes a 50% maximum payment cap if the Net Income goal does not achieve at least Threshold attainment. This ensures sufficient income to fund the program and reiterates the importance of the Net Income Goal. Finally, the Board of Directors has discretion to adjust any payout.

The financial and other metrics for the Company's 2015 Short-Term Incentive Compensation program were:

- Financial – 60%, Comprising of:
  - Net Income – 40%
  - O&M Cost Containment – 20%
- Excellent Operations and Safe Work Environment – 40%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The 2015 financial performance objectives were:

	Threshold	Target	Exceptional
Net Income (in millions) *results interpolated*	$ 139.6	$ 150.1	$ 160.6
O&M Long-Term Increase *final results interpolated*	3.0%	2.0%	1.5%

The 2015 operational and safety performance objectives were:

	Threshold	Target	Exceptional
Excellent Operations			
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	92.43%	93.42%	≥94.42%
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	78-90	57-77	< 57
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Power	640 - 649	650 - 669	≥670
Safe Work Environment			
OSHA Rate (Employee Safety Incident Rate)	1.70	1.50	< 1.00

2015 PEP Results

Summary:

Overall, the 2015 results produced a total weighted performance for all goals of 113.2% of target performance, as summarized in Table A below. The Compensation Committee approved an overall PEP payout of 113.2% of target awards.

Table A: Summary of 2015 PEP Results

Goal	Weighting of Goal (A)	Percentage of Target Performance Achieved (B) [1]	Payout Percentage (A x B)
Net Income	40%	108%	43.2%
Safe Work Environment	10%	50%	5.0%
O&M Cost Containment	20%	150%	30.0%
Excellent Operations	30%	Various	35.0%
	100%		**113.2%**

(1) Additional details provided below.

Net Income Goal:

In 2015, the Company achieved $151.8 million of net income, which was above target performance (results are interpolated). Table B, below, reflects the net income goal, which ranged from $139.6 million (threshold) to $160.6 million (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the actual net income achieved for 2015. Net income must have been more than $139.6 million to produce a payout. The achievement of $151.8 million in net income resulted in a payout level of 108.1% of the target amount for the Net Income performance objective.

Table B: Net Income

(in millions)	Final Result: $151.8 Range										
	$139.6	$141.7	$143.8	$145.9	$148.0	$150.1	$152.2	$154.3	$156.4	$158.5	$160.6
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	↑					↑					↑
	Threshold					Target					Exceptional
						Actual $151.8					

O&M Cost Containment Goal:

Prior to 2015, the O&M cost containment goal focused on achieving a targeted current year O&M spending level. In 2015 the goal was changed to reflect a longer term view of O&M by focusing on results of the 2016 budget (set by management in mid-year 2015) as a percentage increase over the 2015 base O&M budget. The lower increase of year over year budget estimates represents better performance. This O&M goal is meant to trigger longer-term thinking on how the Company's leadership might structurally change its business and processes, using proven process improvement methods, to focus on moving the business forward while containing costs. In 2016, the program design will include a monitoring of performance to the established 2016 budget. Table C, below, reflects the O&M cost containment goal, which ranged from 3.0% increase (threshold) to 1.5% increase (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award (results are interpolated). In 2015 the Company achieved a 2016 O&M budget decrease of 0.5%, which was exceptional performance, and resulted in a payout level of 150% for that performance objective.

Table C: O & M Long Term Increase

(in millions)	Final Result: 1.5% Range										
	3.0%	2.8%	2.6%	2.4%	2.2%	2.0%	1.9%	1.8%	1.7%	1.6%	1.5%
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	↑					↑					↑
	Threshold					Target					Exceptional
											Actual (0.5)%

Excellent Operations Goals:

- Equivalent Availability Factor ("EAF"): The reliability of the Company's plant performance during the peak summer demand season is critical to its customers and due to approved rate design, to financial performance; therefore, a Summer EAF goal is used in measuring the reliability of the Company's generation fleet.

- System Average Interruption Duration Index ("SAIDI"): This reliability measure in the Company's Transmission and Distribution business area is a good outage duration performance measure, because it tracks the length or duration of outages across all customers, giving the Company a focus on reducing the outage time a customer experiences.
- Customer Satisfaction: This reliability metric is measured by the JD Power Customer Satisfaction survey. Improving the Company's interactions with customers is critical to the outcome of this goal.

Safe Work Environment Goal:

- Safety: The Company's safety measure tracks the OSHA Recordable Incident Rate, which is a good indicator of a company's safety efforts. Continued focus on safety initiative components (leadership, employee involvement, and regulatory compliance) is a priority for the Company.

Table D, below, reflects the final achievement at the various levels of performance for the Excellent Operations and Safe Work Environment goals. According to the guidelines set by the Compensation Committee, the achievement of these goals yielded a result of 40% for this combination of performance objectives.

Table D: Excellent Operations/Safe Work Environment Goals

	Weight	Actual Result	Final Value	Totals
Excellent Operations (30% Weighting)				
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	10%	Exceptional	15%	
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	10%	Target	10%	
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Power	10%	Target	10%	
Subtotal: Excellent Operations				***35.0%***
Safe Work Environment (10% Weighting)				
OSHA Rate (Employee Safety Measure)	10%	Threshold	5%	
Subtotal: Safe Work Environment				***5.0%***
Total Percentage for Excellent Operations and Safe Work Environment				**40.0%**

The Company's internal audit department verified that the reported results for the 2015 PEP goals were accurate and reported its findings to the Compensation Committee.

The amounts of the 2015 PEP awards paid to each of the Named Executives are listed in the *Summary Compensation Table* below.

Long-Term Incentive Compensation (Equity Based Awards)

UNS Energy believes that equity-based awards align the interests of executive officers with the interests of Fortis' shareholders and fosters the growth and success of the business of the Company and Fortis in accordance with the vision of both the Company and Fortis. In addition, the vesting provisions applicable to the awards encourages a focus on long-term operating performance, linking compensation expense to the achievement of multi-year financial results and helping to retain executive officers.

In 2015, the Compensation Committee approved the adoption of a new long-term incentive plan under which certain key employees, including executive officers, may be granted long-term incentive awards of performance-based share units ("PSUs") and time-based restricted share units ("RSUs"). Executive officers receive a cash payment for each PSU and RSU that is payable and vested pursuant to the plan. The payment is based on the market price of one share of common stock of Fortis on the applicable payment or vesting date, which is then converted to U.S. dollars in accordance with the plan. All prior long-term incentive awards that predate the current plan were paid out in 2014 as a result of the acquisition of UNS by Fortis.

The long-term incentive ("LTI") opportunity for each Named Executive is based on a percentage of salary. The 2015 LTI multiples are 150% for Mr. Hutchens, 100% for Mr. Larson, and 40% for Ms. Kissinger and Messrs. Hixon and Grant. The dollar values of the Named Executives' long-term incentives are generally in the 25th percentile to median range of the Peer Group. Under the design of the compensation plan for 2015, two-thirds of the award opportunity was granted as performance share units and one-third was to be granted as restricted share units that vest 100% on the third anniversary of grant to support retention objectives as well as succession planning initiatives.

2015 Performance Share Units

Performance share unit awards granted in 2015 will be distributed, along with dividend equivalents (to the extent that the performance share units become earned and vested), at the end of the three-year payment criteria period ending in 2017, based on the following equally-weighted payment criteria:

- TSR Payment Criteria

The first financial performance criteria is the TSR of Fortis stock relative to the TSR of a predefined peer group (the "LTI Peer Group") shown below for the same period.

TSR Percentile Rank	**Payout as a Percent of Target Award**
75^{th} percentile and above	75.0%
50^{th} percentile	50.0%
30^{th} percentile	25.0%
Below 30^{th} percentile	0.0%

Intermediate payouts determined by interpolation.

LTI Peer Group	
AGL Resources	NiSource Inc.
Alliant Energy	Northeast Utilities
Ameren Corp.	OGE Energy Corp.
Atmos Energy Corp.	Pinnacle West Capital Corp.
Canadian Utilities, Ltd.	PPL Corp.
CenterPoint Energy, Inc.	Public Svc Enterprise Group
CMS Energy Corp.	SCANA Corp.
DTE Energy Co.	Sempra Energy
Emera, Inc.	TECO Energy Inc.
Great Plains Energy	UGI Corp.
LTI Peer Group	Westar Energy, Inc.
MDU Resources Group Inc.	Wisconsin Energy Corp.
New Jersey Resources, Corp.	Xcel Energy Inc.

- Cumulative Net Income Payment Criteria

The second financial payment criteria is cumulative net income (CNI) determined in accordance with GAAP and compared to a target cumulative net income of UNS Energy based on an assessment of external and management forecasts for the same period.

Degree of Performance Attainment (in millions)	**Three-Year Cumulative Net Income**	**Payout as a Percent of Target Award Earned**
Exceptional	$ 527	75.0%
Target	457	50.0%
Threshold	387	25.0%
Less than Threshold	< 387	0.0%

Intermediate payouts determined by interpolation.

Equity Grant Timing and Practice

- During the first quarter following the close of a fiscal year, the Compensation Committee approves and grants the long-term incentive awards for that year, including the type of equity to be granted, as well as the size of the awards for Named

Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that apply, the Compensation Committee considers the strategic goals of the Company and Fortis, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, and the impact on Fortis's earnings per share. The timing of awards was not coordinated with the release of material non-public information.

CLAWBACK PROVISION FOR VARIABLE COMPENSATION

Consistent with current "best practices," short- and long-term incentive compensation awards are subject to clawback provisions. The clawback provision may apply to the income derived from the financial component of the PEP and the performance share units in the event of a restatement of financial results that, in the view of the Compensation Committee, results from fraud or intentional misconduct. The Compensation Committee has discretion to determine to whom the clawback will apply and the amount subject to clawback, if such repayment is determined to be necessary.

ELEMENTS OF POST EMPLOYMENT COMPENSATION

Termination and Change in Control

Prior to the Company's acquisition by Fortis, the Compensation Committee had determined that it was in the Company's and shareholders' best interest to enter into change in control agreements with its executive officers in order to attract highly qualified executives and to retain those executives through any future challenges that might arise. All of these agreements were designed to be consistent with contemporary "best practices," such as double trigger severance payments and equity vesting and no excise tax gross-ups. These various agreements are still in effect and are discussed in detail in *Potential Payments Upon Termination or Change in Control*, below.

Generally speaking, the Company does not enter into or extend employment agreements with current officers and instead only uses employment agreements when needed in recruiting a new officer. The Company currently has no employment agreements in place.

UNS Energy also maintains a severance pay plan for all of the Company's non-union employees, including its Named Executives, which continues the Company's historical practice of providing severance pay in certain termination situations without a change in control and provides consistency in that practice.

Retirement and Other Benefits

The Company offers retirement and other core benefits to its employees, including the Named Executives, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The basic retirement and other core benefits are the same for all employees and Named Executives and include medical and dental coverage, disability insurance and life insurance. In addition, the TEP 401(k) Plan (the "401(k) Plan") and the TEP Salaried Employees Retirement Plan (the "Retirement Plan") provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including Named Executives, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each Named Executive. In addition, the Company provides all of its officers with an optional executive physical annually.

In addition to the basic retirement plans, described above, to the extent that any executive officer's retirement benefit exceeds Internal Revenue Code (Code) limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the TEP Excess Benefit Plan (Excess Benefit Plan) and the Management and Directors Deferred Compensation Plan (DCP). These plans provide only the difference between the calculated benefits and Code limits. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive officer compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry. UNS Energy believes the DCP and the Excess Benefit Plan assist with the Company's attraction and retention objectives. The DCP provides an industry-competitive and tax-efficient benefit to the executive officers. The DCP is not funded by the Company; DCP participants are unsecured creditors of the Company with respect to their DCP plan accounts. The Excess Benefit Plan provides the retirement benefits to executive officers that would have been provided under the Retirement Plan if the Code limitations did not apply. For more information on retirement and certain related benefits, see *Pension Benefits* and *Non-Qualified Deferred Compensation*, below.

ROLE OF EXECUTIVES IN ESTABLISHING COMPENSATION

Certain executive officers, including the CEO, the CFO, the General Counsel and the Vice President of Customer and Human

Resources, routinely attend regular sessions of Compensation Committee meetings; however, they are excused for executive sessions when their compensation is discussed and/or determined. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive officer positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive officer and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee has reviewed and discussed with management the *Compensation Discussion and Analysis* section required by Item 402(b) of SEC Regulation S-K and contained in this annual report. Based on such review and discussions, the Compensation Committee recommended to the Board of Directors of TEP that the *Compensation Discussion and Analysis* section be included in TEP's annual report on Form 10-K for the year ended December 31, 2015.

Respectfully submitted,

THE HUMAN RESOURCES AND GOVERNANCE COMMITTEE OF UNS ENERGY CORPORATION

Louise L. Francesconi, Chair
Lawrence J. Aldrich
Robert A. Elliott
Barry Perry

SUMMARY COMPENSATION TABLE – 2015 (1)

The following table sets forth summary compensation information for the years ended December 31, 2013, 2014, and 2015 for the Company's Named Executives:

Name and Principal Position	Year	Salary	Share Awards(2)	Non-Equity Incentive Plan Compensation(3)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings(4)	All Other Compensation(5)(6)	Total
David G. Hutchens	2015	446,942	632,590	432,815	393,142	9,647	1,915,136
President and Chief	2014	397,962	417,359	377,827	555,358	2,529,306	4,277,812
Executive Officer	2013	306,482	432,998	198,513	105,379	14,209	1,057,580
Kevin P. Larson	2015	297,995	280,509	169,081	—	9,647	757,232
Senior Vice President and Chief Financial	2014	289,922	286,845	158,639	259,605	4,122,921	5,117,932
Officer	2013	279,435	327,989	142,107	46,725	12,574	808,831
Todd C. Hixon	2015	231,135	85,736	111,642	32,676	9,647	470,836
Vice President and General Counsel	2014	226,742	86,054	96,072	242,704	460,900	1,112,472
Karen G. Kissinger	2015	221,580	83,223	100,316	36,250	9,647	451,016
Vice President and Chief	2014	219,094	86,054	95,088	325,958	2,272,033	2,998,227
Compliance Officer	2013	216,627	252,798	107,659	—	10,147	587,230
Kentton C. Grant Vice President and Treasurer	2015	212,349	78,884	100,316	87,403	7,645	486,597

(1) The amounts included in the *Summary Compensation Table* represent only the amounts paid by UNS for services to TEP and its subsidiaries and do not include amounts paid by UNS for services to others. For 2015 services, 80.90% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2014 services, 80.46% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2013 services, 79.7% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries.

(2) The amounts included in the *Share Awards* column reflect 80.90% of the grant date fair value calculated in accordance with FASB ASC Topic 718 for restricted share units and performance share units granted in each of the years reported, excluding the effect of forfeitures. Half of the performance share unit awards had a grant date fair value, based on a Monte Carlo simulation, of $36.28 per share. These awards are based on Fortis's Shareholder Return relative to the Peer Group TSR for the three year performance period ended December 31, 2017. The remaining half had a grant date fair value, based on the grant date closing price, of $33.47 per share based on cumulative net income for the performance period ended December 31, 2017. The restricted share units had a grant date fair value, based on the grant date closing price, of $33.47 per share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. The restricted share units vest on the third anniversary of grant over the vesting period. In the case of performance share units, the amounts in the column reflect the grant date fair value assuming the probable outcome of the performance conditions. The 2015 amounts attributable to Restricted Share Units and Performance Share Units are shown on the following table:

	Restricted Share Units	Performance Share Units	Total
David G. Hutchens	224,979	407,611	632,590
Kevin P. Larson	99,762	180,747	280,509
Todd C. Hixon	30,492	55,244	85,736
Karen G. Kissinger	29,598	53,625	83,223
Kentton C. Grant	28,055	50,829	78,884

For the 2015 performance share grant, if the maximum level of performance is achieved and using [the fair market value of a share of Company common stock on the grant date ($36.28)], then the value of the payouts would be: $703,283 for David G. Hutchens, $311,855 for Kevin P. Larson, $95,317 for Todd C. Hixon, $92,524 for Karen G. Kissinger, and $87,699 for Kentton C. Grant.

(3) The 2015 PEP awards included in this column were paid in the first quarter of 2016 to each of the Named Executives.

(4) Any increase in the present value of the accrued benefit in the Retirement Plan and Excess Benefit Plan is reported in this column. All named executives experienced an increase in the present value of their respective accrued pension benefits during 2015. The present value of accumulated benefits payable is reflected in *Pension Benefits*, below. UNS Energy does not pay "above market" interest on non-qualified deferred compensation; therefore, this column reflects change in pension value only. See *Non-qualified Deferred Compensation*, below.

(5) The amounts in the *All Other Compensation* for 2015 column contain only Qualified 401 (k) Plan Matching Contributions.

(6) The amounts in the *All Other Compensation* column for 2014 include payments in exchange for stock awards canceled in connection with the acquisition of UNS Energy by Fortis in 2014.

GRANTS OF PLAN-BASED AWARDS – 2015

The following table sets forth information regarding plan-based awards by UNS to the Company's Named Executives in 2015 on account of services to TEP and its subsidiaries. As described above, 80.90% of the amount paid by UNS on account of services in 2015 is allocable to services to TEP and its subsidiaries. The compensation plans under which the grants in the following table were made are generally described in *Compensation Discussion and Analysis*, above and include the PEP, which provides for non-equity (cash) performance awards, and the 2015 Share Unit Plan, which provides for equity-based performance awards including restricted share units and performance share units.

	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards (#) (2)			All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	Grant Date Fair Value of Stock and Option Awards(4)
Name		**Threshold**	**Target**	**Maximum**	**Threshold**	**Target**	**Maximum**		
DAVID H. HUTCHENS									
PEP	1/1/2015	$ 179,986	$ 359,973	$ 539,959					
Performance Share Units	1/1/2015				6,721	13,442	20,164		$ 407,611
Restricted Share Units	1/1/2015							6,721	224,979
KEVIN P. LARSON									
PEP	1/1/2015	74,837	149,675	224,512					
Performance Share Units	1/1/2015				2,980	5,961	8,941		180,747
Restricted Share Units	1/1/2015							2,980	99,762
TODD C. HIXON									
PEP	1/1/2015	45,766	91,531	137,297					
Performance Share Units	1/1/2015				911	1,822	2,733		55,244
Restricted Share Units	1/1/2015							911	30,492
KAREN G. KISSINGER									
PEP	1/1/2015	44,417	88,835	133,253					
Performance Share Units	1/1/2015				884	1,768	2,653		53,625
Restricted Share Units	1/1/2015							884	29,598

KENTTON C. GRANT

PEP	1/1/2015	43,686	87,372	131,058					
Performance Share Units	1/1/2015				838	1,676	2,514		50,829
Restricted Share Units	1/1/2015							838	28,055

(1) The amounts shown in this column reflect the range of payouts (50%-150% of the target award) for 2015 performance under the PEP, as described in *Compensation Discussion and Analysis - Short-Term Incentive Compensation*, above. These amounts are based on the

individual's current salary and position. The amount of cash incentive actually paid under the PEP for 2015 is reflected in the *Summary Compensation Table* above.

(2) The amounts shown in this column reflect the range (50%-150% of the target award) of payouts in the form of performance share units targeted for 2015-2017 performance under the 2015 Share Unit Plan for long-term incentive compensation, as described in the "Long-Term Incentive Compensation" section of the CD&A, above.

The target 2015 LTI multiples, as a percentage of base salary, are 150% for Mr. Hutchens, 100% for Mr. Larson, and 40% each for Ms. Kissinger and for Messrs. Hixon and Grant. Accordingly, each Named Executive received an LTIP target award of performance share units and restricted share units the total value of which was equal to the executive's base salary multiplied by the applicable multiple (e.g., 100% for CFO), divided by the grant date fair market value of a share of Fortis's common stock ($33.47), rounded down to the nearest 1 share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. For example, the CFO's 2015 base salary attributable to TEP (and LTIP target award) was $299,349, divided by $33.47, and rounded down to the nearest 1 share, resulted in an LTIP target award of 5,961 performance share units and 2,980 restricted share units.

The 2015 awards of performance share units will be paid in cash at the end of the performance period depending on the Company's performance relative to the two performance criteria described in *Compensation Discussion and Analysis*, above. The two performance criteria operate independently; a Named Executive may receive a payment on account of one of the criteria without regard to performance on the other criteria.

(3) The amounts shown in this column represent the number of time-based restricted share units that were granted in 2015 under the 2015 Share Unit Plan and will be paid in cash at the end of the vesting period.

(4) The amounts included in this column reflect 80.90% of the grant date fair value calculated in accordance with FASB ASC Topic 718 for restricted share units and performance share units granted in each of the years reported, excluding the effect of forfeitures. Half of the performance share unit awards had a grant date fair value, based on a Monte Carlo simulation, of $36.28 per share. These awards are based on Fortis's Shareholder Return relative to the Peer Group TSR for the three year performance period ended December 31, 2017. The remaining half had a grant date fair value, based on the grant date closing price, of $33.47 per share based on cumulative net income for the performance period ended December 31, 2017. The restricted share units had a grant date fair value, based on the grant date closing price, of $33.47 per share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. The restricted share units vest on the third anniversary of grant over the vesting period. In the case of performance share units, the amounts in the column reflect the grant date fair value assuming the probable outcome of the performance conditions. For more information about these awards, please refer to footnote 1 of the *Summary Compensation Table* and *Compensation Discussion and Analysis*, above.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END - 2015

		Stock Based Awards			
	Grant Date	Number of Shares or Units of Stock That Have Not Vested[1] (#)	Market Value of Number of Shares or Units of Stock That Have Not Vested [2] ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested [3] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested [4] ($)
David G. Hutchens	1/1/2015	6,721	$218,176	13,442	$436,352
Kevin P. Larson	1/1/2015	2,980	96,745	5,961	193,490
Todd C. Hixon	1/1/2015	911	29,570	1,822	59,140
Karen G. Kissinger	1/1/2015	884	28,703	1,768	57,406
Kentton C. Grant	1/1/2015	838	27,206	1,676	54,413

(1) Number of time-based restricted share units that remain unvested as of December 31, 2015. Restricted share units vest on the third anniversary of the grant date, subject to continued service with the Company through that date.

(2) The market value of restricted share units and performance share units was calculated by multiplying the number of restricted share units outstanding or the number of performance share units (as determined in accordance with the Securities and Exchange Commission, or SEC, rules and footnote 5 below), as applicable, by $32.46 which was the share price as of 12/31/15. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621.

(3) Performance share units vest, if at all, after three years based on the achievement of performance of the cumulative goals over the

applicable three-year period. The performance goals are described in the CD&A.

(4) The amounts for the 2015 performance share unit awards are shown at the target level based on the results for the first year of the 2015-2017 performance period.

OPTION EXERCISES AND STOCK VESTED

There were no stock options exercised or stock or share awards vested during the year ended December 31, 2015.

PENSION BENEFITS

The following table shows 80.90% of the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefit Plan determined using interest rate and mortality rate assumptions used in the Company's financial statements. See Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and the *Retirement and Other Benefits,* above for information regarding the Retirement Plan and the Excess Benefit Plan.

	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
David G. Hutchens	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	20.50	$ 763,775	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	20.50	1,192,238	—
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	30.83	1,272,805	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	30.83	1,366,778	—
Karen G. Kissinger	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	25	1,283,649	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	25	662,945	—
Todd C. Hixon	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	17.58	495,203	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	17.58	194,627	—
Kentton C. Grant	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	20.08	725,334	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	20.08	293,561	—

(1) The Retirement Plan is intended to meet the requirements of a qualified benefit plan for Code purposes and is funded by the Company and made available to all eligible employees. The Retirement Plan provides an annual income upon retirement based on the following formula:

1.6% x years of service (up to 25 years) x final average pay

Final average pay is calculated as the average of basic monthly earnings on the first of the month following the employee's birthday during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement. Basic monthly earnings means the monthly base salary prior to any reduction for contributions to a Code section 401(k) plan, but excluding overtime pay, bonuses or other compensation. Years of service are based on years and months of employment. A Retirement Plan participant vests in his or her retirement benefit after five years of service. The maximum benefit available under the Retirement Plan is an annual income of 40% of final average pay (as defined above). Plan compensation for purposes of determining final average pay is limited by compensation limits under Code Section 401(a)(17). For 2015, the limit was $265,000 in annual income. Employees are eligible to retire early with an unreduced pension benefit if (i) the combination of their age and years of service equals or exceeds 85, or (ii) they are age 62 and have completed 10 years of service. Employees are also eligible for early retirement with a reduced pension benefit at age 55 with at least 10 years of service. The reduction at age 55 with 10 years of service is 42.6% and continues to be reduced at a lesser amount up to age 62, at which point there is no reduction. All optional forms of the benefit are actuarially equivalent. Messrs. Larson and Grant and Ms. Kissinger are currently eligible for early retirement.

(2) The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefit Plan provides the retirement benefits to executive officers that would have been provided under the Retirement Plan if the Code limitations did not apply. The Excess Benefit Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefit Plan is determined without regard to Code limits on compensation and by including voluntary salary reductions to the DCP and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefit Plan is reduced by the benefit payable to that person from the Retirement Plan. Vesting occurs after five years of service. Benefits are payable in a lump sum or annuity, at the participant's election. Messrs. Larson and Grant and Ms. Kissinger are currently eligible for early retirement.

(3) In preparing the aggregate increase in actuarial value of the above plans, the following assumptions and methods were used:

Measurements were made as of Tucson Electric Power Company's ASC 715 measurement date of December 31, 2015.

December 31, 2015 calculations were done using the spot rates underlying the Rate:Link 60-90 Yield Curve as of December 31, 2015 and RP-2014 mortality table, projecting mortality generationally at Scale MP-2015, with the following adjustments:

- The RP-2014 mortality table was adjusted to back out MP-2014 experience to 2006, then add back in MP-2015 through 2015.
- The MP-2015 projection scale was adjusted so that the ultimate rate of 1% at age 85 was reduced to 0.75%.
- The MP-2015 projection scale was further adjusted to reduce the convergence period to 15 years, rather than 20.

No pre-retirement mortality was assumed. For measurements at December 31, 2014, a discount rate of 4.10% and RP-2000 Female with generational projection using scale BB Female for females and RP-2000 Male with generational projection using scale BB Male for males, and both with no pre-retirement mortality were used for the Salaried and Excess Plans. This discount rate reflects rates as of December 31, 2015.

All participants were assumed to elect a 10 year Certain and Life benefit at the earliest age at which they are projected to be eligible for unreduced benefits.

NON-QUALIFIED DEFERRED COMPENSATION

UNS Energy sponsors the DCP for directors, executive officers and certain other employees of UNS Energy. Under the DCP, employee participants are allowed to defer on a pre-tax basis up to 100% of base salary and cash bonuses, and non-employee director participants are allowed to defer up to 100% of their cash compensation. The deferred amounts are valued daily as if invested in one or more of a number of investment funds, including UNS Energy share units, each of which may appreciate or depreciate in value over time. The choice of investment funds is determined by the individual participant. The amounts shown in the table below represent 80.90% of the total amounts, to reflect the portion allocable to TEP and its subsidiaries.

	Executive Contributions in Last Fiscal Year (1)	Aggregate Earnings in Last Fiscal Year (2)	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End (3)
David G. Hutchens	—	—	—	—
Kevin P. Larson	—	8	—	54,372
Todd C. Hixon	—	—	—	—
Karen G. Kissinger	—	19	—	122,451
Kentton C. Grant	42,470	11	—	83,181

(1) Represents contributions to the DCP by the Named Executives during the year. The amounts shown, if any, are included in the

salary column of the *Summary Compensation Table*, above.

(2) Represents the total market based earnings (losses) for the year on all deferred compensation under the DCP based on the investment returns associated with the investment choices made by the Named Executive. Amounts in this column are not included in the *Summary Compensation Table*.

(3) The aggregate balance includes compensation that was previously earned and reported in the Summary Compensation Table for 2013 and 2014 (if any) as follows: Mr. Larson—$8,817 and Ms. Kissinger—$1,287. Benefits under the plan will be distributed on the first to occur of the following events: separation from service, disability or death, in the form of either a lump sum or installment payments. The following table shows the deemed investment options available under the DCP and the annual rate of return for the calendar year ended December 31, 2015.

Name of Fund	Rate of Return	Name of Fund	Rate of Return
Fidelity Retirement Money Market	0.02%	Fidelity Spartan Us Equity Index	1.35%
Fidelity Intermediate Bond	0.68%	Fidelity Growth Company	7.94%
Janus Flexible Bond	0.09%	Fidelity Low Price Stock	(0.45)%
Fidelity Asset Manager	(0.44)%	Janus Worldwide	(2.30)%
Fidelity Equity-Income	(3.41)%	T. Rowe Price Blue Chip Growth	11.15%
Fidelity Managed Income	1.17%	Fidelity Diversified International K	3.24%
RS Value Y	(5.99)%	Franklin Utilities A	(7.38)%
American Beacon Small Cap Value Instl	(5.04)%	Allianz NFJ International Value Instl	(13.15)%
Fidelity Small Cap Stock	2.40%		

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

In order to ensure that the Company is able to retain its Named Executives, the Compensation Committee has determined that it is in the best interest of the Company and its shareholders to enter into change in control agreements with those Named Executives, as well as to maintain a severance pay plan for all of the Company's non-union employees, including the Named Executives.

Change in Control Agreements

Each of our current executive officers, including our named executive officers who are currently employed by the Company, is party to a change in control agreement with UNS Energy entered into prior to the acquisition by Fortis. Under the change in control agreements, the executive officer will be entitled to receive change in control benefits if he or she incurs a separation from service due to the Company's termination of his or her employment without "Cause" or due to the executive officer's termination of employment with the Company for "Good Reason" during the six-month period prior to the occurrence of a Change in Control and if the executive officer's separation from service is effected in contemplation of such Change in Control. The executive officer also will be entitled to receive these benefits if he or she incurs a separation from service due to the Company's termination of his or her employment without Cause or due to the executive officer's termination of employment for Good Reason during the 24-month period following the occurrence of a Change in Control.

A Change in Control is defined as: (i) the acquisition of beneficial ownership of 40% of the common stock of UNS Energy; (ii) certain changes in the Board; (iii) the closing of certain mergers or consolidations; or (iv) certain transfers of the assets of UNS Energy. Notwithstanding the foregoing, a Change in Control will not be deemed to have occurred until: any required regulatory approval, including any final non-appealable regulatory order, has been obtained; and the transaction that would otherwise be considered a Change in Control closes.

A Change in Control with UNS Energy occurred on August 15, 2014, the time of the acquisition of UNS Energy by Fortis. The protection period ends on August 13, 2016. Since there was a Change in Control, if a qualifying separation occurs on or before August 13, 2016, then the executive officer will be entitled to severance benefits in the form of: (i) a single lump sum payment in an amount equal to two (for Mr. Hutchens), one and one-half (for Mr. Larson) or one (for Ms. Kissinger and Messrs. Hixon and Grant) times the greater of (a) the executive officer's annualized base salary as of the date of the executive officer's separation from service, or (b) the executive officer's annualized base salary in effect immediately prior to any material diminution in the executive officer's base salary following execution of the change in control agreement; (ii) a single lump sum cash payment in an amount equal to two (for Mr. Hutchens), one and one-half (for Mr. Larson) or one (for Ms. Kissinger and Messrs. Hixon and Grant) times the average payment to which the executive officer was entitled pursuant to the short-term incentive compensation plan for the three calendar years immediately preceding the calendar year in which the executive officer's separation from service occurs or, if that data is not available, the executive officer's target payment under the short-term incentive compensation plan; (iii) a single lump sum cash payment in an amount equal to a prorated portion of the actual payment to which the executive officer would have been entitled under the short-term incentive compensation plan for the calendar year in which the executive officer's separation from service occurs; and (iv) a single lump sum cash payment in the amount of the payment, if any, to which the executive officer is entitled under the short-term incentive compensation plan (based on the executive officer's actual performance) for the year prior to the year in which the executive officer's separation from service occurs, to the extent not already paid to the executive officer. "Good reason" is defined under these agreements to mean: (i) a material, adverse diminution in the executive officer's authority, duties or responsibilities; (ii) a material change in the geographic location at which the executive officer must primarily perform services; (iii) a material diminution in the executive officer's base salary provided that such diminution is not a result of a generally applicable reduction in the base salary of all officers of the Company in an amount that does not exceed 10%; or (iv) any action or inaction that constitutes a material breach of the agreement by the Company. "Cause" is defined under these agreements to mean: (i) the willful failure of the executive officer to perform any of the executive officer's duties for the Company which continues after the Company has given the executive written notice describing the failure and an opportunity to cure the failure; (ii) a material violation of Company policy; (iii) any act of fraud or dishonesty; (iv) the executive officer's gross misconduct in the performance of the executive officer's duties that results in material economic harm to the Company; (v) the executive officer's conviction of, or plea of guilty or no contest, to a felony; or (vi) the executive officer's material breach of the executive officer's employment agreement with the Company, if any.

The executive officer would also be entitled to continue to participate in TEP's health, life, disability or other insurance benefit plans for a period expiring on the earlier of (a) 24 months (for Mr. Hutchens), 18 months (for Mr. Larson), or 12 months (for Ms. Kissinger and Messrs. Hixon and Grant) following the executive officer's separation from service, or in some cases for the respective period following the Change in Control event, or (b) the day on which the executive officer becomes eligible to receive any substantially similar benefits, on a benefit-by-benefit basis, under any plan or program of any successor employer. In the event the executive officer elected a high deductible health care plan pursuant to which TEP has agreed to make contributions to the executive officer's health savings account, then TEP will pay to the executive officer a single lump sum cash payment in an amount equal to the contributions that TEP would have made to the executive officer's health savings account during the respective benefit continuation period described above had the executive officer not incurred the separation from service.

The Change in Control Agreements provide that the executive officer shall be employed by UNS Energy or one of its subsidiaries or affiliates, in a position comparable to the current position, with base compensation and benefits at least equal to the then-current compensation and benefits, for an employment period of two years after a Change in Control (subject to earlier termination for cause or the executive officer's termination without good reason).

The Change in Control Agreements also contain a number of material conditions or obligations applicable to the receipt of payments or benefits, which require the executive officer to: (i) continue to abide by the terms and provisions of the Company's policies that protect various forms of confidential information and intellectual property; (ii) refrain from consulting with, engaging in or acting as an advisor to another company about business that competes with the Company; (iii) refrain from soliciting business for or in connection with any competing business (a) from any individual or entity that obtained products or services from the Company at any time during the executive officer's employment with the Company or (b) from any individual or entity that was solicited by the executive officer on behalf of the Company; and (iv) refrain from soliciting employees of the Company who would have the skills and knowledge necessary to enable or assist efforts by the executive officer to engage in a competing business. Item (i) referred to in this paragraph contains no durational limit, nor do the Change in Control Agreements include any provision providing for waiver of a breach of item (i). Items (ii) through (iv) referred to in this paragraph are effective for a period of one year following the date of the executive officer's termination. Breach of items (ii) through (iv) is waived if the Company materially defaults on any of its obligations under the Change in Control Agreements.

No excise tax gross-ups are provided. Rather, severance payments to executives are cut back to the safe harbor limit if the reduction results in the executive receiving a greater after-tax benefit than if the excise tax were paid by the executive on the excess parachute payments; otherwise, all payments would be paid and the executive would pay the excise tax.

All long-term incentive awards contain a double trigger vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer and also provide for accelerated vesting upon a qualifying termination following a Change in Control. This double trigger vesting provision applies to future awards and/or if the Named Executive is terminated without cause within 24 months of a Change in Control. The double trigger, which is viewed as a corporate governance "best practice," ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the Change in Control.

On May 2, 2014, Mr. Hutchens was appointed CEO of UNS Energy and TEP in addition to his duties as President and Chief Operating Officer of each company. Incident to the appointment, Mr. Hutchens's Change in Control agreement was modified to increase the benefits to which he will be entitled if his employment is terminated by UNS Energy without cause or by Mr.

Hutchens with good reason following a change in control and to provide that he was not entitled to terminate employment and receive the benefits provided by his Change in Control Agreement solely for the reason that he would no longer be CEO of a publicly traded company as a result of the acquisition of UNS Energy by Fortis.

On November 13, 2014, UNS Energy and Mr. Larson entered into a retention bonus agreement, the terms of which were approved by the UNS Energy Human Resources and Governance Committee. The retention bonus agreement amends Mr. Larson's change in control agreement to provide that changes in Mr. Larson's responsibilities that occurred as a result of the acquisition of UNS Energy by Fortis, or that may occur for succession purposes based on a future mutually-agreed transition process, shall not constitute good reason for Mr. Larson to terminate his employment and receive benefits under the change in control agreement.

Severance Pay Plan

In addition, the Company has a severance pay plan (Severance Plan) for all of the Company's non-union employees, including its Named Executives, which provides for severance benefits in the event of a qualifying termination, which means a termination without cause without a change in control. Cause for termination under the Severance Plan means: (i) the willful failure of the employee to perform any of the employee's duties for the employer which continues after the employer has given the participant written notice describing the failure and an opportunity to cure the failure; (ii) a material violation of Company policy; (iii) any act of fraud or dishonesty; (iv) willful failure to report to work for three days or to report to work on the agreed-upon date after a scheduled leave; or (v) willfully engaging in conduct that is demonstrably and materially injurious to the Company or any affiliate, monetarily or otherwise, including acts of fraud, misappropriation, violence or embezzlement for personal gain at the expense of the Company or any affiliate, conviction of (or plea of guilty or no contest or its equivalent to) a felony, or a misdemeanor involving immoral acts.

In the event of a qualifying termination, the Named Executive would be entitled to: (i) a cash severance payment equal to a multiple of base salary (two times for Mr. Hutchens, one and one-half times for Mr. Larson, and one time for Ms. Kissinger and Messrs. Hixon and Grant; (ii) continued subsidy of the premiums for COBRA medical, dental and vision coverage at the same rate as that paid by the Company prior to the separation from service for a period of the lesser of (a) 12 months, or (b) the date when the Named Executive becomes eligible for comparable benefits offered by a subsequent employer; and (iii) a portion of the amount to which the Named Executive would have been entitled under the Company's PEP or any successor plan, based on the executive's target payment for the year in which the executive's separation from service occurs, had the Named Executive not incurred a separation from service. Receipt of benefits under the Severance Plan is contingent upon execution of a release of claims against the Company and subject to compliance with restrictive covenants, including perpetual confidentiality and non-disparagement provisions, and non-compete and non-solicitation requirements effective for the applicable severance period (two years for Mr. Hutchens, one and one-half years for Mr. Larson, and one year for Ms. Kissinger and Messrs. Hixon and Grant). Duplication of benefits provided under the Severance Plan is not permitted, and benefits payable under the Severance Plan cease in the event the Named Executive becomes eligible for change in control severance benefits or if the Named Executive has an employment agreement that provides for severance benefits.

In the event a Named Executive becomes eligible to receive severance benefits under the Severance Plan and has elected a health care option pursuant to which the Company has agreed to make pre-tax contributions to the Named Executive's Health Savings Account, then the Company will pay the Named Executive an amount equal to the contributions the Company would have made to the Named Executive's health savings account during the twelve-month period immediately following the Named Executive's separation from service, plus a tax allowance in an amount equal to the federal, state and local taxes imposed on the Named Executive with respect to such contributions and with respect to the tax allowance. While as a general matter the Company does not provide tax gross-ups for severance arrangements or other benefits, it was deemed appropriate in this very limited circumstance because: (i) this particular type of benefit would be provided pre-tax, if the individual were still employed; (ii) the amounts in question are exceptionally small; and (iii) this treatment is available to all unclassified employees, not just the Named Executives, who become entitled to severance benefits under the Severance Plan and participate in the type of health care option described in the paragraph above.

Other than the agreements described above, UNS Energy has not entered into any severance agreements or employment agreements with any Named Executives.

The following table and summary set forth potential payments payable to the Named Executives upon termination of employment or a Change in Control assuming their employment was terminated on December 31, 2015.

	If Retirement or Voluntary Termination Occurs [1]	If "Change In Control" and Qualifying Termination Occurs[2]	If Death or Disability Occurs[3]	If "Non-Change In Control" Termination Occurs[4]
David G. Hutchens	$ —	$ 2,428,415	$ —	$ 2,428,415
Kevin P. Larson	—	1,108,825	—	1,108,825
Todd C. Hixon	—	495,409	—	430,778
Karen G. Kissinger	—	512,354	—	512,354
Kentton C. Grant		475,837		475,837

(1) In the event of retirement or voluntary termination, each of the Named Executives would be entitled to receive vested and accrued benefits payable from the Retirement Plan and the Excess Benefit Plan, but no form or amount of any such payment would be increased or otherwise enhanced nor would vesting be accelerated with respect to such plans. In addition, no accelerated vesting of options, restricted share units or performance share units would occur. Retirement Plan and Excess Benefit Plan information for the Named Executives is set forth in the *Pension Benefits Table* above.

(2) The amounts shown represent the following:

	Cash	Prorated Non-equity Incentive Award	Restricted Share Units	Performance Share Units	Medical Benefits	Total
David G. Hutchens	$ 1,380,088	$ 359,973	$ 218,176	$ 436,352	$ 33,826	$ 2,428,415
Kevin P. Larson	666,826	149,675	96,745	193,490	2,089	1,108,825
Todd C. Hixon	309,539	91,531	29,570	59,140	5,629	495,409
Karen G. Kissinger	318,060	88,835	28,703	57,406	19,350	512,354
Kentton C. Grant	294,529	87,372	27,206	54,413	12,317	475,837

Amounts shown in the column headed *Prorated Non-equity Incentive Award* above represent the total "target" PEP award for 2015.

(3) In the event of death, the Named Executive's survivor would be entitled to receive a survivor annuity from the Retirement Plan and Excess Benefit Plan. The amount payable to the survivor would be less than the amount that would otherwise have been payable to the Named Executive had the Named Executive survived and received retirement benefits under the Retirement Plan and Excess Benefit Plan. There would be no enhancements as to form, amount or vesting of such benefits in the event of a Named Executive's death.

(4) This column reflects the amounts payable to the Named Executives in the event of an involuntary termination without cause or a resignation for good reason, as of December 31, 2015, under the Severance Plan. The amounts shown represent the following:

	Cash	Pro-Rated Non-equity Incentive Award	Restricted Share Units	Performance Share Units	Medical Benefits	Total
David G. Hutchens	$ 1,380,088	$ 359,973	$ 218,176	$ 436,352	$ 33,826	$ 2,428,415
Kevin P. Larson	666,826	149,675	96,745	193,490	2,089	1,108,825
Todd C. Hixon	244,908	91,531	29,570	59,140	5,629	430,778
Karen G. Kissinger	318,060	88,835	28,703	57,406	19,350	512,354
Kentton C. Grant	294,529	87,372	27,206	54,413	12,317	475,837

Director Compensation

All TEP directors are also named executive officers of TEP and received no additional compensation for services as a director. All of their compensation is reflected in the *Summary Compensation Table,* above.

Compensation Committee Interlocks and Insider Participation

All members of the UNS Energy Human Resources and Governance Committee during fiscal year 2015 were independent directors, except for Mr. Perry, who is an executive officer of Fortis. No Human Resources and Governance Committee member had any relationship requiring disclosure under *Transactions with Related Persons*, in *Part III, Item 13. Certain Relationships and Related Transactions and Director Independence,* below. During fiscal year 2015, none of the Company's executive officers served on the Human Resources and Governance Committee or the Board of Directors of another entity whose executive officer(s) served on UNS Energy's Human Resources and Governance Committee, any other board committee, or the Board of Directors of UNS Energy or TEP as a whole.

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

All of the outstanding shares of common stock, no par value, of TEP are held by UNS Energy, which is an indirect, wholly owned subsidiary of Fortis.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Director Independence

TEP's directors are not independent since they are executive officers of TEP and UNS Energy. There are no standing committees of the Board of Directors of TEP.

As described in *Part III, Item 10. Directors, Executive Officers and Corporate Governance,* above, the Audit and Risk Committee of the UNS Energy Board of Directors is responsible for overseeing the accounting and financial reporting process and audits of the financial statements of UNS Energy and its consolidated subsidiaries, including TEP.

As described in *Part III, Item 11, Executive Compensation*, above, the Human Resources and Governance Committee of the UNS Energy Board of Directors is responsible for overseeing the executive compensation policies and practices of UNS Energy and its consolidated subsidiaries, including TEP.

The Board of Directors of UNS Energy has adopted Director Independence Standards that comply with New York Stock Exchange (NYSE) rules for determining independence, among other things, in order to determine eligibility to serve on the Audit and Risk Committee and the Human Resources and Governance Committee of UNS Energy. Neither UNS Energy nor TEP has any securities listed on the NYSE or any other national securities exchange or inter-dealer quotation system requiring that directors or committee members be independent but, in approving the acquisition of UNS Energy by Fortis, the ACC required that a majority of the members of the UNS Energy Board of Directors be independent. The written charters of the UNS Energy Audit and Risk Committee and Human Resources and Governance Committee each require that a majority of the members of each such committee meet both UNS Energy's Director Independence Standards and independence standards of the NYSE. The UNS Energy Director Independence Standards are available on TEP's website at www.tep.com/about/investors/.

No director may be deemed independent unless the Board of Directors of UNS Energy affirmatively determines, after due deliberation, that the director has no material relationship with UNS Energy or any of its subsidiaries either directly or as a partner, shareholder or executive officer of an organization that has a relationship with UNS Energy or any of its subsidiaries. In each case, the Board of Directors of UNS Energy broadly considers all the relevant facts and circumstances from the standpoint of the director as well as from that of persons or organizations with which the director has an affiliation and applies these standards.

Annually, the UNS Energy board determines whether each director meets the criteria of independence. Based upon the foregoing criteria, the UNS Energy board has deemed each director of UNS Energy to be independent, with the exception of Messrs. Hutchens, Perry, and Laurito. Mr. Hutchens is the President and Chief Executive Officer of UNS Energy and TEP. Mr. Perry is an executive officer of Fortis. Mr. Laurito is an executive officer of Central Hudson Gas and Electric Corporation, another wholly owned subsidiary of Fortis. For each other director who is deemed independent, there were no other significant transactions, relationships or arrangements that were considered by the UNS Energy board in determining that the director is independent. See *Transactions with Related Persons*, below.

Each member of UNS Energy's Audit and Risk Committee and Human Resources and Governance Committee meets the independence criteria of both the Director Independence Standards and the NYSE listing standards, with the exception of Mr.

Perry, who is an executive officer of Fortis, and Mr. Laurito, who is an executive officer of Central Hudson Gas and Electric Corporation. Mr. Hutchens is not a member of either committee.

Transactions with Related Persons

The UNS Energy Board of Directors has adopted a written Policy on Review of Transactions with Related Persons ("Related Person Policy") under which it reviews related person transactions. The policy is available on TEP's website at www.tep.com/about/investors/. The Related Person Policy specifies that certain transactions involving directors, executive officers, significant shareholders and certain other related persons in which UNS Energy or its subsidiaries, including TEP, is or will be a participant and are of the type required to be reported as a related person transaction under Item 404 of Regulation S-K shall be reviewed by the UNS Energy Audit and Risk Committee for the purpose of determining whether such transactions are in the best interest of UNS Energy and its subsidiaries. The Related Person Policy also establishes a requirement for directors and executive officers of UNS Energy and its subsidiaries to report transactions involving a related party that exceed $120,000 in value. TEP is not aware of any transactions entered into since the beginning of last year that did not follow the procedures outlined in the Related Person Policy.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. UNS Energy's Audit and Risk Committee has adopted a policy pursuant to which audit, audit-related, tax, and other services are pre-approved by category of service. Recognizing that situations may arise where it is in the Company's best interest for the auditor to perform services in addition to the annual audit of the Company's financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for UNS Energy. The policy requires the Audit and Risk Committee to be informed of each service and does not include any delegation of the Audit and Risk Committee's responsibilities to management. The Audit and Risk Committee may delegate to the Chair of the Audit and Risk Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit and Risk Committee approval where the Audit and Risk Committee Chair believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit and Risk Committee meeting. The decisions of the Audit and Risk Committee Chair to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit and Risk Committee.

Fees

Effective October 7, 2014, PwC was dismissed as the independent auditors and replaced with Ernst and Young LLP (EY) as a result of the Fortis acquisition. The table details fees paid to EY for professional services during 2015 and 2014. The Audit and Risk Committee has considered whether the provision of services to TEP by EY, beyond those rendered in connection with their audit and review of TEP's financial statements, is compatible with maintaining their independence as auditor.

TEP's fees for principal accountant services are as follows:

(in thousands)	2015	2014
Audit Fees	$ 1,352	$ 1,206
Audit-Related Fees	—	—
Tax Fees	70	84
All Other Fees	—	—
Total	$ 1,422	$ 1,290

Audit fees include fees for the audit of TEP's consolidated financial statements included in TEP's Annual Report on Form 10-K and review of financial statements included in TEP's Quarterly Reports on Form 10-Q. Audit fees also include services provided in connection with comfort letters, consents and other services related to SEC matters, financing transactions, and statutory and regulatory audits.

Tax fees reported for 2015 and 2014 include fees for tax appeals, and in 2014 for consulting.

All services performed by our principal accountant are approved in advance by the Audit and Risk Committee in accordance with the Audit and Risk Committee's pre-approval policy for services provided by the Independent Registered Public Accounting Firm.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Consolidated Financial Statements as of December 31, 2015 and 2014 and for Each of the Three Years in the Period Ended December 31, 2015

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Report of Independent Registered Public Accounting Firm	43
Consolidated Statements of Income	45
Consolidated Statements of Comprehensive Income	46
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(2) Financial Statement Schedule

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) Exhibits

Reference is made to the Exhibit Index commencing on page 119.

SIGNATURES

Pursuant to the requirements 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.

TUCSON ELECTRIC POWER COMPANY
(Registrant)

Date:	February 18, 2016	/s/ Kevin P. Larson Kevin P. Larson Senior Vice President and Chief Financial Officer

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

Date:	February 18, 2016		/s/ David G. Hutchens* David G. Hutchens President, Chief Executive Officer, and Director (Principal Executive Officer)
Date:	February 18, 2016		/s/ Kevin P. Larson Kevin P. Larson Senior Vice President, Chief Financial Officer, and Director (Principal Financial Officer)
Date:	February 18, 2016		/s/ Frank P. Marino* Frank P. Marino Vice President and Controller (Principal Accounting Officer)
Date:	February 18, 2016		/s/ Todd C. Hixon* Todd C. Hixon Director
Date:	February 18, 2016	By:	/s/ Kevin P. Larson Kevin P. Larson *As attorney-in-fact for each of the persons indicated

EXHIBIT INDEX

*2(a)	Agreement and Plan of Merger, dated as of December 11, 2013, among FortisUS Inc., Color Acquisition Sub Inc., UNS Energy Corporation and solely for purposes of Section 5.5(a) and 8.15, Fortis Inc. (Form 8-K, dated December 12, 2013, File No. 1-05924 - Exhibit 2.1).
*2(a)(1)	First Amendment to the Agreement and Plan of Merger, dated as of August 14, 2014, by and among FortisUS Inc., Color Acquisition Sub Inc. and UNS Energy Corporation (Form 8-K, dated August 14, 2014, File No. 1-05924 - Exhibit 2.2).
*3(a)	Restated Articles of Incorporation of TEP, filed with the ACC on August 11, 1994, as amended by Amendment to Article Fourth of our Restated Articles of Incorporation, filed with the ACC on May 17, 1996. (Form 10-K for the year ended December 31, 1996, File No. 1-05924 - Exhibit No 3(a)).
*3(a)(1)	TEP Articles of Amendment filed with the ACC on September 3, 2009 (Form 10-K for the year ended December 31, 2010, File No. 1-05924 - Exhibit 3(a)).
*3(b)	Bylaws of TEP, as amended as of August 12, 2015 (Form 10-Q for the quarter ended September 30, 2015, File No. 1-05924 - Exhibit 3).
*3(c)	Amendment to Articles of Incorporation of UNS Energy Corporation, creating series of Limited Voting Junior Preferred Stock (Form 8-K dated August 12, 2015, File No. 1-05924 - Exhibit 3.2).
*4(c)(1)	Indenture of Trust, dated as of March 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File No. 1-05924 - Exhibit 4(a)).
*4(c)(2)	Loan Agreement, dated as of March 1, 2008, between the Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File No. 1-05924 - Exhibit 4(b)).
*4(d)(1)	Indenture of Trust, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File No. 1-05924 - Exhibit 4(a)).
*4(d)(2)	Loan Agreement, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File No. 1-05924 - Exhibit 4(b)).
*4(e)(1)	Indenture of Trust, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(A)).

*4(e)(2)	Loan Agreement, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company San Juan Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(B)).
*4(f)(1)	Indenture of Trust, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(C)).

*4(f)(2)	Loan Agreement, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(D)).
*4(g)(1)	Indenture of Trust, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 Exhibit 4(a)).
*4(g)(2)	Loan Agreement, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 - Exhibit 4(b)).
*4(h)(1)	Indenture of Trust, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(c)).
*4(h)(2)	Loan Agreement, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(d)).
*4(i)(1)	Indenture of Trust, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(i)(2)	Loan Agreement, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and TEP, relating to Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(j)(1)	Indenture of Trust, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(j)(2)	Loan Agreement, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(k)(1)	Indenture of Trust, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 14, 2013, File No. 1-05924 - Exhibit 4(a)).

*4(k)(2)	Loan Agreement, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 14, 2013, File No. 1-05924 - Exhibit 4(b)).
*4(l)(1)	Indenture of Trust, dated as of November 1, 2013, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Springerville Project). (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(a)).

*10(b)(2)	Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Finance Co., each as beneficiary under a separate trust agreement, dated as of December 1, 1985, with Wilmington Trust Company, as Owner Trustee, and William J. Wade, as Co-Trustee, and TEP and San Carlos, as Lessee. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(2)).

*10(b)(3)	Participation Agreement, dated as of December 1, 1985, among TEP and San Carlos as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation, and Emerson Finance Co. as Owner Participants, Wilmington Trust Company as Owner Trustee, The Sumitomo Bank, Limited, New York Branch, as Loan Participant, and Bankers Trust Company, as Indenture Trustee. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(3)).
*10(b)(4)	Restructuring Commitment Agreement, dated as of June 30, 1992, among TEP and San Carlos, jointly and severally, as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding, William J. Wade, as Owner Trustee and Co-Trustee, respectively, The Sumitomo Bank, Limited, New York Branch, as Loan Participant and United States Trust Company of New York, as Indenture Trustee. (Form S-4, Registration No. 33-52860 - Exhibit 10(g)(4)).
*10(b)(5)	Lease Supplement No.1, dated December 31, 1985, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee Trustee and Co-Trustee, respectively (document filed relates to Philip Morris Credit Corporation; documents relating to IBM Credit Financing Corporation and Emerson Financing Co. are not filed but are substantially similar). (Form S-4, Registration No. 33-52860 - Exhibit 10(g)(5)).
*10(b)(6)	Amendment No. 1, dated as of December 15, 1992, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 - Exhibit 10(g)(6)).
*10(b)(7)	Amendment No. 1, dated as of December 15, 1992, to Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding Corp., as Owner Participants and TEP and San Carlos, jointly and severally, as Lessee. (Form S-1, Registration No. 33-55732 - Exhibit 10(g)(7)).
*10(b)(8)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(8)).
*10(b)(9)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit Financing Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(9)).
*10(b)(10)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(10)).
*10(b)(11)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip Morris Capital

Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(11)).

*10(b)(12)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit Financing Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(12)).

*10(b)(13)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(13)).
*10(b)(14)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(a)).
*10(b)(15)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit, LLC as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(b)).
*10(b)(16)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(c)).
*10(b)(17)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(d)).
*10(b)(18)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit, LLC as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(e)).
*10(b)(19)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(f)).
*10(b)(20)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.1).

*10(b)(21)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Selco Service Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.2).
*10(b)(22)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Emerson Finance LLC as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.3).

*10(b)(23)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.4).
*10(b)(24)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Selco Service Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.5).
*10(b)(25)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Emerson Finance LLC as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.6).
*10(c)(1)	Participation Agreement, dated as of June 30, 1992, among TEP, as Lessee, various parties thereto, as Owner, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, and LaSalle National Bank, as Indenture Trustee relating to TEP's lease of Springerville Unit 1. (Form S-1, Registration No. 33-55732 - Exhibit 10(u)).
*10(c)(2)	Lease Agreements, dated as of December 15, 1992, between TEP, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 - Exhibit 10(v)).
*10(c)(3)	Tax Indemnity Agreements, dated as of December 15, 1992, between the various Owner Participants parties thereto and TEP, as Lessee. (Form S-1, Registration No. 33-55732 - Exhibit 10(w)).
+10(d)	UNS Energy Officer Change in Control Agreement (a schedule of officers who are covered by the agreement or substantially identical agreements is filed separately), between UNS Energy and officers of UNS Energy.
+10(d)(1)	Schedule of Officers covered by UNS Energy Officer Change in Control Agreement or substantially Identical Agreements.
+*10(f)	Retention Bonus Agreement between Kevin P. Larson and UNS Energy Corporation (Form 8-K, dated November 13, 2014, File No. 1-05924 - Exhibit 10(a)).
+*10(g)	UNS Energy Corporation 2015 Share Unit Plan (Form 8-K, dated February 23, 2015, File No. 1-05924-Exhibit 10(a)).
12	Computation of Ratio of Earnings to Fixed Charges.

21	Subsidiaries of the Registrant.
24	Power of Attorney.
31(a)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by David G. Hutchens.
31(b)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by Kevin P. Larson.
**32	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Previously filed as indicated and incorporated herein by reference.

\+ Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

** Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

EDISON ELECTRIC INSTITUTE

Electric Utilities and Risk Compensation

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Edison Electric Institute

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June 2006

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EXECUTIVE SUMMARY

After a decade of minimal rate activity, investor-owned electric utilities are again filing rate cases. As they do, regulatory commissions are being challenged by new and emerging structural changes in the electric utility industry to approve rates that meet the Supreme Court's requirement to balance:

- Investors' rights to returns that are "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital"; and
- Consumers' rights to rates that are "just and reasonable."

Achieving the balance is complicated by the significant setbacks to investor confidence that have occurred in recent years, and the need for utilities to meet load changes by funding continual distribution system improvements, expanding transmission capacity, maintaining and enhancing reliability and service quality, and meeting new capacity requirements.

This monograph addresses issues that are important to striking the proper balance. It addresses new issues related to: (1) determining the cost of capital in restructured markets, and (2) managing the cost of capital through proactive regulatory policies. Key conclusions are:

1. ***Policymakers should not assume that restructured utilities are less risky than the traditional utilities that preceded them***. There are new risks in restructured markets. These risks may not be captured by traditional cost of capital methodologies, but investors are aware of them. This is why rating agencies have downgraded electric utility debt in recent years, and why investors are focusing on state regulatory policies and decisions to assess utility risk going forward.

2. ***Utility risk should be evaluated on a company-specific basis, using analytic frameworks that address the new risks in restructured markets.*** Among the possible new risks are:

   - **Increased earnings variability due to reliance on competitive wholesale markets**—Wholesale electricity prices can be extremely dynamic, leading to the potential for nonrecovery, or delayed recovery, of wholesale supply costs in regulated retail rates. Insolvency and/or nonperformance by third-party suppliers can exacerbate earnings volatility.
   - **Increased earnings variability due to new delivery infrastructure funding**—Cost increases for new delivery infrastructure, either at the transmission level, such as rising regional transmission organization (RTO) or independent system operator (ISO) costs, or at the distribution level, such as from replacement of aging facilities to maintain reliability, also can produce earnings volatility.
   - **Increased earnings variability due to increased customer switching**—In retail access environments, customer switching increases the volatility of retail loads incumbent utilities must serve pursuant to provider of last resort (POLR)-type service obligations. Increased load volatility can interact with the volatility in wholesale power markets and potential regulatory disallowances to produce increased volatility in earnings.
   - **Cherry-picking customers in retail competition states**—Some competitive models result in the loss of the utility's most profitable customers (in combination with continued use of volumetric rates) and an increase in uncollectible accounts, further impacting earnings volatility.

3. ***Policymakers can control the cost of capital by controlling risk.*** By adopting policies that control utility risk exposure, policymakers can effectively manage utility cost of capital. Key risk-reducing policies include:

   - **Pre-approved resource procurement**—Policies that ensure timely recovery of supply costs by (1) developing a shared understanding of reasonable supply-related resource strategies before costs are incurred, and (2) honoring costs reasonably incurred to implement such strategies. This would not mean an end to regulatory oversight and control, but rather an end to after-the-fact, "perfect hindsight" prudence reviews.
   - **Risk-mitigated POLR policies**—Policies that require large customers to pay stranded costs even when they leave regulated service, and observe minimum stay requirements if they come back to regulated supply from the market, or pay spot market prices when they return. (Note: If switching by small customers increases, similar requirements may be needed to manage risk.)
   - **Limiting counterparty exposure**—Policies that prevent third parties from shifting risk to incumbent utilities, such as by maintaining adequate creditworthiness standards for third parties, and by allocating partial payments to satisfy utility claims before satisfying claims by third-party suppliers.
   - **Timely recovery of infrastructure investments**—Policies and rate mechanisms that provide timely recovery between rate cases of costs incurred to make needed distribution and transmission system improvements. Infrastructure cost pass through must permit timely recovery of RTO/ISO costs as well.
   - **Updated rate design**—Policies that provide for the recovery of a substantial portion of distribution infrastructure costs through fixed customer charges, and increased use of automatic adjustment mechanisms to ensure timely recovery of costs that are highly variable and outside the control of utility management (e.g., fuel).

Section I, Identifying and Quantifying the New Risks, defines investor risk as the variation in utility cash flow, earnings and, ultimately, return on investment. It demonstrates why restructured utilities cannot be assumed to be less risky than the vertically integrated companies that preceded them. Restructuring exposes utilities to new risks, and corporate unbundling tends to magnify the financial impact of specific risks. A framework for evaluating the new risks is defined in terms of the major sources of new risk in restructured markets.

Section II, The Influence of New Risks on the Cost of Capital, examines the implications of the new risks of restructuring. Chief among these is the recognition that comparisons to "comparable" or "peer" utilities are becoming increasingly problematic. Given that the new risk factors vary by state and by company, there really aren't any comparable utilities anymore. This calls into question traditional cost of capital methods, such as use of the capital asset pricing model (CAPM) and discounted cash flow (DCF) model, which rely on comparisons to peer groups, and suggests the need for new approaches that evaluate risk on an individual company basis.

Section III, Potential Regulatory Policies to Estimate, Reduce, and Control Utility Risks, addresses issues related to compensating and/or managing utility risk that are outside the scope of traditional cost of capital determination methods. In terms of compensating utilities for risk, one relevant comparison is the cost of any insurance product(s) that may be available to manage a specific risk; appropriate compensation is approximately equal to the insurance premium required for such insurance coverage. Another approach, for new risks where no substantial empirical or experiential data yet exist, is to base premiums on financial simulations (e.g., Monte Carlo). A related issue is that customer preferences for compensated risk mitigation vary, so customers should be given choices, for example, of service packages that incorporate various levels of risk mitigation. In terms of managing utility risk, policymakers should consider the potential to manage utility cost of capital by calibrating regulatory policies to their impact on utility risk.

Section IV, Conclusions, reiterates that it is not reasonable to assume that restructured utilities are less risky than the integrated companies that preceded them. New risks are introduced by restructuring, and these need to be evaluated on a company-specific basis. Because the new risks are highly company- and jurisdiction-specific, the validity of traditional methodologies—which rely on comparisons to "comparable" or "peer" utilities—is called into question. Policymakers can manage utility cost of capital by managing utility risk.

SECTION I: IDENTIFYING AND QUANTIFYING THE NEW RISKS

The investor-owned electric utility industry has changed significantly over the past decade. The industry has seen movement from traditional vertical integration to unbundling of generation, transmission, and distribution functions, and increased reliance on emerging competitive wholesale markets. It also has experienced the rise and fall of major energy trading businesses and independent generating entities. In addition, many states are in the midst of moving toward competitive retail markets, while others seek to slow down or stop the emergence of competition. Collectively, these events have changed the fundamental risk characteristics of many utilities, leading to increased investor risk.

The increase in risk is reflected in the pattern of declining credit ratings in recent years. During 2001–2003, downgrades of shareholder-owned electric utilities substantially outpaced upgrades, reflecting increased utility risk from energy trading and merchant generation.[1] During 2004, the trend toward declining creditworthiness leveled off, as utilities sold non-core businesses and strengthened balanced sheets; and in 2005 the process of financial recovery continued and creditworthiness began to be rebuilt. During these years, regulated electric shareholder-owned utilities with credit ratings below investment-grade (i.e., below BBB) grew from 23 percent of the sector in 2001 to 39 percent as of December 2003, then receded to 27 percent as of December 2005. Unfortunately, as we look ahead, utility credit is again under pressure; this time because of investor concerns about increasing risk within the regulated business. The issue now is the timely recovery of increasing fuel costs and new capital investments. As one group of analysts expressed it recently: "These fairly steep increases have a number of implications for utilities, as it is not clear if such hikes will be easily digested by ratepayers or their elected representatives. From a regulatory risk perspective, utilities may well face cash deferrals, harsh rate case treatment, and the specter of re-regulation."[2] These same analysts also noted that "Historically, electric utility under-earning coincides with free cash turning negative (which happened in late 2005). When utilities as a group stop generating free cash flow, they earn approximately 225 Gps less than their allowed return on equity (ROE)."

Even where retail restructuring has not taken place, a new risk profile has emerged, requiring a comprehensive review of unique, utility-specific risks. This new pattern of risk has added complexity to estimating capital costs and establishing regulatory policies that mitigate risks, reduce the cost of capital to utilities, and reduce the cost burden to customers. Failure to recognize new risks or to underestimate the consequences of these risks will result in rates of return that are unsatisfactory for investors, a waning of interest in utility debt and equity issuances, and a decline in stock prices. Compounding the issue is the fact that rate designs often produce actual returns below those allowed.[3] It is earned return, not the allowed return, that forms the basis for investor evaluation. When returns are too low, inadequate amounts of capital are available and reliability suffers, even with prudent management of new investments.

[1] EEI Credit Ratings, Q1 2006 Financial Update.

[2] *Capital Lessons*, Lehman Brothers, March 15, 2006.

[3] This paper will not address the ratemaking process *per se*, but will refer to elements of that process that directly affect a utility's ability to actually earn its allowed rate of return.

To determine cost of capital, regulators rely on the concept of comparable risks as espoused in the familiar *Hope* and *Bluefield*[4] cases. To use comparable risk, the risks themselves must be known or knowable, and quantifiable. Without an understanding of the industry's new risk profile, comparable risk approaches cannot work. Moreover, the estimation of risk in most utility cost of capital studies is developed at a high level of aggregation, i.e., over groupings of companies or industries. Such aggregation does not permit the consideration of unique and utility-specific risks that cannot possibly average into the capital cost from a sample of unrelated utilities. The fundamental flaws of the current methodologies are the impairment of comparability and the failure to incorporate differing risk profiles. Risks can differ by company within a single jurisdiction because of company-specific historical precedent, differences in state regulatory policy, and the interplay of federal and state regulation. As discussed later, certain risks are also asymmetric and not susceptible to analysis on any basis other than utility-specific.[5] Asymmetric risk holds the potential for destroying shareholder value to a greater degree than it does for enhancing value. The traditional implied assumption that companies with certain common characteristics face comparable risks cannot be justified.

A. Defining Risk

In the simplest terms, the risk faced by equity investors is the volatility in actual and potential earned return. To fully define and understand the new utility industry risks and identify the changing impact of existing risks, it is useful to define a framework for analyzing utility risk by stating five fundamental postulates:

1. Rates are set on the basis of costs and assumptions that usually are out of date and rarely, if ever, match actual circumstances that occur throughout the rate effective period.
2. Investors make investment choices based on expected total return (the sum of the expected dividend plus expected stock price appreciation), and expected risk (the variability in returns).
3. Regulatory policies and procedures substantially affect utility risk and return.
4. Higher risk requires higher return to compensate investors for bearing such risk.
5. Actual equity returns result from the dollars available after all other costs are paid, including debt service costs.

In examining the risk profile of any given utility, particularly a utility that has been "restructured" (e.g., whose retail customers have been given competitive choice, and which has divested its generation), the essential question is whether the utility has become more risky, or less risky, than its pre-restructuring predecessor. If the returns the utility provides its shareholders have become *more* volatile, then the utility is riskier. If shareholder returns become *less* volatile, the utility is less risky. Numerous factors can bear on this question, and the analyst must exercise professional judgment in identifying and evaluating those factors that are most important in determining current and future return volatility for a given utility. Four factors likely to be of material influence, which are illustrated later with numeric examples, are:

1. Reliance on volatile wholesale markets for utility-provided power supply;
2. The need for new spending on delivery infrastructure;
3. Supplier of last resort (SOLR or POLR) obligations; and
4. The introduction of retail access after a legacy of social ratemaking.

[4] *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works v. P.S.C.*, 262 U.S. 679 (1923).

[5] For a detailed discussion of the problem of asymmetric risks, A. Lawrence Kolbe, William B. Tye, and Stewart C. Myers, *Regulatory Risk*, (Kluwer Academic Publishers, 1993).

B. Two Hypothetical Utilities

The importance, magnitude, and even the existence of each of the components of risk differ from state to state, and between utilities within a single state. For each of the four major risk factors listed above, numeric examples have been developed to illustrate their nature and impact on shareholder return. Two hypothetical electric utilities are used.

As shown in Table A, each of the two utilities serves the same number of customers (750,000), sells the same amount of power (20 billion kWh a year), and operates with the same total revenue requirement ($1.2 billion).[6] The difference is that one is a traditional, vertically integrated utility providing bundled service to its customers (*integrated utility*), while the other has divested both its generation and transmission (*unbundled utility*).

The examples that follow are calculated using the information in Table A that describes each utility. Dollar values have been rounded for simplicity, but are representative of small to medium-sized investor-owned electric utilities in the United States. (This paper will use "M" or "B" to signify million or billions; i.e., $25M is $25 million dollars.)

Table A: Basic Utility Data

	Integrated Utility	Unbundled Utility
	Base Case	**Base Case**
Rate base	$4.0 billion	$1.0 billion
Capital structure	50% debt/50% equity	50% debt/50% equity
Shareholder equity	$2.0 billion	$500 million
Allowed/earned ROE	10%	10%
Equity return	$200 million	$50 million
Debt	$120 million	$30 million
Non-fuel O&M	$330 million	$150 million
Depreciation expense	$160 million	$35 million
Tax	$140 million	$35 million
Fuel	$225 million	
Purchased power	$ 25 million	Hedged $720 million
		Unhedged $180 million
Revenue requirement	$1.2 billion	$300 million
Customer costs	$1.2 billion	$1.2 billion

[6] The revenue requirement for both utilities is the sum of the cost of equity and debt, income taxes, non-fuel operations and maintenance (O&M), depreciation expense, and fuel or purchased power expense.

C. Risks Related to Competitive Wholesale Markets

Competitive wholesale electricity markets produce prices that can be extremely volatile, escalating rapidly when demand begins to overtake supply, and falling equally rapidly when demand falls. This represents a risk factor for electric utilities, because purchased power costs typically do not flow directly into retail rates, but must be deferred for possible subsequent recovery. As the size of deferred purchased power balances grow, so too does the potential for prudence challenges. With this in mind, it is reasonable to view utility dependence on wholesale power purchases as a risk factor, depending on associated regulatory policies and procedures. As illustrated in Table B, the impact can be much greater for an unbundled ("wires-only") utility, than for a traditional, vertically integrated utility.

As the examples illustrate, both traditional integrated utilities and unbundled utilities face a number of new risks resulting from a variety of regulatory and legislative changes in energy markets. The impacts of the risks vary from utility to utility and, contrary to the view that unbundled utilities are less risky, the examples illustrate that the unbundled utility, under the same rules as an integrated utility, can be more risky. The higher risk for unbundled utilities means that higher equity returns are required to compensate the owners of the utility for the risks.

Table B: Basic Utility Data with 10 Percent Energy Price Increase Case

	Integrated Utility		Unbundled Utility	
	Base Case	10% Energy Price Increase Case	Base Case	10% Energy Price Increase Case
Rate base	$4.0 billion		$1.0 billion	
Capital structure	50% debt/50% equity		50% debt/50% equity	
Shareholder equity	$2.0 billion		$500 million	
Allowed/earned ROE	10%	8.75% (12.5% decline)	10%	6.4% (36% decline)
Equity return	$200 million	$175 million	$50 million	$32 million
Debt	$120 million		$30 million	
Non-fuel O&M	$330 million		$150 million	
Depreciation Exp.	$160 million		$35 million	
Tax	$140 million		$35 million	
Fuel	$225 million	$247.5 million		
Purchased power	$25 million	$27.5 million	Hedged $720 million	
			Unhedged $180M	$198 million
Revenue req.	$1.2 billion		$300 million	
Customer Costs	$1.2 billion		$1.2 billion	

Table B depicts the impact of a 10 percent increase in wholesale power and fuel prices on the shareholder returns of our two hypothetical utilities. In each case, a rate freeze is assumed.

Briefly, in a scenario in which the spot market price of fuel and wholesale power rises 10 percent, and in which neither utility can flow these increases into retail rates in a timely fashion, the financial return realized by shareholders of the *unbundled* utility declines about three times further than the return realized by shareholders in the *integrated* utility. This is because the unbundled utility is far more dependent on purchased power than is the integrated utility. A second reason is that the unbundled utility's equity base is one-fourth the size of that of the integrated utility, so adverse events have a much bigger impact on ROE. This shows that *unbundled* utilities can be significantly more risky than *integrated* utilities.

For the *integrated utility*, as shown in Table B, the cost of *fuel* is \$225 million, with a 10 percent increase of \$22.5 million resulting in a total of \$247.5 million. The cost of *purchased power* is \$25 million, with a 10 percent increase of \$2.5 million resulting in a total of \$27.5 million. Thus, a 10 percent increase in both wholesale power and fuel results in a total increase of \$25 million and a final combined cost of \$275 million ([\$225M + \$22.5M] + [\$25M +\$2.5M]).

The change in cost must come out of the shareholders' equity return, since debt holders have a superior claim on earnings. So *equity return* declines by \$25 million, from \$200 million in the *base case*, to \$175 million in the *10 percent energy price increase case*. In percentage terms, the return on equity declines from 10 percent in the base case (\$200 million/shareholders' equity of \$2 billion[7]) to 8.75 percent (\$175M/\$2B), *a 12.5 percent decline in equity return*.

For the *unbundled utility*, the cost of purchased power also increases 10 percent. For illustration, it is assumed that the unbundled utility *hedged* \$720 million of its purchased power expense under long-term purchase contracts, so the 10 percent price increase applies only to the *unhedged* portion, or \$180 million, of its purchased power expense. The 10 percent increase from \$180 million is \$18 million, for a total of \$198 million.

Again, increased operating costs are borne entirely by shareholders, since bondholders have a superior claim on earnings. As a result, the shareholders' return declines by \$18 million, from \$50 million in the *base case*, to \$32 million in the *10 percent energy price increase case*. In percentage terms, the *return on equity* declines from 10 percent in the base case (\$50 million/shareholders' equity of \$500 million[8]) to 6.4 percent (\$32M/\$500M), *a 36 percent decline in equity return*.

Notice how much more severe the decline in shareholder return is for shareholders in the unbundled utility: 36 percent versus 12.5 percent. The impact on the unbundled utility is almost three times greater. Clearly, the unbundled utility is riskier than the integrated utility when it bears the price volatility risk of the market. There are two basic reasons for this.

First, the unbundled utility is far more dependent on purchased power than is the integrated utility. The risks discussed in this section (including price risk and related regulatory risk) are a function of wholesale purchases, so it stands to reason the unbundled utility is more exposed to these sources of risk than is the

[7] The rate base of the integrated utility is \$4 billion, which is funded half by equity.
[8] The rate base of the unbundled utility is \$1 billion, which is funded half by equity.

integrated utility. For the unbundled utility, power purchases can be almost as large as its rate base and have no associated rate base component because the recovery is a cost pass through. One might argue that the unbundled utility should have hedged the entire portfolio, not just the $720 million. Such hedging, however, introduces another large risk, namely, that the market price falls and the regulators impose a penalty on the utility for imprudent purchases. In either case, the potential equity impact is large under a fixed-price SOLR obligation.

Second, the unbundled utility's equity base (shareholder capital) is significantly smaller than that of the integrated utility ($500 million vs. $2 billion), so a given reduction in net income has a much bigger impact on the unbundled utility in terms of reductions in ROE, than on the integrated utility. A relatively small disallowance of purchased power costs can have a huge impact on earnings and ROE.

It was assumed that no fuel adjustment mechanism was available to the integrated utility, so it had to absorb a 10 percent risk in fuel prices. Of course, such mechanisms are frequently in use. Had a fuel mechanism been assumed, the discrepancy in impact on equity return would have been even greater, with the unbundled utility appearing even more risky than the integrated utility. Unbundled utilities may also have fuel adjustment clauses. However, the existence of a fuel clause for competitive utilities creates both market risk and stranded cost risk, and while it may resolve short-term market fluctuations, it will also create larger, long-term issues of cost recovery.

It also is worth mentioning that there is a fundamental asymmetry in the unbundled utility's risk exposure that is not experienced by the integrated utility. The unbundled utility bears large risks related to purchased power transactions, but typically makes *nothing* on them; it simply passes procured power costs along to customers. Integrated utilities, on the other hand, serve customers from supply resources that are mostly in rate base, on which they earn an allowed return.

Finally, wholesale counterparty risk (i.e., the potential for financial loss due to nonperformance by parties with whom the utility has a wholesale supply relationship) probably has increased for both integrated and unbundled utilities. This is due to the rise in natural gas prices in recent years, which has left many merchant generating companies in a weakened (less creditworthy) financial position. Again, since unbundled utilities are far more dependent on purchases than integrated companies, they tend to be more exposed to counter-party risks.

D. Risks Related to New Delivery Infrastructure

Cost increases for new delivery infrastructure, either at the transmission or distribution level, also can produce variation in utility earnings and shareholder return. The size of the financial impact can be much greater for unbundled utilities than for traditional, vertically integrated utilities. This is a new risk factor to the extent that the sources and scale of new delivery cost increases are unprecedented.

At the transmission level, significant costs are being incurred to build new infrastructure to support the operation of restructured transmission systems. These costs tend to be associated with the development of new data processing systems (hardware, software, and personnel).[9] Of course, there also is the potential for

[9] Concerns about the lack of efficiency incentives for RTOs/ISOs, and about the lack of adequate financial oversight by participants in RTOs/ISOs, are raised in EEI comments in FERC Docket No. RM04-12-000, Financial Reporting and Cost Recovery Practices for Regional Transmission Organizations and Independent System Operators, November 9, 2004.

new transmission lines to be built, if a host of siting and other issues can be resolved. RTOs allocate new costs to transmission customers (e.g., regulated utilities), who must then recover them in retail rates. However, if a state has implemented a rate freeze, any increase in transmission-related revenue requirements may be difficult to implement in retail rates, at least not before the freeze expires. (The Federal Energy Regulatory Commission has jurisdiction over transmission revenue requirements, but states have jurisdiction over retail rate designs.) Even without an explicit freeze, timely recovery may be difficult if the state uses an historic test year. Furthermore, states may seek to offset transmission revenue increases with decreases in other legitimate revenues. Table C illustrates the differential impact of a $10 million increase in RTO operating costs. Assuming these costs are not immediately flowed into retail rates, they will come out of shareholder returns.

Briefly, in a scenario in which the utility's share of RTO costs increases $10 million, and in which these costs cannot be flowed timely into retail rates in a timely manner, the financial return realized by shareholders of the *unbundled* utility declines about four times more than returns realized by shareholders of the *integrated* utility. This is because the unbundled utility's equity base is one-fourth the size of that of the integrated utility, so the $10 million hit has a bigger impact on an unbundled utility's equity return. This shows, again, that unbundled utilities can be significantly more risky than integrated utilities.

For the *integrated* utility, this scenario means a reduction in return on equity from 10 percent to 9.5 perecent, or *a 5 percent decrease in return on equity*. For the *unbundled* utility, it means a reduction from 10 percent to 8 percent, or *a 20 percent decrease in return on equity*. As before, the impact on the unbundled utility is four times greater, because its equity base is four times smaller.

Table C: Impact of a $10 Million Increase in RTO Costs

	Integrated Utility		Unbundled Utility	
	Base Case	$10 M RTO Increase Case	Base Case	$10 M RTO Increase Case
RTO costs		$10 million more		$10 million more
Equity return	$200 million	$190 million	$50 million	$40 million
Allowed/earned ROE	10 %	9.5 % (5% decline)	10%	8% (20% decline)

At the distribution level, cost increases are being driven by the need for new facilities to replace aging infrastructure, support demand response, enhance power quality, and support the digital economy, or to serve new customers. Taken together, the scale of the investment required may be unprecedented. As with transmission costs, rate freezes and/or use of an historic test year can impede timely recovery and produce negative financial shareholder impacts.

Briefly, in a scenario in which a $75 million capital investment in the distribution system is needed, there is no effect on the *integrated* utility's ROE, but there is a 42-basis-point decline in the *unbundled* utility's ROE. This is because the integrated utility's rate base is four times the size of that of the unbundled utility, so it can fund the new investment out of annual depreciation expense. The unbundled utility cannot do so and must sell new debt, the service of which reduces returns to shareholders. Again, unbundled utilities can be more risky than integrated utilities.

Table D illustrates the differential impact of a required $75 million investment to rebuild distribution facilities to maintain reliability. This example deals with long-lived assets, as opposed to annual operating expenses in the previous RTO example, so depreciation expense becomes relevant. (Depreciation expense is the amount by which an asset is depreciated each year. It does not affect cash flow, but it does reduce taxable income.) The *integrated* utility, with a rate base of $4 billion, has an annual depreciation expense of $160 million ($4 billion/25-year asset life). The *unbundled* utility, with a rate base of $1 billion, has an annual depreciation expense of only $40 million ($1 billion/25-year asset life).

The *integrated* utility can fund the $75 million from depreciation expense, so no net new rate base is required and the impact on earnings is negligible. The *unbundled* utility, however, cannot do this, because $75 million is substantially more than its annual $40 million depreciation expense. So, either the unbundled utility uses $35 million in current earnings to pay for the rebuilding, or it sells new debt for this purpose. It is assumed the unbundled utility sells additional debt.

Table D: $75 Million Distribution Investment

	Integrated Utility		Unbundled Utility	
	Base Case	**$75 Million Distribution**	**Base Case**	**$75 Million Distribution**
Rate base	$4.0 billion		$1.0 billion	
Annual depreciation	$160 million		$40 million	
Debt	$120 million		$30 million	$ 65 million
Cost of new debt at 6%				$2.1 million
Equity return	$200 million	$200 million	$50 million	$47.9 million
Allowed/earned ROE	10%		10%	**9.58% (4.2% decline)**

The bottom line is that for the *integrated* utility, the same $75 million infrastructure replacement event has no effect on shareholder returns since it can be paid for out of annual depreciation. However, for the *unbundled* utility, the cost of new debt must be paid for out of equity returns, so shareholder returns *are reduced by 4.2 percent, from 10 percent to 9.58 percent.*

E. Risks Related to Provider of Last Resort Supply Obligations

Retail access can create significant new risks for utilities which have divested their own supply resources, but must nevertheless stand ready to supply those customers not served by the market. Such supply obligations are known generically as provider of last resort, or POLR, supply obligations.[10] In addition to price risk, described above, POLR obligations can create more material risks for utility shareholders.

The most important of these is probably volume risk, or energy imbalance risk. This is the risk that the utility will suffer a financial loss because it purchases too much, or too little, power to serve retail customers. Volume risk increases as customers shift from regulated supply to the market, and back to the utility. Such customer shifting increases the variability of POLR loads and makes it harder for utilities to know how much energy to procure.

Briefly, in a scenario in which POLR load drops 20 percent, the *unbundled* utility's equity return declines 288 basis points. This is because the utility realizes a loss when it sells power it bought via a long-term contract that it no longer needs. The *integrated* utility is not involved in this scenario, because POLR supply obligations are associated with retail access markets in which the integrated incumbents typically have divested their generation.

Table E describes the impact on shareholder return of a scenario in which the spot market price of electricity falls 10 percent, prompting customers to leave POLR service and shift to the market because they can get a better price. It is assumed that the utility's POLR load declines by 20 percent as a result. To meet this reduced load, the utility continues to buy $720 million worth of power pursuant to its multiyear supply contract, which is now above the spot market price, and another $130 million worth of power in the spot market.

Table E: Volume Risk—Market Price Decrease

	Integrated Utility		Unbundled Utility	
	Base Case	**20% POLR Load Decline**	**Base Case**	**20% POLR Load Decline**
Purchased power	$ 25 million		Hedged $720 million	Resale $129.6 million with a $14.4 million loss
			Unhedged $180M	Unhedged $130 million
Total purchased power			$900 million	$720.4 million
Equity return	$200 million		$50 million	$35.6 million
Allowed/earned ROE	10%		10%	7.12% (28.8% decline)

[10] In some jurisdictions this is called default service, basic generation service, etc.

The *unbundled* utility must continue buying in the spot market because its load varies throughout the day. If it didn't, the utility's multiyear contract, which represents 80 percent of its supply in the base case, would exactly meet its needs. However, the utility's load is not constant, but varies throughout the day: there are hours in which it is greater than 80 percent of the base case, and hours in which it is less. Therefore, to meet its peak load, the unbundled utility must buy $130 million worth of power in the spot market.

It is assumed that the 20 percent reduction in load translates equally into a 20 percent reduction in the need for power purchased via the multiyear contract, and a 20 percent reduction in the need for power purchased in the spot market. So, of the $720 million incurred to buy hedged power, 20 percent, or $144 million worth, is not used and must be resold in the spot market. This power is sold at a loss, since the spot market price is now 10 percent lower than the price the utility paid under its multiyear contract. As a result, the utility resells its unused power for ($144M x 0.9M =) $129.6 million, realizing a loss of ($144M - $129.6M =) $14.4 million. Return on equity declines accordingly, from ($50M/$500M = 10%) in the base case, to ([50M - 14.4M]/500M =) 7.12 percent.

This example illustrates how a relatively small change in spot market price can produce a large swing in ROE. As noted in Section C, the *unbundled* utility can experience much larger variation in equity return (i.e., is more risky) than an *integrated* utility, because it is far more dependent on procured power and has a smaller equity base than an integrated utility.

Of course, spot market prices can move in the other direction as well. Table F illustrates a scenario in which spot prices rise above the rate for POLR service. In this case, it is assumed that the spot market price rises 5% above the utility's POLR rate, and that the POLR load grows 2%, because customers switch back to POLR service to get a better price.

Table F: Volume Risk—Market Price Increase

	Integrated Utility		Unbundled Utility	
	Base Case	**2% POLR Load, 5% Cost Increase**	**Base Case**	**2% POLR Load, 5% Cost Increase**
Purchased power	$ 25 million		Hedged $720m	$720 million
			Unhedged $180m	$207.9 million
Total purchased power			$900 million	$927.9 million
Equity return	$200 million		$50 million	$22.1million
Allowed/earned ROE	10%		10%	4.4% (55.8% decline)

As customers shift back to POLR, the utility must buy additional supply in the spot market, at prices that now exceed the approved POLR rate. The utility needs a total supply of ($900M x 1.02M =) $918 million at the old (base case) price. Of this amount, $720 million worth is available from the multiyear supply contract. This leaves ($918M – $720M =) $198 million of new power cost under the base case price that must be procured in the spot market. This additional power now costs ($198M x 1.05M =) $207.9 million. So total purchased power cost rises to ($720M + $207.9M =) $927.9 million under the new scenario. POLR rates are frozen, so these additional supply costs must come out of shareholder earnings. Return on equity declines from 10 percent in the base case, to 4.4 percent in the new scenario. A very small rise in market prices and POLR load has produced a huge drop in return on equity—at least, unless and until these costs can be recovered.

In addition to volume risk, POLR obligations can create two other risks for utilities. One is credit risk, which is the risk that the utility will suffer a financial loss because its customers don't pay their bills. Credit risk can increase in retail access markets because, as solvent customers switch to market-based suppliers, the concentration of "bad debt" customers in POLR loads tends to increase. Moreover, commissions may, in the interest of "jump starting the market," require incumbent utilities to take over bad debt customers from market-based retailers.

The second is retail counterparty risk, which is the risk that the utility will suffer financial loss because market-based retailers (serving end-use consumers) become insolvent and cease operations. The utility may suffer a loss because a supplier fails to deliver power and the utility must go into the market and purchase replacement power under unfavorable terms and conditions. Alternatively, a utility may experience a loss because a retailer fails to reimburse the utility for distribution and/or customer care services that the retailer has purchased on behalf of the customer.

Neither of these two additional risks is illustrated with a numeric example, but they are just as real. Considering all three POLR-related risks together, it is understandable why rating agencies are looking at POLR policies as a key risk driver for unbundled utilities.[11]

F. Earnings Volatility Due to Social Ratemaking

When retail access is implemented, it becomes increasingly difficult, if not impossible, to administer subsidies, no matter how well intentioned they may be. This is because retail access forces rate unbundling, which allows customers to see what they are paying for various components of electric service. If regulatory policy has led to inter-class return differentials (e.g., where large customers are paying more than the cost of service, and small customers less), this creates another risk for utility shareholders. There are two possible components of this risk.

Briefly, in a scenario in which there are inter-class return differentials in the incumbent's regulated rates, and in which 10 percent of the load in the highest-return customer class (i.e., the large commercial and industrial customer class) shifts to market-based suppliers, the incumbent *unbundled* utility experiences a reduction in realized ROE of 74 basis points. This is because the loss of high-margin customers produces a disproportionate reduction in equity return, and high-margin customers are easy for third-party suppliers to serve at lower cost.

First, there is a class of service that produces a higher than average return for the utility. Marketers are able to attract away these customers, which produces a disproportionate loss of contribution to margin. Consider

[11] See for example, Standard & Poor's Keys to Success for U.S. Electricity Transmission and Distribution Companies, March 11, 2004.

the case where an integrated utility is allowed a 10 percent return overall, but a single class of customers that represents 30 percent of the load provides a 15 percent return. The loss of those customers reduces the return by the percentage of return related to services other than delivery (here assumed to be 75 percent) times the portion of customer that the class represents (here assumed to be 30 percent). This equals a reduction in utility return of 22.5 percent (75 percent x 30 percent). This also assumes that return is uniform for delivery and production services. Of course, if the utility can resell the power, it can mitigate the impact of a 22.5 percent reduction in earnings as long as the regulatory climate allows those returns to be credited to the shareholders. In many cases, off-system sales have no impact on return and/or are in part shared with ratepayers.

Second, this same result may occur even if the rate classes all produce the system average return. In this case, customers within a class with the more profitable load profile will be attracted away. The same analysis as discussed above applies and the utility's return will decline. Thus, cherry-picking opportunities that result from subsidies that are sustainable only under complete regulation cannot be sustained in the open market. The existence of those subsidies in an unbundled market with integrated utility service cause added earnings volatility.

The risks described in this section are associated with both bundled and unbundled utilities under certain assumptions regarding regulatory treatments. The examples illustrate that risks may vary materially for utilities operating in restructured markets, and underscore the assertion (above) that utility risk must be assessed on a utility-specific basis.

SECTION II: THE INFLUENCE OF NEW RISKS ON THE COST OF CAPITAL

Traditional cost of capital estimation methods can only partly reflect the new risk profiles and risk-related costs of the utility industry. The industry changes and related risk factors described in the previous section suggest a variety of issues pertinent to the adequacy of traditional approaches to determining the cost of capital to enable utilities to actually earn adequate returns on equity.

A. Loss of Peer Group Relevance

Traditional approaches to the cost of capital rely on comparisons of one utility's risk profile and earned returns to an aggregate group of "comparable" or "peer" utilities. The discounted cash flow (DCF) method, capital asset pricing model (CAPM), or comparable earnings models use a set of comparable companies to develop the estimate of a market-based equity return. However, many utilities no longer derive their earned returns solely from the regulated utility business. Financial market data drawn from such "peer" utilities reflect the earnings of the total, consolidated enterprise, and not necessarily of the "pure play" utility subsidiary.

Added to the complexity are differing legislative and regulatory mandates and policies in various states, which result in differences in earnings volatility of each peer utility. Many regulatory policy factors distinguish the risk profiles of individual utilities within a group of peers that would otherwise appear homogenous. Examples include differences in the levels of fixed cost recovery within the fixed components of the rate structure, line extension policies, test period assumptions, regulatory lag, use of hypothetical vs. actual capital structures, and POLR/SOLR obligations. These other factors have a direct effect on the utility's real financial and operating risk profile, its income volatility and, perhaps most important, its ability to actually earn its allowed return. Traditional cost of capital approaches rarely, if ever, take these factors into account.

B. Asymmetric Risks

Any determination of the cost of capital must also address counterparty and other asymmetric risks identified in Section I. Further, the evaluation of asymmetric risks requires a detailed analysis of the individual utility and the legislative and regulatory policies applicable to the utility. Many institutional investors who are focused on steady returns, dividend growth, and the preservation of capital are very much concerned about avoiding "downside" risks, and are willing to give up the "upside" potential.

Traditional cost of capital theory does not address asymmetric risks. Worse, aggregated peer group analysis, without a deep analysis of regulatory practices, can easily mask risk asymmetry. Importantly, the basic premise of cost-based regulation and the ability of regulatory agencies to initiate rate cases causes the asymmetry to destroy, rather than enhance, shareholder value.

C. Capital Market Risks

For many years, utilities' use of capital markets has been primarily to refinance debt, and occasionally capital expansion, because few utilities faced the need to build new production or transmission capacity, or expand the distribution system. As a result, they benefited from financial flexibility since their capital requirements were largely discretionary. However, changes in load and the need to reinforce infrastructure are requiring utilities to turn to capital markets to finance system expansion. As the need for capital has increased, utilities face a new challenge related to liquidity in energy markets as well as the perception of changing credit risk. Since 2002, the number of downgrades in power sector debt has far exceeded the number of upgrades, although recently the rate of downgrades began slowing.

Access to capital markets at a reasonable cost is a critical component for investing in the utility infrastructure required to maintain safe, reliable, utility service. The cost of capital includes both debt and equity costs. Further, there is a direct relationship between the cost of equity capital and the portion of debt in the capital structure. The existence of leverage increases the cost of equity.[12] Where retained earnings are insufficient to maintain the debt equity ratio, new equity issues may be required. If the allowed return is less than the market requires, issuing equity dilutes the value for current shareholders. It is difficult to support an equity issue in that event. As a result, the cost of both debt and equity is likely to rise as the debt-to-equity ratio increases. When coupled with the competitive market for new capital to fund the growth in infrastructure replacement, inadequate returns in the short run will significantly increase the long-run cost of replacing existing facilities and refinancing debt.

There is no question that utilities must compete for new debt, not only among themselves but also with the growing investment in other markets worldwide. Maintaining investment grade bond ratings in the "A" range is critical to financial flexibility. At this level, utilities have broader access to capital and can finance debt at lower interest rates because of the stronger financial position. Since many utilities are currently rated below the "A" level, it will be necessary to allow higher equity returns over a long period to restore the credit needed to efficiently replace the existing infrastructure and to expand capacity where the utility must own and construct new generation.

D. Commodity Risks

The liquidity or lack of liquidity of the wholesale markets for power and for financial hedging products is another new source of risk. To the extent that markets are not liquid, the risk associated with fixed price, physical or financial contracts increases. This risk is borne directly by the party, usually the utility, required to provide a fixed price product to the market. As discussed more fully below, there are opportunities to mitigate the risk to the utility. However, there is no way to mitigate this risk for the consumers of the fixed price product.

[12] See, for example, Kolbe, Read, and Hall, *The Cost of Capital*, pp. 16-19.

SECTION III: POTENTIAL REGULATORY POLICIES TO ESTIMATE, REDUCE, AND CONTROL UTILITY RISKS

A. Non-traditional Approaches to Risk Compensation

Two methods offer a reasonable basis for calculating the level of compensation (in absolute dollar terms) necessary to match risk and reward for specific risks arising from changing conditions:

- Market-based tests
- Rate impact simulation

Market-based Tests

The use of the cost of market-based insurance instruments to estimate the costs of various risks is an accepted process for certain utility risks, since the cost of insuring against a risk is an acceptable O&M expense for a utility. Thus, if insurance products are available to manage risk, the required compensation is approximately equal to the insurance premium and the risk is mitigated by the purchase of the insurance product. Many insurance companies now offer, or will develop on a tailored basis, products that insure against relatively exotic factors such as weather and liability-specific litigation risk, or more mundane, everyday matters, such as errors and omissions, and directors and officers liability insurance. Typically, these products are offered where the risk is either known through significant experience, or is susceptible to analysis by business, subject matter, and underwriting experts.

The cost of insurance, that is, the premium, would ordinarily be considered as a regular cost of doing business. The utility should be indifferent between: (a) a revenue requirement that permits the inclusion of such an equity risk premium, and (b) an adjustment that compensates the utility for the risk directly through an upward adjustment to its return. Similarly, regulators should allow the utility to recover the cost of hedging power supply prices.

Both hedging and insurance provide for risk mitigation on an incomplete basis. Insurance deductibles require the utility to absorb some of the insured loss. Similarly, the hedged product may have some portion of the cost of power where no compensation is paid. Regulators must ensure that these costs are recovered in rates.

Risk Impact Simulation

Where risks are specific to a utility, and where there is no substantial empirical or experiential risk data, the analyst must rely on financial simulation modeling. The exact form of this kind of analysis varies widely, although Monte Carlo simulation techniques are frequently used. While knowing the distribution of outcomes may be problematic since many events in the utility industry are new, through simulation based on expert knowledge an analyst can estimate the possible range of risks and associated costs that would be incurred under various business, regulatory, and environmental scenarios. In turn, those estimates can become the foundation for fixing an absolute dollar-equity risk premium, or establishing a revenue requirement add-on that would compensate the utility for the risks not captured through the traditional cost of capital analysis.

B. Importance of Customer Choice in Risk Compensation

The recognition and estimation of risks is the initial step in determining the appropriate strategy for managing them. Ultimately, the process must incorporate the required risk-adjusted return, risk compensation, the cost of risk mitigation, or some combination of all three into the rates paid by consumers. Regardless of the method chosen, utilities incur costs that must be recovered. For example, the use of hedge products to fix energy prices over the long run raises the delivered cost of energy. In return, customers get a stable, albeit slightly higher, price.

In a competitive market, consumers choose the level of price stability that fits their risk preferences and pay for the hedge through the market. Under a regulated rate, the preferences of customers will not be identical. As a result, choosing the optimum hedging strategy under a one-size-fits-all model cannot produce an optimum outcome for all consumers. Risks often suggest regulatory solutions for mitigating them. Where risk mitigation is accomplished through policies and procedures that maintain the integrity of rate regulation and permit broad stakeholder input, utilities and consumers benefit.

Care must be taken, however, that risk mitigation not create new risks or inappropriate incentives for the utility. One consequence of the traditional, adversarial rate-setting process is the tendency to develop win/lose solutions rather than solutions that benefit all parties. As a result, regulators often must choose between conflicting positions that create the possibility for unintended outcomes. These outcomes include the inability to earn the allowed return, excess returns, incentives to game the system at the expense of efficient outcomes, and other suboptimal behavior.

C. Regulatory Options for Controlling Utility Risk

In addition to measuring utility risk and determining fair compensation for investors, policymakers should think about the potential to control the cost of capital by controlling utility risk. Indeed, institutional investors and rating agencies are focusing on regulation as the dominant driver of risk for utilities, and are differentiating among regulatory jurisdictions as never before. By calibrating regulatory policies to control risk, jurisdictions can obtain new capital (e.g., for needed investments in infrastructure) on more reasonable terms and conditions. Since consumers ultimately pay for this, reducing the cost of capital obviously is in the public interest. Among the policies to focus on in this regard are the following.

Resource Procurement

Timely recovery of costs incurred to supply retail customers probably is the best, most effective way to stabilize utility revenue and earnings, and achieve lower cost of capital. Industry experience since the California market "meltdown" of 2000 and 2001 suggests that there are five keys to providing greater regulatory certainty in this area. They are:

1. **Develop consensus resource strategies**—Recognizing the new uncertainties inherent in resource planning and procurement, utilities and regulators should agree (prospectively) on what the most important resource-related uncertainties (risks) are, and how they are going to manage them.

2. **Understand the implications of risk management**—Utilities and regulators need to understand that risk management cannot be used to minimize cost; it inevitably adds cost. For this reason, customers may want choices about the amount of risk management they pay for.
3. **Provide regulatory commitment**—Once reasonable resource strategies have been identified and agreed to, regulators should honor the recovery of associated costs in rates. The reasonableness of resource strategies, including hedging strategies, should not be subject to after-the-fact prudence review.
4. **Institutionalize regular communications**—Utilities should communicate regularly with regulatory staff. Regular meetings (e.g., regularly scheduled progress reports) can help regulators keep abreast of market developments and avoid surprises.
5. **Support new construction** – To be sustainable over the long term, new regulatory planning and approval policies must support long-term investments in new generation and other needed infrastructure.

Provider of Last Resort

POLR-type service, known variously as supplier of last resort, default, standard offer, basic generation, and provider of last resort service, represents a call option for customers that can create huge risks for utilities and their investors. Policies that reduce the risk incurred by utilities in providing POLR service include:

- Continuation of stranded cost payments for customers who leave regulated service;
- Minimum stay requirements for customers who come back to regulated service after having gone to the market; and
- Flow through of spot wholesale prices to customers who come back to regulated service.

While these are important for all customers, they are especially important for larger customers or smaller customers if the number of customers is large.

Counterparty Risk

Policies that shift risk from third parties to incumbent utilities also increase the utility's overall risk profile. To ensure that this does not happen, policymakers should examine policies in the following areas, where applicable:

- **Creditworthiness standards** that suppliers must meet in order to be eligible to participate in auctions and other competitive procurement programs. The stronger such standards are, the less utilities will be exposed. A related issue is the imputation by rating agencies of additional debt into the utility's capital structure to reflect the risk that is transferred to utilities when they enter into long-term power purchase commitments. Recognition of this added risk and the impact on capital structure is required to determine the capital cost of the utility. This imputation of debt has a real impact on the cost of capital and must be taken into consideration in determining allowed rate of return. Where utilities purchase power under these contacts, regulators must either impute additional equity to the traditional capital structure or allow a larger equity base for the utility.
- **Supplier consolidated billing policies,** which make utilities dependent on the performance of third parties to remit revenues. Supplier consolidated billing should not be used on a mandatory basis without providing sufficient credit protection to assure that the utility receives payment for its portion of the customer bill from the third party.

- **Payment-processing policies** that require the utility to buy receivables from third-party marketers. This can shift significant risk to utilities, if third parties lower their own credit standards, knowing they can sell delinquent accounts to the utility. Utilities should be allowed to negotiate such purchases voluntarily, but should not be required to do so.
- **Policies governing the allocation of partial payments** between the utility and a third-party marketer. To the extent marketer charges are satisfied before those of the utility, the effect is to shift risk to the utility.

Infrastructure

The degree of regulatory support for new spending on needed distribution system improvements is another factor that affects the utility's overall risk profile. Wise, risk-reducing policies in this area may start with revised planning procedures that focus on the distribution system, recognizing that distribution system engineering on a stand-alone basis becomes more important as the system is unbundled. As distribution system needs are identified, new policies should be considered to support spending on approved projects between rate cases. This can be accomplished by indexing distribution revenues to customer growth or other parameters that are correlated with distribution capacity needs. It also can be accomplished with an automatic adjustment mechanism that tracks approved infrastructure projects. To the extent financial incentives are tied to defined parameters of service quality, it is important that such incentives be symmetric by having an upside that balances the downside. Asymmetric incentives such as penalties-only approaches increase utility risk. Other issues, such as depreciation rates that reflect the economic life of the assets, are equally important in assuring adequate investment in infrastructure.

Automatic Adjustment Clauses

The most common risk mitigation measures are automatic adjustment clauses, which offer a means to mitigate the price volatility from wholesale markets and fuel prices. An appropriate fuel clause requires regulatory review of the strategy underlying the provision of energy to be recovered. Prior to implementation, automatic adjustment clauses undergo regulatory scrutiny and modification based on stakeholder input. As long as the utility follows the provisions of the plan, it is assured full cost recovery. If the utility deviates from the plan, recovery is not guaranteed. Where the utility produces lower costs for consumers, in many cases the utility is rewarded with a predetermined share of the benefits produced.

Utilities can use adjustment clauses to mitigate the price risk from more than just fuel and energy. They are useful wherever the level of cost associated with a service or program is beyond the control of the utility and inherently uncertain, or the evidence points to the likelihood of asymmetric outcomes. They may be appropriate for uncollectible accounts expense, conservation program costs, and other specific risk factors for a utility.

Formula and Special Purpose Rates

In addition to the mitigation provided by adjustment clauses, formula rates, special purpose rate options, and other rate mechanisms limit risk. For example, a rate mechanism that can adjust retail rates based on the level and cost of infrastructure replacement investments enables a utility to upgrade transmission and distribution and recover those costs more quickly. Through a collective process, regulation offers a variety of options for mitigating risk as opposed to determining the return requirement needed to compensate for the unique risk elements.

SECTION IV: CONCLUSIONS

1. ***Policymakers should not assume that restructured utilities are less risky than the traditional utilities that preceded them.*** Some advocates argue that all the risk in the utility business is in the generation segment, and that utilities that have divested their generating assets are less risky than they were before. As this discussion demonstrates, the truth is more complicated than that. Utilities that have divested all, or much, of their own generation usually retain a POLAR-type supply obligation. This puts them in the position of having to procure resources at wholesale in markets where prices can fluctuate wildly, to serve loads that also can fluctuate wildly. Such utilities are still in the generation business; they just have much less control over costs than they used to. Moreover, all utilities can be exposed to new risks at the wholesale level. Many have increased their dependence on purchased resources, and may be exposed to counterparty risks. They also may be procuring transmission services from newly formed RTOs or ISOs, whose costs may be rising well ahead of approved retail tariffs.

2. ***Utility risk should be evaluated on a company-specific basis, using analytic frameworks that consider possible exposures to new risks in restructured wholesale and retail markets.*** That is not to say that every utility is riskier, but rather that every utility's risk profile needs to be evaluated objectively in relation to the new risks, and that such evaluation needs to be done without reference to comparison groups. Restructuring has *increased* the differences among electric utilities, so analyses based on groups of "like utilities" are increasingly unreliable. The risk profile of each utility must be evaluated on its own, based on exposure to the new risks in restructured wholesale and retail markets. These risks can include:

   - **Competitive wholesale markets**—Exposure to volatile wholesale energy prices. These prices fluctuate far more than they used to when they were cost-based. As a result, there can be huge uncertainties about the optimal timing of purchases (e.g., decisions to buy today, next week, next month; one year out, five years out, 10 years out). Another exposure can be to nonperformance by third-party suppliers, forcing utilities back into the market (to replace supplies) at times when prices are very high.

   - **Delivery infrastructure**—Exposure to rising transmission costs, which may not be recovered in a timely manner in retail rates. Transmission costs may be rising because RTOs/ISOs are building new hardware/software systems, and hiring new personnel, to operate restructured transmission systems. Transmission costs also may be rising to reflect congestion on the transmission system. At the retail level, utilities also may be exposed to increased costs, which may not be recovered in a timely manner in retail rates. Distribution costs may be rising because utilities are making needed investments to serve new customers, improve reliability, or for other reasons.

   - **Retail competition**—Exposure to earnings erosion as customers leave the utility and take service from third-party suppliers. The potential for such erosion is larger if distribution costs are recovered through volumetric (kWh) rates, and if there are inter-class rate of return differentials. An example is if the return realized from commercial customers is larger than from residential customers. In this event, commercial customers have an added incentive to leave the utility. Another retail exposure can be to an increase in uncollectible accounts, perhaps because the utility is required to buy uncollectibles from marketers.

- **Provider of last resort**—Continued service obligations in the context of customer choice expose utilities to wholesale energy price volatility, and retail load volatility due to customers' ability to leave with little or no notice. These risks are compounded by the potential for after-the-fact cost disallowances and/or rate freezes that limit recovery.
- **Customer service policy**—Exposure to earnings erosion due to the introduction of asymmetric (penalties-only) service quality incentives. Another exposure can result from a failure to update policies regarding service deposits. For example, if the size of the required service deposit was established many decades ago (when energy rates were much lower), it is likely the utility will be forced to absorb losses when customers are in default, because the value of the energy consumed exceeds the value of the deposit.

3. ***Controlling utility risk can control utility cost of capital.*** Cost of capital is a function of risk: capital markets determine the price of investor capital (i.e., the required return on stocks and bonds) based on the riskiness of a borrower in relation to other would-be borrowers. The lower the risk, the lower the market-determined cost. Since investors see regulation as the dominant risk driver for regulated electric utilities, it follows that by calibrating regulatory policies to manage the utility's risk exposure, cost of capital can be managed. Policymakers who pursue this path should consider the following kinds of policies:

   - **Resource procurement**—The timely recovery of costs incurred to supply retail customers probably is the best, most effective way to stabilize utility revenue and earnings, and achieve a lower cost of capital. The goal should be to minimize total risk, not shift risk to customers or shareholders. To do this, utilities and regulators must work together to identify key resource-related uncertainties (risks), and to decide how best to manage them. This needs to be done prospectively, before costs are incurred. Once resource strategies are agreed to, regulators should honor costs incurred. The reasonableness of resource strategies, including hedging strategies, should not be subject to after-the-fact prudence reviews.
   - **Provider of last resort**—Regulated supply service can be provided in the context of retail choice in ways that do not shift large uncompensated risks to incumbent utilities. The key is to reduce utility exposure to opportunistic behavior by large customers, who will tend to go to the market when prices are low, and come back to regulated service when market prices are high. This can be done by requiring exit fees for large customers who leave regulated service, and by imposing minimum stay requirements on large customers seeking to return from the market to regulated rates.
   - **Counterparty risk**—To prevent third parties from shifting risk to incumbent utilities through financial relationships, policies are needed to establish adequate creditworthiness standards for parties seeking to bid on utility procurements. Other policies are needed to avoid mandatory consolidated supplier billing (i.e., where a third party processes customer bills and remits funds to the utility), and to allocate partial payments to satisfy utility claims first, before they are allocated to satisfy third-party claims.
   - **Infrastructure**—Policies that ensure the timely recovery of costs incurred for needed distribution system improvements also contribute to stable utility revenue and earnings. Utilities with an ongoing need to connect new customers and replace aging facilities need to recover costs between rate cases. Use of a future test year in conjunction with a rate adjustment mechanism to recover costs for approved projects is one approach. Another is to index distribution revenues to defined growth parameters (e.g., new customers, cost escalation).

- **Pension benefits**—Policies that provide for recovery of minimum pension liabilities also will contribute to stable utility revenue and earnings.
- **Rate design**—Rate policies have a direct effect on the stability of utility revenue and earnings (or lack thereof). Rates that recover a substantial portion of distribution facility cost through fixed customer charges, and which rely on adjustment mechanisms to track costs that vary significantly and over which the utility has little or no control (e.g., fuel, uncollectible accounts, and conservation program costs) will reduce the utility's risk profile.

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- Advocating Public Policy
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EXHIBIT
TASC16
judicial notice

This document is intended to serve as Appendix F, Distributed Generation Interconnection Requirements, for those certain COMMERCIAL/INDUSTRIAL PHOTOVOLTAIC GENERATING FACILITY DISTRIBUTION SYSTEM INTERCONNECTION AGREEMENTS, and shall supplement as additional terms and conditions to those certain Grid-Tied Residential Solar Electric Photovoltaic (PV) Applications.

TEP

TUCSON ELECTRIC POWER COMPANY

DISTRIBUTED GENERATION INTERCONNECTION REQUIREMENTS ("DGIRs")

Conformed To ACC Docket No. E-00000A-99-0431

Decision No. 69674

June 28, 2007

The Generating Facility must at all times meet the system qualification requirements as set forth in the "Distributed Generation Interconnection Requirements" (DGIRs) as amended from time to time, the terms of which are fully incorporated herein by reference. A complete copy of the "Distributed Generation Interconnection Requirements" conformed to ACC Docket No. E-00000A-99-0431 are located at https://www.tep.com/customer/construction/esr/ **under the "Customer Care" - "Construction Services" tab. Customer acknowledges that it has adequate notice of and access to these online documents, has read the documentation, and waives any objection thereto. Hard copies will be provided upon request.**

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OVERVIEW

This Interconnection Document ("Document") specifies Tucson Electric Power Company ("TEP" or "Utility") requirements for safe and effective interconnection of a Distributed Generator ("DG") with a utility radial distribution system. Interconnection requirements as outlined here are for those installations that will be connected to TEP's electric power distribution and/or transmission systems. A Distributed Generator must also comply with Western Systems Coordinating Council ("WSCC"), Arizona Corporation Commission ("ACC"), Arizona Independent Scheduling Administrator ("AZISA"), North American Electric Reliability Council ("NERC"), Federal Energy Regulatory Commission ("FERC") and Regional Transmission Operator ("RTO") requirements as applicable. Facilities that will be connected directly to the transmission system will be reviewed by the Utility on an individual basis.

Neither this Document nor any interconnection agreement provides for nor include transmission service. The availability of transmission service on the transmission system may not be inferred or implied from TEP's execution of any interconnection agreement. Transmission service on the transmission system is available pursuant to the TEP's Open Access Transmission Tariff ("OATT").

For the purpose of simplicity, the term "Customer" will be used here to refer to a TEP customer who installs, owns or operates a distributed generator, cogenerator or small power producer, even though the Customer may not actually be a purchaser of power from the Utility, and includes any independent party or entity that either invests in, owns or operates a distributed generator or generation facility.

The required protective relaying and/or safety devices and requirements specified in this document are for protecting Utility facilities and other Utility customers' equipment from damage or disruptions caused by a fault, malfunction or improper operation of the distributed generating facility. They are also necessary to ensure the safety of Utility workers and the public. The requirements specified herein do not include additional relaying, protective or safety devices as may be required by industry and/or government codes and standards, equipment manufacturer requirements and prudent engineering design and practice to fully protect Customer's generating facility or facilities; those are the sole responsibility of the Customer. In addition to all applicable regulatory, technical, safety, and electrical requirements and codes, Customers will also be subject to contractual and other legal requirements, which will govern over the general provisions in this Document.

Customers and Utility personnel shall use this Document when planning the installation of distributed generation to be connected to or expecting back-up electrical service from TEP. Note that these requirements may not cover all details in specific cases. TEP encourages the Customer to discuss project plans with TEP before designing their facility or purchasing and installing equipment. This Document must be applied in conjunction with applicable utility rate tariffs and electrical service schedules and requirements that pertain to the operation of distributed generation with the utility electrical distribution system.

1. APPLICABILITY

1.1 Applicable Generating Facilities

This Document applies to all Generating Facilities with power ratings of 10 MW or less, operating (or applying to operate) in parallel with an electric public utility distribution system in Arizona. This Document establishes technical and procedural requirements, terms, and conditions that will promote the safe and effective parallel operation of Customer-owned Generating Facilities. This Document includes provisions for interconnecting to a radial or -secondary spot network system. It includes the three distinct types of generators: (a) solid-state or static inverters, (b) induction machines, and (c) synchronous machines.

These Interconnection procedures are limited to 10 MW or less. The total capacity of an individual Customer's Generating Facility may exceed 10 MW; however, no more than 10 MW of a facility's capacity will be interconnected at a single Point of Interconnection as provided for in these procedures. The electric rates and schedules, terms and conditions of service, or other contract provisions governing the electric power sold by an electric public utility to an Arizona retail customer are subject to the jurisdiction of the Arizona Corporation Commission ("ACC"). The ACC also has jurisdiction when the Utility purchases excess power from Customer-owned Qualifying Facilities ("QFs") under 18 C.F.R. §§292.303, 292.306(2004). The Federal Energy Regulatory Commission has jurisdiction over all Interconnections with facilities that are subject to the electric public utility's OATT at the time the interconnection request was made.

1.2 Types of Generating Facilities

Generating Facilities include induction and synchronous electrical generators as well as any type of electrical inverter capable of producing *NC* power. The Customer may elect to run his Generating Facility in Parallel with the Utility's system (either on a continuous basis or momentarily), or he may run it as a Separate System with non-parallel load transfer between the two independent power systems. A description and the basic requirements for these methods of operation are outlined below.

Parallel System

A Parallel, or interconnected, generator is connected to a bus common with the Utility's system, and a transfer of power between the two systems is a direct result. A consequence of such interconnected operation is that the Customer's Generating Facility becomes an integral part of the distribution system, and it must be considered in the electrical protection and operation of the distribution system.

Parallel Systems include any type of Generating Facility that can electrically parallel with, or potentially backfeed the Utility system. Additionally, any Generating Facility system using a . "closed transition" type transfer switch or a multi-breaker transfer scheme, or an electrical inverter that can be configured or programmed to operate in a "Utility interactive mode," may be required to have relays to prevent potential backfeeding to the Utility system, and is classified as a Parallel System. Continuous uninterruptible power supply, units without grid tie capability, and islanding inverter technologies are not considered Parallel Systems provided they are not a potential backfeed source to the Utility.

The Utility has specific interconnection, contractual, and inspection requirements, as outlined in these provisions, that must be complied with and information that needs to be submitted for all interconnected Generating Facilities. These may include protective relaying, metering, special rate schedules, applicable safety devices, and information requirements (as specified in each Utility's Interconnection Manual). There are two sub-types of Parallel Systems, as described below: Momentary Parallel Systems and Islandable Systems. Momentary Parallel Systems have similar requirements as regular Parallel Systems, whereas Islandable Systems are unique.

- **Momentary Parallel System**. A Momentary Parallel System is one that transfers electrical load between the Utility grid and the Customer's Generating Facility by means of a "make- before break" transfer scheme. Momentary Parallel Systems synchronize the Generating Facility with the Utility grid for a period not to exceed ten seconds for the purpose of uninterrupted load transfer.
  Momentary Parallel Systems are useful for customers who wish to have greater reliability of electric service without experiencing the momentary outage of service that occurs under a "break-before-make" transfer switch scheme. Additionally, this approach allows the customer to more effectively test the switchgear and generator with load during weekly and monthly testing.

- **Islandable System**. An Islandable System is a Generating Facility interconnected to a bus common with the Utility's system, where the Generating Facility is designed to serve part of the Utility grid that has become or is purposefully separated from the rest of the grid. Currently there are no rules, standards, or protocols governing this type of system operation. As such, an Islandable System as defined herein is not allowed.

Separate System

A Separate System is one in which there is no possibility of electrically connecting or operating the Customer's Generating Facility in parallel with the Utility's system. The Customer's equipment must transfer load between the two power systems in an open transition or non- parallel mode. If the Customer claims a Separate System, the Utility may require verification that the transfer scheme meets the non-parallel requirements.

Separate Systems used to supply part or all of the Customer's load during a Utility power outage must be connected to the Customer's wiring through a double throw, "break-before-make" transfer switch specifically designed and installed for that purpose. The transfer switch must be of a fail-safe design, which, under no circumstances, will allow the Generating Facility to electrically interconnect or parallel with Utility's system. The transfer switch must always disconnect the Customer's load from the Utility's power system prior to connecting it to the Generating Facility. Conversely, the transfer switch must also disconnect the load from the Generating Facility prior to re-connecting it with the Utility's system. These requirements apply to both actual emergency operations as well as any testing of the Generating Facility. All transfer switches and transfer schemes must be listed by a Nationally Recognized Testing Laboratory ("NRTL") for the purpose as used, and also inspected and approved by the jurisdictional electrical inspection agency. Separate Systems that are not connected with the Utility system and do not pose a potential backfeed source are not subject to ACC jurisdiction or the provisions in this Document, short of verifying that the transfer scheme meets the non-parallel requirements.

There is one sub-type of Separate System, as described below: Portable Generators.

- **Portable Generators.** Portable Generators are not designed to be connected to a building's permanent wiring system, and are not to be connected to any such wiring unless a permanent and approved transfer switch is used. Failure to use a transfer switch can result in backfeed into the Utility system. (The generator voltage can backfeed through the Utility transformer and be stepped up to a very high voltage.) This can pose an electrocution hazard to anyone working on the power lines or on Utility equipment. Portable Generators that are not connected with the Utility system and do not pose a potential backfeed source are not subject to ACC jurisdiction or the provisions in this Document short of verifying that the transfer scheme meets the non-parallel requirements.

2. RIGHTS AND RESPONSIBILITIES

2.1 Customer Rights and Responsibilities

A Customer has the right to interconnect a Generating Facility with the electric Utility system. A Customer has the right to expect prompt, reasonable, and professional responses from the Utility at every step of the interconnection process. A Customer has the right to expect reasonable cost estimates, outlines of the proposed work, supporting data, and justification for proposed work before the Utility undertakes any studies or system upgrades to accommodate the Generating Facility.

A Customer has the responsibility of disclosing to the Utility items specified herein on the Generating Facility and its operation. The Customer also has the responsibility of ensuring that:

(a) the Generating Facility meets all minimum safety and protection requirements outlined in these provisions and the Utility's Interconnection Manual;
(b) the Generating Facility meets all applicable construction codes, safety codes, electric codes, laws, and requirements of government agencies having jurisdiction;
(c) all the necessary protection equipment is installed and operated to protect its equipment, Utility personnel, the public, and the Utility system;
(d) the Generating Facility design, installation, maintenance, and operation reasonably minimizes the likelihood of causing a malfunction or other disturbance, damaging, or otherwise impairing the Utility system;
(e) the Generating Facility will not adversely affect the quality of service to other customers (but no more or less than the present standard of care observed by regular Utility/consumer connections;
(f) the Generating Facility will minimally hamper efforts to restore a feeder to service (specifically when a clearance is required);
(g) the Generating Facility is maintained in accordance with applicable manufacturers' maintenance schedule; and
(h) the Utility is notified of any emergency or hazardous condition or occurrence with the Customer's Generating Facility, which could affect safe operation of the Utility system. (This notification can be through electronic communication.)
(i) the Generating Facility will comply with all applicable service schedules and requirements, pricing plans, tariffs, Rules and Regulations, and any other applicable requirements approved by the Arizona Corporation Commission.

The Customer is required to meet the timeframes specified in this Document unless the Utility and Customer mutually agree on other time frames and so long as the project moves forward in a fair and reasonable manner. The Customer is responsible for all Interconnection facilities required to be installed to interconnect the Customer's Generating Facility to the Utility system. These may include connection, transformation, switching, protective relaying, metering and safety equipment, and any other requirements as outlined in these provisions or other special items specified by the Utility. All such interconnection facilities are to be installed by the Customer at its sole expense.

The Customer will own and be responsible for designing, installing, operating and maintaining control and protective devices, in addition to minimum protective relays and devices specified in the Utility's Interconnection Manual, to protect its facilities from abnormal operating conditions such as, but not limited to, electric overloading, abnormal voltages, and fault currents. Such protective devices must promptly disconnect the Generating Facility from the Utility's system in the event of a power outage on the Utility's system. The Customer will also own and be responsible for designing, installing, operating and maintaining interconnection facilities on the Customer's premises as may be required to deliver power from the Customer's Generating Facility to the Utility's system at the Point of Interconnection.

In the event that additional facilities are required to be installed on the Utility's system to accommodate the Customer's generation, the Utility will install such facilities at the Customer's expense. The Utility shall provide notice to the Customer of intent to install such facilities early in the process. The Customer is not responsible for Utility upgrades for other customers unrelated to the Generating Facility installation. All Customers interconnecting a Generating Facility with the Utility system shall (a) sign an Interconnection/Connection Agreement, and all other applicable purchase, supply, and standby agreements, in accordance with the prevailing Document in effect at that time; and (b) comply with all applicable tariffs, rate schedules and Utility service requirements.

2.2 Utility Rights and Responsibilities

A Utility is obligated to interconnect Generating Facilities, subject to the requirements set forth in these provisions and in each Utility's Interconnection Manual. A Utility has the right to expect prompt, reasonable, and professional responses from the Customer during the interconnection process.

Because a Utility is required to safeguard its system, other consumers, and the general public, a Utility has the right and responsibility to ensure that an interconnected Generating Facility:

(a) will not present any unreasonable hazards to Utility personnel, other customers, or the public;
(b) minimizes the possibility of damage to the Utility and other customers' equipment; and
(c) minimally hampers efforts to restore a feeder to service (specifically when a clearance is required)

The Utility will notify the Customer if there is any evidence that the Customer's Generating Facility operation causes disruption or deterioration of service to other customers served from the Utility system or if such operation causes damage to the Utility system. A Utility is required to meet the time frames specified in this Document unless the Utility and Customer mutually agree on other time frames and so long as the project moves forward in a fair and reasonable manner. A Utility has the responsibility to make its Interconnection Manual, standard Application form(s) and Interconnection Agreement(s) readily available to Customers, and as soon as practical, readily accessible on its website. A Utility has the responsibility to ensure that Customers with Generating Facilities are treated without discrimination. Before the Utility undertakes any studies or system upgrades that will be charged to the Customer, a Utility has the responsibility to provide a detailed cost estimate, outline of the proposed work, supporting data, and justification for the proposed work. A Utility must show good cause why a Customer's Generating Facility that satisfies the requirements of this Document and the Utility's Interconnection Manual should not be approved for interconnected operation.

If facility upgrades are needed to accommodate the Generating Facility, a Utility will reduce the charge of the upgrade to the customer by the amount of benefits, if any, to the grid that are readily quantifiable by the Utility._In addition, a Utility cannot reject an Application on the basis of distribution system conditions that are already deficient, or charge a Customer for facility upgrades that are overdue or soon to be required to ensure compliance with good Utility practice, except that applications can be rejected in instances where reliability or safety would be further compromised by a DG installation. A Utility shall not charge a Generating Facility Customer differently than any other Customer for facility upgrades in accordance with generally applicable Commission-approved tariffs.

2.3 Easements / Rights of Way

Utility Right to Access Utility-Owned Facilities and Equipment. Where an easement or right of way does not exist, but is required to accommodate the interconnection, the Customer must provide to the Utility suitable easements or rights of way, in the Utility's name, on the premises owned, leased, or otherwise controlled by the Customer. If the required easement or right of way is on another's property, the Customer must obtain and provide to the Utility a suitable easement or right of way, in the Utility's name, at the Customer's sole cost and in sufficient time to comply with the Interconnection Agreement requirements. The Utility will use reasonable efforts to utilize existing easements to accommodate the interconnection to the extent possible and will assist the Customer in securing necessary easements at the Customer's expense that do not exist but are necessary to accommodate the interconnection.

2.4 Insurance

The Customer is not required to provide general liability insurance coverage as a condition for Interconnection. Due to the risk of incurring damages, it is recommended that every Interconnection Customer protect itself with insurance or other suitable financial instrument sufficient to meet its construction, operating, and liability responsibilities. At no time shall the Utility require that the Customer negotiate any policy or renewal of any policy covering any liability through a particular insurance provider, agent, solicitor, or broker. The inability of the Utility to require the Customer to provide general liability insurance coverage for operation of the Generating Facility is not a waiver of any rights the Utility may have to pursue remedies at law against the Customer to recover damages.

2.5 Non-Circumvention

A Utility and its affiliates shall not use knowledge of proposed distributed generation projects submitted to it for interconnection or study to initiate competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects. Customers are not precluded from sharing information in their possession regarding a potential distributed generation project with a Utility or its affiliates, or from using information regarding a potential distributed generation project to negotiate a discounted rate or other mutually beneficial arrangement with a Utility or its affiliates. The Utility shall be permitted to inform the Customer of existing or pending (awaiting approval by the ACC) rate schedules that may economically benefit or otherwise affect the Customer's project.

2.6 Meter Installations
TEP has metering requirements for a GF that may depend on the pricing plan selected and service requirements of the Customer. The Customer shall contact the Utility, or its ESP or MSP if applicable, for design requirements and installation details.

2.7 Electric Supply / Purchase Agreement
Customers purchasing energy from either TEP or an ESP, utilizing an interconnected DG system, may be required to sign an agreement for backup, supplemental and maintenance power from their energy supplier. Customers operating a parallel generator may also be required to sign an agreement or take service under a tariff with TEP that provides for movement of power over TEP's distribution grid and transmission systems. The Customer may sell power to TEP, other utilities, ESPs, or electric wholesalers. These entities may or may not be obligated to purchase this power and any such sales would be made under the terms and conditions offered by the purchaser. For a Customer who wishes to sell power to others, the customer will be required to:

(a) Choose the applicable TEP tariff that allows for the movement of power over TEP's distribution grid and transmission systems;
(b) Sign an agreement with the purchaser of the electric power, and/or
(c) Become an ESP and sell power to retail customers.
(d) Follow all applicable criteria/protocols established by NERC, WSCC, the approved RTO, and AZISA regarding the sale of power to others.

All tariffs under the purchase and supply arrangements are subject to change by the Utility and approval of the ACC.

2.8 Interconnections
TEP will not install or maintain any lines or equipment on a Customer's side of the Point of Interconnection, except that TEP may install its meter and/or research equipment. Only TEP authorized employees may make and energize the service connection between the Utility system and the Customer's service entrance conductors. Normally, the interconnection will be arranged to accept only one type of standard service at one Point of Interconnection. If a Customer's generating facility requires a special type of service, or if sales to TEP will be at a different voltage level, the services will only be provided according to additional specific terms that are outlined in the Electric Supply/Purchase Agreement, applicable service schedules, or other terms and conditions governing the service.

3. GENERAL PROCESS AND PROCEDURES FOR ALL LEVELS

3.1 Designation of Contact Persons
Each Utility shall designate a person or persons who will serve as the Utility's contact for all· matters related to distributed generation Interconnection, identify to the Commission its distributed generation contact person, and provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its distributed generation contact person(s). Each customer applying for Interconnection shall designate a contact person or persons, and provide to the Utility the contact's name, telephone number, mailing address, and electronic mail addresses.

3.2 Non-discrimination
All Applications for interconnection and parallel operation of distributed generation shall be processed by the Utility in a non-discriminatory manner.

3.3 Application Submission Requirements
The Utility may require additional documentation to be submitted with the Application. Each Utility's Application form will specify what additional documentation is required. Additional documentation may include an electrical one-line diagram, an electrical three-line diagram, AC and DC control schematics, plant location diagram, and site plan. Upon request, the Utility will provide the Customer with sample diagrams that indicate the preferred level of detail and type of information required for a typical inverter-based system.

3.4 Minor Modifications

It is recognized that certain Applications may require minor modifications to the Generating Facility or the Application while they are being reviewed by the Utility. Such minor modifications to a pending Application shall not require that it be considered incomplete and treated as a new or separate Application.

3.5 Certification

Compliance with codes and standards. In order to qualify as "Certified" for any interconnection procedures, relevant equipment shall comply with the following codes, guides, and standards as applicable, and as specified in this document:

(a) IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity);
(b) IEEE1547.1 Standard for Conformance Testing Procedures or equipment Interconnecting Distributed Resources with Electric Power Systems;
(c) UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems;
(d) IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems;
(e) NFPA 70 (2002), National Electrical Code;
(f) IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems;
(g) IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers;
(h) IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers;
(i) IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors;
(j) IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits;
(k) IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (lOOOV and Less) AC Power Circuits;
(1) ANSI C84.1-1995 Electric Power Systems and Equipment - Voltage Ratings (60 Hertz);
(m) IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms NEMA MG 1-1998, Motors and Small Resources, Revision 3;
(n) IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems; and
(o) NEMA MG 1-2003 (Rev 2004), Motors and Generators, Rev. 1.

Requirements for Certification. Generating Facility equipment proposed for use separately or packaged with other equipment in an Interconnection system shall be considered Certified for interconnected operation if:

(a) it has been tested in accordance with industry standards for continuous Utility interactive operation in compliance with the appropriate codes and standards referenced above by any Nationally Recognized Testing Laboratory (NRTL) recognized by the U. S. Occupational Safety and Health Administration to test and certify Interconnection equipment pursuant to the relevant codes and standards listed above;
(b) it has been labeled and is publicly listed by such NRTL at the time of the Interconnection application; and
(c) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

The Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this Interconnection procedure and the Utility's Interconnection Manual. Nothing herein shall preclude the need for project Interconnection review and approval by the Utility or on-site commissioning testing prior to the Interconnection nor follow-up production testing by the NRTL. If the certified equipment includes only interface components (switchgear, inverters, or other interface devices), then a Customer must show that the Generating Facility is compatible with the interface components and is consistent with the testing and listing specified for this type of Interconnection equipment. Certified equipment does not include equipment provided by the Utility.

3.6 No Additional Requirements

If a Customer's Generating Facility complies with all applicable requirements in this Document and the Utility's Interconnection Manual, a Utility may not require the Customer to install additional controls, or perform or pay for additional tests, in order to obtain approval to interconnect except as mutually agreed to by the parties or required by the Commission. Additional equipment may be installed by the Utility at its own expense.

3.7 Disconnect from or Reconnect with the Grid Procedure

A Utility may disconnect a Customer's Generating Facility from the Utility system under the following conditions:

(a) **Expiration or termination of Interconnection Agreement.** The Interconnection Agreement specifies the effective term and termination rights of the Utility and the Customer. Upon expiration or termination of the Interconnection Agreement with a Customer, in accordance with the terms of the agreement, the Utility may disconnect a Customer's Generating Facility.

(b) **Non-compliance with technical Interconnection requirements.** A Utility may disconnect a Customer's Generating Facility if the facility is not in compliance with the technical requirements. Normally within two business days from the time the Customer notifies the Utility that the facility has been restored to compliance with the technical requirements, the Utility shall have an inspector verify such compliance. Upon such verification, the Customer in coordination with the Utility may reconnect the facility.

(c) **System emergency**. A Utility may temporarily disconnect a Customer's Generating Facility without prior written notice in cases where continued Interconnection of the Generating Facility will endanger persons or property. During the forced outage of a Utility system, the Utility shall have the right to temporarily disconnect a Customer's facility to make immediate repairs on the Utility's system. When possible, the Utility shall provide the Customer with reasonable notice and reconnect the Customer as quickly as reasonably practical.

(d) **Routine maintenance, repairs, and modifications.** A Utility may disconnect a Customer's Generating Facility from the grid with reasonable prior notice of a service interruption for routine maintenance, repairs, and Utility system modifications. The Utility shall allow reconnection of the Customer's Generating Facility as quickly as reasonably possible following any such service interruption.

(e) **Absence of executed Interconnection Agreement**. In order to interconnect a Customer's Generating Facility to a Utility system, the Customer and the Utility must execute an Interconnection Agreement. The Utility may refuse to connect or may disconnect the Customer's Generating Facility if an executed Interconnection Agreement is not in effect.

(f) **Locked open disconnect.** In the event authorized TEP personnel lock open the DG Service Disconnect, the Customer shall not remove or tamper with such lock.

(g) **TEP clearance**. Following the release of a TEP clearance, where it was necessary for the Utility to open the DG Service Disconnect, Utility personnel will normally leave the disconnect in the open position. It will be the Customer's responsibility to close the disconnect after ensuring that all generation sources that could potentially energize the Customer's side of the disconnect are off, or isolated, so as to eliminate any possibility of paralleling the Utility grid with an out-of-sync generator. However, TEP personnel may, without liability, close the DG Service Disconnect provided that (a) Customer requests and agrees to allow TEP to close the disconnect following the release of a TEP clearance, and (b) TEP personnel can verify that the Customer side of the DG Service Disconnect is not energized.

(h) **Upon termination of the Interconnection Agreement.** The Customer shall be responsible for ensuring that the DG Service Disconnect is immediately opened, and that the electric conductors connecting the Customer's generator(s) to the DG Service Disconnect are physically removed, so as to preclude any possibility of inadvertent interconnected operation in the future. TEP reserves the right to inspect the Customer's facility to verify that the generator is appropriately disconnected.

The Parties shall cooperate with each other to restore the Generating Facility and the Utility system to their normal operating state as soon as reasonably practicable.

Temporary disconnection by Customer. The Customer retains the option to temporarily disconnect its Generating Facility from the Utility's system at any time. Such temporary disconnection shall not be a termination of the Interconnection Agreement unless specified as such.

Agreement survival rights. The Interconnection Agreement between the Utility and the Customer shall continue in effect after disconnection or termination of electric service to the extent necessary to allow or require either party to fulfill rights or obligations that arose under the agreement.

Duration and Termination of the Interconnection Agreement. The Interconnection Agreement shall become effective on the effective date specified in the Agreement and shall remain in effect thereafter unless and until:

(a) it is terminated by mutual agreement of the parties;

(b) it is replaced by another Interconnection Agreement with mutual consent of the parties;

(c) it is terminated by either party pursuant to a breach or default of the Agreement; or

(d) the Customer terminates its electric Utility service with the Utility and/or vacates or abandons the property on which the Generating Facility is located, or the Generating Facility, without mutual agreement of the parties.

Upon termination of the Interconnection Agreement, the Customer shall be responsible for ensuring that the electrical conductors connecting the Generating Facility to the Utility system are immediately lifted and permanently removed, so as to preclude any possibility of interconnected operation in the future. The Utility reserves the right to inspect the Customer's Generating Facility to verify that it is permanently disconnected.

3.8 Dispute Resolution

If a dispute arises between the parties regarding a provision contained in this Document and/or Agreement, or a party's performance of its obligations as stated in this Document and/or Agreement, or any other matter governed by the terms of the Document and/or Agreement, the parties agree that such dispute will be resolved in the manner prescribed in this section.

(a) **Notification and Response**. Promptly upon the occurrence of the dispute, the aggrieved party will notify the other party in writing (the "Claimant's Statement"), setting forth in sufficient detail the basis for the dispute, the aggrieved party's position, and its proposal for resolution of the dispute. Within ten (10) business days following receipt of the Claimant's Statement, the other party will respond in writing (the "Responsive Statement") setting forth in sufficient detail the respondent's position and its proposal for resolution of the dispute.

(b) **Good Faith Negotiation.** Within ten (10) business days after the aggrieved party's receipt of the Responsive Statement, the parties will meet and attempt in good faith to expeditiously negotiate a resolution to the dispute. In attendance for each party at that opening session and throughout the dispute resolution procedure described in this section will be a representative or representatives of each party who are authorized to act for the party and resolve this dispute without resort to higher authority.

(c) **Dispute Resolution by Mediation**. Any dispute(s) arising out of or relating to this Document shall be subject to binding mediation by a mutually acceptable mediator. If no mediator is mutually acceptable, then a mediator shall be appointed by the Arizona Office of the American Arbitration Association, at the request of any party. The costs of mediation shall be borne by the losing party and as prescribed by the mediator.

(d) **Arizona Corporation Commission.** In the event such dispute is not resolved by mediation, then the parties consent to jurisdiction to resolve any such dispute by the Arizona Corporation Commission of the State of Arizona.

4. SPECIFIC PROCESS AND PROCEDURES FOR EACH LEVEL

4.1 Summary of Interconnection Levels / Tracks

Level 1 Super Fast Track: Certified inverter-based facilities that have a power rating of **10 kW or less,** are interconnected on a radial line, and meet screens (e) and (f) in Section 4.2 below. Refer to Section 4.3 for additional details.

Level 2 Fast Track: Generating Facilities that have a power rating of **2 MW or less**, are interconnected on a radial line, and meet screens (a) through (i) in Section 4.2 below. Refer to Section 4.4 for additional details.

Level 3 Study Track: Generating Facilities that have a power rating of **10 MW or less** that do not meet the criteria or screens for other Levels. Interconnection studies may be required. Refer to Section 4.5 for additional details

Distribution Networks: On an interim basis, certified inverter-based Generating Facilities that have a power rating of **10 kW or less** will be allowed to be interconnected on a secondary spot network system and otherwise as approved by the Utility. Generators will only be interconnected on a trial, pilot basis, at the discretion of the Utility, under the interconnection process set forth in the Utility's Interconnection Manual (See Section 6 herein). This process may be revised upon completion of IEEE 1547.6. Refer to subsection 4.6 for additional details.

4.2 Screens

(a) For Interconnection of a proposed generator to a radial distribution circuit, the aggregated generation, including the proposed generator, on the circuit will not exceed 15 percent of the total circuit annual peak load as most recently measured at the substation or on a line section. In the case of generators certified to UL 1741 and IEEE 1547, a line section is that portion of a distribution system connected to a customer's facility bounded by automatic sectionalizing devices, or the end of the distribution line. For non-certified generators, a line section is that portion of a distribution system connected to a customer's facility bounded by automatic sectionalizing devices, a fused lateral, or the end of the distribution line. The aggregated generation, including the proposed generator, must also be less than 50 percent of the minimum daytime feeder or line section load, where these data are available, unless the minimum load is zero.

(b) The proposed generator, and new motors associated with the proposed generator, in aggregation with other generation on the distribution circuit, will not contribute more than 10 percent to the distribution circuit's maximum fault current at any point on the Utility's distribution system, including normal contingency conditions that may occur due to reconfiguration of the feeder or the distribution substation.

(c) The proposed generator, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or customer equipment on the system, to exceed 90 percent of the short circuit interrupting capability; nor is the Interconnection proposed for a circuit that already exceeds 90 percent of the short circuit interrupting capability.

(d) The proposed generator is interconnected to the Utility as shown in the table below:

Primary distribution line configuration	Interconnection to primary distribution line
Three-phase, three wire	If a three-phase or single phase generator, Interconnection must be phase-to-phase
Three-phase, four wire	If a three-phase (effectively grounded) or single-phase generator, Interconnection must be line-to-neutral

(e) If the proposed generator is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, cannot exceed 10 kW, and the proposed generator must be listed to UL 1741.

(f) If the proposed generator is single-phase and is to be interconnected on a transformer center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20 percent of nameplate rating of the service transformer.

(g) The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level busses from the Point of Interconnection).

(h) The proposed generator's Point of Interconnection will not be on a transmission line.

(i) The generator cannot exceed the capacity of the customer's existing electrical service.

4.3 Level 1 Super Fast Track Process

The Level 1 Process is available to Customers interconnecting either a single certified static inverter, with a continuous output power nameplate rating of **10 kW or less,** or multiple certified static inverters with a combined continuous power nameplate rating of 10 kW or less (screen "e") to the Utility's distribution system. The inverter(s) must be UL 1741 listed, and certified to meet the shutdown protective functions (under/over voltage, under/over frequency and anti- islanding) specified in IEEE 929 (screen "f"). The Generating Facility must also meet all applicable codes and standards, as well as comply with the Utility Interconnection and contractual requirements. Nothing in this process precludes the Customer and Utility from mutually agreeing to different timeframes or other procedures for the approval of interconnected operation of a Generating Facility, so long as the project moves along in a fair and reasonable manner. Nothing in this process precludes the Customer from starting construction prior to contacting the Utility; however, the Customer accepts the risk of potentially needing to modify or substantially change the installation.

The Level 1 Process steps are as follows:

(a) **Customer Submits Application**. The Customer completes the Interconnection Application and submits it to the Utility along with all required supplemental information which shall be noted on the Application form. The Customer may submit a pre-executed Interconnection Agreement together with the Interconnection Application, if permitted by the Utility. No initial application fee or processing fee will be charged.

(b) **Application is Received and is Complete or Incomplete**. The Utility notifies the Customer within five (5) business days of receipt of the Application as to whether it is complete or incomplete

- (i) If the Application is incomplete, the Utility will specify what information or material is necessary to complete the Application.
- (ii) The Customer has thirty (30) business days after receipt of such notification to submit the required information or materials (or request an extension), or the Application may be considered withdrawn.

(c) **Utility Reviews Application.** Within ten (10) business days following the receipt of a complete Interconnection Application, the Utility reviews the proposed Interconnection and notifies the Customer of one of the following determinations:

- (i) The proposed Generating Facility design appears to meet all Interconnection requirements and the Interconnection Application is approved as submitted. An Interconnection Agreement (if not already pre-executed) will be prepared by the Utility and forwarded to the Customer for review and signature in accordance with Step (d) below; or
- (ii) The proposed Generating Facility design has failed to meet one or more of the Interconnection requirements, and the Interconnection Application is denied. The Utility provides an explanation of the reason(s) for the denial (in writing, if requested by the Customer), and specifies what additional information and/or modifications to the Customer's Generating Facility or Utility system are required in order to obtain approval of the proposed design.

  If the Application is denied, the Customer notifies the Utility within twenty (20) business days whether or not it wishes to proceed with the project. If the Customer does not wish to proceed with the project, or the Utility is not notified within the specified time frame, the Application may be considered withdrawn. If the Customer wishes to proceed with the project, then a new Application shall be submitted to the Utility for review and processing (Step (a) above is re-initiated), along with any additional information and/or modifications to the Customer's Generating Facility. Alternatively, the Customer may request processing under Level 2 or Level 3 and shall provide any additional information requested by the Utility and necessary to process the request under Levels 2 or 3.

(d) **Interconnection Agreement.** If the Generating Facility meets all of the applicable interconnection requirements and the Application is approved, then:

(j) Within five (5) business days after the notice of Application approval, or following receipt of any "as built" or final diagrams from the Customer, the Utility sends to the Customer the appropriate Interconnection Agreement for review and signature. (This step may be omitted if the Utility has received a pre-executed Interconnection Agreement).

(ii) The Customer reviews, signs, and returns the Interconnection Agreement to the Utility.

(iii) The Customer then completes installation of the Generating Facility within 180 days after execution of the Interconnection Agreement, unless an extension is mutually agreed to by the parties, which extension shall not be unreasonably withheld. The Utility has the right to terminate any Agreements, and the Interconnection Application may be considered withdrawn, in the event that this timeframe is exceeded without extension.

(e) **Inspection and Testing.** The Customer will give the Utility at least five (5) business days notice to schedule the Utility site inspection and inverter shutdown testing. The Utility may schedule metering replacement, if necessary, and labeling of Utility equipment to occur at the same time. There will be no charge for one initial site inspection by the Utility. The Utility performs the site inspection as arranged and verifies that the Generating Facility, as best as can be determined, is in compliance with all applicable interconnection and safety requirements. At a minimum, it is suggested that the Utility shall verify the following:

(i) An electrical permit and/or clearance has been issued by the authority having jurisdiction, if required;

(ii) All Generating Facility equipment is properly labeled;

(iii) Generating Facility system layout is in accordance with the plant location and site plan(s) submitted to the Utility;

(iv) Inverter nameplate ratings are consistent with the information submitted to the Utility;

(v) Utility has unrestricted 24-hour access to the Disconnect Switch (if required), and the switch meets all applicable requirements;

(vi) The inverter shuts down as required upon simulated loss of Utility voltage; and

(vii) The Generating Facility is wired, as best as can be determined, in accordance with the electrical diagrams submitted to the Utility.

The Utility will normally before or at the time of the site inspection:

(i) Install appropriate metering if required;

(ii) Label all Utility equipment; and

(iii) Ensure that the Generating Facility is properly incorporated onto Utility operating maps and identified as a backfeed source.

The Utility does not have the right to fail a site inspection in the event that any of the above three requirements (metering, Utility equipment labeling, and the identification of the Generating Facility on the operating maps) are not in place at the time of the Site Inspection. The Utility does have the right to fail any Generating Facility that does not meet the applicable Interconnection requirements, is not installed substantially in accordance with the documentation submitted to the Utility, or as a result of any safety or protection violation.

(f) **Notification.** Immediately following completion of the site inspection (and upon receipt of all final applicable signed interconnection documents), the Utility shall determine whether or not the Generating Facility meets all applicable requirements, and notify the Customer that:

(i) The Generating Facility is approved for parallel operation with the Utility's distribution system per the agreed terms and conditions. Within one (l) business day, following such oral notification, the Utility shall provide the Customer with such notice in writing; or

(ii) The Generating Facility has failed to meet one or more of the applicable requirements or a safety or protection violation has been identified, and the Generating Facility is not approved for parallel operation. The Utility must provide the reason(s) (in writing, if requested by the Customer) for not approving parallel operation. Furthermore, the Utility has the right to take any reasonable steps (including locking open the Disconnect Switch) to prevent the Generating Facility from parallel operation. Operation of a generator in parallel without Utility approval may result in immediate termination of electric service to the Customer.

(g) **Corrections (if necessary).** In the event that the Generating Facility does not pass the initial Utility site inspection:

(i) The Customer must correct any outstanding issues and schedule a re-inspection. The Utility shall re-inspect upon five (5) business days notice from the Customer to verify that the deficiencies have been remedied. A fee not exceeding one hundred dollars ($100) may be assessed for each re-inspection conducted by the Utility. Within one (1) business day following any site re-inspection, where the Utility approves parallel operation of the Generating

Facility, the Utility will provide written notification to the Customer that the Generation Facility is approved for parallel operation.

(ii) If updated diagrams are required to reflect "as-built" conditions, the Customer must submit these to the Utility for review and approval within ten (10) business days following the site inspection. The Utility will process and mail an amendment to the Interconnection Agreement within five (5) business days after receipt and acceptance of the revised diagrams for Customer review and signature.

4.4 Level 2 Fast Track Process

The Level 2 Process is available to Customers interconnecting a Generating Facility with a continuous output power nameplate rating of **2 MW or less** to the Utility's distribution system. In order to qualify for Level 2, the Generating Facility must meet screens (a) through (i) in Section 4.2 above. The Generating Facility must also meet all applicable codes and standards, as well as comply with the Utility Interconnection and contractual requirements. Nothing in this process precludes the Customer and Utility from mutually agreeing to different timeframes or other procedures for the approval of interconnected operation of a Generating Facility, so long as the project moves along in a fair and reasonable manner. Also, nothing in this process precludes the Customer from starting construction prior to contacting the Utility; however, in such case the Customer accepts the risk of potentially needing to modify or substantially change the installation.

The Level 2 Process steps are as follows:

(a) **Prior to applying.** The Customer is encouraged to contact and work closely with the Utility at the conceptual stages of the design to discuss the proposed design, installation, and operation.
A preliminary electrical one-line diagram would be very helpful at this stage. This step will ensure that proposed projects proceed in a smooth and timely manner, and that the Utility and Customer understand whether any special considerations, protective equipment, system modifications, or studies may be required. Upon the Customer's request, the Utility shall meet with the Customer prior to submission of an Application.

(b) **Customer Submits Application**. The Customer completes the standard Interconnection Application and submits it to the Utility along with all required supplemental information which shall be noted on the Application form. A Utility may charge an application fee, if a tariff containing such a fee is approved by the Commission.

(c) **Application is Received and is Complete or Incomplete**. The Utility notifies the Customer within five (5) business days of receipt of the Application as to whether it is complete or incomplete.

(i) If the Application is incomplete, the Utility will specify what information or material is necessary to complete the Application.

(ii) The Customer has thirty (30) business days after receipt of such notification to submit the required information or materials (or request an extension), or the Application may be considered withdrawn.

(d) **Utility Reviews Application**. Within fifteen (15) business days following the receipt of a complete Interconnection Application, the Utility reviews the proposed Interconnection and notifies the Customer of one of the following determinations:

(j) The proposed Generating Facility design appears to meet all Interconnection requirements and the Interconnection Application is approved as submitted. An Interconnection Agreement will be prepared by the Utility and forwarded to the Customer for review and signature in accordance with Step (e) below; or

(ii) The proposed Generating Facility has failed to meet one or more of the screens, but the initial review indicates that Additional Review may enable the Utility to determine that the Customer's Generating Facility can be interconnected consistent with safety, reliability, and power quality. In such case, the Utility shall offer to perform Additional Review (typically about 3 hours of study) to determine whether minor modifications to the electric distribution system (for example, changing meters, fuses, or relay settings) would enable the Interconnection to be made consistent with safety, reliability and power quality. The Utility shall provide to the Customer a non-binding, good faith estimate of the costs of such Additional Review, and/or such minor modifications. The Utility shall undertake the Additional Review or minor modifications only after the Customer consents to pay for the review and/or modifications. Such Additional Review shall take place within 20 business days after the Customer has submitted payment for the estimated costs; or

(iii) The proposed Generating Facility design has failed to meet one or more of the Interconnection requirements, and the Interconnection Application is denied. The Utility provides an explanation of the reason(s) for the denial (in writing, if requested by the Customer), and specifies what additional information and/or modifications to the Customer's Generating Facility or Utility system are required in order to obtain approval of the proposed design.

If the Application is denied, the Customer notifies the Utility within twenty (20) business days whether or not it wishes to proceed with the project. If the Customer does not wish to proceed with the project, or the Utility is not notified within the specified time frame, the Application may be considered withdrawn. If the Customer wishes to proceed with the project, then a new Application shall be submitted to the Utility for review and processing (Step (a) above is re-initiated), along with any additional information and/or modifications to the Customer's Generating Facility. Alternatively, the Customer may request processing under Level 3 and shall provide any additional information requested by the Utility and necessary to process the request under Level 3.

(e) **Interconnection Agreement.** If the Generating Facility meets all of the applicable Interconnection requirements and the Application is approved, then:

(i) Within normally not more than ten (10) business days after the notice of Application approval, or following receipt of any "as built" or final diagrams from the Customer, the Utility sends to the Customer the appropriate Interconnection Agreement for review and signature.

(ii) The Customer reviews, signs, and returns the Interconnection Agreement to the Utility.

The Customer then completes installation of the Generating Facility within 180 days after execution of the Interconnection Agreement, unless an installation schedule has been submitted with an alternative in-service date, or the parties have mutually agreed to an extension. The Utility has the right to terminate any Agreements, and the Interconnection Application may be considered withdrawn, in the event that this timeframe is exceeded without extension.

(f) **Inspection and Testing.** The Customer will contact the Utility to schedule the Utility site inspection and witness of the testing of the protective devices. The Utility site inspection and witness of the testing of the protective devices will normally occur within ten (10) business days of request from the Customer. The Utility may schedule metering replacement, if necessary, and labeling of Utility equipment to occur at the same time. A Utility may charge for the initial site inspection, if a tariff containing such a fee is approved by the Commission.

The Utility performs the site inspection as arranged and verifies that the Generating Facility, as best as can be determined, is in compliance with all applicable interconnection and safety requirements. At a minimum, it is suggested that the Utility shall verify the following:

(i) has been issued An electrical permit and/or clearance by the authority having jurisdiction, if required;

(ii) All Generating Facility equipment is properly labeled;

(iii) Generating Facility system layout is in accordance with the plant location and site plan(s) submitted to the Utility;

(iv) Generator nameplate ratings are consistent with the information submitted to the Utility;

(v) Utility has unrestricted 24-hour access to the Disconnect Switch (if required), and the switch meets all applicable requirements;

(vi) The Utility will witness the required protective relay calibration and functional tests. (The Utility may accept a certified test report in lieu of witnessing the tests); and

(vii) The Generating Facility is wired, as best as can be determined, in accordance with the electrical diagrams submitted to the Utility.

The Utility will normally, before or at the time of the site inspection:

(i) Install appropriate metering if required;

(ii) Label all Utility equipment; and

(iii) Ensure that the Generating Facility is properly incorporated onto Utility operating maps and identified as a backfeed source.

The Utility does not have the right to fail a site inspection in the event that any of the above three requirements (metering, Utility equipment labeling, and the identification of the Generating Facility on the operating maps) are not in place at the time of the site inspection. The Utility does have the right to fail any Generating Facility that does not meet the applicable Interconnection requirements, is not installed substantially in accordance with the documentation submitted to the Utility, or as a result of any safety or protection violation.

(h) **Notification.** Immediately following completion of the site inspection (and upon receipt of all final applicable signed Interconnection documents) the Utility shall determine whether or not the Generating Facility meets all applicable requirements. The Utility shall provide the Customer oral notification within twenty-four (24) hours and written notification within three (3) business days that:

(i) The Generating Facility is approved for parallel operation with the Utility's distribution system per the agreed terms and conditions; or

(ii) The Generating Facility has failed to meet one or more of the applicable requirements or a safety or protection violation has been identified, and the Generating Facility is not approved for parallel operation. The Utility must provide the reason(s) (in writing, if requested by the Customer) for not approving parallel operation. Furthermore, the Utility has the right to take any reasonable steps (including locking open the Disconnect Switch) to prevent the Generating Facility from parallel operation. Operation of a generator in parallel without Utility approval may result in immediate termination of electric service to the Customer.

(i) **Corrections (if necessary).**.In the event that the Generating Facility does not pass each Utility site inspection:

(i) The Customer must correct any outstanding issues and schedule a re-inspection. The Utility shall re-inspect upon ten (10) business days notice from the Customer to verify that the deficiencies have been remedied. A Utility may charge a fee for a re- inspection, if a tariff containing such a fee is approved by the Commission. Following any site re-inspection where the Utility approves parallel operation of the Generation Facility, the Utility will provide to the Customer such oral notification within twenty- four (24) hours and such written notification within three (3) business days that the Generation Facility is approved for parallel operation.

(i) If updated diagrams are required to reflect "as-built" conditions, the Customer must submit these to the Utility for review and approval within ten (10) business days following the site inspection. The Utility will process and mail an amendment to the Interconnection Agreement within five (5) business days after acceptance of the revised diagrams for Customer review and signature.

Customer Timeframes. The Utility timeframes contained herein do not include the time for the Customer to execute agreements or submit needed documentation. If at any point in the Level 2 Fast Track process, the Customer does not submit requested materials necessary to process the interconnection Application, or submit applicable executable agreements within thirty (30) business days, or request an extension, the Application may be considered withdrawn.

Fees for Level 2 Additional Review. A Utility may charge a fee for an Additional Review, if a tariff containing the hourly rate for Additional Review is approved by the Commission. The Utility shall provide a non-binding good faith estimate of the fee for such additional review. The Customer must submit a deposit for the estimated fee before the Additional Review will be initiated. In addition, costs for Utility facilities and/or equipment modifications necessary to accommodate the Customer's generator interconnection will be the responsibility of the Customer.

4.5 <u>Level 3 Study Track Process</u>

Level 3, also called the Study Track, is the interconnection procedure to be used for all Generating Facilities that do not meet the screening requirements for Level 1 Super Fast Track or Level 2 Fast Track. It is an in-depth engineering review of whatever aspects of generator performance and/or grid interaction the Utility deems necessary to study. More details are available in each Utility's Interconnection Manual (Included in this document). For generators that are certified, no review of the generator's protection equipment is required, although the Utility may study the interface between the Generating Facility and the Utility. The Generating Facility is required to meet applicable local electric codes and standards, as well as comply with all terms and conditions of the Utility's Interconnection Manual and Interconnection Agreement. Nothing in these procedures shall preclude the Customer and Utility from mutually agreeing to different timeframes or other procedures for the approval of interconnected operation of a Generating Facility, so long as the project moves along in a fair and reasonable manner.

The Level 3 Study Track interconnection process is as follows:

(a) **<u>Prior to applying</u>**. The Customer is encouraged to contact and work closely with the Utility at the conceptual stages of the design to discuss the proposed design, installation, and operation. A preliminary electrical one-line diagram would be very helpful at this stage. This step will ensure that proposed projects proceed in a smooth and timely manner, and that the Utility and the Customer understand whether any special considerations, protective equipment, system modifications, or studies may be required. Upon the Customer's request, the Utility shall meet with the Customer prior to submission of an Application. TEP approvals given pursuant to the review and approval process and the Interconnection Agreement shall not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective device or the design, construction, installation or operation thereof.

(b) **<u>Customer Submits Application.</u>** The Customer completes the Interconnection Application and submits it to the Utility along with all required supplemental information (which shall be noted on the Application form). A Utility may charge an application fee, if a tariff containing such a fee is approved by the Commission.

(c) **<u>Application is Received and is Complete or Incomplete.</u>** The Utility notifies the Customer in normally not more than ten (10) business days of receipt of the Application (or transfer from Level 1 or 2) as to whether it is complete or incomplete.

(i) If the Application is incomplete, the Utility will specify what information or material is necessary to complete the Application.

(ii) The Customer has normally not more than thirty (30) business days after receipt of such notification to submit the missing information or materials (unless other mutually agreeable arrangements are made); otherwise the Application may be considered withdrawn.

(iii) Once the Customer submits any missing information, the Utility has normally not more than another ten (10) business days to determine if the Application is complete or incomplete and notify the Customer.

(d) **<u>Utility Reviews Application.</u>** Normally within ten (10) business days following the receipt of a complete Interconnection Application, the Utility reviews the proposed interconnection and notifies the Customer of one of the following determinations:

(i) The Generating Facility design as submitted appears to meet all of the applicable Interconnection requirements and no further studies, special protective requirements, or system modifications are required. An Interconnection

Agreement will be prepared by the Utility and forwarded to the Customer for review and signature in accordance with Step (j) below; or

(ii) The Generating Facility cannot be interconnected without further information, data, engineering studies, and/or modifications to the Utility system or Generating Facility. In this case, the Interconnection proceeds according to the following meeting and study process, as deemed necessary by the Utility. All itemized costs and timelines for the studies are to be disclosed and agreed upon by the Utility and Customer prior to the start of each one. In addition, all studies are to be made available to the Customer directly after their completion.

(e) **Scoping Meeting.** This is a high-level, initial review meeting between the Utility and the Customer, where the Customer describes the proposed Generating Facility design and the Utility talks about system conditions at the proposed Point of Interconnection. This meeting can also allow the Utility and Customer to discuss which of the following study elements are needed. The Utility and the Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. This meeting shall be held in normally not more than ten (10) business days after an Application is deemed complete unless other mutual agreements are made.

(f) **Acknowledgement Letter.** The Utility will provide an Acknowledgement Letter following the Scoping Meeting upon request from the Customer. The letter will describe the project scope and include a good faith cost estimate by the Utility. If requested, the Acknowledgement Letter will be sent out normally within 10 business days following the Scoping Meeting.

(g) **Interconnection Feasibility Study.** If requested by the Customer, the Utility shall undertake an Interconnection Feasibility Study. The Utility shall provide the Customer, as soon as possible, but in normally not more than ten (10) business days after the Scoping Meeting, an Interconnection Feasibility Study Agreement including an outline of the scope of the study and a non-binding, good faith, detailed estimate of the materials and labor costs to perform the study. Once the interconnecting Customer executes the Interconnection Feasibility Study Agreement, provides all requested Customer information necessary to complete the Study, and pays pursuant to the good faith estimate contained therein, the Utility will conduct the Interconnection Feasibility Study. The Feasibility Study will be completed in normally not more than twenty (20) business days, unless other mutually agreeable terms are made.

The Interconnection Feasibility Study provides a preliminary review of the potential impacts on the distribution system that will result from the proposed Interconnection. The Interconnection Feasibility Study will review short circuit currents including contribution from the proposed generator as well as coordination of and potential overloading of distribution circuit protection devices. This study principally benefits the Customer by providing initial details and ideas on the complexity and likely costs to interconnect prior to commitment of costly engineering review. The Interconnection Feasibility Study may also be used to focus or eliminate some or all of the more intensive System Impact study.

(h) **System Impact Study.** If deemed necessary by either party, the Utility shall undertake a System Impact Study. The Utility shall provide the Customer as soon as possible, but in normally not more than fifteen (15) business days after completing the previous study or meeting, a System Impact Study Agreement including an outline of the scope of the study and a non-binding, good faith, detailed estimate of the materials and labor costs to perform the study. Once the Customer executes the System Impact Study Agreement, provides all requested Customer information necessary to complete the Study, and pays any required deposit pursuant to the good faith estimate contained therein, the Utility will conduct the Impact Study. The System Impact Study will be completed in normally not more than thirty (30) business days, unless other mutually agreeable terms are made.

The System Impact Study is a full engineering review of all aspects of the generator's impact on the Utility system, including power flow, Utility system protective device coordination, generator protection schemes (if not certified), stability, voltage collapse, frequency impacts, and short circuit duty. The System Impact Study reveals all areas where the Utility system would need to be upgraded to allow the generator to be built and interconnected as designed. It may include discussions with the Customer about potential alterations to generator design, including downsizing to limit grid impacts. If the Utility determines, in accordance with Good Utility Practice, that the Utility electric system modifications required to accommodate the proposed Interconnection are not substantial, the System Impact Study shall identify the scope and detailed cost of the modifications. If the Utility determines, in accordance with Good Utility Practice, that the system modifications to the Utility electric system are substantial, a Facilities Study shall be performed. Each Utility shall include in its Interconnection Manual a description of the various elements of a System Impact Study it would typically undertake pursuant to this Section including:

(i) Load Flow Study;
(ii) Short-Circuit Study;
(iii) Circuit Protection and Coordination Study;
(iv) Impact on System Operation;

(iv) Stability Study (and the conditions that would justify including this element in the Impact Study); and
(vi) Voltage Collapse Study (and the conditions that would justify including this element in the Impact Study).

(i) **Facilities Study**. If deemed necessary by the Utility, the Utility shall undertake a Facilities Study. The Utility shall provide the Customer as soon as possible, but in normally not more than five (5) business days after completing the previous study or meeting, a Facilities Study Agreement including an outline of the scope of the study and a non-binding, good faith, detailed estimate of the materials and labor cost to perform the study. Once the interconnecting Customer executes the Facilities Study Agreement, provides all requested Customer information necessary to complete the Study, and pays pursuant to the good faith estimate contained therein, the Utility will conduct the Facilities Study. The Facilities Study will be completed in normally not more than thirty (30) business days, unless other mutually agreeable terms are made. The Facilities Study is a comprehensive analysis of the actual construction needed to take place based on the outcome of the Impact Study. It delineates the detailed costs of construction and milestones. construction may include new circuit breakers, relocation of reclosers, new construction of Utility grid extensions, reconductoring lines, new transformers, protection requirements and interaction. Where no Utility construction is required there would be no Facilities Study.

(j) **Interconnection Agreement.** If the Generating Facility meets all of the applicable Interconnection requirements, all items identified in any Meeting or Study have been resolved and agreed to (if applicable), and the Utility has received the final design drawings, then:

(i) The Utility shall send to the Customer in normally not more than ten (10) business days an executable Interconnection Agreement, which shall include as an exhibit the cost for any required Utility system modifications.
(ii) The Customer reviews, signs, and returns the signed Interconnection Agreement and any balance due for Interconnection studies or required deposit for facilities.
(iii) Following TEP's approval of the Customer's proposed interconnection, the Customer cannot remove, alter or otherwise modify or change the equipment specifications, including, without limitation, the operational plans, control and protective devices or settings, and the generating facility system design, type, size or configuration. If the Customer desires to make such changes or modifications, the Customer must revise and resubmit to TEP plans describing the changes or modifications for approval by TEP. No change or modification may be made without the prior written approval of TEP.
(iv) The Customer then completes installation of the Generating Facility and the Utility completes any Utility system modifications, according to the milestones set forth in the Interconnection Agreement. The Utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

(k) **Inspection and Testing.** The Customer will contact the Utility to schedule the Utility site inspection and witness of the testing of the protective devices. The Utility site inspection and witness of the testing of the protective devices will normally occur within ten (10) business days of notice from the Customer. The Utility may schedule metering replacement, if necessary, and labeling of Utility equipment to occur at the same time. The Utility performs the site inspection as arranged and verifies that the Generating Facility, as best as can be determined, is in compliance with all applicable Interconnection and code requirements. At a minimum, it is suggested that the Utility verify the following:

(i) An electrical permit and/or clearance has been issued by the authority having jurisdiction, if required;
(ii) All Generating Facility equipment is properly labeled;
(iii) Generating Facility system layout is in accordance with the plant location and site planes) submitted to the Utility;
(iv) Generator nameplate ratings are consistent with the information submitted to the Utility;
(v) The Utility has unrestricted access to the Disconnect Switch (if required), and the switch meets all requirements;
(vi) The Utility will witness the required protective relay calibration and functional tests. Calibration shall include on-site testing of trip set points and timing characteristics of the protective functions as required herein. Functional testing, witnessed by TEP personnel, must demonstrate that each protective relay or device function as required herein, upon a (simulated) out-of-tolerance input signal, will trip the generator breaker. Functional testing shall also include a simulated loss of control power to demonstrate that the generator breaker or contactor will open. A trip timing test (simulated loss of voltage) will suffice for static inverters rated 50kW or less. Customer shall supply TEP with a copy of calibration and functional tests (if required).
(vii) The Customer shall have all protective devices tested at the time of installation, prior to initial interconnection, and at intervals not to exceed four years. The Customer shall (i) notify the Utility as to when such tests are to be performed at least fifteen (15) working days prior to such tests and allow TEP personnel to witness the testing, and (ii) provide TEP with a certified copy of the test results.
(viii) The Generating Facility is wired, as best can be determined, in accordance with the electrical diagrams submitted to the Utility.

The Utility will normally, before or at the time of the site inspection:

(i) Install all appropriate metering, if required;

(ii) Label all Utility equipment; and
(iii) Ensure that Generating Facility is properly incorporated onto Utility operating maps and identified as a backfeed source.

The Utility shall not have the right to fail a site inspection in the event that any of the above three requirements (metering, Utility equipment labeling, and the identification of the Generating Facility on the operating maps) are not in place at the time of the site inspection. The Utility does have the right to fail any Generating Facility that does not meet the applicable Interconnection requirements, is not installed substantially in accordance with the documentation submitted to the Utility, or as a result of any safety or protection violation.

(1) **<u>Notification</u>.** Immediately following completion of the site inspection (and upon receipt of all final applicable signed Interconnection documents) the Utility shall determine whether or not the Generating Facility meets all applicable requirements. The Utility shall provide the Customer oral notification normally within twenty-four (24) hours and written notification normally within three (3) business days that:

(i) The Generating Facility is approved for parallel operation with the Utility's distribution system per the Interconnection Agreement. The Utility shall provide the Customer with such notification in writing in normally not more than three (3) business day following the Utility inspection under (k) above; or
(ii) The Generating Facility has failed to meet one or more of the applicable requirements or a safety violation has been identified, and the Generating Facility is not approved for parallel operation. The Utility shall provide the reason(s) (in writing, if requested by the Customer) for not approving parallel operation. Furthermore, the Utility has the right to disconnect and lock out the Generating Facility to prevent the Generating Facility from parallel operation, and the Customer must reschedule the site inspection with the Utility. The Customer may not operate in parallel until it receives written approval from the Utility, and violation of this condition may result in immediate termination of electric service to the Customer.

(m) **<u>Correction (if necessary).</u>** In the event that the Generating Facility does not pass the initial Utility site inspection:

(i) The Customer must correct the deficiencies identified by the Utility and schedule a re-inspection. The Utility shall re-inspect normally not more than ten (10) business days notice from the Customer to verify that the deficiencies have been remedied. Following any site re-inspection where the Utility approves parallel operation of the Generation Facility, the Utility will provide to the Customer such oral notification normally within twenty-four (24) hours and such written notification normally within three (3) business days that the Generation Facility is approved for parallel operation.
(ii) If updated documentation is required to reflect "as-built" conditions, the Customer must submit these to the Utility for review and approval within ten (10) business days following the site inspection. The Utility may charge a fee, if a tariff containing such a fee is approved by the Commission. The Utility will process and mail an amendment to the Interconnection Agreement normally not more than five (5) business days after receipt and <u>acceptance of the revised diagrams for Customer review and signature.</u>

<u>Customer Timeframes</u>. The Utility timeframes contained herein do not include the time for the Customer to execute agreements or submit needed documentation. If at any point in the Level 3 Study Track process, the Customer does not submit requested materials necessary to process the Interconnection Application, or submit applicable executable agreements in normally not more than thirty (30) business days, or request an extension, the Application may be considered withdrawn.

<u>Fees for Level 3 Interconnection.</u> A Utility may charge a fee for an engineering review, if a tariff containing the hourly rate for engineering review is approved by the Commission. The Utility shall provide a non-binding good faith estimate of the fee for such engineering review. The Customer must submit a deposit for the estimated fee before the engineering review will be initiated. In addition, costs for Utility facilities and/or equipment modifications necessary to accommodate the Customer's generator interconnection will be the responsibility of the Customer. The Customer may not be charged for the review of a certified generator's protection equipment. The Utility may charge a fee for an initial inspection or for a re-inspection, if a tariff containing such a fee is approved by the Commission.

4.6 <u>Interconnection to Secondary Spot Network Systems</u> (Not applicable for TEP)

The requirements for interconnecting generating facilities to Secondary Spot Network Systems are different than those for Interconnection to radial distribution systems. In the Secondary Spot Network System, there are technical requirements to be considered particularly with the design and operational aspects of network protectors that are not required on radial systems.

Currently, Arizona Public Service ("<u>APS</u>") is the only Utility in Arizona that has Secondary Spot Networks. As such, APS has developed the following interim criteria for interconnecting a small amount of inverter-based customer generation to a Secondary Spot Network System. Because the maximum level of generation that could be interconnected to a Secondary Spot Network System is unknown at this time, this "Pilot" effort should be viewed as a trial basis only. APS reserves the right to suspend it at any time. APS has initiated this Pilot effort in a proactive attempt to include distributed generation in the State of Arizona on Secondary Spot Network Systems.

The Pilot criteria require that the generation meet all of the following conditions simultaneously:
(a) Inverter based units must be less than 10 kW;
(b) Units must be "Certified" as prescribed in this Document, and must meet current IEEE 1547 and UL 1741 standards; and
(c) Must be less than or equal to 10% of the interconnecting customer's verifiable minimum load during the operation of the inverter. (For photovoltaics, the minimum load refers to the daytime minimum.)

APS reserves the right to suspend, change, modify, or add to the above conditions based on the results from future test reports or guidelines as they become available. Once the 1547.6 standards are completed, APS (and any other Arizona Utilities who have since added Secondary Spot Networks) will review the Pilot criteria for possible modification to include guidelines for Interconnection to the Secondary Spot Network Systems. The process for interconnecting to a Secondary Spot Network System will be determined by the Utility.

5. UTILITY REPORTING REQUIREMENTS

Interconnection Manual. Each Utility shall file an Interconnection Manual for approval with the Commission no later than ninety (90) calendar days after adoption of this document. Each Interconnection Manual shall contain procedural and technical requirements necessary to interconnect a Generating Facility to each Utility's respective distribution system but shall not be inconsistent with this Document. An updated Interconnection Manual shall be provided to the Commission upon any substantive revision by the Utility and shall become effective within sixty (60) days unless otherwise acted upon by the Commission. **(TEP's Interconnection Manual is part of this document.)**

Documentation of projects. Each electric Utility shall maintain records concerning Applications received for Interconnection and parallel operation of distributed generation. Such records will include the date each Application is received, documents generated in the course of processing each Application, correspondence regarding each Application, the final disposition of each Application, and the date on which the Application was approved (if approved).

Annual Interconnection report to the Commission. By March 30 of each year, every Utility shall file with the Commission a distributed generation Interconnection report for the preceding calendar year that lists the new Generating Facilities interconnected with the system since the previous year's report, any distributed generation facilities no longer interconnected with the Utility's system since the previous report, and the capacity of each facility. The annual report shall include, for the reporting period, a summary of the number of complete Applications received, the number of complete Applications approved, the number of complete Applications denied by level, and the reasons for denial. The annual report shall also include a list of special contracts, approved by the Commission during the reporting period, that provide discounted rates to customers as an alternative to self-generation.

6. INTERCONNECTION TECHNICAL MANUAL

The requirements and specifications outlined in this section are applicable to distributed generation interconnected for parallel operation with the Utility distribution system, unless otherwise specified. The protection and safety devices and other requirements specified in the following sections are intended to provide protection for the Utility system, Utility workers, other Utility customers and the general public. They are not imposed to provide protection for the Customer's generation equipment or personnel; this is the sole responsibility of the Customer.

With respect to the above protection objectives, it is necessary to disconnect the parallel generator when trouble occurs. This is to:
(a) ensure if a fault on the Utility system persists, the fault current supplied by the Customer's generator is interrupted;
(b) prevent the possibility of reclosing into an out-of-synch isolated system composed of the Utility distribution system, or a section thereof, and the Customer's generator; and
(c) prevent reclosing into the Customer's generation system that may be out of synchronization or stalled.

The protection requirements are minimal for smaller installations, but increase as the size of the Customer's generation increases. Small installations usually ensure that, for any fault on the Utility system, Utility protective devices will operate and normally isolate the generation with a large amount of load, causing under-voltage automatic shutdown of the generator. For larger installations the probability of isolated operation is higher since the available generation may be sufficient to carry the entire load, or part thereof, of the local Utility circuit. In instances where the Utility system arrangement is such that it is possible that the generators will not always be isolated with comparatively large amounts of load, additional protection (including a transfer trip scheme) and generator shutdown schemes are required.

TEP applies automatic reclosing to overhead distribution and transmission circuits. When the Utility source breaker trips, the Customer must ensure that his generator is disconnected from the Utility circuit prior to automatic reclosure. TEP applies instantaneous reclosing at the substation, in which the distribution circuit can be re-energized in less than 20cycles (333 msec) after a protective relay trip. In order to assure reliable service to other TEP customers, the Customer's generator shall be disconnected from the Utility's system within 5 cycles (83.3 msec) of a Utility initiated protective relay trip. Inability of the Customers equipment to meet these time constraints may require the Customer to install a transfer trip scheme. In addition, automatic reclosing out-of-synch with the Customer's generator may cause severe damage to Customer equipment and could also pose a serious hazard to Customer or Utility personnel. In a few cases there are in-line reclosers away from the substation. In these situations transfer trip is not possible. Additional review by TEP is required in these cases.

6.1 Design Considerations and Definition of Classes

Protection requirements are influenced by the size and characteristics of the parallel generator along with the nature and operational characteristics of the associated Utility system. Therefore, similar units connected to different lines could have different protection requirements based on varying load conditions, as well as on the specific Utility feeder and transformer characteristics.

(a) **Synchronous Units.** Synchronous generators are generally capable of supplying sustained current for faults on TEP's system. These units can also supply isolated Utility load providing the load is within the units' output capability, and must be prevented from energizing a de-energized Utility line. The Utility will specify the maximum allowable protective relay time settings for a particular proposed distributed generator installation. The Customer is responsible for ensuring generator separation prior to Utility circuit re-energization to prevent out-of-sync paralleling.

(b) **Induction Units.** Induction generators are basically induction motors that are mechanically driven above synchronous speed to produce electric power. These units do not have a separate excitation system and, as such, require that their output terminals be energized with AC voltage and supplied with reactive power to develop the magnetic flux. Induction generators are therefore normally not capable of supplying sustained fault current into faults on the Utility system. Such units are generally not capable of supplying isolated load when separated from the Utility system; however, it is possible for an induction generator to become self-excited if a sufficient amount of capacitance exists at its output terminals. Under conditions of self-excitation, an induction generator will be capable of supplying isolated load, providing the load is within the units' output capability. In most cases when self-excitation occurs it will be accompanied by a sudden increase in terminal voltage. The Utility and its other customers must be protected from out-of-sync closing and over-voltages that can occur whenever an induction generator becomes self-excited. Induction units shall therefore be designed to automatically separate from the Utility system upon loss of Utility voltage and prior to reclosing of the Utility feeder.

(c) **Static Inverters.** Static inverters convert DC power to AC by means of electronic switching. Switching can be controlled by the AC voltage of the Utility's supply system (line-commutated) or by internal electronic circuitry (forced-commutated). Line-commutated inverters are generally not capable of operating independently of the Utility's AC supply system and, as such, cannot supply fault current or isolated loads under normal conditions. Forced-commutated, or self-commutated, inverters are capable of supplying fault current and load independently of the AC supply system. Any forced-commutated inverter that is to be interconnected with the Utility must be specifically designed for that purpose, i.e. it must be designed to accommodate parallel interfacing and operation. Static inverters must be designed to automatically separate from the Utility system upon loss of Utility voltage and prior to reclosing of the Utility feeder.

(d) **Definition of Generator Size Classes.** The following generator size classifications are used in determining specific minimum protective requirements for distributed generation facilities. Specified ratings are for each connection to the Utility system. Customers must satisfy, in addition to the general requirements specified in this document, the minimum relaying requirements given in this document for each generator class.

- (i) Class I 50 kW or less, single or three phase
- (ii) Class II 51 kW to 300 kW, three phase
- (iii) Class III 301 kW to 5,000 kW, three phase
- (iv) Class IV over 5,000 kW, three phase

6.2 General Technical Requirements

(a) Customer is responsible for obtaining and maintaining all required permits.

(b) Multiple generator connections on the same Utility service are permitted; however, a DG Service Disconnect for the facility will be required (normally located at the service entrance section).

(c) In the event that a generator, or aggregate of generators, are of sufficient size to carry the entire (minimum) load of the TEP distribution feeder, or if a generator size and physical location on a feeder is such that it could support an isolated (islanded) section of the feeder, then a transfer trip scheme shall be required at the Customer's expense. If a transfer trip is required, a communication channel and telemetering shall also be required, at the Customer's expense, to facilitate proper parallel operation.. The transfer trip channel may be leased telephone, power line carrier, pilot wire, microwave or other TEP approved medium. The transfer trip equipment will be configured to trip the Customer's generator for loss of the channel signal.

(d) For synchronous generators, the Customer shall ensure that any potential open points such as breakers, fused disconnect switches, etc, located between the generator breaker and Utility service are appropriately equipped with either (1) keyed or other suitable mechanical interlocks to prevent them from being inadvertently opened when the generator breaker is closed, or (2) contacts that will instantaneously trip the generator breaker if any such switch were opened while the generator breaker was closed. The intent of the above is to prevent the opening and subsequent (inadvertent) re-closing of such a breaker or switch onto an un-synchronized generator.

(e) Customer shall ensure that the design and installation of electric meter(s) is such that the meter(s) are located on the Utility-side of the generator breaker on a normally energized bus.

(f) The Customer is responsible for the design, installation, operation and maintenance of all equipment on the Customer's side of the Point of Interconnection. It is required that the Customer submit specifications and detailed plans as specified in the Application and Equipment Information Form (see Appendix) for the installation to the Utility for review. Review by the Utility does not indicate acceptance or approval by the Utility or other authorities.

(g) All photovoltaic generators 5kW or less are exempted from this document.

6.3 DG Service Disconnect

The Customer shall install and maintain a DG Service Disconnect in order to isolate all ungrounded conductors of the Customer's generating facility from the Utility system. The DG Service Disconnect will normally be required to be installed at the Customer's electrical service entrance section; however it may be located in the immediate vicinity of the generator, subject to Utility approval. The DG Service Disconnect must be rated for the voltage and current requirements of the generation facility, and must meet all applicable UL, ANSI and IEEE standards. The DG Service Disconnect shall meet the requirements of the National Electric Code ("NEC"), and shall be properly grounded.

In cases where the DG Service Disconnect is a load break switch, the switch blades, jaws and the air-gap between them shall all be clearly visible when the switch is in the "open" position. It is not acceptable to have any of the "visible open" components obscured by the switch case or an arc-shield, etc. Only switches specifically designed to provide a true "visible open" are acceptable. Such switch shall be installed in a place so as to provide easy and unrestricted accessibility to Utility personnel on a 24-hour basis. The Utility shall have the right to lock open the switch without notice to the Customer when interconnected operation of the Customer's generating facility with the Utility system could adversely affect the Utility system or endanger life or property, or upon termination of the Interconnect Agreement. For multi-phase systems, the switch shall be gang-operated. In cases where the DG Service Disconnect will be installed on a line at a voltage above 500V,TEP may require the customer to install a rack-out breaker, along with a racking tool and grounding device, in lieu of a load break switch. In these cases, the Utility will work with the Customer to determine the best option and ensure that the safety requirements are met.

6.4 Dedicated Transformer

Customer generators with a combined total rating of over 10 kW, as measured at the service entrance, may be required to be isolated from other customers fed off the same Utility transformer by a dedicated power transformer connecting to the Utility distribution feeder. The primary purpose of the dedicated transformer is to ensure that (a) the generator cannot become isolated at the secondary voltage level with a small amount of other-customer load, and (b) the generator does not contribute any significant fault current to other customers' electrical systems. Dedicated transformers also help to confine any voltage fluctuation or harmonics produced by the generator to the Customer's own system. The Utility will specify the transformer winding connections and impedance.

6.5 Power Quality

Customer shall ensure that the electrical characteristics of its load and generating equipment will maintain the serving Utility's normal power quality requirements. Any deviation from sine wave form or unusual short interval fluctuations in power demand or production shall not be such as to result in impairment of service to other customers or in interference with operation of computer, telephone, television or other communication systems or facilities. Those power quality items will generally include the following:

(a) Current Imbalance
(b) Harmonics
(c) Voltage Flicker
(d) Power Factor

Exhibit 1 lists, for general informational purposes, TEP's Power Quality requirements which may be updated from time to time. The Customer should verify actual requirements before designing/installing GF.

6.6 Voltage Requirements

Customer generating equipment must deliver at the Point of Interconnection, 60 Hertz, either single or three-phase power at one standard Utility voltage as may be selected by the Customer subject to availability at the premises.

6.7 Telemetry

For generators Class III or greater, Customer shall provide to TEP, at Customer's cost, MW and MVAR transducer output quantities for the purpose of control area system load calculations.

6.8 WSCC/NERC Requirements

Customer shall comply with WSCC/NERC generator testing criteria, including but not limited to, the applicable criteria regarding the installation and operation of Power System Stablizers ("PSS") and Automatic Voltage Regulators ("AVR").

6.9 Labeling Requirements

(a) **General Requirements.** The Customer shall conform to the NEC for labeling of generation equipment, switches, breakers, etc. TEP will assume the responsibility for labeling any Utility owned equipment.

(b) **DG Service Disconnect.** The Customer shall label the DG Service Disconnect by means of a permanently attached placard with clearly visible and permanent letters 1" high. In addition, the Utility may need to attach its own label to the DG Service Disconnect.

(c) **Service Entrance.** A sign shall be placed at the service entrance indicating type and location of onsite emergency power sources, legally required standby power sources, and onsite optional standby power sources, as defined by the NEC. The NEC also requires a permanent directory, denoting all electrical power sources on or in the premises, shall be installed at each service equipment location and at locations of all electric power production sources capable of being interconnected. Installations with large numbers of power production sources shall be permitted to be designated by groups.

6.10 Protective Requirements

(a) **General Requirements**

(i) The Customer shall be solely responsible for properly protecting and synchronizing his generator(s) with TEP's system. The Customer is solely responsible for the protection of their equipment from automatic reclosing by the Utility.

(ii) Devices with definite level and timing characteristics (e.g., micro-processor type relays) will be necessary to meet the requirements established herein.

(iii) Generator classes II and above (>50 kW), must utilize discreet relays, separate and independent voltage and frequency relays and associated trip paths to the generator breaker (automatic interrupting device). This is to ensure a redundant trip function in the event of a single relay failure or out-of-tolerance condition.

- The instantaneous/time overcurrent functions can be integrated into a single ground overcurrent relay.
- The over/under voltage functions can be integrated into a single o/u voltage relay.
- The over/under frequency functions can be integrated into a single o/u frequency relay.

Protective relays or microprocessor based devices may be used provided that the require functionality described herein is demonstrated. For generating equipment that is capable of sustained operation above its normal current rating, phase overcurrent tripping shall be required to trip the unit should it exceed this rating.

(iv) For generator protection schemes that utilize microprocessor based, multi-function relays, one of the following requirements must be met:

- Protective relay failure will not only alarm but will also trip the generator breaker/contactor.
- If relay failure alarms, but does not trip the generator breaker, then additional relaying which meets the requirements stated herein for each class must be provided.

(v) With the addition of generation at a Customer site, the ground fault current magnitude might increase to the level where the grounding grid is insufficient to protect personnel from step or touch potentials. Therefore, the Customer is required to ensure the adequacy of the Customer's grounding grid to keep the step and touch potentials at a safe level in the vicinity of equipment accessible by Utility personnel or the general public.

(vi) The Customer shall ensure that the GF protective relaying and controls are adequately protected from electrical surges that may result from lightning, Utility switching or electrical faults.

(vii) Addition of the Customer's GF may require additional control, metering and protective devices at TEP's facilities. The Customer will be responsible for all labor and material costs associated with their installation.

(viii) Exhibit 2 lists for general informational purposes TEP's relay settings which may be updated from time to time. The Customer should verify with TEP prior to designing/installing a GF.

(b) **Generator Class Protective Requirements**
TEP shall require the following as minimum acceptable protection:

(i) **Class I** (Single or Three Phase: **50 kW or less**)
- The minimum protection required is an under-voltage contactor.
- For all synchronous generators and forced commutated inverters, either a manual or automatic synchronizing scheme is required.

(ii) **Class II** (Three Phase: **51-300 kW**)
- Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.
- For all synchronous generators and forced commutated inverters, either a manual or automatic synchronizing scheme is required
- Phase time and instantaneous overcurrent relays are required.
- A ground time and instantaneous overcurrent relay is required. For installations interconnected to the Utility through a transformer with connections that will not supply current to a ground fault on the Utility system, a special ground fault detection scheme shall be necessary. The Utility will notify Customer of any such requirements after a preliminary review of the Customer's proposed installation.
- Other equipment such as supervisory control and alarms, telemetering, transfer trip and associated communications channel may be required in some instances, including but not limited to the following situations: (a) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (b) the GF is involved in power transactions requiring the grid, or (c) the GF is remotely controlled by, or dispatched by the Utility. The Utility will notify Customer of any communications requirements after a preliminary review of the proposed installation.
- Overload tripping shall be required for any generator capable of sustained operation above its normal current rating

(iii) **Class III** (Three Phase: **301-5,000 kW**)
- For this class of installation, Utility grade protection devices and equipment will be required.
- Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.
- For all synchronous generators and forced commuted inverters, either a manual or automatic synchronizing scheme is required.
- A ground time and instantaneous overcurrent relay is required. For installations interconnected to the Utility through a transformer with connections that will not supply current to a ground fault on the Utility system, a special ground fault detection scheme shall be necessary. The Utility will notify Customer of any such requirements after a preliminary review of the Customer's proposed installation.
- Voltage-controlled/restrained time overcurrent relays may be required.
- A phase sequence voltage relay is required.
- Other equipment such as supervisory control and alarms, telemetering, transfer trip and associated communications channel may be required in some instances, including but not limited to the following situations: (a) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (b) the GF is involved in power transactions requiring the grid, or (c) the GF is remotely controlled by, or dispatched by the Utility. The Utility will notify Customer of any communications requirements after a preliminary review of the proposed installation.
- Overload tripping shall be required for any generator capable of sustained operation above its normal current rating

(iv) **Class IV** (Three Phase: **Greater than 5,000 kW**)
- For this class of installation, Utility-grade protective devices and equipment will be required.
- Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.
- For all synchronous generators and forced commutated inverters, either a manual or automatic synchronizing scheme is required.
- A ground time and instantaneous overcurrent relay is required. For installations interconnected to the Utility through a transformer with connections that will not supply current to a ground fault on the Utility system, a special ground fault detection scheme shall be necessary. The Utility will notify Customer of any such requirements after a preliminary review of the Customer's proposed installation.
- Voltage-controlled/restrained time overcurrent relay
- Negative sequence time overcurrent relay

- Overexcitation relay
- Loss of excitation relay
- Phase sequence voltage relay.
- Other equipment such as supervisory control and alarms, telemetering, transfer trip and associated communications channel may be required in some instances, including but not limited to the following situations: (1) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (2) the GF is involved in power transactions requiring the grid, or (3) the GF is remotely controlled by, or dispatched by the Utility. The Utility will notify Customer of any communications requirements after a preliminary review of the proposed installation.
- Overload tripping shall be required for any generator capable of sustained operation above its normal current rating.

7. DEFINITIONS

"ANSI": American National Standards Institute. See www.ansi.org.
"Application": The standard form for applying to interconnect a Generating Facility with the Utility system.
"Arizona Corporation Commission" ("ACC" or "Commission"): The regulatory agency of the state of Arizona having jurisdiction over public service corporations operating in Arizona.
"Backfeed": To energize a section of a Utility electric system that is supplied from a source other than its normal source.
"Business Day": Monday through Friday, excluding Federal and Arizona State Holidays.
"Certified Equipment": Specific generating and protective equipment system or systems that have been certified as meeting the requirements in Section 3.4 relating to testing, operation, safety, and reliability by an entity approved by the Commission.
"Clearance Point": A clearance point is the physical location on a piece of line or equipment that is to be de-energized from all known sources of power and tagged. Further, that piece of line or equipment shall remain in the condition stated until released by the person having the clearance.
"Cogeneration Facility": Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.
"Customer": An electric consumer that generates electricity on the consumer's side of the Utility meter.
"Disconnect Switch": A device that the Customer may be required to install and maintain that is a visible open, manual, gang operated, load break disconnect device, capable of being locked in a . "visible open" position by a standard Utility padlock that will completely isolate the Customer's Generating Facility from the Utility grid. "Visible open" has the same definition as used in the National Electric Code. If the voltage is over 500 volts, it has to be capable of being grounded on the Utility side.
"Distributed Generation" ("DG"): Any type of Customer electrical generator, static inverter, or Generating Facility interconnected with the distribution system that either (a) has the capability of being operated in electrical parallel with the Utility's distribution system, or (b) can feed a customer load that can also be fed by the Utility's electrical system. A distributed generator is often referred to as a "Generating Facility" in this Document.
"Distribution System": The infrastructure constructed, maintained, and operated by an electric Utility to deliver electric service to retail customers.
"Electric Supply or Purchase Agreement": An agreement, together with appendices, signed between the Utility and the Customer covering the terms and conditions under which electrical power is supplied to and/or purchased from the Utility.
"ESP" ("Electric Service Provider"): A company supplying, marketing or brokering at retail any competitive services pursuant to a Certificate of Convenience and Necessity.
"Equipment Package": A group of components connecting an electric generator with a Utility distribution system, and includes all interface equipment including switchgear, inverters, or other interface devices. An equipment package may include an integrated generator or electric source.
"Fault Current": The level of current that can flow if a short circuit is applied to a voltage source.
"Generating Facility": All or part of the Customer's electrical generator(s) or inverter(s) together with all protective, safety, and associated equipment necessary to produce electric power at the Customer's facility. A Generating Facility also includes any Qualifying Facility ("QF").
"Good Utility Practice": Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.
"Hold For Orders": The method used as an aid in protection of personnel working on or near energized equipment, whereby automatic or remote re-closing of a line is disabled. When a hold tag (see Exhibit 3) is in effect, if the circuit trips open, it will

not be re-closed until the system operator receives a release from the person to whom the hold was issued. As it relates to distributed generation, circuits with hold tags shall have all potential sources of backfeed removed by opening, locking and tagging the appropriate disconnect switch.

"IEEE": The Institute of Electrical and Electronic Engineers. See www.ieee.org.

Interconnection Agreement: An agreement, together with appendices, signed between the Utility and the Customer, covering the terms and conditions governing the Interconnection and operation of the Generating Facility with the Utility.

"Interconnection": The physical connection of Customer's Generating Facility to the Utility system.

"Interconnection Manual": A separate document developed and maintained by each Utility, made available on each Utility's website, and approved by the Commission, containing detailed technical, safety, and protection requirements necessary to interconnect a Generating Facility to each Utility's respective distribution system. The Interconnection Manual shall be consistent with this Document. The Interconnection Manual for TEP is in Section 6 of this Document.

"Interconnection Study": A study or studies that may be undertaken by a Utility (or a Utility designated third party) in response to its receipt of a completed Application for Interconnection and parallel operation with the Utility system. Interconnection studies may include, but are not limited to, Interconnection Feasibility Studies, System Impact Studies, and Facilities Studies.

"Island": A condition in which a portion of a Utility electric power system is energized solely by one or more local electric power systems throughout the associated Point of Interconnection while that portion of the Utility electric power system is electrically separated from the rest of the Utility electric power system. Islands can either be intentional (planned) or unintentional (unplanned).

"Islandable System": A Generating Facility interconnected to a bus common with the Utility's system, where the Generating Facility is designed to serve part of the Utility grid that has become or is purposefully separated from the rest of the grid.

"Metering Service": All functions related to measuring electricity consumption.

"Minimum Protective Devices, Relays, and Interconnection Requirements": The minimum required protective relaying and/or safety devices or requirements specified in this Document, are for the purpose of protecting only the Utility and its other customer facilities from damage or disruptions caused by a fault, malfunction, or improper operation of the Customer's Generating Facility. Minimum Protective Relaying and Interconnection Requirements do not include relaying, protective, or safety devices as may be required by industry and/or government codes and standards, equipment manufacturing and prudent engineering design and practice to fully protect the Customer's Generating Facility; those are the sole responsibility of the Customer.

"MSP" ("Meter Service Provider"): An entity providing Metering Service, as that term is defined herein.

"NEMA": National Electrical Manufacturers Association. See www.nema.org.

"NFPA": National Fire Protection Association. See www.nfua.org.

"Parallel System": The operation of a Generating Facility that is electrically interconnected to a bus common with the Utility's electric distribution system, either on a momentary or continuous basis.

"Point of Interconnection": The physical location where the Utility's service conductors are connected to the Customer's service conductors to allow parallel operation of the Customer's Generating Facility with the Utility's electric distribution system.

"Primary Network": An AC power distribution system that uses two or more dedicated primary voltage feeders, connected in parallel, to simultaneously supply power to one customer. The system includes automatic protective devices intended to isolate faulted primary feeders, while maintaining uninterrupted service to the customer served from the other primary feeder circuit(s).

"Qualifying Facility" ("QF"): Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

"Radial Line": A distribution line that originates from a substation and is normally not connected to another substation or another circuit sharing the common supply of electric power.

"Relay": An electric device that is designed to interpret input conditions in a prescribed manner and after specified conditions are met to respond to cause contact operation or similar abrupt change in associated electric control circuits.

"Secondary Spot Network System": An AC power distribution system in which a Customer is simultaneously served from three-phase, four-wire low-voltage (typically 480V) circuits supplied by two or more network transformers whose low-voltage terminals are connected to the low voltage circuits through network protectors. This is not applicable to TEP.

"Separate System": The operation of a Generating Facility that has no possibility of operating in parallel with the Utility's system.

"Small Power Production Facility": A facility that uses primarily biomass, waste or renewable resources, including wind, solar, and water to produce electric power.

"Transfer Trip Scheme": A form of remote trip in which a communication channel is used to transmit a trip signal from the relay location to a remote location.

"Transmission System": Utility-owned high-voltage lines (69 kVa or higher) and associated equipment for the movement or transfer of electric energy between power plants and the distribution system.

"UL": Underwriters Laboratories Inc. See www.ul.com.

"Utility": An electric distribution company that constructs, operates, and maintains the electrical distribution system for the receipt and/or delivery of power. TEP is the Utility in this Document.

"Utility Grade Relays": Relays specifically designed to protect and control electric power apparatus, tested in accordance with the following ANSI/IEEE standards:

(a) ANSI/IEEE C37.90-1989 (R1994), IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

(b) ANSI/IEEE C37.9.01-1989 (R1994), IEEE Standard Surge Withstand (SWC) Tests for Protective Relays and Relay Systems.

(c) ANSI/IEEE C37.90.2-1995, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

EXHIBIT 1
TUCSON ELECTRIC POWER COMPANY
POWER QUALITY CHARACTERISTICS

SETTING TYPE	TEP
Power Factor [1]	No greater than 0.85 for Class II units and above
Phase Current Imbalance	[3]
Voltage Characteristics	ANSI C84.1
Sine Wave Form	IEEE 519
Harmonics [2]	Voltage: 5% THD, with no single harmonic greater than 3% of the fundamental, IEEE Std. 519-1992, Sect. 10.3 Current: See Table 10.3 of IEEE Std. 519-1992, Sect. 10
Voltage Flicker	IEEE 519, Sect. 10.5[3]

Notes:

[1] This power factor provides for spinning VAR support and minimizes the impact of many small generators on TEP's system voltage stability.

[2] Harmonics limits shall be met for all generation levels from 10 – 100% of each generator's nameplate kVA or kW rating.

[3] Customer to consult with TEP.

EXHIBIT 2
TUCSON ELECTRIC POWER COMPANY RELAY SETTINGS AND RE-CLOSING PRACTICES

SETTING TYPE	TEP
Over-frequency Time delay [1]	61.1 Hz 0.1 Seconds
Under-frequency Time delay [2]	58.9 Hz 0.1 Seconds
Over-voltage Time Delay	105% 0 Seconds
Under-voltage Time Delay	95% 0 Seconds
Re-closing, first shot [3]	Instantaneous
Re-closing, second shot [3]	15 to 30 Seconds [4]
Re-closing, third shot [3]	165 Seconds

Notes:

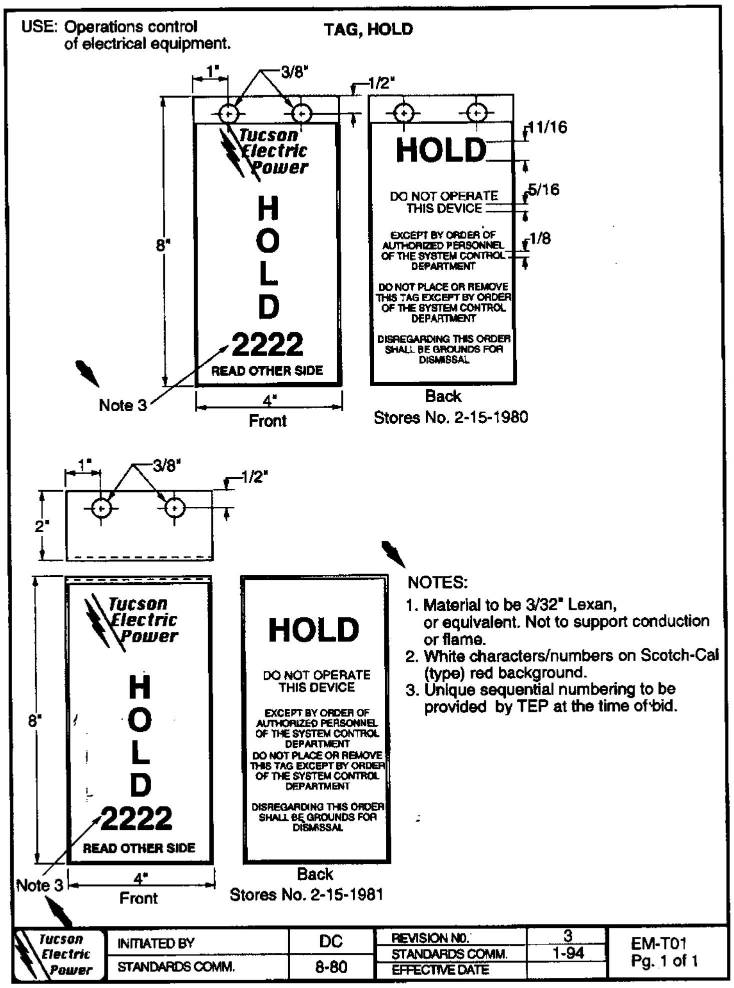
[1] Guidelines do not specify a setting or time delay; they state "trip the circuit breaker when the frequency varies from the nominal 60 Hz."

[2] If generator is considered a WSCC generator, the under-frequency setting might be different to comply with WSCC guidelines.

[3] Times are for typical overhead/residential type feeders (not necessarily line reclosers), and are the time delay from the trip to the next reclosure. Actual number of re-close shots on a particular feeder may vary.

[4] Varies based on type of reclosing utilized.

EXHIBIT 3
TUCSON ELECTRIC POWER COMPANY
HOLD



APPENDIX A
TUCSON ELECTRIC POWER COMPANY

TEP

APPLICATION AND EQUIPMENT INFORMATION FORM – ROUND ROTOR

SITE AND CUSTOMER INFORMATION
(Complete all items)

Customer Name ______________________________ Telephone ____________________

Company Name (if applicable)____

Mailing Address____

Generating Facility Address ____

Project Contact________________________ Telephone______________________________

Utility Account Number ____________________ Electric Meter No. ____________________

ESP (if different from serving Utility) ____

MSP (if different from serving Utility) ____

Completed By __________________________ Telephone______________________________

PROPOSED OPERATION
(Answer all questions)

A. Does the Generation Facility plan on being a net exporter of energy into the Utility grid? (Yes or No)_____. If "Yes", explain the proposed operation and estimated power to be exported, and also provide name of proposed purchaser of this power:

____

____

B. If the Generating Facility will be used only for on-site power, will it be operated as a peak-shaving unit during Utility peak load conditions, or as a base-loaded unit operating 24 hrs a day?

____

GENERATOR INFORMATION
(Complete for each rotating generator only)

A. Manufacturer ______________________________

B. Type (Synchronous, Induction, D.C.) ______________________________

C. Nameplate rating
Voltage ______________ kW ______________
Power Factor ______________ Frequency ______________
Model No. ______________ Single or Three Phase______________

D. Type of Excitation System (Self or Separate)______________________________

E. Generator Electrical Characteristics (on the machine base, for Class II and above)

Synchronous Reactance (X'd) ______________
Transient Reactance (X'd) ______________
Subtransient Reactance (X"d) ______________
Zero sequence reactance (XO) ______________
Negative sequence reactance (X2) ______________

PRIME MOVER
(Complete for rotating machinery only)

A. Manufacturer ______________________________
B. Manufacturer's Reference Number ______________________________
C. Energy Source (Natural Gas, Steam, etc.) ______________________________

INTERFACE EQUIPMENT
(Complete for each rotating generator only)

A. Synchronizer for Synchronous Generator:
Manufacturer ______________________________
Manufacturer's Model Number ______________________________
Automatic or Manual Synchronizer ______________________________

B. Inverter for DC generator:
Manufacturer ______________________________
Manufacturer's Model Number ______________________________
Line or Self Commutated Inverter ______________________________

SUPPLEMENTARY INFORMATION – Round rotor

(Information below to be submitted for all projects. All diagrams are to be professionally and neatly drawn. Generally, free hand drawn or illegible diagrams will not be accepted by Utility).

A. Electrical One-Line Diagram:

Provide 5 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and Utility meter.

B. Electrical Three-Line Diagram:

Provide 5 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and Utility meter, and include all neutral and ground conductors and connections.

C. AC & DC Control Schematics:

Provide 5 sets, including any and all revisions or changes as they are made, for all projects comprising rotating machinery. Diagrams must show the detailed wiring of all protective relays and control functions, and include control power source and wiring.

D. Detailed Map:

Provide 5 sets of detailed maps, including any and all revisions or changes as they are made. Maps should show major cross streets and proposed plant location, and include the street address.

E. Site Plan:

Provide 5 sets of site plans, including any and all revisions as they are made, showing the arrangement of the major equipment, including the electric service entrance section and Utility meter, location of generator and interface equipment, and location of the Disconnect Switch. Include the street address, and location of the any lock-boxes, etc.

F. Testing Company:

Provide the name of the company that will do the protective relay bench testing and the trip circuit functional tests and the anticipated start up date.

G. Point of Contact

If the interconnection and start-up process is to be coordinated through a party or individual other than the Customer, provide the name, company, address and phone number of that individual or party with whom the Utility is to coordinate the interconnection.

APPENDIX B
TUCSON ELECTRIC POWER COMPANY

TEP

PV INTERCONNECTION APPLICATION
(GREATER THAN 20 kWac)

Customer Information

Business Name: ______________________________

Mailing Address: ______________________________

City: ______________________, AZ Zip Code: ______________

Street Address: (if different from above) ______________________________

Phone Number: ______________________________

E-mail Address: ______________________________

Solar - PV Equipment Information

Module Manufacturer: ____________________ Nameplate DC Rating: __________ Watts

Module Model Number: ____________________ Quantity of Modules: __________

Module Warranty: ________years

Inverter Manufacturer: ____________________ Inverter Model Number: ____________

Inverter conforms to UL1741 for grid connected: ______Yes ______ No

Inverter Warranty: _______years

Project Information

Will system be grid connected: _____Yes _____ No Is there a battery system:_____Yes _____No

Utilities Contact for system interconnection: _____ Customer _____ Installer

Has a City/County Permit been secured: _______Yes ______ No

Does this installation meet all TEP Interconnection Requirements: ______Yes ______ No

Estimated Installation Date: ______________

System Cost: ______________

Installer Information

Company Name: ______________________________

Installer's Name: ______________________________

Business Address: ______________________________

Arizona Registrar of Contractors (AZROC) License Information

AZROC License Number: ______________ Class: ____________ Expiration Date: ______________

Contractor's License: ______________ Class: ____________ Expiration Date: ______________

Completed By: ______________________________

TEP Customer Signature: ______________________________

SUPPLEMENTARY INFORMATION – Photovoltaic

(Information below to be submitted for all projects. All diagrams are to be professionally and neatly drawn. Generally, free hand drawn or illegible diagrams will not be accepted by Utility).

A. Electrical One-Line Diagram:

Provide 3 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and Utility meter.

B. Electrical Three-Line Diagram:

Provide 3 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and Utility meter, and include all neutral and ground conductors and connections.

C. Detailed Map:

Provide 3 sets of detailed maps, including any and all revisions or changes as they are made. Maps should show major cross streets and proposed plant location, and include the street address.

D. Site Plan:

Provide 3 sets of site plans, including any and all revisions as they are made, showing the arrangement of the major equipment, including the electric service entrance section and Utility meter, location of generator and interface equipment, and location of the Disconnect Switch. Include the street address, and location of the any lock-boxes, etc.

E. Point of Contact

If the interconnection and start-up process is to be coordinated through a party or individual other than the Customer, provide the name, company, address and phone number of that individual or party with whom the Utility is to coordinate the interconnection.

EXHIBIT
TASC 17
judicial notice

Interconnection Requirements

For

Distributed Generation

Arizona Public Service Company

Effective April 2016
Rev 8.1

APS Interconnection Requirements for Distributed Generation Statement of Ownership

This Interconnection Requirements manual is owned and maintained by the APS Interconnection Engineering & Power Quality team. Originally published by APS in June 1985, this document continues to be updated from time to time in order to address ongoing issues such as evolving industry standards, industry recommended practices, safety concerns, technology advancements, and various regulatory requirements. This document is updated and approved via committee with input from various internal and external groups. Internal input is typically obtained from APS departments such as Protection Engineering, SCADA, Operations, Meter Shop, Legal, Regulatory, Program, Technical Projects, Safety and Interconnection. External input is obtained from various industry experts and interested parties, including Generating Facility designers and installers, consulting engineers, electric utilities, and equipment manufacturer representatives. Any questions or suggestions regarding this document should be directed to the APS Interconnection Engineering and Power Quality team.

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1 INTRODUCTION

This document specifies the minimum requirements for safe and effective operation of any Distributed Generation electrically interconnected (or paralleled) with the Arizona Public Service Company (APS) radial distribution system (21 kV or less). APS Customers and/or Customer's authorized representatives and APS personnel shall use this document when planning for the installation of any Backup Generator or GF. Application for interconnection is made by completing and submitting to APS the applicable Interconnection Application specified in Section 17 of this document.

Installations that are directly connected to the transmission system or sell power for resale, except in limited circumstances described later, have additional APS requirements. In such cases an interconnection application may need to be made in accordance with APS' Open Access Transmission Tariff ("OATT"). Further information can be obtained by accessing the following website: http://www.oatioasis.com/azps/index.html and clicking on the link entitled Applications.

If a generator interconnects to the APS transmission system (higher than 21 kV), and is not subject to APS' OATT, such interconnection may be performed in accordance with this document. APS will work with Customer and advise of additional requirements.

These requirements may not cover all details in specific cases. This document must be applied in conjunction with the following APS documents that pertain to the parallel operation of Customer-owned Distributed Generation with the APS System:

- Schedule #1, Terms and Conditions for Standard Offer and Direct Access.
- Schedule #2, Terms and Conditions for Energy Purchases from Qualified Cogenerators and Small Power Production Facilities.
- Schedule #4, Totalized Metering of Multiple Service Entrance Sections at A Single Site for Standard Offer and Direct Access Service.
- Schedule #5, Guidelines for Electric Curtailment.
- Schedule #6, Interconnection Services and Fees for Non-FERC Generation Facilities.
- APS Electric Service Requirements Manual ("ESRM").

The Service Schedules listed are available on the following website link:

http://www.aps.com/en/ourcompany/ratesregulationsresources/serviceplaninformation/Pages/business-sheets.aspx

The ESRM is available at: http://www.aps.com/ESRM

The minimum required protective relaying and/or safety devices and requirements specified in this document, are for protecting only APS facilities and the equipment of other Customers from damage or disruptions caused by a fault, overcurrent condition, malfunction or improper operation of the GF. These requirements are also necessary to ensure the safety of utility workers and the public. Minimum protective relaying and interconnection requirements do not include additional relaying, protective or safety devices as may be required by industry and/or government codes and standards, equipment manufacturer requirements and prudent engineering design and practice to fully protect the Customer's GF; those are the sole responsibility of such Customer.

In addition to all applicable regulatory, technical, safety, and electrical requirements and codes, which are not contained in their entirety in this document, Customers are also subject to contractual and other legal requirements, which may only be summarized or referenced in this document. Those regulations, requirements, contracts and other materials contain complete information concerning interconnection and govern over the general provisions in this document.

The technical interconnection requirements outlined in this document also apply to any interconnected utility-owned or operated GF.

This document, as well as the various Agreements and rate schedules, is subject to revision from time to time. Check with APS for the latest revision prior to commencing your project.

APS is committed to ensuring that interconnection applications are handled promptly, and to do everything possible to complete the interconnection process in a safe and timely manner. At APS, we look forward to working with you to ensure a successful generation project.

2 DEFINITIONS

The following capitalized terms, as used in this document, shall have the meanings specified:

Advanced Metering Infrastructure (AMI): The APS-owned Metering system whereby electrical meters transmit electric usage and other data via a radio and/or cell phone communication system to a central data collection system.

Agreement: See "Interconnection Agreement."

AHJ: Authority Having Jurisdiction, the organization, office, or individual responsible for enforcing the requirements of a code or standard or for approving equipment, materials, an installation, or a procedure.

AMI: See "Advanced Metering Infrastructure".

ANSI: American National Standards Institute. See www.ansi.org.

Application: The standard form as specified in Section 17 for applying to interconnect a GF with the APS System also referred to as the "Interconnection Application".

APS: Arizona Public Service Company.

APS Interconnection Requirements: The requirements set forth in this document entitled "Interconnection Requirements for Distributed Generation Arizona Public Service Company" and all additional requirements that are referenced in this document.

APS System (also referred to as the **"APS System"** or **"Utility System"):** Refers to APS' Electrical Transmission or Distribution System.

Arizona Corporation Commission ("ACC" or **"Commission"):** The regulatory agency of the State of Arizona having jurisdiction over public service corporations, including APS, operating in Arizona.

Backfeed: To energize any section of the APS System from an electric source other than the normal utility source.

Backup Generator: An independent power generation source or sources located at a Customer's facility installed for the sole purpose of supplying on-site generated power to selected loads upon failure or outage of the normal Utility source. A Backup Generator shall be understood to include Critical, Emergency and Standby Power Systems as defined in IEEE Std. 446 and the NEC.

Behind the Meter: A term used to describe a power generation application in which the GF generation is not directly interconnected to the APS System but rather, to a Customer-owned electric system that is itself electrically connected to APS System via an APS retail billing meter.

Bi-directional Meter: A meter having two separate metering registers, one to record electricity delivered to Customer and the other to record electricity received from Customer.

Business Day: Monday through Friday, excluding Federal and Arizona State holidays.

Clearance: A Clearance is a statement by one having complete authority over all parts of a circuit or piece of electrical equipment that said circuit or equipment is disconnected from all known sources or power. It is assurance that all proper precautionary measures have been taken and workers may proceed with grounding the circuit.

Clearance Point: The physical location on a section of a power line or equipment that is to be visibly disconnected from all known power sources of power.

Closed Transition Transfer (CTT): The transfer of electrical load between two power sources (normally the Utility grid and Customer's Generator) in which the power sources electrically synchronize and parallel for a period of time to transfer load between the power sources without interrupting power to the load. This is also referred to as a "make-before-break" Transfer Switch or Scheme. A CTT may be accomplished by either a Momentary Parallel Transition or a Smooth Parallel Transition.

Cogeneration Facility: Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

Continuous Parallel: A GF that electrically parallels with the APS System for more than 15 seconds.

Customer: A Customer is considered to be an APS account holder or APS "Customer of Record" that receives electric service from APS and which may also generate electricity at the property receiving electric service. A Customer shall be understood to include any independent party or entity that either invests in, owns or operates the GF including without limitation its grantees, lessees or licensees.

Dedicated Utility Feeder: A Distribution System feeder placed into service with the sole purpose of serving a single Customer. A non-Dedicated utility feeder (sometimes referred to as a "Shared Feeder") serves multiple Customers.

DG: See "Distributed Generation".

Disconnect Switch: A visible open disconnect device that Customer is required to install and maintain in accordance with the requirements set forth in this document. It will completely isolate Customer's GF from the APS System, including the Utility metering equipment located at the SES.

Distributed Generation (DG): Any type of electrical Generator, Static Inverter or GF interconnected with the APS System that either (a) has the capability of being operated in electrical parallel with APS' System, or (b) can feed a Customer load that can also be fed by the APS System. A Distributed Generation facility is also referred to as a "Generating Facility" or "GF" in this document.

Distribution System: The infrastructure constructed, maintained, and operated by APS to deliver electric service at the distribution level (21 kV or less) to retail Customers. This is also referred to as the APS System or APS' System.

Electric Service: Service provided by APS to Customer in accordance with all applicable APS requirements, including but not necessarily limited to APS Service Schedule 1 ("Terms and Conditions for Standard Offer and Direct Access Services") and the APS ESRM, whereby electricity may be delivered by APS to Customer, or electricity may be received by APS from Customer.
The APS Service Schedules are available at:
http://www.aps.com/en/ourcompany/ratesregulationsresources/serviceplaninformation/Pages/home.aspx

EMS Meter (Energy Management System Meter): A Bi-Directional Meter installed at the Generating Facility SES that measures and records instantaneous Watts, kVA, kVARs, Volts, Power Factor, Amps, and cumulative kWh which has the capability to transmit such data via a Remote Terminal Unit back to APS for planning, forecasting and billing purposes.

ESRM: APS Electric Service Requirements Manual. See http://www.aps.com/ESRM.

Electric Supply/Purchase Agreement: An agreement, together with appendices, signed between APS and Customer covering the terms and conditions under which electrical power is supplied to and/or purchased from APS.

Fault Current: The level of current that can flow if a short circuit is applied to a voltage source.

FERC: Federal Energy Regulatory Commission.

Generating Facility (GF): All or part of Customer's electrical Generator(s) together with all protective, safety, and associated equipment and improvements associated with the interconnection to, or operation in conjunction with, the APS System. A GF shall be understood to include a facility with a Backup Generator.

Generator: A Rotating Machine or Static Inverter used to produce electrical power.

GF: See "Generating Facility".

Good Utility Practice: Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

IEEE: The Institute of Electrical and Electronic Engineers. See http://www.ieee.org/index.html .

Interconnection: The physical connection of Customer's GF with the APS System.

Interconnection Agreement (also referred to as an **"Agreement"**)**:** An agreement, together with appendices, signed between APS and Customer, covering the terms and conditions governing the Interconnection and parallel operation of the GF with APS.

Interconnection Application (refer to **"Application"**)**:** An application form and all supplementary information specified and attached within this document.

Interconnection Generation Design Review Agreement: An agreement signed between APS and Customer covering the terms for APS to proceed with a detailed study (i.e. Interconnection Study) of the impact of Customer's DG on the APS System.

Interconnection Study: A study or studies that may be undertaken by APS (or an APS designated third party) in response to its receipt of a completed Application for Interconnection and parallel operation with the APS System. Interconnection studies may include, but are not limited to, Interconnection Feasibility Studies, System Impact Studies, and Facilities Studies.

Island: A condition in which a portion of a Utility electric power system is energized solely by one or more local electric power systems throughout the associated Point of Interconnection while that portion of the Utility electric power system is electrically separated from the rest of the Utility electric power system.

Main-Tie-Main (or Main-Tie-Tie-Main): A Transfer Scheme consisting of two main power source breakers and one or two tie breakers, designed such that electrical load can be transferred between two power sources.

Metering: The function related to measuring the transfer of electric power and/or energy.

Microgrid: A group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid connected or island mode.

Minimum Protective Devices, Relays, and Interconnection Requirements: The minimum required protective relaying and/or safety devices or requirements specified in this document, as may be revised from time to time, for the purpose of protecting only APS and its other customer facilities from damage or disruptions caused by a fault, malfunction or improper operation of Customer's GF. Minimum Protective Relaying and Interconnection Requirements do not include relaying, protective or safety devices as may be required by industry and/or government codes and standards, equipment manufacturers and prudent engineering design and practice to fully protect Customer's GF or facilities; those are the sole responsibility of Customer.

Momentary Parallel Transition: A form of Closed Transition Transfer in which the transfer of electrical load between two power sources occurs by electrically paralleling the power sources for a brief period of time in order to effect a rapid transfer of load between the power sources. A Momentary Parallel Transition is accomplished by paralleling the power sources for a period not to exceed ten cycles.

NEC: National Electric Code. See www.necdirect.org.

NEMA: National Electrical Manufacturers Association. See http://www.nema.org.

NERC: North American Electric Reliability Corporation. See http://www.nerc.com.

Net Metering: A billing process whereby an electric "net metering" rate allows energy delivered by a Customer into the electric grid to be netted with energy received by Customer from the grid over the billing period. A Bi-directional meter is required to be installed in the SES in order to effect Net Metering.

NFPA: National Fire Protection Association. See http://www.nfpa.org

Non-Parallel Connection Agreement: An agreement, together with appendices, signed between APS and Customer, covering the terms and conditions governing the non-parallel connection and operation of the GF with APS.

NRTL: Nationally Recognized Testing Laboratory.

Operations Center: A Customer owned facility in which monitoring and/or control of the Generating Facility occurs. The Operations Center can be a combination of automatic and manual controlled/monitored devices (i.e. relays, generator controllers, switches, etc...) to ensure the reliability and safe operation of the GF. The operations center is generally manned 24-7 and shall be reachable via APS.

Open Transition Transfer: The transfer of electrical load between two power sources (normally the Utility grid and Customer's Generator) in which the power sources are prevented from being electrically paralleled or interconnected with each other. Also referred to as a "break-before-make" transfer switch or scheme. An Open Transition transfer results in a momentary loss of power to the load from the two sources during the transfer (an Uninterruptible Power Source is sometimes used to prevent loss of power to the load or part of the load).

OSHA: Occupational Safety and Health Administration. See http://www.osha.gov.

Parallel System: A GF that can be electrically interconnected to a bus common with the Utility's electric power system, and can operate in electrical parallel either on a momentary or continuous basis.

Partial Requirements Service: Electric service provided to a Customer that has on-site interconnected generation whereby the output from its electric Generator(s) first supplies its own electric load requirements with any excess generation (over and above Customers own load requirements at any point in time) then being back-fed into the APS System. APS supplies any supplemental electric load requirements of Customer (those not met by Customer's own generation).

Potential Open Point: For the purpose of this document, a Potential Open Point constitutes any circuit breaker, contactor, switch or similar device that can be opened and/or closed, and which is not equipped with either a sync check or synchronizing function.

Production Meter: An APS-owned electric meter installed at a Generating Facility and configured so as to record the energy output of the GF Generator or Generators. The Production Meter will be an AMI type, unless otherwise specified by APS.

Point of Interconnection (POI): The physical location where APS' service conductors are connected to a Customer's conductors, bus, and/or service equipment to allow parallel operation of Customer's GF with the APS System. Also referred to as the Point of Common Coupling (POCC).

POI: See "Point of Interconnection".

Primary Network: An AC power distribution system that uses two or more dedicated primary voltage feeders, connected in parallel, to simultaneously supply power to one Customer. The system includes automatic protective devices intended to isolate faulted primary feeders, while maintaining uninterrupted service to Customer served from the other primary feeder circuit(s).

QF: See "Qualifying Facility".

Qualifying Facility (QF): Any Cogeneration or Small Power Production Facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, and Subpart B of the Federal Energy Regulatory Commission's Regulations.

Radial Line: A distribution line that originates from a substation and is normally not connected to another substation or another circuit sharing the common supply of electric power.

Readily Accessible: Capable of being reached quickly and conveniently on a 24 hour basis without requiring climbing over or removing obstacles, obtaining special permission, keys or security clearances.

Reclosing: The act of automatically re-energizing a utility power line in an attempt to restore power following a fault on the line.

Relay: An electric device that is designed to interpret input conditions in a prescribed manner and after specified conditions are met to respond to cause contact operation or similar abrupt change in associated electric control circuits.

Rotating Machine: An induction or synchronous machine (or machines) used to generate alternating current (AC) electric power.

Secondary Spot Network System: An AC power distribution system in which a Customer is simultaneously served from three-phase, four-wire low-voltage (typically 480V) circuits supplied by two or more network transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The low voltage circuits do not have ties to adjacent or nearby secondary network systems. The secondary spot network system has two or more high-voltage primary feeders. These primary feeders are either dedicated network feeders that serve only other network transformers, or a non-dedicated network feeder that serves radial transformers in addition to the network transformer(s), depending on network size and design. The system includes automatic protective devices and fuses intended to isolate faulted primary feeders, network transformers, or low-voltage cable sections while maintaining uninterrupted service to Customers served from the low-voltage circuits.

Separate System: The operation of a GF that has no possibility of operating in parallel with, or potentially back-feeding onto, the APS System.

Service Entrance Section (SES): The Customer-owned main electrical panel or equipment located at its premises to which the Utility delivers electric energy via the Utility service drop or service lateral.

SES: See "Service Entrance Section".

Site Inspection (or APS Site Inspection): verification performed by an APS qualified representative (inspector) prior to granting permission to parallel/operate a Generating Facility (GF). The inspection may include, but not limited to, verification that the GF is in compliance with the NEC as adopted by the local AHJ, meets all APS ESRM and Interconnection requirements, and other applicable local and/or national safety codes.

Small Power Production Facility: A facility that uses primarily biomass, waste or renewable resources, including wind, solar, and water to produce electric power.

Smooth Parallel Transition: A form of Closed Transition Transfer in which the transfer of electrical load between two power sources occurs by electrically synchronizing and paralleling the power sources for a period of time in order to effect a smooth loading (sometimes referred to as "soft loading") or unloading of the respective power source. A Smooth Parallel Transition is normally accomplished by paralleling the power sources for a period of 5 to 10 seconds.

Source Device: An electrical device (e.g. switching cabinet, primary transition, or primary metering device) which is directly powered by an APS Distribution System circuit or feeder at distribution level voltage (21 kV or less).

Source Transfer Equipment: Equipment specifically designed and installed to transfer electrical load between two separate power sources. Such equipment may consist of either a Transfer Switch which must be tested and certified to UL 1008/1008A, or a custom engineered Transfer Scheme which is not listed to UL 1008/1008A. The load transfer may be accomplished via either an Open Transition Transfer or via a Closed Transition Transfer.

Static Inverter: An electronic device (or devices) used to convert direct current (DC) power into alternating current (AC) power.

Totalized Metering: The measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy consumption of a Customer who receives electric service at more than one SES at a single site in accordance with APS Service Schedule 4.

Transfer Scheme: Source Transfer Equipment which is specifically engineered and custom designed for the purpose of transferring electrical load from one power source to another. Transfer Schemes are generally not tested to UL 1008/1008A.

Transfer Switch: Source Transfer Equipment which may be automatically or manually operated for the purpose of transferring electrical load from one power source to another. Transfer Switches must be certified and tested to UL 1008/1008A.

Transfer Trip Scheme: A form of remote trip in which a communication channel is used to transmit a trip signal from the relay location (e.g. utility substation) to a remote location (e.g. GF).

Transmission System: Utility-owned high-voltage lines (69 kV or higher) and associated equipment for the movement or transfer of electric energy between power plants and the Distribution System.

UL: Underwriters Laboratories Inc. See http://www.ul.com.

UL Listed: Equipment identified herein that is required to be tested and certified to an applicable UL Standard and which shall also be listed and labeled according to Section 110.3 of the NEC.

UL 98: UL Standard for Enclosed and Dead-Front Switches

UL 1008: UL Standard for Transfer Switch Equipment.

UL 1008A: UL Standard for Medium Voltage Transfer Switches.

UL 1741: UL Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.

Utility: The electric power company (in this case APS) that constructs, operates and maintains its electrical power system for the receipt and/or delivery of electric power.

Utility System: See "APS System".

Utility-grade Relays: Relays specifically designed to protect and control electric power apparatus, tested in accordance with the following ANSI/IEEE standards:

(1) ANSI/IEEE C37.90-1989 (R1994), IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

(2) ANSI/IEEE C37.9.01-1989 (R1994), IEEE Standard Surge Withstand (SWC) Tests for Protective Relays and Relay Systems.

(3) ANSI/IEEE C37.90.2-1995, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

WECC: Western Electricity Coordinating Council. See https://www.wecc.biz

Wholesale Generation: A GF connected directly to the APS System that sells energy and capacity directly to a utility under a power purchase contract.

3 APS POLICY ON CUSTOMER-OWNED GENERATION

Any Customer qualifying as a QF under the Public Utility Regulatory Policies Act (PURPA) of 1978 may operate its GF in parallel with the APS System provided Customer GF will:

(1) not present any hazards to APS personnel, other Customers or the public,

(2) minimize the possibility of damage to APS and other Customer equipment,

(3) not adversely affect the quality of service to other Customers, and

(4) not hamper efforts to restore a feeder to service (specifically when a Clearance is required).

Customer must also comply with all of the following prior to paralleling a GF with APS:

(1) The GF must meet all the interconnection, safety, and protection requirements outlined in this document or as otherwise determined by APS.

(2) Customer must sign an Interconnect Agreement, as well as an Electric Supply /Purchase Agreement, as applicable, with APS.

(3) Customer must comply with and is subject to all applicable service and rate schedules and requirements, rate tariffs and other applicable requirements as filed with and approved by the Arizona Corporation Commission, and as otherwise referenced in this document.

(4) The GF must be inspected by APS.

(5) Written permission to parallel/operate must be obtained from APS.

Note: When APS issues a permission to parallel/operate letter to Customer, the letter does not relieve Customer of the responsibility of full compliance with the APS Interconnection Requirements and all applicable building and safety codes, and local permitting requirements.

It is APS policy to permit Customer generating equipment with an aggregate generation nominal nameplate AC rating of less than 1 MW that is not qualified as a QF under PURPA to operate in parallel with the APS System, provided that all of the conditions outlined above are complied with and Customer does not fall under FERC jurisdiction.

APS requires any GF (other than a Backup Generator), that is not owned by APS, interconnecting with the APS System, with an aggregate nominal AC nameplate rating of greater than 1 MW to provide documentation acceptable to APS (including FERC Form 556), that confirms the GF has achieved Qualifying Facility status under 18 CFR, Chapter 1, Part 292, Subpart B, including, without limitation, §292.207 of the FERC's regulations, as amended.

This self-certification will be required from all QF's, regardless of the voltage at the Point of Interconnection.

An exception to the self-certification requirement in the paragraph above is granted for GFs that are: 1) installed in Behind the Meter installations, and 2) not expected to ever produce more energy from the GF than is consumed by the host Customer's facility on any 12 month calendar basis.

The links to FERC for “Frequently Asked Questions” and “Form 556” are listed below:

http://www.ferc.gov/help/faqs/qf-faqs.asp

http://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf

Due to relay coordination and potential back-feed problems, APS cannot permit any DG with an AC nameplate output rating of greater than 10 kW to be connected to a Primary or Secondary Spot Network System, without a detailed Interconnection Study being undertaken at Customer's expense to determine, among other things, special relaying, communication channels and other operational constraints that need to be implemented. A DG connected to either a Primary or Secondary Spot Network system will nonetheless not be permitted to back-feed any power into the APS System.

The minimum protective and safety devices (relays, circuit breakers, disconnect switches, etc.) specified must be installed and placed into service before allowing parallel operation of Customer's GF with the APS System. These devices isolate Customer's generating equipment from the APS System whenever faults, over-current conditions, or disturbances occur, as well as for maintenance purposes. Modifications to the APS electrical system configuration or protective equipment may also be required at the expense of Customer in order to accommodate parallel generation.

APS will not assume any responsibility for the protection of Customer's generator(s), or of any other portion of Customer's electrical equipment. Customer is fully and solely responsible for protecting its equipment in a manner to prevent any faults or other disturbances from damaging, or otherwise adversely affecting, the operation of Customer's equipment.

In addition to complying with all required codes, ordinances and statutes, Customer must obtain an electrical permit and inspection indicating that Customer's GF complies with the NEC, as adopted by the AHJ. In the event that a Customer's GF is located in a locality where there is no AHJ, or the AHJ does not issue a permit or perform an inspection of the GF, then Customer will be required to sign a “Letter-in-Lieu of Electrical Clearance”. APS will forward this letter for Customer's notarized signature.

APS can disallow the interconnection of a Customer's GF if, upon review of Customer's design, or as the result of a Site Inspection, it determines that the proposed design is not in compliance with applicable safety codes, as it could constitute a potentially unsafe or hazardous condition.

If APS believes that there may be a potential safety issue or code violation then APS reserves the right to forward the GF diagrams to, and/or discuss same with, the AHJ.

4 DISTRIBUTED GENERATION TYPES

Distributed generators include induction and synchronous electrical generators as well as any type of Static Inverter capable of producing AC power. A **Separate System** is one so designed that the generation never interconnects (operates in electrical parallel) with, or is capable of ever back-feeding, the APS System. A **Parallel System** is one where a Generator can electrically parallel, or has the potential to be paralleled with the APS System. Such parallel operation may be performed on either a momentary or on a continuous basis.

Customer may elect to configure its Generator as a Separate System with open transition transfer of load between two independent power systems as described in Section 4.1, or Customer may configure its Generator to run in parallel with the APS System as is described in Section 4.2.

4.1 Separate System

A Separate System is one in which there is no possibility of electrically connecting or paralleling a Backup Generator with the Utility System, or of a Backup Generator otherwise posing a potential risk of back-feeding the Utility System. Load must be transferred between the two power systems by utilizing a Transfer Switch specifically designed to operate in an Open Transition Transfer mode. The Transfer Switch must always disconnect the load from the APS System prior to connecting it to the Generator. Conversely, the Transfer Switch must also disconnect the load from the Generator prior to re-connecting it with the APS System. These requirements apply to both actual emergency operations as well as to testing the Generator.

The Transfer Switch shall satisfy either one of the following design conditions:

(1) It must be tested and certified to UL 1008 (or UL 1008A), and/or

(2) It must be a true <u>double-throw</u>, fail-safe mechanical throw-over design which inherently precludes any possibility of the Utility and Generator sources from ever being connected together, even in the event of a switch failure such as welded contacts at one of the power source switch contacts. <u>Note that a Transfer Switch or Transfer Scheme comprised of two interlocked electrical breakers or contactors will not meet this requirement, irrespective of how they may be interlocked.</u> The Transfer Switch shall be manually operated and be tested and certified to UL 98.

In addition to meeting either of the design conditions specified above, the Transfer Switch installation shall also meet the following requirements in order to qualify as a Separate System:

(1) The Transfer Switch must be a permanent installation in the facility and must be inspected by the AHJ.

(2) The normal source (utility) electrical conductors and the emergency (generator) electrical conductors feeding the Transfer Switch shall not be routed in the same conduit or raceway or in any way share a common enclosure except inside the approved Transfer Switch.

An Open Transition Transfer Switch or Scheme that does not satisfy the requirements for a Separate System as outlined above, constitutes a potential back-feed source to the APS System. As such, APS has certain requirements that must be adhered to. These are described in Section 13 of this document. Also refer to Section 104.11 of the APS ESRM for further details.

If Customer claims a Separate System, APS may require verification that the Transfer Switch and its installation are in accordance with these requirements.

Note: Portable generators are normally not designed to be connected to a building's permanent wiring system, and are not to be connected to any such wiring unless approved Source Transfer Equipment is used and the installation is inspected by the AHJ. Opening a source circuit breaker or disconnect switch (such as the main breaker in an SES) in order to connect a portable generator is prohibited. Failure to use approved Source Transfer Equipment can result in back-feed into the APS System – the generator voltage can be stepped up to a very high voltage through the APS transformer. This can pose a potentially fatal shock hazard to anyone working on the Utility power lines or equipment.

4.2 Parallel System

In a Parallel System, a Generator is connected to a bus common with the APS System, and a transfer of power between the two systems is a direct result. A consequence of such interconnected operation is that Customer's Generator must be considered in the electrical protection and operation of the APS System.

A Parallel System encompasses any type of Generator or GF that can electrically parallel with, or potentially back-feed the APS System. This includes any GF using a Closed Transition Transfer Switch or Transfer Scheme as well as any Static Inverter that can be configured or programmed to operate in a "utility interactive" mode.

APS has specific interconnection, inspection and contractual requirements, as outlined in this document that must be complied with and information that needs to be submitted for all interconnected generators. These requirements include a "visible open" Disconnect Switch meeting certain requirements to isolate Customer's System from the APS System, as well as protective relaying, metering, special rate schedules, and other safety and information requirements. Customer will be responsible for having the GF protective schemes tested by a qualified testing/calibration company. APS personnel will inspect the system and Customer will be required to sign an Interconnect Agreement and, if applicable, an Electric Supply/Purchase Agreement with APS.

In certain instances, APS and Customer will need to sign a "Non-Parallel Connection Agreement" and/or an "Operating Agreement". APS will advise Customer of requirements after reviewing the proposed design.

APS does not extend "blanket approval" to any specific type of Generator or generation scheme since each project is site specific and needs to be reviewed on a case-by-case basis.

In addition to the various other requirements specified in this document, Parallel Systems shall specifically comply with the technical requirements outlined in the Interconnection Technical Requirements section (Section 8) of this document.

5 CUSTOMER RESPONSIBILITIES

5.1 The Customer is responsible for all facilities required to be installed solely to interconnect the Customer's generation facility to the APS System. This includes connection, transformation, switching, protective relaying, metering and safety equipment, including a visibly-open Disconnect Switch and any other requirements as outlined in this document, the ESRM and applicable rate schedules as well as any other special items specified by APS. All such Customer facilities are to be installed by the Customer at the Customer's sole expense. In the event that additional facilities are required to be installed on the APS System to accommodate the Customer's generation, APS will install such facilities at the Customer's expense. APS may also charge the Customer for any administrative costs and/or the costs of studies required to interconnect the Customer's generation.

5.2 Customer will own and be responsible for designing, installing, operating and maintaining:

(1) The GF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

(2) Control and protective devices, in addition to minimum protective relays and devices specified in this document, to protect its facilities from abnormal operating conditions such as, but not limited to, electric overloading, abnormal voltages, and fault currents. Such protective devices must promptly disconnect the generating facility from APS' system in the event of a power outage on APS System. (From APS Service Schedule 2)

(3) Interconnection facilities on Customer's premises which may be required to deliver power from Customer's GF to the APS System at the Point of Interconnection.

5.3 Due to risks associated with interconnecting and operating a GF with the APS System, such as serious bodily injury, death or property damage, it is recommended that every Customer protect itself with insurance or other suitable financial instrument sufficient to meet its construction, operating and liability responsibilities. A Customer should consult with its insurance advisor to determine what issues may be posed by the installation of the GF, since current policies may not have contemplated its addition, and changes may need to be made to the existing insurance policy to include coverage of the GF itself and the consequences of its operation. APS does not require that the Customer negotiate any policy or renewal of any policy covering any liability through a particular insurance provider, agent, solicitor or broker.

5.4 Any Customer operating a static inverter based GF with an aggregate nominal AC output rating of greater than 2 MW, or operating a Rotating Machine(s) with an aggregate nominal AC output rating of greater than 50 kW shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to the Interconnection Agreement. The amount of insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the GF being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. Customer shall obtain additional insurance only if necessary as a function of owning and operating a GF. Insurance shall be obtained from an insurance provider authorized to do business in Arizona. Certification that insurance is in effect shall be provided upon APS' request, except that Customer must show proof of the insurance to APS no later than ten (10) business days prior to the date upon which the GF commences interconnected operation with the APS System. If Customer is determined by APS to be of sufficient credit-worthiness, Customer may propose to self-insure for liabilities.

5.5 Interconnected Customers will be required to sign an Interconnection Agreement in addition to any other agreements that may be applicable. Customers that connect a static inverter to the utility, and which will be programmed so as not to back-feed into the utility system (i.e. non-utility interactive mode), will need to sign a Non-Parallel Connection Agreement with APS, since such an arrangement can constitute a potential back-feed source. Customers that purchase power from, or sell power to, APS may be required to sign an Electric Supply/Purchase Agreement.

5.6 In the event that Customer's facility is fed by more than one APS electrical service, Customer shall:

(1) Have controls and operating procedures that are acceptable to APS to ensure that services will never be paralleled; and

(2) Ensure that the GF is never connected to an electrical service other than the one specified in Customer's Interconnection Application and/or Interconnection Agreement. Additional information is given in Section 104.12 "Protection and Isolation Requirements for Multiple Utility Services to a Customer Facility" of the APS ESRM.

6 MUTUAL UNDERSTANDINGS

6.1 Interconnections

APS will not install or maintain any lines or equipment on a Customer's side of the Point of Interconnection (POI), except it may install electric meters and at times research equipment. Only authorized APS employees (with credentials to identify their company affiliation) may make and energize the service connection between the APS System and Customer's service entrance conductors.

6.2 Easements and Rights of Way

Where an easement or right of way is required to accommodate the interconnection, Customer must provide to APS suitable easements or rights of way, in APS' name, on the premises owned, leased or otherwise controlled by Customer. If the required easement or right of way is on another's property, Customer must obtain and provide to APS a suitable easement or right of way, in APS' name, at Customer's sole cost and in sufficient time to meet the Interconnect Agreement requirements. All easements or rights of way must be on terms and conditions acceptable to APS.

6.3 Rate Schedules

The rate applicable to the interconnection of a Customer's GF will depend on the system size, type and configuration. Refer to section 10 of this document for the rate schedules applicable to Distributed Generation. Because of varied and diverse requirements and operating modes associated with the interconnection, Customer must evaluate and determine which system configuration and electric rate is most appropriate and if it qualifies for the particular rate. Customer remains fully responsible for such matters, APS assistance or information should not be taken as constituting any representation or warranty about any particular option.

Any energy purchases from Customer's facility will be in accordance with the rate schedule and/or an Electric Supply/Purchase Agreement, any changes required by law or regulation, and rates authorized by law. Generating facilities with requirements of unusual size or characteristics may require special rate and contract arrangements.

APS will not be obligated to buy energy or capacity from a Customer if the purchase would result in greater cost to APS than if APS generated the energy itself or purchased it from another source. APS will give reasonable notice so that Customer may discontinue deliveries to APS or may opt to sell energy to APS at a lower rate.

6.4 ACC Jurisdiction

The rates, terms or other contract provisions governing the electric power sold to a Customer or purchased from Customer by APS are subject to the jurisdiction of the ACC. APS retains at all times and without restriction the right to file a unilateral ACC application for a change in requirements, charges, classification, or service, or any rule, regulation or agreement as allowed by law.

7 DESIGN CONSIDERATIONS AND DEFINITION OF CLASSES

Protection requirements are influenced by the size and characteristics of the parallel generator along with the nature and operational characteristics of the associated APS System. Therefore, similar units connected to different lines could have different protection requirements based on varying load conditions, as well as on utility feeder and transformer characteristics.

7.1 Synchronous Units

Synchronous generators are generally capable of supplying sustained current for faults on the APS System. These units can also supply isolated APS load providing the load is within the units' output capability.

Reclosing of the Utility power source onto synchronous units must be blocked to prevent out-of-synch paralleling and must also be prevented from energizing a de-energized utility line. Automatic reclosing by APS is time-delayed which allows for automatic Customer Generator separation prior to re-energization of the Utility source.

7.2 Induction Units

Induction generators are basically induction motors that are mechanically driven above synchronous speed to produce electric power. These units do not have a separate excitation system and, as such, require that their output terminals be energized with AC voltage and supplied with reactive power to develop the magnetic flux. Induction generators are therefore normally not capable of supplying sustained fault current into faults on the utility system. Such units are generally not capable of supplying isolated load when separated from the utility system; however, it is possible for an induction generator to become self-excited if a sufficient amount of capacitance exists at its output terminals.

Under conditions of self-excitation, an induction generator will be capable of supplying isolated load, providing the load is within the units' output capability. In most cases when self-excitation occurs it will be accompanied by a sudden increase in terminal voltage. APS and its other Customers must be protected from out-of-phase closing and over-voltages that can occur whenever an induction generator becomes self-excited. Induction units must therefore be designed to automatically separate from the utility system upon loss of utility voltage and prior to reclosing of the utility feeder.

7.3 Static Inverters

Static inverters convert DC power to AC by means of electronic switching. Switching can be controlled by the AC voltage of the utility's supply system (line-commutated) or by internal electronic circuitry (forced-commutated).

Line-commutated inverters are generally not capable of operating independently of the utility's AC supply system, cannot normally supply any appreciable fault current, or continue to energize isolated loads provided proper protective functions are in place. To accommodate such protective functions, any line-commutated inverter that is electrically paralleled with the APS System shall be tested and certified to UL Standard for Inverters, Converters and Controllers for use in Independent Power Systems, UL1741 by a NRTL certified by OSHA to perform the UL1741 test standard.

Forced-commutated, or self-commutated, inverters are capable of energizing load independently of the utility system. Any forced-commutated inverter, the output of which is to be directly interconnected with the utility, needs to be specifically designed for that purpose. It would need to be designed to accommodate parallel interfacing and operation. However, it is not anticipated at this time that any forced-commutated inverters will be interconnected to the utility system. APS would consider this type of interconnection on a case-by-case basis. Under no circumstance shall the self-commutated output of a "battery backup" type inverter which is normally designed to energize a subpanel independently of the utility, be connected to the utility system.

7.4 Definition of Generator Size Classes

The following generator size classifications are used in determining specific minimum protective requirements for distributed GFs. Specified ratings are for each connection to the APS System. Customers must satisfy, in addition to the general requirements specified in this document, the minimum relaying requirements given in this document (Section 8.7) for each generator class.

Class I -- 50 kW or less, single or three phase

Class II -- 51 kW to 300 kW, three phase

Class III -- 301 kW to 5,000 kW, three phase

Class IV -- over 5,000 kW, three phase

8 INTERCONNECTION TECHNICAL REQUIREMENTS

The requirements and specifications outlined in this Section are applicable to DG interconnected for parallel operation (continuous or momentarily) with the APS System, unless otherwise specified. The protection and safety devices and other requirements specified in this Section are intended to provide protection for the APS System and its workers, other APS Customers, and the general public. They are not intended to provide protection for Customer's generation equipment or personnel. This is the sole responsibility of Customer.

With respect to protection objectives, it is necessary to disconnect a Generator operating in parallel with the APS System when trouble occurs. This is to:

(1) ensure if a fault on the APS System persists, the fault current supplied by Customer's Generator(s) is interrupted;
(2) prevent the possibility of reclosing into an out-of-sync isolated (islanded) system composed of the APS System, or a section thereof, and Customer's Generator(s);
(3) prevent reclosing the Utility source onto Customer's GF that may be out of synchronism or stalled;
(4) prevent unintentional islanding.

The protection requirements are minimal for smaller installations, but increase as the size of Customer's generation increases. Small installations usually ensure that the Generator is small compared with the magnitude of any load with which it might become isolated. Thus, for any fault on the Utility system, Utility protective devices will operate and normally isolate the generation with a large amount of load, causing voltage collapse and automatic shutdown of the Generator.

Section 11, Additional Requirements for GFs with an Aggregate AC Generation ≥ 1 MW, contains requirements that apply to any GF that is nominally rated to generate 1 MW or more and is interconnected with the APS System for continuous parallel operation.

For larger installations the probability of isolated operation is higher since the available generation may be sufficient to carry the entire load, or part thereof, of the local APS circuit. In instances where the APS System arrangement is that it is possible that the generators will not always be isolated with comparatively large amounts of load, additional protection and generator shutdown schemes are required.

Customer is solely responsible for the protection of its equipment from automatic reclosing by the Utility. APS normally applies automatic reclosing to overhead electric distribution circuits. When the APS source breaker trips, Customer must ensure that its generator is disconnected from the Utility circuit prior to automatic reclosing by the Utility. The automatic reclosing on APS distribution feeders is normally delayed by at least 2 seconds. Automatic reclosing out-of-sync with Customer's Generator may cause severe damage to Customer equipment and could also pose a serious hazard to Customer or Utility personnel.

8.1 General Technical Requirements

(A) Customer is responsible for obtaining and maintaining all required permits and inspections indicating that Customer's GF complies with all applicable codes, ordinances and statutes relating to safety, construction and operation.

(B) Multiple Generator connections on the same Utility service are permitted subject to APS approval; however, a single Disconnect Switch for the GF will generally be required (normally located at the SES). If APS approves more than one Disconnect Switch behind a Utility Service, then the Disconnect Switch shall be labeled per Section 8.6.2.

(C) A transfer trip scheme, and in some instances, a Dedicated Utility Feeder will be required at customer expense if the Generator or aggregate Generators:

(1) Are of sufficient size to carry the (minimum) load of APS' distribution feeder, or

(2) Size or physical feeder location could support an isolated (islanded) section of the feeder.

If a transfer trip is required, or Customer's aggregate generation is one MW or greater, a communication channel and telemetering will also be required. These will be at Customer's expense. Refer to Sections 11 & 16.6 for additional information. In such instances, APS will need to perform an Interconnection Study to determine required facilities.

(D) Whenever a synchronous Generator is configured to operate in electrical parallel with the Utility grid, Customer shall ensure that any Potential Open Point ("Open Point") located in the circuit between the Generator output and the Utility service is suitably interlocked to preclude the possibility of a potential out-of-sync closure occurring between the power sources. A Potential Open Point includes any circuit breaker, contactor, switch, etc., that is capable of being opened and/or closed, and which is not equipped with either a sync check or synchronizing function.

A Potential Open Point may be interlocked by installing either of the following:

(1) A keyed or other suitable mechanical interlock that will prevent the Open Point from ever being opened unless a circuit breaker in the circuit, which is equipped with either a sync check or synchronizing function, is first opened. This breaker, when opened, shall immediately break the electrical path between the power sources.

(2) An electrical interlock consisting of a set of electrical contacts on the Open Point which are directly wired to instantaneously trip open a circuit breaker in the circuit, which is equipped with either a sync check or synchronizing function, whenever the Open Point is opened. This breaker, upon opening, shall immediately break the electrical path between the power sources.

(E) If APS is required to install electric meter(s) to record the output of Customers Generator(s), Customer shall ensure that the design is such that the meter(s) are located on the utility-side of any Generator breaker on a normally energized bus. Electronic meters are not designed to be de-energized for any length of time.

(F) If a Generator is connected or tapped on the supply (utility) side of an SES service disconnecting means, as may be permitted by the NEC, the installation is subject to all applicable NEC requirements and/or requirements adopted by the AHJ. The required disconnecting means shall also be in accordance with the APS ESRM.

(1) A Supply Side Connection (SSC), also referred to as a Line Side Tap constitutes a new service as defined by the National Electric Code (NEC), and is subjected to all applicable NEC requirements and/or requirements adopted by the Authority Having Jurisdiction (AHJ). In addition, any such connection must comply with the APS ESRM and Good Utility Practice. The required SSC service disconnecting means shall also be in accordance with the APS ESRM. Any SSC shall be made without any modifications to any factory installed and/or UL listed equipment or components, unless expressly authorized by the panel manufacturer and/or listing agency. It must be performed in strict accordance with the panel manufacturer's directions and specifications. In order for APS to approve a SSC interconnection, the following are required:

a. Interconnection drawings shall be stamped by a professional electrical engineer licensed in the state of Arizona (refer to Section 17 for further details of these requirements).

b. Rigid Metal Conduit (RMC) shall be used between the SSC connection in the Service Entrance Section (SES) and an externally mounted (external to the SES) SSC fused service disconnect (SSC Service Disconnect).

c. The ampere rating of the conductor feeding an SSC Service Disconnect shall not be less than the ampere rating of the SSC Service Disconnect. The minimum ampere rating of the SSC Service Disconnect shall be 60 A per NEC Art 230.79(D).

d. The SSC Service Disconnect shall be mounted "immediately adjacent" to the SES (10' or less), located on the same wall and the circuit shall not be routed through any other enclosures (i.e. junction boxes and/or distribution panels) between the SES and the SSC Service Disconnect.

e. A neutral to ground (N-G) bond must be re-established in the SSC Service Disconnect, and GEC installed. Note however, that if the SSC is made via a breaker or fused disconnect switch located within the SES (i.e. not an externally mounted service disconnect), then the existing N-G bond will suffice.

f. If panel manufacturer authorization is granted to the preform a SSC, proof of such authorization and AHJ approval shall be provided to APS as part of the Interconnection Application process.

   i. No drilling, tapping or replacing of factory installed bus bars or conductors unless performed by the manufacturer or its designated representative.

   ii. If lugs are replaced to accommodate additional conductors, the panel manufacturer must specify a listed kit or provide written approval of the parts to be used. Appropriate torque specs shall also be provided.

iii. When connecting to a field installed conductor a UL listed tap should be used. Breaking the conductor should be avoided – using a lay in lug is preferred. The connector's make and model number should be provided.

iv. Fused and unfused conductors shall not occupy the same raceway unless they are isolated from each other via a firewall barrier in a manner acceptable to APS.

v. In the event a field evaluation is required in order to perform the SSC, Customer shall provide APS the Letter of Compliance issued to the NRTL certified by OSHA to perform the evaluation (i.e. CSA, TUV, UL, etc.) as well as a photograph of the approval sticker affixed to the SES at the time the work is completed in the field.

g. Per NEC Art 225.32, the Service Disconnect shall be Readily Accessible.

h. Per NEC Art 240.24(B), all over-current devices protecting the conductors supplying the premises shall be Readily Accessible to the occupant.

(2) No Customer connections or equipment are permitted in the Utility sealed metering compartment or pull-section of the SES. Any SSC shall be made only in the applicable Customer accessible section of the SES panel, and a label shall be placed at the SES in accordance with Section 8of this document.

(3) APS secondary electrical service conductors are not fused and can only be de-energized by APS personnel. Customer will need to contact APS to arrange for the electrical service to be de-energized prior to performing a SSC. Since APS will not re-energize the service following completion of the SSC unless an electrical clearance ("green tag") has been issued by the AHJ, it is important that Customer coordinate this work very closely with APS and the AHJ.

(4) The maximum output current nameplate rating of the Generator(s) shall not exceed the 100% continuous duty rating of the APS transformer or service run. Note that the ratings of the APS transformer and service run do not necessarily match the SES rating. APS will notify Customer if any APS equipment is over-dutied following APS review of the Interconnection Application. Any required equipment upgrades shall be performed at Customer's sole expense.

(G) A Load Side Tap constitutes a "tap" as defined by the National Electric Code (NEC), and is subject to all applicable NEC requirements and/or requirements adopted by the Authority Having Jurisdiction. In addition, the connections must comply with the APS ESRM and Good Utility Practice.

The following requirements were prepared for applications where a generator is tapped on the load side of the main service disconnect:

(1) The tap originating from the SES shall terminate at an accessible and lockable overcurrent protective device in accordance with NEC Art 240.4.

(2) For taps 10 ft. or less (distance between SES and first overcurrent device), conductors shall be sized per 2014 NEC Art 240.21(B)(1)(4).

(3) For taps 25ft. or less (distance between SES and first overcurrent device), conductor shall be sized per 2014 NEC Art 240.21(B)(2)(1).

(4) The tap shall be made without altering any factory installed bus bars or conductors unless performed by the manufacturer or its designated representative.

a. No drilling, tapping or replacing of factory installed bus bars or conductors unless performed by the manufacturer or its designated representative.

b. If lugs are replaced to accommodate additional conductors, the panel manufacturer must specify a listed kit or give written approval of the parts to be used. Appropriate torque specs shall also be provided.

c. When connecting to a field conductor a UL listed tap should be used. Breaking the conductor should be avoided – using a lay in lug is preferred. The connector's make and model number should be provided.

d. In the event a field evaluation is required in order to perform the tap connections, Customer shall provide APS the Letter of Compliance issued to the NRTL certified by OSHA to perform the evaluation (i.e. CSA, TUV, UL, etc.) as well as a photograph of the approval sticker affixed to the SES at the time the work is completed in the field.

(5) Per NEC Art 225.32, the overcurrent protective device shall be Readily Accessible.

(6) Per NEC Art 240.24(B), all overcurrent devices protecting the conductors supplying the premises shall be readable accessible to the occupant.

(7) Per NEC Art 250.122(G), the equipment grounding conductor run with the tap conductors shall be sized per the SES Main overcurrent setting but shall not be required to be larger than the tap conductors.

Note: For a typical Load Side Tap installation, APS requires a two disconnect switch configuration. The first switch is fused and constitutes the Customer Fused Disconnect Switch as required by the NEC. The second switch is the Photovoltaic System Utility Disconnect Switch required by APS.

(H) Customer is responsible for the design, installation, operation and maintenance of all equipment on Customer's side of the POI. It is strongly recommended that Customer submit specifications and detailed plans as specified in the Interconnection Application (refer to Section 17) for the installation to APS for review and written acceptance prior to ordering any equipment. Written acceptance by APS does not indicate acceptance by other authorities.

(I) While APS recommends the use of copper conductors, if Customer nonetheless elects to use aluminum conductors to connect any equipment either owned by, or placed under operational jurisdiction of APS (GF metering, Utility Disconnect Switch, etc.), then Customer must comply with the following requirements:

(1) An oxidation inhibitor must be applied to the cleaned aluminum conductor.

(2) A UL Listed 2 hole bolted lug, compression type terminal, must be used for the terminations of the aluminum conductors.

(3) Compression terminal shall clearly indicate the conductor and the die to be used on the crimping tool, and the connection shall be made in strict accordance with manufacturer specifications.

(4) Locations of aluminum conductors must be clearly identified on the Interconnection Application diagrams submitted to APS for review.

APS will not assume any responsibility for any maintenance or inspection of conductors within an APS sealed portion of the GF. It shall be the sole responsibility of Customer to schedule and arrange for any such inspection.

8.2 Disconnect Switch

Customer shall install and maintain a visual-open, manually operated, load break disconnect switch ("Disconnect Switch") that will completely open and isolate all ungrounded conductors of Customer's GF from the APS System. For multi-phase systems, the switch shall be gang-operated.

The Disconnect Switch shall comply with the following additional requirements:

(A) **Visual Open and Lockable Requirements**

The Disconnect Switch shall be visible-open such that the switch blades, jaws and the air-gap between them shall all be clearly visible when the switch is in the "open" position and the front cover of the switch box is opened. It is not acceptable to have any of the "visible open" components obscured by a switch "dead front" or an arc-shield, etc. Only switches specifically designed to provide a true "visible open" are acceptable. The switch handle shall be capable of being locked in the "open" position by a standard APS padlock with a 3/8" shank. The switch front cover shall also be capable of being locked shut via a hasp accepting a similar 3/8" shank padlock. The Disconnect Switch hasp shall not be field modified in any way.

If a second service disconnecting means is required to be installed as in the case of a supply side connection (SSC), the second service disconnect cover shall be locked closed with a customer provided lock. In the event Customer installs additional disconnect switches which are separate from the APS required Utility Disconnect Switch, the covers of any such shall be locked closed with a customer provided lock.

(B) **Switch Connection**

The Disconnect Switch shall be connected so that the blades (and any fuses if present) are de-energized when the switch is in the "open" position in accordance with NEC 404.6(C) and NFPA 70E. For example, the switch blades (load side) will be connected to the inverter side of a static inverter based circuit and the switch jaws (line side) to the utility source side.

The Disconnect Switch shall be located on the utility source side of any meter installed to measure the output of the GF Generator(s) (i.e. Production Meter).

(C) **Switch Location**

The Disconnect Switch shall be installed in a Readily Accessible location (easily accessed by APS on a 24 hour basis – refer to definition) so as to provide safe (no tripping hazards, domesticated animals or other obstructions, etc.) and easy, unrestricted and unimpeded access to APS personnel. It must be installed adjacent to the Customer's SES; however, subject to APS' express approval, it may be located in the immediate vicinity of the Customer's Generator, provided that APS' access to the Disconnect Switch is not impeded. The Disconnect Switch shall be installed in accordance with all applicable NEC and APS requirements. It shall be located between 36" and 60" measured from final grade to the center of the switch and include a minimum clear working space of 36" by 36" in front of the switch. The working space may be greater than 36" by 36" (e.g. NEC Article 110 requirements). The Disconnect Switch shall not be:

(1) located behind an electrically operated gate or door unless the electric operator is backed up by an uninterruptible power source to ensure that it can be operated in the event of a utility power outage,

(2) installed under a breezeway, patio, porch or any area that can be enclosed,

(3) installed behind a gate, fence, wall or other barrier.

NOTE: APS may grant an exception to commercial Customers who locate equipment (i.e. APS Utility Disconnect Switch) behind a locked door or gate just as long as the equipment is installed in a safe location (no tripping hazards, domesticated animals or other obstructions, etc.). In this case, APS can provide a lock-box to be installed by the commercial Customer for APS to gain access to the Disconnect Switch or any other APS equipment, the lock-box needs to be installed within 36" of the door or gate, etc., and it shall be located no less than 36" above grade and no more than 60" above grade. Indoor equipment locations require access from the exterior of the building.

(D) **Electrical Ratings**

The Disconnect Switch must be rated for the voltage and current requirements of the Generating Facility, and must be listed and conform to all applicable UL, ANSI and IEEE standards. The switch shall be rated to withstand the available fault duty current and shall not be fused, unless expressly agreed to by APS. (Reference NEC Art 110.9, NEC Art 110.10, OSHA 1910.303(b)(4) and OSHA 1910.303(b)(5)). In the case where Customer installs a fused Disconnect Switch to limit the fault current a second unfused Disconnect Switch for APS use will need to be installed subject to Section 8.2(C) above. In instances where a visible-open switch is not commercially available (e.g. due to a high system current), APS may accept a Customer installed rack-out breaker, along with a racking tool and grounding breaker (to ground the utility side) as may be required, in order to effect an electrical clearance or establish a safe working area. In these cases, APS will work with Customer to determine the best option and ensure that all appropriate safety requirements are met.

(E) **Switch Grounding**

The switch enclosure shall be properly grounded via an equipment ground wire attached to a factory provided grounding lug or an appropriately UL listed grounding lug or terminal.

In cases where the Disconnect Switch will be installed on a line at a voltage above 600V, APS has specific grounding requirements that will need to be incorporated into the Disconnect Switch in order to ground the phase conductors on the utility side of the switch when it is necessary to establish a safe working area for APS personnel. Refer to the APS ESRM for further details. APS also has certain requirements that will need to be adhered to for the purpose of obtaining electrical clearances or establishing a safe working area, including the entering into an “Operating Agreement” with Customer.

(F) **Switch Conductors**

The Disconnect Switch shall be a stand-alone device, and electrical conductors and/or cables entering into and exiting from the Disconnect Switch shall be kept physically separated and shall not be routed in the same raceway or in any way share a common enclosure.

Under no circumstances shall the Disconnect Switch enclosure be used as a conduit or raceway for any conductors other than those phase conductors being switched and the associated grounded conductor (neutral) and grounding conductor (equipment ground).

(G) **Operational Jurisdiction**

The Disconnect Switch will be placed under the operational jurisdiction of APS for systems with a line voltage of 600V or less, and the cover of such switch will be locked closed with a standard 3/8” shank APS padlock following satisfactorily completion of the APS Site Inspection.

APS shall have the right to lock open, or cause to be locked open, the Disconnect Switch without notice to Customer when interconnected operation of the Customer's GF with the APS System could adversely affect the APS System or endanger life or property, or upon termination of the Interconnect Agreement.

8.3 Dedicated Transformer

A GF with a combined total generation rating of over 10 kW may be required to be isolated from other Customers fed off the same utility transformer by a dedicated power transformer connecting to the utility distribution feeder. The primary purpose of the dedicated transformer is to ensure that (A) the generation cannot become isolated at the secondary voltage level with a small amount of other-Customer load, and (B) the generation does not contribute any significant fault current to other Customer's electrical systems. It also helps to confine any voltage fluctuation or harmonics produced by the Generator to Customer's own system. APS will specify the transformer winding connections and any grounding requirements based on the specific Customer site location and generator type.

8.4 Power Quality

In order to minimize interference on the Utility system Customer must ensure that the electrical characteristics of its load and generating equipment meet, as a minimum, the specifications outlined below.

(A) **Power Factor**

When the GF acts as a net load to the APS System, the power factor of the net load shall not be less than 90% lagging (absorbing VArs) as measured at the Point of Interconnection (POI), and shall not be leading (exporting VArs), unless agreed to by APS.

When the GF acts as a generation source to the APS System, and the nominal AC output nominal rating is less than 10 MW the power factor of the generation source shall not be less than 90% leading (absorbing VArs) as measured at the Point of Interconnection (POI), and shall not be lagging (exporting VArs), unless otherwise required by APS.

When the GF acts as a generation source to the APS System, and the nominal AC output nominal rating is 10 MW or greater the GF shall be capable of operating in any of the modes specified in Section 12.1 (Dynamic Response Requirements) of this document.

(B) **Current Imbalance**

The phase current imbalance for a three-phase system as measured at Customer's SES shall not be greater than ten percent (10%) at any time For further information refer to APS Service Schedule 1.

(C) **Harmonics**

The electrical output of Customer's GF shall not contain harmonic content which may cause disturbances on or damage to the APS System, or other Customer's systems, not limited to computer, telephone, communication and other sensitive electronic or control systems. Harmonics, as measured at the Point of Interconnection, shall not exceed the limits promulgated in the latest version of IEEE 519-1992.

(D) **Power Fluctuations**

Customer must exercise reasonable care to assure that the electrical characteristics of its load and generating equipment, such as deviation from sine wave form or unusual short interval fluctuations. It shall not result in impairment of Customer's service or service to other Customers, interference with operation of computer, telephone, television, other communication systems or facilities.

(E) **Voltage Flicker**

If Customer utilizes the APS System to facilitate start-up of its GF, the voltage flicker level shall not exceed APS standards as outlined in the latest version of IEEE 519.

(F) **Service Voltage Ranges**

Customer shall ensure its GF does not cause the RMS voltage at the Point of Interconnection to vary beyond the Favorable Voltage Service Range (Range A) of +/- 5% as specified in ANSI standard C84.1. APS will not be responsible for voltage excursions outside of this range caused by the GF.

8.5 Voltage Requirements

Customer generating equipment must be rated at 60 Hertz, and be either a single or three-phase system connected at a standard utility voltage that may be selected by Customer subject to utility availability at the premises.

The DG shall follow, and not attempt to oppose or regulate changes in the voltage at the Point of Interconnection, unless otherwise required by Section 12 of this document.

8.6 Labeling Requirements

(A) **General Requirements**

Customer shall conform to the National Electric Code (NEC), as adopted by the local Authority Having Jurisdiction, for labeling of all GF equipment, including the SES. APS will assume responsibility for labeling any utility-owned equipment. All APS-required labels shall consist of a permanently attached weatherproof/UV resistant placard, letters shall be engraved or embossed/raised, and letters will be a minimum of 1/4 inch tall unless otherwise specified by APS. If applicable, any adhesive backing shall be rated for outdoor applications in the Arizona environment with UV inhibitors. It is also acceptable to rivet labels to the applicable equipment as long as the attachment means does not violate the UL Listing of the equipment. Labels shall be made of (a) aluminum, brass or other approved corrosive resistant metal, or (b) a high density polyethylene material 55 mils thick comprised of a 35 mil black polyethylene base film capped (co-extruded) with a 20 mil color polyethylene. Labels should follow the ANSI Z535.1 -1998 color codes when applicable.

(B) **Disconnect Switch**

Customer shall label the Disconnect Switch "Generator Utility Disconnect Switch" or "Photovoltaic System, Wind Turbine, etc., Utility Disconnect Switch", as the case may be. In the event APS grants approval to install the Disconnect Switch at a location other than the electrical SES, Customer shall install a placard at the SES giving concise directions to, and the location of, the Disconnect Switch.

In the event APS allows more than one Disconnect Switch to be installed at a Customer's facility, the switches shall be labeled 1/x, 2/x, etc. where x is the total number of Disconnect Switches.

A warning label shall be mounted on the Disconnect Switch front cover with the following words: "Warning: Electric Shock Hazard. Do Not Touch Terminals. Terminals On Both The Line And Load Sides May Be Energized In The Open Position".

(C) **Production Meter**

Customer shall label the Production Meter enclosure and/or socket as "Production Meter". In the event APS grants approval to install the Production Meter at a location other than the SES, Customer shall install a placard at the SES giving concise directions to, and the location of, the Production Meter.

In the event that more than one Production Meter is installed at a Customer's facility, the meters shall be labeled 1/x, 2/x, etc. where x is the total number of Production Meters.

(D) **Service Entrance Section (SES)**

When a photovoltaic system is connected on the supply (utility) side of the SES main breaker, in accordance with the NEC and requirements specified in this document, a label shall be placed adjacent to the main service breaker stating:

"Warning: A Generation Source is connected to the Supply (Utility) Side of the Service Disconnecting Means. Follow proper Lock-Out/Tag-Out Procedures to ensure the Photovoltaic System Utility Disconnect Switch is opened prior to performing work on this device".

8.7 Protective Relaying Requirements

(A) **General Requirements**

(1) Customer shall be solely responsible for properly protecting and electrically paralleling its generator(s) and/or static inverter(s) with the APS System.

(2) For Generators, Customer facility shall include an automatic interrupting device (normally the generator breaker) that is rated to interrupt available fault (short circuit) current and is tested and certified to applicable UL standards. The interrupting device shall be directly tripped (and not via a programmable logic controller, etc.), as a minimum, by all protective devices required herein. If a Local/Remote control selector switch or any other component is wired in series with the trip and/or close circuit, said component(s) shall not impede or bypass any of the protective devices required herein, or the ability to trip/close the automatic interrupting device. Breakers downstream of the main shall have adequate overcurrent protection (i.e. 50, 51, 50N and 51N).

(3) Inherent characteristics of induction disk type voltage and frequency relays render their use unsuitable for some generator interface protection applications. Therefore, relays with definite level and timing characteristics (e.g., solid state type relays) will be necessary to meet the minimum requirements established herein.

(4) For rotating generator classes II and greater (> 50 kW) utilizing discrete relays that require both voltage and frequency relay protection, separate and

independent voltage and frequency relays and associated trip paths to the automatic interrupting device are required. This is to ensure a redundant trip function in the event of a single relay failure or out-of-tolerance condition.

It is acceptable however, for the over/under voltage functions to be integrated into a single o/u voltage relay, and for the over/under frequency functions to be integral to a single o/u frequency relay.

As an option, the frequency and voltage functions may be incorporated into a single microprocessor-based protective relay provided that the relay incorporates relay failure alarm contacts, and such output is wired to trip the automatic interrupting device upon (1) relay failure or (2) loss of power to the relay. In lieu of tripping the automatic interrupting device, and with APS approval, Customer may configure the relay to alert a 24 hour Operations Center for a relay failure condition.

(5) For rotating generator protective schemes that utilize microprocessor based, multi-function relays, the protective relay failure alarm contacts will be configured to trip the automatic interrupting device. This requirement shall also apply to any GF utilizing static inverters with an aggregate nominal nameplate rating of 1000 kW and greater.

(6) The generator protective scheme referenced in Section 8.7(A)(5) above shall be of a fail-safe design such that loss of the protection scheme control power will immediately cause the automatic interrupting device to open. Additionally, control power to the relay shall be fed via a dedicated hard-wired UPS circuit.

(7) With the addition of generation at a Customer site, ground fault current magnitude might increase to level where the existing grounding grid is insufficient to protect personnel from step or touch potentials. Customer shall ensure the adequacy of the facility grounding grid to keep any step and touch potentials at a safe level.

(8) Customer shall ensure that the GF protective relaying and controls are adequately protected from electrical surges that may result from lightning, utility switching or electrical faults.

(9) A GF utilizing a Momentary Parallel Transition transfer scheme shall install an independent backup timer that directly trips the main breaker(s) feeding the SES. The trip circuit shall not be routed through any circuits or logic scheme that could inhibit or block the trip signal, and not via a PLC, etc. Refer to Section 13.2 for additional details.

(10) A GF comprised of one or more generators with an AC continuous nameplate rating of 10 MW or greater will be required to be equipped with Automatic Voltage Regulating (AVR) capability, the capability to operate in Power Factor Control (PFC) mode, and the capability to operate in MVAR Control mode as specified in Section 12.1.

(11) Any GF comprising static inverters with an aggregate generator nominal nameplate rating of 10 MW or less and interconnecting with a Non-Dedicated Utility Feeder, shall utilize inverters that have been tested and certified to UL1741, by a NRTL certified by OSHA to perform the UL1741 test standard.

In the event APS determines additional voltage regulation is required at the POI, APS will advise Customer as to any such requirements (e.g. power factor, reactive power and/or automatic voltage regulation) and any associated set point(s) during the Interconnection Application process. Customer will be fully responsible for implementing any identified requirements.

(12) Any GF comprising static inverters with an aggregate generator nominal nameplate rating of 10 MW or less, and interconnecting with a Dedicated Utility Feeder, shall utilize inverters that have been tested and certified as specified in Section 8.7(A)(10), or Customer shall ensure, at a minimum, that the inverter performance tests specified below are performed and certified by a NRTL to ensure compliance with the following Sections of IEEE 1547-2003 (per Section 40.1 of UL 1741-2010):

Section 4.3 Power Quality

a. Section 4.3.1 Limitation of DC injection
b. Section 4.3.2 Limitation of flicker induced by the DR
c. Section 4.3.3 Harmonics

Customer shall provide APS with a copy of the test results and certification from the NRTL, for APS review and approval.

(13) Any GF comprising static inverters with an aggregate generator nominal nameplate rating of greater than 10 MW and interconnecting with a Dedicated Utility Feeder, shall be equipped to support the options specified per Section 12.1. However, Customer shall ensure, at a minimum, that the inverter performance tests specified below are certified by a NRTL to ensure compliance with the following Sections of IEEE 1547-2003 (per Section 40.1 of UL 1741-2010):

Section 4.3 Power Quality

a. Section 4.3.1 Limitation of DC injection
b. Section 4.3.2 Limitation of flicker induced by the DR
c. Section 4.3.3 Harmonics

Customer shall provide APS with a copy of the test results and certification from the NRTL, for APS review and approval.

(B) **Minimum Relaying Requirements**

(1) **Class I (Single or Three Phase: 50 kW or less)**

a. The minimum protection required for induction and synchronous generators is an under-voltage relay.
b. Synchronous generators require a synchronizing scheme, either manual with a synch check relay, or an automatic synchronizer.
c. Static inverters shall be tested and certified to UL 1741, by a NRTL certified by OSHA to perform the UL1741 test standard.

(2) **Class II (Three Phase: 51-300 kW)**

a. The minimum protection required for induction and synchronous generators is under-voltage, over-voltage, under-frequency, and over-frequency.

b. Synchronous generators require a synchronizing scheme, either manual with a synch check relay, or an automatic synchronizer.

c. Inverters shall be tested and certified to UL 1741, by a NRTL certified by OSHA to perform the UL1741 test standard, unless otherwise provided for in Section 8.7(A).

d. For installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a ground fault detector may be necessary. APS will advise Customer of any such requirements after a preliminary review of Customer's proposed installation.

e. Other equipment such as supervisory control and alarms, telemetering and associated communications channel may be necessary. This is especially the case when the generator, or an aggregate of generators, is large relative to the minimum load on a feeder or sectionalized portion thereof. APS will advise Customer of any communications requirements after a preliminary review of the proposed installation. Refer to Section 11 for more details.

(3) **Class III (Three Phase: 301-5,000 kW)**

a. For this class of installation, utility grade protection devices and equipment are required.

b. The minimum protection required for induction and synchronous generators is under-voltage, over-voltage, under-frequency, over-frequency, and negative sequence time overcurrent.

c. Synchronous generators require a synchronizing scheme, either manual with synch check relay, or an automatic synchronizer.

d. Static inverters shall be tested and certified to UL1741, by a NRTL certified by OSHA to perform the UL1741 test standard, unless otherwise provided for in Section 8.7(A).

e. A redundant over/under voltage relay will be required for static inverters with an AC output nominal rating of ≥1000 kW, or whenever the aggregate inverter AC output nominal rating of a GF ≥1000 kW.

f. For installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a ground fault detector may be necessary. The utility will advise Customer of any such requirements after a preliminary review of Customer's proposed installation.

g. Other equipment such as supervisory control and alarms, telemetering, and associated communications channel may be necessary. APS will advise Customer of any requirements after a preliminary review of the proposed installation. Refer to Section 11 for details.

(4) **Class IV (Three Phase: Greater than 5,000 kW)**

NOTE: Induction Generators or Line Commutated Inverters in this size range are not anticipated.

a. For this class of installation, utility-grade protective devices and equipment are required.

b. Relays for under-voltage, over-voltage, under-frequency, and over-frequency are required.

c. Synchronous generators require a synchronizing scheme, either manual with synch check relay, or an automatic synchronizer.

d. A ground time overcurrent and ground instantaneous overcurrent relay, or for installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a ground fault detection scheme is required.

e. The following protective functions are also required:

   i. Voltage-controlled time overcurrent

   ii. Loss of excitation

   iii. Over-excitation

   iv. Negative sequence time overcurrent

f. Other equipment such as supervisory control and alarms, telemetering, and associated communications channel are generally required. APS will advise Customer of any such requirements after a preliminary review of the proposed installation. Refer to Section 11 for further details.

The minimum protective relaying requirements for parallel operation of distributed generation are summarized in the table below. An exception to the relaying requirements on the following table may be made for Momentary Parallel Transition systems – refer to Section 13.2 for applicable requirements.

Note that depending on the specific application of the GF, a Reverse Power relay may be required. APS will advise Customer of any such requirement after a preliminary review of the proposed installation.

Summary of Minimum Protective Relaying Requirements

	Induction Generator	Synchronous Generator	Static Inverter
Class I 50 kW or less	Undervoltage	Undervoltage, Synchronizing	UL 1741*
Class II 51 to 300 kW	Overvoltage, Undervoltage Overfrequency, Underfrequency	Overvoltage Undervoltage, Overfrequency, Underfrequency Synchronizing	UL 1741*
Class III 301 to 5,000 kW	Overvoltage, Undervoltage Overfrequency, Underfrequency Negative Sequence Time Overcurrent	Overvoltage, Undervoltage, Overfrequency, Underfrequency Synchronizing Negative Sequence Time Overcurrent	*UL 1741 with redundant Over/Under voltage for > 1000 kW
Class IV Greater than 5,000 kW	No induction generators of this size anticipated	Overvoltage, Undervoltage, Overfrequency, Underfrequency, Synchronizing, Ground Time Overcurrent, Ground Instantaneous Overcurrent, Voltage-controlled Time Overcurrent, Loss of Excitation, Overexcitation, Negative Sequence Time Overcurrent	**No individual inverters of this size anticipated. Refer to Sections 8.7(A), 11, and 12 for additional GF aggregate requirements.

*Inverters shall be tested and certified to UL1741 unless the requirements specified in Sections 8.7(A) and 12.1 apply. Redundant O/U voltage protection is required for individual inverters with an AC output nominal rating of ≥1000 kW, or whenever the aggregate inverter AC output nominal rating of a GF is ≥1000 kW. Such protection shall be applied to one or more breakers external to the inverter(s).

**For utility scale installations utilizing static inverters with an aggregate AC output nominal rating of ≥10 MW a redundant O/U voltage and O/U frequency protection will be required. Such protection shall be applied to one or more breakers external to the inverter(s) (i.e. the main GF breaker(s)). Refer to Section 11 for further details.

(C) **Relay Settings**

NOTE: Voltage and frequency relays needed for minimum interface protection for all classes will have setting limits as specified below with exception to Generating Facilities subject to PRC-024-1 Frequency and Voltage Ride Through Requirements, Section 12.2.

(1) Under-voltage relays will operate at no less than 80% of the nominal voltage level and will have a maximum time delay of 1.0 seconds.

(2) Over-voltage relays will operate with a maximum time delay of 1.0 seconds for a voltage range of higher than 110% and less than 120% of nominal voltage. The relay will operate instantaneously at 120% or higher of nominal voltage to provide a maximum clearing time of 10 cycles.

(3) Under-frequency relays will operate at no less than 58 Hz and have a maximum time delay of 1.0 seconds.

(4) Over-frequency relays will operate instantaneously at any frequency higher than 60.5 Hz to provide a maximum clearing time of 10 cycles.

(5) Additional settings for Class I, II, III & IV installations and/or any other relays that may be required due to unusual circumstances will be handled on an individual basis.

9 METERING REQUIREMENTS

This Section applies to any Generating Facility that electrically parallels with the APS System other than a Backup Generator.

9.1 Service Entrance Section Metering

Customer must provide and install, at Customer's expense, meter sockets and metering cabinets in accordance with APS service standards, in Readily Accessible locations acceptable to APS, to accommodate any meter(s) that are required by applicable rate schedule(s) or other APS agreement (e.g. Totalized Metering) or other APS requirements (e.g. EMS Meter). Such standards are specified in the APS Electric Service Requirements Manual (ESRM), available at the following website: http://www.aps.com/esrm

Metering Installation Requirements are addressed in Section 300 of the ESRM.

APS will furnish, own, install and maintain meter(s) located at the GF SES as required by APS, and any meter(s) that may be required by the applicable electric rate schedule to measure the output of the Generator(s). The responsibility for the costs of providing and maintaining any required meters and communication circuitry as required will be specified in the applicable rate schedule or other APS agreement. Refer to Section 9.3 of this document for Metering Communication requirements.

Any Metering provided by APS as described in this Section shall be located in appropriately sealed compartments, and no Customer wiring, connections, or equipment is permitted in any such APS sealed metering compartment or pull-section of the SES.

9.2 Production Metering Requirements

All Generating Facilities other than those comprising a Backup Generator must include provisions to allow APS to install an AMI type Production Meter (or Meters as the case may be). This Metering shall be configured so as to measure and record the AC energy production of the Generator(s).

The Production Meter enclosure and associated equipment must be installed in compliance with Section 300 of the APS Electric Service Requirements Manual (ESRM), available on APS' website. A valid neutral is required for APS Metering to work properly.

Until such time that APS installs the APS-owned Production Meter, Customer has the option of either installing a Customer-owned "test meter" or an approved meter cover over the meter socket. **Under no circumstances is the meter socket to be left open or otherwise exposed at any time.** Once Customer notifies APS that the GF is ready for the APS site inspection and/or Production Meter installation, APS will schedule the installation of its Production Meter. APS will then remove any Customer installed test meter(s) or meter cover(s), install an AMI type Production Meter along with any associated metering equipment, and seal the meter socket ring and metering enclosure.

An approved meter cover will be a commercially available meter cover designed and approved by the manufacturer for outdoor use on meter sockets. It shall be constructed of materials such as fiberglass, rigid plastic, and glass. Note that a cardboard cover (typically used for shipping purposes) is not an acceptable material. The meter cover shall be properly installed and sealed to the meter socket

Under no circumstances shall any metering enclosure be used as a raceway for any conductors other than those phase conductors being metered and the associated grounded conductor (neutral) and grounding conductor (equipment ground).

For Current Transformer (CT) rated installations (greater than 200A), APS will install the Production Meter, CTs, any PTs, test switches and required wiring. Customer shall be responsible for installing, in accordance with APS' requirements a ring type production metering enclosure with meter socket. Customer shall adhere to the following additional requirements regarding production metering enclosures:

(A) For Secondary Voltage systems (phase to phase voltage less than 600V) of 200A and less, Customer shall provide a ring type self-contained metering enclosure and a meter per the APS ESRM. Note that safety test blocks are not required for commercial (or residential) installations. For Secondary Voltage systems greater than 200A (with phase to phase voltage less than 600V), Customer shall provide a ring type CT rated enclosure per the APS ESRM.

(B) For Medium Voltage Systems (phase to phase voltage 600V and higher), Customer shall provide a medium voltage lineup along with grounding provisions per the APS ESRM.

(C) For Static Inverter based battery backup systems, Customer shall provide production metering provisions in accordance with APS Sample Diagrams. The APS Sample Diagrams can be downloaded at www.aps.com/dg. In some cases based on the inverter technology and/or GF configuration two or more ring-type metering sockets/enclosures must be provided and installed by Customer.

(D) Production Meter enclosures/sockets shall be labeled in accordance with Section 8.6 (C) of this document.

Customer shall provide and maintain communication circuitry depending on the applicable rate schedule or other APS agreement. Refer to Section 9.3 of this document for Metering Communication requirements.

All CT rated metering enclosures shall have the bus identified with reference to the generation source side prior to metering installation with a temporary tag labeled "Generation Source".

Customer must provide a suitable visual-open disconnecting means, subject to APS' approval, to electrically isolate any Current Transformer (CT) rated meter from all potential sources of power. For meters installed on systems with a phase to phase voltage of 600V or higher, suitable grounding provisions shall also be required in accordance with the APS ESRM (Section 1100) and subject to APS approval.

Exception: For static inverter based systems certified to UL1741, all CT Rated Production Meters with phase to phase voltage less than 600V may, in place of a visual open switch, utilize circuit breaker(s) or disconnect switch(es) with locking provisions in order to isolate the Generator source side of the CT Rated Metering Equipment subject to APS review and approval. APS will not accept electronic disconnect devices (i.e. push-button type). The exception does not preclude the need for a visual open Disconnect Switch on the Utility side of the CT Rated Production Metering Equipment required per Section 8.2. If the Generator source side AC isolation device is not located within the same work space as the CT Rated Production Metering, Customer shall provide a placard with explicit directions as to the location of the Generator source side isolation device.

All CT rated metering enclosures shall be submitted by equipment manufacturer to the APS Meter Shop for review and approval in accordance with the APS ESRM. Submittal shall clearly indicate the points of connection of the Utility and Generator sources.

In order to submit to the APS Meter shop, do the following:

- E-mail shop drawings of the metering enclosure to: submittals.metershop@apsc.com
- Reference the GF System Address and GF System Type (wind, photovoltaic, induction generator, synchronous back-up generator, etc.).

Such metering enclosure shall be tested and marked to withstand the available short circuit current (Reference NEC Art 110.9, NEC Art 110.10, OSHA 1910.303(b)(4) and OSHA 1910.303(b)(5)).

Production Meters shall be installed in a Readily Accessible location (available 24 hours) to provide safe (no tripping hazards, domesticated animals or other obstructions, etc.) and unrestricted access to APS personnel per APS Requirements. This includes but is not limited to Section 300 of the APS ESRM ("Electric Service Requirements Manual") and Service Schedule 1 ("Terms and Conditions for Standard Offer and Direct Access Services"). Customer provided metering enclosures shall be installed adjacent to Customer's SES unless otherwise approved by APS. The Production Meter shall not be:

(1) Located behind an electrically operated gate or door unless the electric operator is backed up by an uninterruptible power source to ensure that it can be operated in the event of a utility power outage.

(2) Installed under a breezeway, patio, porch or any area that can be enclosed.

(3) Installed behind a gate, fence, wall or other barrier.

NOTE: APS may grant an exception to commercial Customers who locate equipment (i.e. APS Production Meter) behind a locked door or gate just as long as the equipment is installed in a safe location (no tripping hazards, domesticated animals or other obstructions, etc.). In this case, APS can provide a lock-box to be installed by the commercial Customer for APS to gain access to the Production Meter or any other APS equipment, the lock-box needs to be installed within 36" of the door or gate, etc., and it shall be located no less than 36" above grade and no more than 60" above grade. Note that any indoor equipment locations require access from the exterior of the building.

9.3 Metering Communication

Where the applicable rate schedule or other APS agreement requires billing meter(s) to be installed on the output of the facility Generators, Customer will provide acceptable meter sockets and/or enclosures in accordance with the APS ESRM. APS will install AMI meters to measure the output of the Generators. For Generating Facilities 1MW and greater, APS has additional requirements for metering and associated communication. Refer to Section 11.4(3) of this document for more information.

In the event that it is not possible to install AMI meters, Customer will be required to provide a dedicated analog dial tone phone line to each Production Meter and also to the GF SES utility meter(s) and/or sub meters if necessary. Each dedicated phone line is to be landed on the APS-provided telephone interface module, normally located within two feet of the meter. The phone line is referred to as a Single Business Line, Type 1FB, and should be ordered with NO additional features such as Call Waiting, Call Transfer, Call Hold, Message Waiting, etc., and no long distance service.

For network systems with IPBX or VoIP, an IP to analog (or gateway) device with modem pass through capabilities shall be installed by Customer and shall support analog modem service of 56kBps and higher. The IP to analog device shall also support CCITT V.90 and CCITT V.92 standards, and lower.

Customer is responsible for paying monthly fees for dedicated analog phone lines. In the event phone service is disrupted, Customer is responsible for resolving the issue.

Customer will be advised at time of application if APS has additional requirements for production metering and/or communication circuitry.

9.4 Third Party Customer Metering

If Customer installs third party metering equipment, Customer shall ensure that no wiring, or other Customer-owned equipment enters into any APS sealed compartment or enclosure. **Customer-installed meters and associated equipment installed to measure Generator output shall be located on the Generator side of APS' Production Meter. Third party metering equipment must be clearly labeled to distinguish it from the APS Production Metering equipment.** Refer to the Example Equipment Tags located at www.aps.com/dg.

Any connections made on the Generator side of the Production Meter in order to accommodate third party metering or monitoring equipment shall be of negligible load so as to not affect the GF output as measured on the Production Meter.

10 RATE SCHEDULES APPLICABLE TO DISTRIBUTED GENERATION

10.1 APS Rate Schedules

The rate schedules shown below are applicable to Customer owned generation that electrically parallels with the APS electric distribution system. Note that participation under a particular rate schedule is subject to the Generating Facility qualifying for that schedule.

- EPR-6, "Rates for Renewable Resource Facilities for Partial Requirements"

  This rate schedule requires a bi-directional meter to be installed at the SES to effect Net Metering. Bi-directional metering is currently not available to Customers participating in Totalized Metering under Service Schedule 4.

- EPR-2, "Purchase Rates for Qualified Cogeneration and Small Power Production Facilities under 100kW Receiving Partial Requirements or Interruptible Service."

- E-56, "Partial Requirements Service"

  Rate schedule E-56 is applicable to Customers installing generation equipment with a nameplate AC output rating of greater than 100 kW. (Customer should consider qualifications for the EPR-6 and E-56 R rates before selecting the E-56 rate).

- E-56 R, "Partial Requirements-Renewable"

  Rate Schedule E-56 R is applicable to Customers installing solar/photovoltaic, wind, geothermal, biomass and biogas generation systems with a nameplate AC output rating of greater than 100 kW. (Customer should consider qualifications for the EPR-6 rate before selecting the E-56 R rate).

The above rates can be accessed at the following website:
http://www.aps.com/en/ourcompany/ratesregulationsresources/serviceplaninformation/Pages/business-sheets.aspx
The rates specified above do not apply to backup or standby generation that is used solely for emergency purposes, and that parallels with the utility for brief periods in order to effect a power transition from the utility to the backup generation and vice versa.

10.2 Rates Disclaimer

(1) APS electric rates, basic charges and service fees are subject to change. Future adjustments to these items may positively or negatively impact any potential savings or the value of Customer's GF.

(2) Customer will be responsible for paying any future increases to electric rates, basic charges or service fees from APS.

(3) Customer's GF is subject to the current rate schedules, rules and regulations established by the ACC. The ACC may alter its rules and regulations and/or change rates in the future which could directly impact the economics of Customer's GF.

(4) APS and/or the ACC do not sponsor or approve any future electric rate projections presented to Customer. These rates are based on projections formulated by external third parties not affiliated with APS and/or the ACC.

11 ADDITIONAL REQUIREMENTS FOR GF ≥ ONE (1) MW

This Section covers additional requirements that apply to any one GF or aggregate of GFs with a combined AC nominal nameplate output rating of 1 MW or greater, interconnected with the APS System for Continuous Parallel operation.

The 1 MW threshold applies to one or more Generators (a) connected to any single APS metered point of electric service delivery or (b) connected to multiple metered points of electric service delivery connected to a single APS System Source Device.

A GF with an aggregate generator nominal nameplate AC rating of less than 1 MW will not typically need to incorporate the requirements specified in this Section. However, depending on the GF's impact to the APS System, APS may require the GF to incorporate one or more of the requirements outlined in this Section.

APS will identify the actual requirements, and the optimum method of implementation, normally as part of the Interconnection Study (refer to Section 16.6). APS can also assist Customer in addressing any design requirements prior to submitting an application and drawings for review.

11.1 Transfer Trip

(1) A Transfer Trip scheme will normally comprise a relay located at the APS substation feeder breaker which communicates via fiber optic cable with a relay located at the GF along with associated control circuits. Whenever the APS substation breaker opens, a trip signal is sent to the GF to automatically trip the generation off line.

(2) If GF is fed from a Dedicated Utility Feeder, and it is determined during the interconnection review process that a transfer trip scheme is needed, APS will require Customer to install a relay and communication link that interfaces with the APS substation relay. In the event that a transfer trip is required, Customer will need to install and maintain a Schweitzer SEL 351-7 relay for transfer trip control of the Generator breaker along with the associated instrumentation transformers and circuitry. APS will install, at Customer's expense, a SEL 351-7 relay at the APS substation.

(3) In accordance with the APS ESRM, APS will provide Customer with the overcurrent relay settings (50, 50N, 51, and 51N) for the SEL 351-7 relay located at the GF for coordination with the SEL 351-7 relay at the APS substation. Customer will activate device functions 27 (Undervoltage), 59 (Overvoltage), and 81 O/U (Over/Under Frequency) in the SEL 351-7 relay located at the GF with trip set points in accordance with Section 8.7(C) of this document. Customer shall incorporate a relay failure alarm in accordance with 8.7(A)(5) of this document. Customer will submit settings for APS review and approval.

(4) In the event that there is a loss of Mirrored Bits communication between the APS Substation relay(s) and GF relay(s), the GF breaker(s) shall trip open via the GF relay(s) settings. It is acceptable to add a 15 cycle delay for loss of Mirrored Bits within the GF relay(s) settings to avoid nuisance trips.

11.2 Remote Trip

(1) A Remote Trip is a manual trip signal issued by the APS Control Center to trip the generation off line and isolates it from the APS Distribution System. This signal will normally be communicated via fiber optic cable originating at the APS substation or communicated via a VG36 leased telephone line provided by the local telephone company. It will generally trip the generator breaker(s) via a Customer installed breaker control circuit.

(2) A GF with an aggregate generator nominal nameplate rating less than 1 MW will not typically require remote trip capability specified. However, depending upon the GF's impact on the APS System, APS may require remote trip and remote monitoring capability.

(3) The Remote Trip function will be accomplished via a Remote Terminal Unit (RTU) provided by APS at Customer's expense and installed by Customer at Customer's Facility.

(4) For a GF comprising static inverters located on a non-Dedicated Utility Feeder, should APS need to switch the section of the normal feeder on which the GF is located, to another feeder for line/breaker maintenance, feeder sectionalizing/switching, and/or load transfer operations, APS reserves the right, without liability, to remotely trip the GF off-line for the duration of any such operation.

(5) If adverse operating conditions occur on the APS System due to the GF, APS reserves the right to open the Generator breaker without notice until such conditions are addressed. Customer will assume full responsibility for the inverters shutting down in accordance with UL1741/IEEE1547 in the event of a utility outage or system fault.

(6) For a GF located behind a primary meter on a Dedicated Utility Feeder, an exception to the remote trip requirements may be granted by the Energy Delivery Compliance Committee (EDCC). APS Planning, Operations and Interconnection Engineering shall mutually agree to submit the exception request to EDCC prior to the request submittal. Remote monitoring or GF production data in 15 minute intervals may still be required.

11.3 Remote Monitoring

(1) The GF shall be equipped for remote monitoring by the APS Control Center. APS will install, at Customer's expense, an EMS Meter (in addition to the billing meter) along with communication wiring in the SES incoming metering section to provide instantaneous Watts, kVA, VARS, Volts Power Factor, Amps and cumulative kWh readings to the RTU.

(2) For all installations, Customer must provide two meter sockets and two sets of test switches at the SES metering compartment in accordance with the APS ESRM – one set for the EMS Meter and the other for the billing meter. APS may elect to temporarily install, and at APS' expense, transducers in place of the EMS Meter, in the event this meter is not available at the time of the GF start-up. Once the EMS meter becomes available, APS will coordinate with Customer to install it and remove the transducers.

(3) For Behind the Meter applications, in addition to metering located at the SES as required per section 11.3(1) above, a meter is required to be installed to monitor the Generator output, Customer will provide a metering section in accordance with the APS ESRM. APS will install, at Customer's expense, an EMS meter along with communication wiring in the metering section to provide instantaneous Watts, VARS, Volts and cumulative kWh readings to the RTU.

(4) Customer will provide hard-wired open/close contact (b contact) status points and control wiring to the RTU for any breaker with Remote Control capability by APS so that APS can monitor the status of this breaker remotely.

11.4 Technical Details

(1) At Customer's expense, APS will provide, operate and maintain an RTU. Customer shall install the RTU enclosure as provided by APS, and APS will install and program the RTU. Customer shall provide a 120 VAC, 15 Amp (minimum) power supply to the RTU, and shall install 2" rigid metallic conduits for all required circuits associated with the RTU. The 120VAC/15A circuit must be from a dedicated feed upstream from the Generator breaker, so it remains energized in the event the Generator breaker is open. The RTU and associated equipment installed at the GF must be located at a Readily Accessible location (available 24 hours) for APS personnel. For all PPA/Customer Owned GF, the dedicated 120 VAC circuit shall not be backed up via Customer provided UPS.

(2) The RTU will be housed in an enclosure along with an appropriate communication device (e.g. fiber converter, or modem as specified by APS), and battery backup system. The RTU enclosure typically measures 36"X30"X10", and is a NEMA 3R outdoor rated cabinet. Additional RTUs may be required if a single RTU cannot be located in the immediate vicinity of the SES and any required metering on the generation output. The top of the RTU cabinet shall not exceed more than 6' from final grade.

(3) Customer is responsible for securing a communication path back to the APS communication system (e.g. fiber optic back to APS Substation or VG36 leased line via the local telephone company). Any VG36 leased line shall be a Class B, Type 3, and Full Duplex Data Circuit with sealing current, 1200 Baud. Customer shall provide a leased data quality VG36 phone line from the RTU through the Telco Point of Presence (POP) network to APS designated location. Customer is responsible for paying the monthly service fee for the communication path. In the event the communication path is disrupted for any reason, Customer is responsible for remedying the issue.

In some instances, APS may provide a communication path back to the APS communication system via a MAS radio. Customer will be responsible for all associated costs, and shall also provide a location to install antennas tall enough to provide line of site from the MAS radio antenna to APS communication towers in the area.

(4) In the case the communication system located at the APS Substation (or designated APS location) communicating back to the APS EMS system cannot support the additional data points, Customer will be responsible for upgrading the communication path. The cost of any communication upgrades, and the monthly service fee will be passed on to Customer.

(5) Equipment and means of completing the communication path will be determined by APS and communicated to Customer during the Interconnection Study process (refer to Section 16.6).

(6) Customer will provide, install and maintain Generator breaker control circuitry ("Breaker Control Scheme") that will accept two remotely initiated control functions from the APS EMS system through the APS RTU (for each generation breaker). If a Local/Remote control selector switch or any other component is installed and wired in series with the trip and/or close circuit associated with the Generator Breaker, the APS remote trip & block close/close permissive control circuit must not be impeded. APS must be able to remotely trip the Generator breaker open regardless of the position of the Local/Remote control switch.

i. Trip Function: Contacts will close momentarily when APS issues a trip command through the RTU.

The trip function contacts within the APS RTU are "dry" (not powered). Maximum ratings for the contacts on the trip relay in the APS RTU are as follows:

- 10A, 120VAC
- 3A, 125 VDC
- 10A, 28VDC

ii. Remote Close Function: Contacts will close momentarily when APS issues a remote close command through the RTU.

The close function contacts within the APS RTU are "dry" (not powered). Maximum ratings for the contacts on the trip relay in the APS RTU are as follows:

- 10A, 120VAC
- 3A, 125 VDC
- 10A, 28VDC

Note: Remote Close Function is only required for APS Owned projects with an RTU. Customer may opt to install a separate remote close scheme for Customer owned GFs.

iii. Block Close / Close Permissive Function: Contacts will latch in the open position when APS issues a block close command. Contacts will latch in the closed position when APS removes the block close, i.e. issues a close permissive.

The generator breaker control logic will allow Customer to operate associated breaker. However it will be necessary for APS enable the close permissive first, allowing Customer to close the breaker.

Note: The only acceptable means by which the GF breaker(s) is permitted to be closed shall be via the breaker control circuitry (locally or remotely). Circumventing the breaker control circuitry by manually closing the GF breaker(s) for purposes of energizing the GF is not allowed by APS. Customer shall disable manual closure of the GF breaker(s) by installing a mechanical blocking accessory (i.e. close defeat cover plate) or other means acceptable to APS.

The block close function contacts within the APS RTU are "dry" (not powered). Maximum ratings for the contacts on the block close relay in the APS RTU are as follows:

- 10A, 120VAC
- 0.5A, 125 VDC
- 10A, 28VDC

Customer is responsible for providing an interposing relay and any associated power source if needed to ensure that the APS RTU contact ratings are not exceeded.

Depending on the GF system configuration, these functions may be applied to either individual Generator breaker within Customer gear or to a single main Generator breaker for the GF in order to isolate the Generator(s) from the APS System.

Note: APS will provide a "wetting" voltage of 24 VDC for Customer generation breaker status contacts. APS will require an AC/DC schematic diagram for the Breaker Control Scheme as part of final interconnection diagram submittal showing terminal connections and sequence of operations of the Trip and Block Close/Close Permissive functions.

(7) APS can provide upon request sample diagrams showing typical RTU/Communication requirements. These requirements must be incorporated on the final Electrical One-Line Diagram required for APS interconnection review.

(8) Customer shall include an Uninterruptable Power Supply (UPS) or battery bank with a DC to AC inverter for any required Breaker Control Scheme and any SEL 351-7 relay to be operational if the normal power source should fail. The UPS shall be capable of supplying backup power for at least six continuous hours and shall be hard-wired (a "plug in" UPS is not acceptable).

(9) Customer will perform periodic maintenance on the UPS batteries to ensure that it remains in operational condition at all times. Documentation shall be provided that the UPS has been tested and is operational as part of the APS final inspection.

11.5 Project Details

(1) Circuit requirements are dependent on generation size and all system additions and system improvements to meet the needs of Customer for its DG installation. Any additions/improvements to the APS System as a result of the DG installation will be expensed to Customer. A cost summary will be provided to Customer as part of the Interconnection Study.

(2) The materials required for the RTU and specialized metering are long lead time items taking as long as 4 months to receive. APS cannot allow Customer to place the GF on-line until after all APS and Customer required work outlined in the Interconnection Study has been completed and all applicable requirements being implemented as delineated in APS Interconnection Requirements.

(3) Customer is advised to communicate need dates to APS as soon as practically possible so as to avoid project delays.

(4) A communication shelter may be required (specifically for APS owned projects) to house the Supervisory Control and Data Acquisition (SCADA), communication, and any security equipment. At Customer's option, a second service can be provided at the applicable retail rate and system voltage for the communication shelter electrical service. In such cases, APS will coordinate the RTU and associated communication equipment arrangement and installation details with Customer.

(5) The communication shelter will be provided and installed by Customer. Customer shall provide and install instrumentation racks inside the communication shelter. Racks shall be properly grounded utilizing #4/0 copper wire. A GPS clock shall also be provided and installed by Customer (i.e. Arbiter Systems 1094B GPS Substation Clock). Customer shall provide time synch from the GPS clock to the protective relays installed at the medium voltage switchgear.

(6) If a communication shelter is required APS suggests ample time be allotted for ordering, delivering, and installation of the communication shelter and associated equipment. All conduits, wiring, and components related to the SCADA, communication, and any security system shall be installed prior to final commissioning. APS will provide additional details during the construction phase.

(7) Any proposed generation 1 MW and greater will normally require an APS Site Impact Study (SIS) to determine the impact to the APS System. Please refer to Section 16.6 of the APS Interconnection Requirements for additional details. Depending on the results of the SIS, APS may require a Dedicated Utility Feeder. The following are potential triggers used to determine the need for a Dedicated Utility Feeder:

  a. A GF greater than ½ of a typical APS distribution feeder rating.
  b. In Metro, the typical distribution feeder rating is 13 MW/MVA, but the rating could be less in State Region depending on the area.
  c. A Rotating Machine (i.e. synchronous generator) normally 1MW and greater.
  d. If it is determined that the DG penetration limits of the distribution feeder will be exceeded.
  e. The aggregated generation (including the GF) shall not exceed 50% of the distribution feeder's continuous rating.

(8) The Customer is expected to pay the cost for designing, installing and maintaining the installation of a Dedicated Utility Feeder interconnecting to the APS System.

(9) Refer to Section 16.10 for Application and drawing review time frames for systems 1MW and larger.

12 ADVANCED GRID SUPPORT FEATURES

The requirements outlined in this Section apply to any GF with an aggregate nominal nameplate AC output rating of 10 MW and greater, interconnected with the APS System and configured for Continuous Parallel Operation. These requirements are in addition to those specified in Sections 8 and 11 of this document. Note that any GF of this rating will require an Interconnection Study per Section 16.6 of this document.

A GF with an aggregate generator nominal nameplate AC rating of less than 10 MW will not typically require the Operational Control Modes specified in this Section. However, depending upon the GF's impact to the APS System, APS may require the GF to operate in one or more of the modes specified in Section 12.1(A)(1), (2) and (3) below. Any such requirements will be identified in the Interconnection Study or as otherwise determined by APS.

<u>Note:</u> Operating a GF at other than unity power factor may result in a reduction of real power output. APS strongly recommends that Customer take this into consideration during the GF design. Additional Generator nameplate capacity may need to be installed at the GF to achieve a specified real power output when operating in the control modes specified below.

12.1 Dynamic Response Requirements

(A) Operational Control Modes:

Any GF with an aggregate generator nominal AC nameplate rating of 10 MW and greater, shall be capable of meeting all of the operational/control modes specified below. As part of the Interconnection Study, APS will specify whether these operational/control modes shall be measured at the SES or POI.

(1) Capability to operate in Power Factor Control ("PFC") mode at a fixed power factor within the range of plus or minus 0.95 pf at any power output level up to the maximum rated MW output of the GF.

<u>Customer shall set the GF to operate at the APS default setting of 0.98 leading (absorbing VARS at the GF) unless a different set point or operating mode is specified by APS. It is acceptable for Customer to achieve this default setting at the Generator output terminals.</u>

The reactive power level calculated at 0.95 power factor (either lagging or leading) with the GF producing full rated real power output represents the required reactive power capability of the GF. The GF must be capable of delivering or absorbing this amount of reactive power at the POI in any of the active control modes specified in this Section.

(2) Capability to operate at any fixed reactive power ("MVAR") output at any power level within the full reactive power range calculated in 12.1(A)(1) above while the GF is producing power.

(3) Capability to operate in Automatic Voltage Regulating ("AVR") mode to regulate the voltage to a selected voltage set point within a voltage range of 0.95 pu to 1.05 pu, to the extent that such voltage regulation can be achieved with the available reactive power calculated in Section 12.1(A)(1).

Voltage regulation shall be within 0.50% of the voltage set point.

From time to time, APS will specify whether Customer will operate the GF in PFC, MVAR or AVR mode, and APS will specify the associated set point. Such specification may be based upon the results of the Interconnection Study and/or changes to, or conditions arising on, the APS System.

(B) Controller and System Performance Requirements:

(1) The GF shall incorporate a suitable controller (e.g. "Power Plant Controller" or "Dynamic Reactive Device") capable of operating/controlling the GF in all of the modes specified in Section 12.1(A)(1), (2), and (3) above.

(2) Upon the controller receiving a step change in a reference point value, it shall drive the plant output to 90% of the new reference point value within 4 seconds of receiving the step input, and shall settle/damp out to a final value within 8 seconds of step input irrespective of operating mode.

(3) Customer shall provide written control system specifications which shall include an executive summary as to how the control system works and meets APS requirements noted, bill of materials, control system block and single line diagram(s) and the anticipated performance parameters for APS review and acceptance.

(4) Customer shall provide a written performance testing procedure as part of the drawing and application submittal. A sample procedure and/or checklist may be provided by APS.

(5) Once the GF is on-line at full power output, Customer shall be ready to complete performance testing of the GF within ten (10) business days. Customer will contact APS to coordinate scheduling the performance testing on mutually agreed upon date(s). In the event APS personnel are not available to witness any/all performance testing, Customer shall provide a certified test report and supplemental information demonstrating conformance to APS requirements noted herein for APS' review and acceptance.

A supplemental document outlining Dynamic Voltage/VAR Response Testing Procedures is available at:
http://www.aps.com/library/solar%20renewables/SupplementalDynamicVoltVARGuide.pdf

(6) In the event of a control system failure, (eg. loss of communication) the GF shall be configured to revert to the default setting as specified in 12.1(A)(1). APS must be notified as soon as possible in the event of a control system failure, but no later than the following business day.

Note: For a Static Inverter based GF, if plant-wide power factor control were to fail (e.g. due to a blown PT fuse), the GF may revert to inverter-controlled fixed power factor mode with a local power factor setting of 0.98 leading.

(7) The control system shall be designed to allow its performance to be evaluated in all three of the operating control modes specified above by inputting a reference step change into the controller. In the case of the AVR mode, the step change shall constitute a change to the plant's desired output voltage set point. Figure 1 below depicts the typical response of a plant control system to a step change at time t1.

Note: There may be a time delay after t_2 expires before the plant output begins to respond to the step input. The time t_3 to reach 90% of the final output value is noted on the plot as well. After the output has attained 90% of its final value, there may be some overshoot and oscillatory response until the plant output settles out to its final value at t_4. There will be a small difference between the final value and the desired value specified by the setpoint. This difference is expressed as a percent error band referenced to the desired setpoint versus the actual final value.

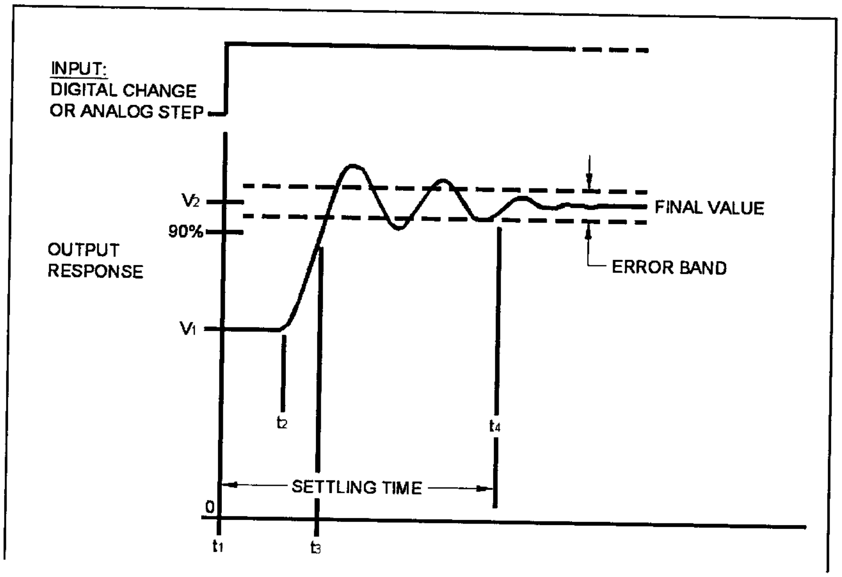

Figure 1 – Generalized Plant Response to a Reference Step Input Change

(8) If APS contacts Customer to change the operating mode or set point, Customer will implement request within four (4) hours if request is made between the hours of 6:00 am to 4:00 pm. If request is made outside these hours, request must be implemented by 8:00 am the following morning. Any such request will be made by the APS Energy Control Center (ECC).

12.2 NERC Standard PRC-024-1 Frequency and Voltage Ride-Through Requirements

The requirements outlined in NERC Standard PRC-024-1 ("Standard") apply to any GF interconnected to the APS System with an aggregate nominal nameplate AC output rating of 10 MW or greater. APS may grant an exception to a GF interconnected to a non-dedicated distribution feeder. Refer to NERC Standard PRC-024-1 for more details. As a system, the entire GF must ride through the disturbances described in this Standard. This includes but is not limited to relay settings, Static Inverter ride through settings and in the case of synchronous generators, the excitation system settings.

GFs subject to this Standard shall submit documentation depicting individual systems' Frequency Capability Curves, Trip Times, Voltage Ride-Through Time Duration Curves and any other information explaining how the GF meets the Standard. Customer shall provide an overlay of voltage and frequency ride through capability for the site superimposed on top of the PRC-024-1 Standard curves. For frequency, the WECC values specified in this Standard shall be used.

13 SOURCE TRANSFER EQUIPMENT

The requirements outlined in this Section apply to a Customer facility utilizing Source Transfer Equipment to transfer all or part of the facility electrical load between two or more power sources – typically one source being the Utility and the other being a Backup Generator. This Section provides supplemental information to that outlined in Sections 4 and 8 of this document.

Source Transfer Equipment may consist of either a transfer switch which must be tested and certified to UL 1008 or UL 1008A, or a true double throw switch listed to UL 98, or it could comprise an engineered and custom-built transfer scheme which is not tested to UL 1008/1008A. While either a Transfer Switch or Transfer Scheme may be used to transfer Customer load between a Utility source and a Backup Generator, a Transfer Scheme must be used when transferring from one Utility source to another Utility source, for instance when a Customer SES is fed via two Utility services. While Backup Generators are designed to primarily operate in a stand-alone mode (electrically isolated from the Utility source) in order to power emergency load, they may be designed to electrically parallel with the utility for short periods (< 15 seconds) in order to effect a power transition between power sources.

All Source Transfer Equipment shall have adequate interrupt ratings and fault withstand capabilities in accordance with paragraphs 1910.303(b)(4) and 1910.303(b)(5) of OSHA Rules and Regulations as well as NEC Articles 110.9 and 110.10.

The connection with, and the operating modes of, Source Transfer Equipment connected to the APS System is subject to APS review and acceptance as is described below. APS may request additional details following APS receipt of a Customer Application and associated Supplementary Information submitted in accordance with Section 17 and Appendix B of this document. An Interconnection Study may be required depending on the size, configuration, location and/or operating mode of the Source Transfer Equipment. APS will advise Customer of any such requirement following an initial engineering review of the proposed design.

Note: In instances where APS provides multiple (redundant) electric services (feeder sources) to a Customer facility, Customer is prohibited from ever paralleling the Utility services (sources) in a Closed Transition Transfer (CTT) mode, (neither via a Momentary or Smooth or Smooth Parallel Transition transfer) when effecting a power transfer between the services. Refer to the APS ESRM, Section 104.12 "Protection and Isolation Requirements for Multiple Utility Services to a Customer Facility" for additional information.

13.1 Open Transition Transfer Equipment

(A) Open Transition Transfer Switch:

Provided the Transfer Switch is (i) installed in accordance with the NEC and the APS ESRM, and (ii) meets the requirements for a Separate System as specified in Section 4.1 of this document, then Customer will generally not be required to fill out an Application or enter into an Agreement with APS. Customer will not have to install a Disconnect Switch provided the above requirements are met. APS does however reserve the right to require Customer to submit an electrical one-line diagram and the switch specifications in the event APS has reason to believe the installation or transfer switch may not be in accordance with the stated requirements.

(B) Open Transition Transfer Scheme:

Backup Generator Transfer Scheme: If Customer desires to install an open transition transfer scheme in order to transfer to or from a Backup Generator source, that is not tested and certified to UL 1008/1008A, or otherwise does not meet all of the requirements specified for a Separate System in Section 4.1 of this document, then Customer shall submit an Application along with applicable Supplementary Information in accordance with Section 17 and Appendix B of this document. Customer's design shall include a Disconnect Switch (or Switches) as specified in Section 8.2 of this document that will completely isolate Customer's GF from the APS System. Following APS' review and acceptance of the proposed design, APS will develop a Non-Parallel Connection Agreement and possibly an Operating Agreement for execution by APS and Customer. Customer shall not put the Backup Generator into service until the installation has been satisfactorily inspected by APS and written notification has been provided by APS.

Utility Services Transfer Scheme: When Customer installs a transfer scheme in order to perform an open transition transfer from one Utility source (service) to another Utility source, then the installation shall comply with the requirements outlined in Section 104.12 of the APS ESRM.

13.2 Momentary Parallel Transition

A Momentary Parallel Transition transfer is accomplished by paralleling the Utility and Generator power sources (when both sources are in synchronism) for a time period not to exceed 167 milliseconds (ten cycles at 60 Hz) in order to effect a load transfer. Power to the load is not interrupted during the transfer. Such a transfer may be accomplished via either a CTT switch (tested and certified to UL 1008/1008A), or via a CTT scheme (not certified to UL 1008/1008A) and is classified as a Parallel System.

Customer shall submit an Application along with associated Supplementary Information in accordance with Section 17 and Appendix B of this document for APS review and acceptance. Following APS acceptance of the proposed design, APS will develop an Interconnection Agreement and possibly an Operating Agreement for execution by APS and Customer.

The requirements outlined in this document for a Parallel System apply to a GF utilizing a Momentary Parallel Transition transfer switch or scheme, including the requirement for a Disconnect Switch (or Switches) as specified in Section 8.2 of this document that will completely isolate Customer's GF from the APS System.

The following additional technical requirements apply:

(1) A primary timer shall be installed to limit the closed transition period to a maximum of 167 milliseconds. The timer shall begin timing when the two power sources are paralleled through their respective circuit breakers (Utility breaker and Generator breaker) and shall trip open either one or the other breaker within the specified time.

(2) In lieu of the minimum protective relaying requirements specified in Section 8.7 of this document, Customer may elect to install a redundant independent backup timer. This backup timer shall be configured to trip, at a minimum, a circuit breaker that is independent of the breakers constituting the transfer switch or scheme in the event the primary timer fails to break parallel between the power sources within the specified time. The backup timer shall:

   a. Begin timing concurrently with the primary timer.

   b. Be set to a maximum time of 1 second.

   c. Directly trip the independent circuit breaker in order to break parallel between the sources in the event of a malfunction (i.e. extended parallel beyond 167 milliseconds) of the normal transfer sequence. The trip circuit shall not be routed through any circuit or logic scheme that could potentially inhibit or block the trip signal, and shall not be routed through a Programmable Logic Controller (PLC) or other such programmable device.

   d. The backup timer and associated circuit design are subject to APS review and acceptance.

(3) For a transfer switch or scheme equipped with a relay incorporating reverse power protective function(s), such function(s) shall be activated for both the Generator and Utility source circuit breakers.

   For instances where this feature is not available with Closed Transition Transfer switches tested and certified to UL 1008/1008A, APS will not require the reverse power functions.

(4) Overcurrent lockout protection shall be incorporated into the CTT protective relaying scheme to prevent any source breaker from being manually or automatically closed into a fault.

(5) When a transfer switch or scheme is manually operated to transfer load between the power sources, automatic retransfer **is not permitted.**

   This requirement correlates with the general safety practice that if a transfer is manually initiated, then the re-transfer also needs to be performed manually.

13.3 Smooth Parallel Transition

A Smooth Parallel Transition transfer is accomplished by synchronizing and paralleling the Utility and Generator power sources for a time period of normally 5 to 15 seconds in order to effect a smooth load transfer (sometimes referred to as "soft loading") between the sources. Power to the load is not interrupted during the transfer. Such a transfer is accomplished via a CTT scheme (not certified to UL 1008/1008A) and is classified as a Parallel System.

Customer shall submit an Application along with associated Supplementary Information in accordance with Section 17 and Appendix B of this document for APS review and acceptance. Following APS acceptance of the proposed design, APS will develop an Interconnection Agreement and possibly an Operating Agreement for execution by APS and Customer.

The requirements outlined in this document for a Parallel System apply to a GF utilizing a Smooth Parallel Transition transfer scheme, including the requirement for a Disconnect Switch and minimum relaying requirements specified in Section 8 of this document. The following additional technical requirements apply:

(1) Reverse power function(s) shall be activated in the CTT protective relaying for both the Generator and Utility source circuit breakers.

(2) Overcurrent lockout protection shall be incorporated into the CTT protective relaying scheme to prevent any source breaker from being manually or automatically closed into a fault.

(3) When a transfer switch or scheme is manually operated to transfer load between the power sources, automatic retransfer **is not permitted.**

This requirement correlates with the general safety practice that if a transfer is manually initiated, then the re-transfer also needs to be performed manually.

(4) Prolonged parallel operation greater than 15 seconds of the Customer's GF with the APS System is not permitted nor otherwise agreed upon.

13.4 Closed Transition Transfer Scheme Safety Requirements

The requirements specified in this Section apply to all CTT schemes utilizing a synchronous generator that electrically parallels with the Utility source. These requirements supplement those outlined in Sections 13.2 and 13.3 of this document.

All Potential Open Points located in the circuit between a Generator output and the Utility source shall be suitably interlocked to preclude the possibility of a potential out-of-sync closure occurring between the two power sources. A Potential Open Point includes any circuit breaker, contactor, switch, or similar device, (referred to as an "Open Point" in this Section) that is capable of being opened and/or closed, and which is not equipped with either a sync check or synchronizing function.

An Open Point may be interlocked by installing either of the following:

(1) A keyed or other suitable mechanical interlock that will prevent the Open Point from ever being opened unless a circuit breaker in the circuit, which is equipped with either a sync check or synchronizing function, is first opened. This breaker, when opened, shall immediately break the electrical path between the power sources.

(2) An electrical interlock consisting of a set of electrical contacts on the Open Point which are directly wired to instantaneously trip open a circuit breaker in the circuit, which is equipped with either a sync check or synchronizing function, whenever the Open Point is opened. This breaker, upon opening, shall immediately break the electrical path between the power sources.

Closed Transition transfer schemes shall also incorporate the following safety features:

a. Breaker auxiliary switch contacts to provide transfer scheme interlocks and permissive functions that are in addition to any control switching and interlock functions that may be provided by a microprocessor or PLC based control device. The auxiliary switch contacts shall be connected to the appropriate breaker closing/ tripping control paths.

b. Fail-safe control circuit design to prevent interlocks from being circumvented in the event of loss of control power.

c. Close defeat cover plates on the transfer scheme source breakers to prevent inadvertent unsafe out of sequence manual operation.

d. ***Provisions that allow both of the transfer scheme source breakers to be in the open and racked-***out position at the same time to allow the load to be disconnected from both sources.

e. Overcurrent lockout protection shall be installed to prevent either source breaker from being closed into a fault.

f. Electrical equipment subject to the paralleled power sources shall be rated to withstand the combined fault current available from the power sources.

g. Written procedures and/or interlocks to ensure that automatic transfer and retransfer operations are disabled when either of the transfer scheme source breakers is in the racked-out position. This requirement correlates with general safety practices in lockout-tagout switching procedures.

h. Protection against islanding and out of phase reclosing shall be installed between a Generator and the Utility source.

13.5 Main-Tie-Main Transfer Schemes

Main-Tie-Main and Main-Tie-Tie-Main Transfer Schemes ("M-T-M Transfer Scheme") typically consist of two or more main source breakers and one or two tie breakers. Such schemes are used to (1) transfer load from one utility source to another, or (2) transfer load between a Utility source and a Generator source (or sources). The requirements for each of these are as follows:

(1) Load Transfer between Utility Sources:

When an M-T-M Transfer Scheme is used to transfer load between Utility sources (services), then the transfer shall be accomplished in an Open Transition Transfer mode to ensure that the Utility sources are never electrically paralleled. The installation shall comply with the requirements outlined in Section 13.1 of this document (refer to "Utility Services Transfer Scheme") and to Section 104.12 of the APS ESRM.

(2) Load Transfer between the Utility and Generator Sources:

When an M-T-M Transfer Scheme is used to transfer load between a Utility source (service) and a Generator source, then the transfer may be accomplished in either an Open Transition Transfer mode or in a Closed Transition Transfer mode. In addition to the respective requirements previously specified for these two transfer modes, the following common requirements also apply to an M-T-M Transfer Scheme:

a. When the load is manually transferred between the sources (eg. to de-energize equipment for maintenance), then any re-transfer of load back to the original source shall only be permitted to be performed in manual (operator supervised and initiated) mode (the transfer scheme shall not permit any automatic re-transfer).

b. For facilities where multiple Main-Tie-Main Systems co-exist, Customer must ensure that they are properly coordinated.

Note: If automatic retransfer logic is part of a standard controller and the logic cannot be modified, then the automatic retransfer logic will need to be disabled and appropriate placards and procedures need to be put in place as a reminder to personnel.

(3) Excessive fault currents under closed transition conditions may violate the interrupting rating of circuit breakers or the through fault withstands rating of source transformers, and may damage other connected equipment. Thus, if there is a failure such that the intended main or tie fails to trip, the new source device must automatically be tripped.

14 TESTING AND START-UP REQUIREMENTS

The information outlined in this Section constitutes Start-Up Requirements that apply to any GF. APS may impose additional Start-Up requirements depending on the system impact, type, size, and/or location where the GF is interconnected to the APS System. APS will communicate additional requirements as soon as practically possible to the Customer prior to final commissioning and/or testing of the GF.

14.1 General Start-Up Requirements

(1) Customer shall, at a minimum, have all specified interface equipment, shutdown and associated protective devices tested and calibrated at the time of installation by qualified personnel and shall also perform functional trip testing of these relays and associated Generator breaker.

  a. Calibration must include on-site bench testing of pickup and timing characteristics of the relays.

  b. Functional testing must demonstrate that each protective relay trip function as required herein, upon a (simulated) out of tolerance input signal will trip the generator breaker, and shall also include a simulated loss of control power to demonstrate that the generator breaker will open.

(2) Customer must have all equipment installed and certified to any applicable APS, Federal and State requirements and/or codes. **APS may require certifications and/or test reports to be stamped by a Professional Electrical (PE) Engineer licensed in the State of Arizona.**

(3) A trip timing test (simulated loss of voltage) will suffice for static inverters tested and certified to UL1741.

(4) The Customer is required to have a signed Interconnection Agreement with APS, and must also provide APS with any other required documentation, prior to electrically paralleling the GF with APS' system. The Customer must provide APS with a copy of the Final Electrical Clearance ("Green Tag") for the GF as provided by the AHJ, or provide APS with a duly signed and notarized Letter-in-Lieu of Electrical Clearance if no AHJ electrical inspection is required, before APS will schedule the Site Inspection and meter order.

(5) Customer shall not commence interconnected operation of the GF with the APS System until the GF has been inspected by an authorized APS representative and written notification is received from APS allowing the GF to commence parallel operation with the APS System.

14.2 Static Inverter Systems 1MW and Larger or any Rotating Machine

(1) The Customer shall provide APS with a certified copy of calibration and functional test results for all GFs comprised of a Rotating Machine and for any GF comprised of Static Inverters with an aggregate AC nameplate rating of 10MW or larger performed at the time of commissioning of the GF. Customer must also notify APS at least ten (10) business days in advance that such tests are to be performed and allow APS personnel to witness the tests.

(2) For Rotating Machines (Generators), Customer shall repeat such tests performed as specified in section 14.2(1) at intervals not to exceed four (4) years by

qualified test personnel. The Customer shall provide APS with a certified copy of such test results upon request by APS.

(3) The Customer shall give APS at least ten (10) business days prior notice of when initial startup of GF is to begin, and APS will have the right to have a representative present during initial energizing and testing of the GF.

(4) Customer shall provide necessary certification confirming the GF has achieved Qualifying Facility (QF) status as specified in Section 3 of this document.
NOTE: Backup Generators do not qualify as a QF.

(5) Customer shall submit a pre-test calibration and functional test check list, prior to witnessing calibration and functional testing of the GF protective devices (relays) associated with the Generating Facility breaker(s)and full plant trip timing test report for all GF's comprised of Rotating Machines and Static Inverters with an aggregate AC nameplate rating of 10 MW or greater prior to APS witness testing.

a. Customer shall provide documentation/certification to APS ensuring that the control wiring (along with CT and PT circuitry) has been completed and verified, relay settings have been applied, and any internal trip path testing has been performed (i.e. dry run).

b. Customer shall provide relay test report(s), equipment test reports (transformers, inverters, generators, etc.) and any other required certification/documentation required by APS prior to granting full permission to parallel with the APS System.

(6) For any GF comprising of Static Inverters with an aggregate AC nameplate rating of 10MW or larger, Customer shall hire a 3rd party testing firm to perform full plant trip timing test.

a. Customer shall provide a test report performed by a qualified testing firm. Test report shall provide trip time, voltage and frequency profile graphs with all inverters on-line (recommend at low power output). Any communication latency between plant equipment at t=0 shall be communicated within the test report.

b. Customer must notify APS at least ten (10) business days in advance that such tests are to be performed and allow APS personnel to witness the tests. APS, at its option, may elect to connect its test equipment along with, or in lieu of, Customer's test equipment for the purpose of performing the trip timing test.

c. For the purposes of the trip timing test Customer may be required to disable the Mirrored Bits Receive function at the GF relay(s) for APS Direct Transfer Trip.

15 OPERATIONAL AND MAINTENANCE REQUIREMENTS

15.1 Customer will be responsible for operating and maintaining the GF in accordance with the requirements of all applicable safety and electrical codes, laws and governmental agencies having jurisdiction.

15.2 Customer shall protect, operate and maintain the GF in accordance with prudent engineering and utility practices (Good Utility Practice) and methods. Additionally, Customer shall operate and maintain the GF lawfully in a safe manner and in a non-hazardous condition.

15.3 Customer will allow APS and its authorized agents access to the protective relaying and control facilities to conduct startup or periodic tests APS deems necessary. APS will provide Customer with advance notice of such tests, so that Customer's representatives may be in attendance when tests are performed.

15.4 Customer shall pay annual fees for the Operations and Maintenance (O&M) of APS' new distribution facilities built to accommodate the interconnection of the Customer's GF to the APS System. The Operations and Maintenance Charges (O&MC) covers the costs of the line extension and upgrades and its associate equipment. This O&MC is derived utilizing an APS standard methodology:

- (A) Following construction of the dedicated generator tie line, the O&MC is calculated and charged to the Customer based on actual costs of construction.
- (B) The actual cost-based O&MC charge will be for the life of the Generator Interconnection Agreement.
- (C) The estimated O&MC is the percentage of the actual construction cost (based on the FERC Form-1 data) and is an annual cost to the Customer.
- (D) The estimated annual charge will include a 3% escalation for inflation per year over the life of the contract.
- (E) Customers required to pay an O&MC will be informed of the fee details during the Interconnection Study process (refer to Section 16.6 of this document).
- (F) Behind the Meter Customers will not be assessed an O&MC.

15.5 In the event APS or its authorized agents lock open the Disconnect Switch, Customer shall not remove or tamper with such lock.

15.6 APS will be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment will be owned, furnished, installed and maintained by APS.

15.7 APS (including its employees, agents and representatives) shall have the right to enter Customer's premises to:

- (A) Inspect Customer's GF, protective devices, and to read or test instrumentation equipment that APS may install, provided that reasonable notice is given to Customer prior to entering its premises;
- (B) Maintain, replace or repair APS equipment, which may require APS personnel to open the Disconnect Switch without notice;
- (C) Immediately and without prior notice disconnect or cause Customer to immediately disconnect, the GF or otherwise render the GF disconnected from the APS System (including by opening the Disconnect Switch) if, in APS' opinion, a hazardous condition exists and such immediate action is necessary to protect persons, APS

facilities, or other customers' or third parties' property and facilities from damage or interference, or if, in APS' opinion, any of the protective devices or switching apparatus is not or does not appear to be operating properly;

(D) Open the Disconnect Switch without notice if an operating clearance is required by APS personnel;

(E) Close the Disconnect Switch upon completion of APS work performed under an operating clearance.

15.8 Upon termination of the Interconnect Agreement, Customer shall be responsible for ensuring that the Disconnect Switch is immediately opened, and that the electric conductors connecting Customer's generator(s) to the Disconnect Switch are lifted and permanently removed, so as to preclude any possibility of interconnected operation in the future. APS reserves the right to inspect Customer's facility to verify that the generator is permanently disconnected.

16 APPLICATION PROCESS AND GENERAL REVIEW REQUIREMENTS

16.1 For a static inverter-based GF with an aggregate nominal AC nameplate output rating of less than 1 kW that interconnects with the APS System, Customer is not required to submit an Interconnection Application. APS will not inspect the installation or prepare an Interconnection Agreement; however, it remains Customer's responsibility to:

(A) Have the system properly permitted and inspected by the AHJ.

(B) Ensure inverters are tested and certified to UL1741per Section 8.7(A)(11).

(C) Conform to all applicable APS interconnection requirements as specified in this document.

16.2 Customers wishing to interconnect a static inverter-based GF less than 1MW are required to submit:

(A) A completed APS Interconnection Application (Appendix A or B).

(B) Diagrams specified per Appendix A or B.

(C) A copy of the Building Permit issued by the AHJ (See Note Below).

The building permit shall be issued by the AHJ following their approval of the diagrams and not the "permit application" form.

Note: it is not necessary to submit a building permit and/or permitted diagrams for 1MW or greater static inverter based systems or rotating machines to begin the APS Interconnection Application review.

An "Interconnection Application" form must be completed and all supplementary information requested per Appendix A or B shall be provided.

Additionally, diagrams shall be prepared and submitted per requirements specified (refer to Appendix A or B) and in the format depicted on APS Sample Diagrams located at www.APS.com/dg.

Note that APS may accept a set of the required diagrams (normally one-line, three-line, array, plant location and site plan) approved by the AHJ provided these diagrams have been prepared in accordance with the APS Sample Diagrams and contain the necessary information shown therein and as otherwise specified in this document and its appendices.

16.3 Depending on the GF type and size, APS will review the Interconnection Application and required diagrams for consistency with APS Interconnection Requirements and provide comments back to Customer or their designee. Diagrams must be in compliance with all NEC, APS, and AHJ requirements. APS will not generally require re-submittal of the Interconnection Application or required diagrams unless the diagrams or system design is revised prior to scheduling APS Site Inspection, or APS requests a resubmittal. As a part of the APS Site Inspection, APS will inspect to ensure all applicable diagram comments made by APS have been incorporated.

If there is no plan review or permit requirement imposed by the AHJ, drawings must be submitted per Appendix A or B of the Interconnection Requirements. A notarized copy of APS' Letter-in-Lieu of Electrical Clearance form is required. Drawings may need to be stamped by an Electrical PE in Arizona.

Note: Diagram reviews by APS do not relieve Customer of the responsibility of full compliance with the APS Interconnection Requirements and all applicable building and safety codes, and local permitting requirements.

16.4 APS' review of documentation submitted by Customer or their designee shall not be construed as a warranty or representation regarding the safety, durability, reliability, performance or fitness of Customer's GF and service facilities (i.e. SES), its control or protective devices, or the design, construction, installation or operation thereof.

16.5 APS strongly encourages Customer to work closely with APS at the conceptual stages of the design to ensure that the project proceeds smoothly. A single point of contact with which to coordinate the interconnection process is preferred.

16.6 Following receipt of Customer's Interconnection Application, APS may perform an engineering review to determine if an Interconnection Study (Study) is required. Systems rated at 1 MW or greater nominal generator AC nameplate rating will require a Study (Schedule 6 may apply).

The Study determines whether any modifications, upgrades or additional facilities will be required to the APS System. The Study will also provide estimated costs. It may take 90 days or longer to complete the Study, so it is important for Customer to submit the Interconnection Application as soon as possible.

The Study will determine any special technical requirements and the cost of any APS System upgrades. Customer will be responsible for any costs associated with upgrading the APS System in order to accommodate interconnection of the GF.

16.7 APS will provide Customer with the estimated costs and construction schedule should it be necessary for to upgrade the APS System (i.e. install Dedicated Utility Feeder(s), control or protective devices, remote terminal unit(s), etc.) in order to accommodate or protect Customer's GF or APS equipment. Customer will be responsible for all costs incurred to the extent they exceed those normally incurred by APS for Customers who do not have self-generation facilities, and which must be paid prior to the commencement of any such work .

16.8 Following APS' final Site Inspection of the Customer's Generating Facility, Customer shall not remove, alter or otherwise modify or change the equipment specifications, including, without limitation, the plans, control and protective devices or settings, and in general the Generating Facility system configuration or any facilities appurtenant thereto that are subject to the APS Interconnection Requirements. If the Customer desires to make such changes or modifications, the Customer must resubmit to APS revised plans describing the changes or modifications for review by APS. No change or modification may be made without the prior written acceptance of APS.

16.9 Following APS' review of Customer's Interconnection Application and associated diagrams, APS will prepare the Interconnection Agreement, and any applicable other agreements (e.g. Electric Supply/Purchase Agreement, Construction Agreement, Line Extension Agreement, and Operating Agreement) and/or other required documents for execution by APS and Customer.

16.10 Following the submittal of a completed Interconnection Application and all supplementary information as required by Appendix A or B, APS will generally require 4-6 weeks for review of Static Inverter based systems of 1MW or greater and all Rotating Machine projects. APS may require additional time depending on the size and complexity of any such GF. APS will communicate with the Customer's representative should additional time be required for review as soon as practically possible. Customer should discuss project plans with APS before designing its DG or purchasing and installing equipment.

17 INTERCONNECTION APPLICATION INSTRUCTIONS

A Customer requesting to interconnect a GF to the APS System and not subject to FERC jurisdiction must do the following:

(1) Complete the appropriate Interconnection Application (refer to table 17-1 of this Section). If Appendix A for Static Inverter installations or Appendix B for Rotating Machinery installations is to be completed, be sure to provide all required Supplementary Information in the relevant Appendix.

(2) Provide a copy of the AHJ building permit along with the Interconnection Application. Refer to section 16.2 of this document for additional details regarding AHJ building permit and permitted diagrams. If the AHJ does not review diagrams or approve and grant permits for Generating Facilities, then provide a notarized copy of APS' Letter-in-Lieu of Electrical Clearance for the GF. Contact APS for a copy of the Letter-in-Lieu of Electrical Clearance form.

(3) Forward required items (1) and (2) above to APS via the contact information noted below.

(4) If general liability insurance is per Section 5 of the Interconnection Requirements, then proof of insurance must be provided to APS prior to the date of interconnected operation.

(5) If the GF aggregate nominal nameplate rating is 1 MW or greater, and the exception specified in Section 3 of the Interconnection Requirements manual does not apply, then documentation as specified in Section 3 must be provided to APS prior to the date of interconnected operation.

APS will review the Customer provided documentation to determine if the design conforms to APS' requirements. APS reserves the right to require diagrams submitted to be stamped by a Professional Engineer (Electrical) registered in the State of Arizona.

APS notification that the system design appears to be in conformance with APS' Interconnection Requirements does not represent APS' approval of system's design, nor is it an assurance that the system complies with all applicable electric codes, laws, regulations and requirements applicable to its installation and operation.

The APS Interconnection Site Inspection is in addition to, but not in place of, an AHJ inspection. Final drawings shall be provided by Customer per Section 17 of this document prior to APS scheduling and performing the Site Inspection.

It is important that GF not be interconnected (in parallel with the APS System) and/or operated until APS has inspected the GF and issues written notification (i.e. permission to parallel and/or operate) that the system design conforms to APS' requirements.

If you have any questions call 602-371-6160 for assistance.

Submit all documentation electronically in .pdf format to:
Commercial-Renewables@aps.com

Include Customer name in subject line of email.

Table 17-1 below shows the appropriate interconnection application to be completed for the GF being contemplated.

Non-Residential Applications	Wholesale Generation	For FERC interconnections use the application located at APS' Oasis Website at: http://www.oatioasis.com/azps/index.html For Non-FERC interconnections, Use the appropriate application (Appendix A or B) available at: http://www.aps.com/dg
	Behind the Meter 1 kW or greater	Use the appropriate application (Appendix A or B) available at: http://www.aps.com/dg
	Behind the Meter less than 1 kW	No APS application is required. Customer must still follow all code and local permitting requirements. Refer to Section 16.1 of the APS Interconnection Requirements
Residential Applications	Non Incentive-Interconnect Only Process 1 kW or greater	Please review the process guide located at http://aps.com/dg under the residential tab to complete an application
	Relocating system and participated in the APS Incentive Program 1 kW or greater	Send email for transfer packet to renewables@aps.com – Subject: Transferring system to new location
	Relocating system and participated in the Non Incentive – Interconnect Only Process 1 kW or greater	Please review the process guide located at http://aps.com/dg under the residential tab to complete an application
	Systems less than 1 kW	No APS application is required. Customer must still follow all code and local permitting requirements. Refer to Section 16.1 of the APS Interconnection Requirements

Table 17-1

APPENDIX A

INTERCONNECTION APPLICATION FOR STATIC INVERTERS ONLY

For APS use

APS Reservation # (if applicable)	
APS Installation #	

CUSTOMER OF RECORD AND SITE SPECIFIC INFORMATION

APS Customer Account Holders Name(s): ______________________

Customer Contact Person's Name: ______________________

Telephone (day): ____________ E-mail: ______________________

Generating Facility Address: ______________________

____

Customer Contact Mailing Address: ______________________

____

APS Account Number: ____________ APS Meter #: ______________________

Is there an existing Generator interconnected behind this meter? (Yes or No): ____________

If Yes, provide kW size and type of existing Generator: ______________________

Is there an existing Generator connected behind a different meter at this site? (Yes or No): ____________

If Yes, provide kW size and type of existing Generator: ______________________

Is this GF being interconnected behind a sub-meter constituting a Totalized Metering arrangement?

(Yes or No): ________ If Yes, provide the APS sub-meter # feeding the GF: ____________

Is the Customer of record a federally owned entity? (Yes or No): ______________________

STATIC INVERTER INFORMATION

A. Manufacturer: ____________ Model #: ______________________

B. Inverter nameplate continuous AC power output rating [kW] ______________________

No. of Units: ________ Total System Nameplate AC rating [kW]: ______________________

C. Tested and Certified to UL1741? (Yes or No): ____________

If No, explain: ______________________

D. Energy Source (photovoltaic, thermal solar, wind, etc.): ______________________

E. Prime Mover for Thermal Solar (concentrating dish, solar trough, with Sterling Engine, etc.): ____________

____

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

F. Are the Inverter(s) Non-Isolated (Transformer-less) (Yes or No): ___________

PHOTOVOLTAIC SYSTEM INFORMATION - complete only for photovoltaic systems

A. PV Module Manufacturer: ________________________ Model #: ___________________ # of Modules ________

B. Total PV Module DC rating [kW]: ___________________

C. PV Modules Tested and Certified to UL1703? (Yes or No): _______________

UTILITY DISCONNECT SWITCH INFORMATION

A. Utility Disconnect Switch Manufacturer: ________________________ Model #: _____________________________

BATTERY INFORMATION – complete only for battery systems

A. Battery Manufacturer: ____________________________ Model #: ______________________ # of Units ________

B. Total System Maximum Power [kW]: ________________

C. Total System Energy [kWh]: ____________________

D. Batteries Tested and Certified to UL1973? (Yes or No): ___________
Include Battery Spec Sheet with Interconnection Application

PROPOSED OPERATION

A. Specify whether the inverter will be programmed to operate in parallel with the utility or in backup ("battery charger") mode only:

________ Parallel mode

________ Backup mode

B. If the inverter will operate in parallel with the utility, specify which one of the following options you desire:

_______ Net metering per EPR-6 rate

_______ Partial Requirements Service per E-56 R rate (> 100 kW)

_______ Sell excess energy to APS per EPR-2 rate (≤ 100kW)

_______ Sell excess energy to APS under a Power Purchase Agreement (PPA)

_______ None of the above. Specify: ____

C. Provide the anticipated project in-service date: ____

D. Is an electrical permit and/or inspection required by the Authority Having Jurisdiction?

(Yes or No): __________ If No, explain: ____

E. Is access by APS personnel to the Utility Disconnect Switch, the facility SES and any utility-required inverter production metering in any way restricted or impeded (e.g. fences, locks, gates, walls, animals, etc.)?

(Yes or No): __________ If Yes, explain how APS will have 24/7 unrestricted access: _____________________

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

F. If the GF aggregate generation nominal nameplate AC rating is 1MW or greater, and is not installed in a Behind the Meter application, is documentation (including FERC Form 556) confirming the GF has achieved QF status included with this Interconnection Application? (Refer to Section 3 of the APS Interconnection Requirements).

(Yes, No or N/A):_____ If No, explain:______________________________

____

G. If the GF aggregate generation nominal nameplate AC rating is 1 MW or greater, and is installed in a Behind the Meter application, does Customer warrant that, to the best of Customer's knowledge, even when considering the expected degradation of the power rating over its expected life and future potential increased electrical load needs of Customer, the GF is not expected to produce more energy over the 12 month period between January 1 and December 31 of any given year than what Customer consumes behind the APS bi-directional billing meter.

(Yes, No or N/A): _____ If No, explain ______________________________

____

H. Is general liability insurance required per Section 5 of the Interconnect Requirements?

(Yes or No): _________ If Yes, explain when proof of insurance will be provided to APS:_______________

____

I. Is the production metering enclosure CT Rated (e.g. Secondary Service > 200A, Primary Service, etc.)?

(Yes or No): _________

If Yes, shop drawings must be submitted by equipment manufacturer to the APS Meter shop for Review and Approval via e-mail to submittals.metershop@apsc.com. Reference the type of system (wind, photovoltaic solar, etc.) on the submittal in addition to the GF Site Address.

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

IMPORTANT NOTE:

APS requires disclosure of the transaction that Customer is undertaking with the installation of the interconnected GF on its premises.

SYSTEM OWNER

If the GF is owned by a person or entity, including Customer's grantee or lessee, other than Customer, complete the following:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ________________________ E-mail: _____________________________________

SYSTEM LESSEE

If the GF is not owned by Customer, but is instead leased, identify the lessee and the lessor:

Lessee:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ________________________ E-mail: _____________________________________

Lessor:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ________________________ E-mail: _____________________________________

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

SYSTEM OPERATOR

If the GF is to be operated and/or maintained by a person or entity other than Customer, including the System Owner or Lessee, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

PROPERTY OWNER

If Customer does not own the property upon which the GF is located, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

LANDLORD

If Customer is a tenant upon the property at which the GF is located, provide the following information on the landlord:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

INTERCONNECTION PROCESS PRIMARY CONTACT

If the Primary Contact for coordinating the interconnection process is a person or entity other than Customer, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

INSTALLER INFORMATION

If the installer is not the Primary Contact for the interconnection process, complete the following:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: __________________________ E-mail: ______________________________

SYSTEM DESIGN OR ENGINEERING FIRM INFORMATION

If the system is being designed by an entity or person other than the installer, complete the following:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: __________________________ E-mail: ______________________________

CUSTOMER CERTIFICATION

This Application is complete and accurate to the best of my knowledge, and as the APS Customer of Record, I hereby grant APS permission to coordinate the interconnection process with the person or entity specified as the Primary Contact in the Interconnection Process Primary Contact Section above, if such Section is completed.

- I understand that I will be required to sign off on a rate disclaimer per Section 10 of the APS Interconnection Requirements. **Failure to submit the disclaimer form may delay processing of your application (Residential Only).**

I further understand that APS will not accept any drawings that are copyrighted, proprietary, or contain confidential material. APS reserves the right to reject any Interconnection Application which it deems illegible or does not meet the mandatory requirements set forth in the APS Interconnection Requirements or the APS sample drawings.

Name: ____

Signature: ______________________________ Date: ______________________

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

SUPPLEMENTARY INFORMATION

Diagrams specified below must be submitted along with a copy of the Building Permit issued by the AHJ for non-residential Static Inverter based systems with an aggregate generator nominal AC nameplate rating of less than 1 MW and interconnecting at less than 12 kV, and are to be submitted in pdf format. Refer to Section 16.2 & 16.3 of the APS Interconnection Requirements for additional information. **APS will not accept any copyrighted, proprietary or confidential drawings. Drawings must be site specific regarding the information requested below, without extraneous information and must be prepared for APS' use. All electrical connections to equipment must be shown –"block diagrams" will be rejected. Diagrams are to be professionally drawn, using only black print on white paper, and are not to be in color or shaded. Free hand drawn, faxed diagrams and drawings that are otherwise difficult to read will not be accepted by APS**. All diagrams must include the project name and street address and include any updated diagram revision numbers and dates. If the required information is not provided on the drawings, application and/or supplemental information, then APS will require clarifying information. Clarifying information may include requesting manufacturers cut sheet(s) or the UL certification documents for the device/equipment in question.

APS has prepared several sample diagram sets that indicate the general layout, level of detail, keyed notes, and other information, with the quality required by APS for typical inverter-based systems. These diagrams are located at: www.aps.com/dg

Standard industry electrical symbols shall be used on the diagrams and must be legible when printed on 11"x17" paper.

(a) Electrical One-Line Diagram:
Diagram(s) must show all generation sources (e.g. photovoltaic panels, wind generator, etc.), associated DC electrical components, inverter(s), combiner panels, metering, Utility Disconnect Switch, as well as the electric service entrance. The utility meter, connection points of facility loads, and all other associated electrical components must be shown including any required dedicated metering phone lines, transfer trip communication path(s) along with the associated relaying and trip circuits, and any APS required Remote Terminal Unit (RTU) with associated communication channels and trip/block close/close permissive circuitry (refer to Section 11.4 of the APS Interconnection Requirements). The electrical ratings of the wire and equipment including all back-fed breakers or fuses and any subpanels, and associated keyed notes/labels must be indicated.

(b) Electrical Three-Line Diagram:
Diagram(s) must show detailed phase wiring of all electrical equipment as specified in the Electrical One-Line Diagram, as well as all neutral, equipment ground and grounding electrode equipment (G.E.C.) conductors and connections.

(c) AC & DC Control Schematics:
For systems greater than 1MW only (unless required otherwise by APS), Diagram(s) must show the detailed phase wiring of all electrical equipment as specified for the Electrical One-Line Diagram, including protective relaying, associated instrument transformers, breaker control circuitry, and additional control schemes. Include control power source and all associated AC and DC connections.

(d) Plant Location Diagram: Note (1)
Diagram must show major cross streets and location of facility. Include a North arrow.

(e) Site Plan:
Diagram must clearly show the major GF equipment individual components and their locations, including the electric Service Entrance Section and utility meter, location of the inverter(s), Utility Disconnect Switch and any lock-boxes, etc. Include building structure location and any walls, fences and gates etc., to clearly indicate unobstructed access to APS equipment, including any required special metering and the Utility Disconnect Switch. Include a North arrow.

(f) Relay Setting Sheet(s):
For systems greater than 1MW only (unless required otherwise by APS), setting sheet(s) for the APS-required minimum protective relay functions must show the trip set points and times. Settings may be provided after the initial APS review, once the final system configuration has been determined.

APPENDIX A: INTERCONNECTION APPLICATION FOR STATIC INVERTERS (cont'd)

(g) Disclaimer Form (Residential Only):
Customer shall submit a signed copy of the disclaimer form available on the APS Website.

(h) Consumer Acknowledgement Form:
Customer shall submit a signed copy of the consumer acknowledgement form available on the APS Website.

Note 1: A Plant Location Diagram will not be required for residential systems.

APPENDIX B

INTERCONNECTION APPLICATION FOR ROTATING MACHINERY ONLY

	For APS use
APS Reservation # (if applicable)	
APS Installation #	

CUSTOMER OF RECORD AND SITE SPECIFIC INFORMATION

APS Customer Account Holders Name(s): ______________________________

Customer Contact Person's Name: ______________________________

Telephone (day): ______________ E-mail: ______________________________

Generating Facility Address: ______________________________

____

Customer Contact Mailing Address: ______________________________

____

APS Account Number: ______________ APS Meter #: ______________

Is there an existing Generator interconnected behind this meter? (Yes or No): ______________

If Yes, provide kW size and type of existing Generator: ______________________________

Is there an existing Generator connected behind a different meter at this site? (Yes or No): ______________

If Yes, provide kW size and type of existing Generator: ______________________________

Is this GF being interconnected behind a sub-meter constituting a Totalized Metering arrangement?

(Yes or No): __________ If Yes, provide the APS sub-meter # feeding the GF: ______________

Is the Customer of record a federally owned entity? (Yes or No):

____

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

GENERATOR INFORMATION

A. Manufacturer: ______________________ Model #: ______________________

B. Generator Type (Synchronous, Induction): ______________________

C. Generator Nameplate Rating:

Voltage: ______________________ Single or Three Phases: ______________________

Power Factor: ______________________ Continuous Power kW: ______________________

No. of Units: ______________________ Total System kW: ______________________

D. Generator Electrical Characteristics (on the machine base, for above 50 kW):

Synchronous Reactance (Xd): ______________________

Transient Reactance (X'd): ______________________

Subtransient Reactance (X"d): ______________________

Stator Resistance (Ra): ______________________

Zero Sequence Reactance (X0): ______________________

Zero Sequence Resistance (R0): ______________________

Negative Sequence Reactance (X2): ______________________

Negative Sequence Resistance (R2): ______________________

E. Generator Neutral Grounding (for above 300 kW):

Specify whether the generator neutral will be solidly grounded or grounded through a neutral resistor:

____

If grounded through a neutral resistor, specify the resistance: ______________________

PRIME MOVER

A. Manufacturer: ______________________ Model #: ______________________

B. Fuel Source (Natural Gas, Landfill Gas, etc.): ______________________

C. Is useful heat recovered from the prime mover? (Yes or No): ______________________

D. Will the installation be certified as a Qualifying Facility (QF)? (Yes or No): ______________________

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

INTERFACE EQUIPMENT AND PROTECTIVE RELAY INFORMATION
(Complete all applicable items; attach a separate sheet if necessary).

A. Synchronizer for Synchronous Generator:

Manufacturer: ______________________ Model #: ______________________

Automatic or Manual Synchronizer: ______________________

B. Manufacturer's name and model number for each protective device (Refer to Section 8):

____

____

____

____

____

C. Proposed settings (trip set point and time) for each protective device (Refer to Section 8):

____

____

____

____

____

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

PROPOSED OPERATION

A. Specify the mode in which the Generator will operate:

_____ Open Transition

_____ Continuous Parallel

_____ Smooth Parallel Transition (normally 5-15 seconds)

_____ Momentary Parallel Transition (normally 1/6 second)

B. If the Generator will operate in continuous parallel with the utility, specify which one of the following options you desire:

__________ Net metering per EPR-6 rate

__________ Partial Requirements Service per E-56 R rate (> 100 kW)

__________ Partial Requirements Service per E-56 rate (> 100 kW)

__________ Sell excess energy to APS per EPR-2 rate (≤ 100kW)

__________ Sell excess energy to APS under a Power Purchase Agreement (PPA)

__________ None of the above.

Specify: ____

C. Provide the anticipated project in-service date: ____________________________________

D. Is an electrical permit and/or inspection required by the Authority Having Jurisdiction?

(Yes or No): ______________ If No, explain: ____________________________________

____

E. Is access by APS personnel to the Utility Disconnect Switch, the facility SES, and any utility-required generation metering in any way restricted or impeded (fences, locks, gates, walls, animals, etc.)?

(Yes or No): _________ If Yes, explain how APS will have 24/7 unrestricted access ______________

____

F. If the GF (other than Backup Generation) aggregate generation nominal nameplate AC rating is 1 MW or greater, and is not installed in a Behind the meter application, is documentation (including FERC Form 556) confirming the GF has achieved QF status included with this Interconnection Application? (Refer to Section 3 of the APS Interconnection Requirements).

(Yes, No or N/A): ___________

If No, explain: ____

____

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

G. If the GF aggregate generation nominal nameplate AC rating is 1 MW or greater, and the GF is installed in a Behind the Meter application, does Customer warrant that, to the best of Customer's knowledge, even when considering the expected degradation of the power rating over its expected life and future potential increased electrical load needs of Customer, the GF is not expected to produce more energy over the 12 month period between January 1 and December 31 of any given year than what Customer consumes behind the APS bi-directional billing meter.

(Yes, No or N/A): _____ If No, explain ____

____

H. Is general liability insurance required per Section 5 of the Interconnect Requirements?

(Yes or No):__________ If Yes, explain when proof of insurance will be provided to APS:________________

____

I. Is the production metering enclosure CT Rated (e.g. Secondary Service > 200A, Primary Service, etc.)?

(Yes or No): __________

If Yes, shop drawings must be submitted by equipment manufacturer to the APS Meter shop for Review and Approval via e-mail to submittals.metershop@apsc.com. Please reference the type of system (Induction wind Turbine, Synchronous Backup Generator, Induction Back-feed GF, etc.) on the submittal in addition to the GF Site Address.

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

IMPORTANT NOTE:

APS requires disclosure about the transaction that Customer is undertaking with the installation of the interconnected GF on its premises.

SYSTEM OWNER

If the GF is owned by a person or entity, including Customer's grantee or lessee, other than Customer, complete the following:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ______________________________ E-mail: ______________________________

SYSTEM LESSEE

If the GF is not owned by Customer, but is instead leased, identify the lessee and the lessor:

Lessee:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ______________________________ E-mail: ______________________________

Lessor:

Name: ______________________________ Company: ______________________________

Mailing Address: ____

____

Phone: ______________________________ E-mail: ______________________________

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

SYSTEM OPERATOR

If the GF is to be operated and/or maintained by a person or entity other than Customer, including the System Owner or Lessee, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

PROPERTY OWNER

If Customer does not own the property upon which the GF is located, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

LANDLORD

If Customer is a tenant upon the property at which the GF is located, provide the following information on the landlord:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

INTERCONNECTION PROCESS CONTACT INFORMATION

If the primary contact for interconnection process is to be coordinated by someone other than Customer, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

INSTALLER INFORMATION

If the installer is not the primary contact for interconnection process, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

SYSTEM DESIGN OR ENGINEERING FIRM INFORMATION

If the system is being designed by an entity or person other than the installer, complete the following:

Name: ______________________ Company: ______________________

Mailing Address: ______________________

____

Phone: ______________________ E-mail: ______________________

CUSTOMER CERTIFICATION

This Application is complete and accurate to the best of my knowledge, and as the APS Customer of Record, I hereby grant APS permission to coordinate the interconnection process with the person or entity specified as the Primary Contact in the Interconnection Process Primary Contact Section above, if Section is completed.

I understand that I will be required to sign off on a rate disclaimer per Section 10 of the APS Interconnection Requirements. **Failure to submit the disclaimer form may delay the processing of your application.**

I further understand that APS will not accept any drawings that are copyrighted, proprietary, or contain confidential material. APS reserves the right to reject any Interconnection Application which it deems illegible or does not meet the mandatory requirements set forth in the APS Interconnection Requirements or the APS sample drawings.

Name: ______________________

Signature: ______________________ Date: ______________________

APPENDIX B: INTERCONNECTION APPLICATION FOR ROTATING MACHINERY (cont'd)

SUPPLEMENTARY INFORMATION

Diagrams and information specified below are to be specifically prepared for APS' use, and to be submitted in pdf format for all rotating machinery based projects. **APS will not accept any copyrighted, proprietary or confidential drawings. Drawings must be site specific regarding the information requested below, without extraneous information and must be prepared for APS' use. All electrical connections to equipment must be shown – "block diagrams" will be rejected. Diagrams are to be professionally drawn, using only black print on white paper; and are not to be in color or shaded.** Free hand drawn, faxed diagrams and drawings that are otherwise difficult to read will not be accepted by APS. All diagrams must include the project name and street address and include any updated diagram revision numbers and dates. If the required information is not provided on the drawings, application and/or supplemental information, then APS will require clarifying information. Clarifying information may include requesting manufacturers cut sheet(s) or the UL certification documents for the device/equipment in question.

Standard industry electrical symbols shall be used on the diagrams and must be legible when printed on 11"x17" paper.

(a) Electrical One-Line Diagram:
Diagram(s) must show generators and all major associated electrical components including protective relaying and associated trip paths, any interlocks and control functions, as well as the electric service entrance, utility meter, connection points of facility loads, any transformers, generator metering, and Utility Disconnect Switch including any required dedicated metering phone lines, transfer trip communication path(s) along with the associated relaying and trip circuits, and any APS required Remote Terminal Unit (RTU) with associated communication channels and trip/block close/close permissive circuitry (refer to Section 11.4 of the APS Interconnection Requirements). Any interlocks or permissive functions and / or control paths shall be clearly indicated on the drawing (e.g. as dashed lines). The electrical ratings of the equipment and associated keyed notes/labels must be indicated.

(b) AC & DC Control Schematics:

Diagram(s) must show the detailed phase wiring of all electrical equipment as specified for the Electrical One-Line Diagram, including protective relaying, associated instrument transformers, breaker control circuitry, and additional control schemes. Include control power source and all associated AC and DC connections.

(c) Plant Location Diagram:

Diagram must show major cross streets and location of facility. Include a North arrow.

(d) Site Plan:

Diagram must clearly show the individual major GF equipment components and their locations, including the electric Service Entrance Section and utility meter, location of generator(s), interface equipment, Utility Disconnect Switch and location of any lock-boxes, etc. Include building structure location and any walls, fences and gates etc., to clearly indicate unobstructed access to APS equipment including any required special metering and the Utility Disconnect Switch. Include a North arrow.

(e) Relay Setting Sheet(s):

Setting sheet(s) for the APS-required minimum protective relay functions must show the trip set-points and times. Settings may be provided after the initial APS review, once the final system configuration has been determined.

(f) Sequence of Operations:

Customer shall submit a description of any sequence of operations or other operational controls of a particular system or control scheme. Customer may also provide a one-line block diagram depicting any/all parallel paths, breaker schemes (e.g. main-tie-tie-main or main-tie-main) as well as identifying any interlocks, normal open points, and transfer schemes.

(g) Disclaimer Form:

Customer shall submit a signed copy of the applicable disclaimer form available on the APS Website if required.

TRANSMISSION AND DISTRIBUTION DEFERMENT USING PV AND ENERGY STORAGE

Mark Ralph[1], Abraham Ellis[1], Dan Borneo[1], Garth Corey[1], and Sara Baldwin[2]
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ABSTRACT

It is often assumed that distribution-connected PV can help defer the need for distribution system upgrades, but there is not a general approach for assessing the deferment value of distribution-connected PV and distribution-connected PV combined with a storage system (e.g., battery). A vital component of such an analysis is time-coincident load and solar resource data, since load (especially peak load) is usually correlated with solar resource and temperature conditions, and both factors determine PV system performance as well. This paper demonstrates a methodology to analyze the value of using PV to defer distribution system upgrades. The paper also assesses the additional benefit of combining energy storage with PV to increase this deferment value. The case study involves replacement of a station transformer.

T&D VALUE OF PV GENERATION

At the local distribution system, PV generation reduces feeder and transformer load, as well as system losses. The reduction in load offers a possible opportunity for deferment of transformer replacement or other system upgrades. The deferment benefits are specific to the situation and require a study the actual load and solar resource for an accurate evaluation. Methodologies to estimate the T&D value of distribution-connected PV, including deferment value, has been explored before—see [1] for example. The value of energy storage has also been discussed extensively in the literature—see [2] for example. The potential synergy between PV and energy storage has not been discussed as much.

Several factors must be considered in the analysis of the deferment value of PV and PV combined with a storage system. These factors include:

- time-coincident solar and load profiles,
- the nature of the system limitations,
- utility business practices,
- other technical options available such as load transfer, and
- other non-technical factors or constraints

To the extent that the solar resource aligns well with the load profile, PV output can reduce system peaks and thus reduce the likelihood of overloads. It is often the case that PV output is not well aligned with the demand curve. If the peak load occurs at night, PV deployment alone would have no impact on the peak load. If the peak load occurs in during the day, increasing PV penetration may reduce peak load up to the point where the net load peak occurs in the evening. The capacity value is dependent on penetration level and the load shape. Integration of energy storage could be an alternative to further reduce system peak depending on the situation.

Combined deployment of PV and energy storage could provide a better overall business case compared to deployment of energy storage only. This is because the size of the energy storage system may be reduced. In this paper, a method for assessing the deferment value of PV and PV plus storage is presented. In addition to deferral value, PV and energy storage could provide a range of benefits that continue through the life of the PV system and energy storage systems.

ANALYSIS METHODOLOGY

For the analysis, data from several distribution stations in Salt Lake City were analyzed. The data included historical 15 minute load and solar resource data, load growth rate and station limits (transformer overload in this case). The historical load data and local solar irradiance data must be available for the same time period, and covered one recent operating year. PV output profiles were generated based on the solar resource data. The load duration curves with and without PV were compared to determine the capacity factor, which is a measure of how effectively PV reduces the peak load. PV penetration levels of 10% and 20% based on station rating were analyzed. The deferment value was estimated based on the hours of overload for each PV deployment scenario. The second part of the analysis involves evaluation of energy storage solutions for each PV deployment scenario, to achieve deferment of station upgrades. Figure 1 shows the calculation of net station load when both PV and energy storage are considered. For this analysis, the impact of feeder losses was ignored.

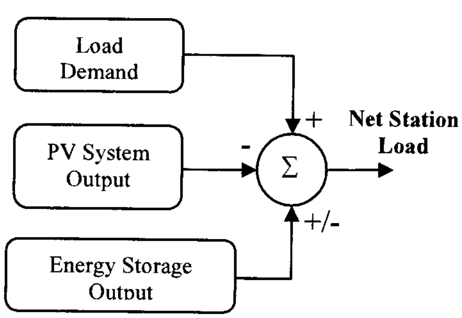

Figure 1 –Simulation Model

SOLAR OUTPUT MODEL

Solar Resource data for the operating year and for the same locality was obtained from the National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Irradiance Study Network (ISIS) station in Salt Lake City [3]. The ISIS data includes:

- Direct Normal Irradiance
- Diffuse Horizontal Irradiance (DHI)
- Total Horizontal Irradiance (THI)

The ISIS solar resource data is collected at a 3-minute resolution. For the purposes of this analysis, the data was averaged over a 15 minute period for convenience (to match the 15 minute load data sampling rate), and to partially account for geographical diversity of distributed PV generation. There are more sophisticated approaches to account for geographic diversity, but this simple method was deemed to be sufficient for the purposes of this analysis.

A simple algorithm was implemented to estimate the PV array output. It uses the Ephemeris Equations [4] to calculate the sun position at the location of interest (Salt Lake City, in this case). The Angle Of Incidence (AOI) on the PV array can be calculated based on sun position and array orientation. Once the AOI has been determined, the direct and diffuse components of the Plane of Array (POA) irradiance and PV output can be calculated using the following equations [5]:

*Direct POA irradiance = DNI * cos (AOI)*

*Diffuse POA irradiance = DHI * (1+cos (ArrayTilt)) / 2 + THI *(0.012 .* Zenith - 0.04) .* ((1-cos(ArrayTilt))/2)*

*Solar Power Output = PV Rating * (Direct POA + Diffuse POA)*

where:

- ArrayTilt is the assumed average tilt angle of array with respect to horizontal in degrees
- Zenith is the zenith angle of the sun in degrees
- PV Rating is assumed to be the total AC rating

Figure 2 depicts the solar data processing procedure.

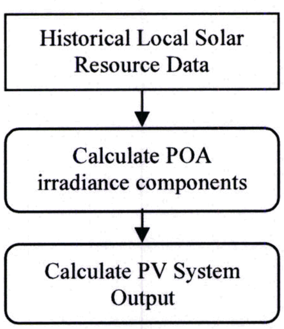

Figure 2 – Estimation of PV array Output

ENERGY STORAGE MODEL

Figure 3 shows the assumed operation of an energy storage system for a deferment application. The support window corresponds to the time period of the day where load is high and the energy storage system is armed to discharge. The recharge window is a period of time where load is low (night) and the storage system is programmed to recharge from the grid. During the charge and recharge periods, constraints such as the energy storage size (defined by the energy storage capacity and interface power rating), charge/discharge rates, and minimum state of charge (SOC) are respected.

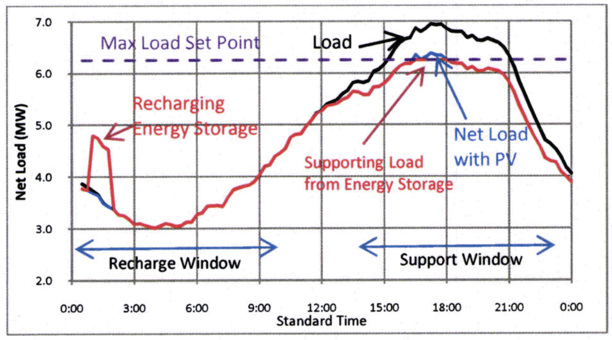

Figure 3 –Support and Recharge Windows

During the support window, the energy storage system could be scheduled to discharge at a pre-determined rate over the support period, or it could be programmed to discharge as needed to keep transformer load form exceeding a certain level. The latter control objective was used for this analysis. The net load is compared to a Max Load set point for the substation. If the load exceeds the set point, energy was discharged from the energy storage to reduce the net substation load to the maximum load set point. The discharge rate setting in the inverter controls may come into play.

During the recharge window, the charger will use energy increasing the net load on the substation. When the Energy Storage reaches a full state of charge, charging is stopped. A charging efficiency is used to account for inefficiencies in the Energy Storage system.

ANALYSIS FOR DEFERRAL VALUE OF PV

To assess the deferral value of PV on a feeder it is first necessary to obtain time-coincident load and solar resource data. Solar data at arbitrary locations is typically available as Global Horizontal irradiance. A PV array model is used to predict PV output from system configuration (tracking and module technology), solar irradiance and temperature. Finally, the net load (load served beyond a certain level of PV penetration) is calculated by subtracting predicted PV output from measured load at each time interval.

An example of the effect of PV output on net load is shown in Figure 4. These results show a commercial load profile for three consecutive days starting with a Sunday. Two levels of PV penetration (10% and 20%) and two orientations for a fixed latitude tilt array (facing due south and southwest) are shown. It is noted that orienting a fixed array southwest slightly shifts power production to later in the day so that the production might better match the load profile and have a larger impact on peak load reduction.

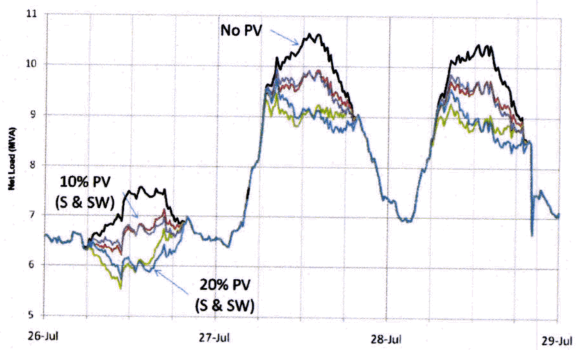

Figure 4 –Substation Net Load (black) with 10% and 20% PV penetration and orientation South (S) and Southwest (SW), assuming a fixed array.

The method for estimating the deferral value involves analysis of a full year of load data. The red curve in Figure 6 shows the upper portion of the load duration curve. High loading is of primary interest since we are interested in peak load reduction. The green curve shows the net substation load with 20% penetration of PV. The Capacity Value (CV) of the PV can be inferred from the reduction in the load duration curve of the substation or feeder with and without PV. As shown in Figure 5 the effect of adding a PV array to reduce the load on the substation so that the overload is less than some acceptable level for some acceptable period of time (1% in this example). The paper will describe the technical reasons why it makes sense to use this approach rather than looking solely at the impact on absolute peak load.

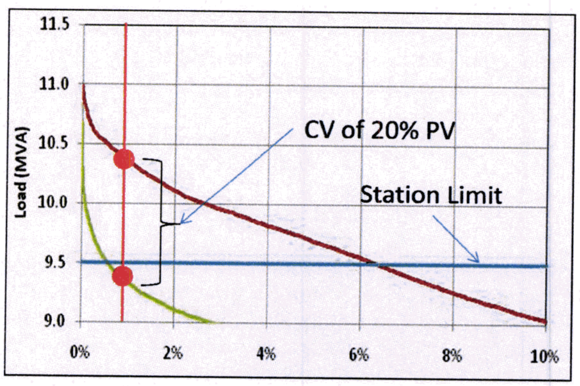

Figure 5 – Load Duration Curve with PV (green) and without PV (red). The horizontal axis is percent of the time over a one year period.

Further analysis to quantify the deferment value of PV is shown in Table 1 for a specific feeder and load. This table lists the projected growth (assumed to be 4%) of a substation load starting in 2009 and ending in 2016. In addition this table shows the number of hours that the load exceeds the substation rating and the peak load during the year. The net load is also shown for the substation with 10% (950 kW) PV and 20% (1.9 MW) of PV penetration on the substation. In 2013, the load exceeds the substation rating of 9.5 MVA for 17.5 hours. Adding 10% PV delays the overload condition for one year, possibly for two years. The 20% PV penetration delays the overload condition until 2015 or 2016 depending on the acceptability of a small number of hours in an over rating condition.

Year	No PV		10% PV		20% PV	
	Hrs >R	Peak Load	Hrs > R	Peak Load	Hrs > R	Peak Load
2009	0.0	8.4	0.0	8.2	0.0	8.1
2010	0.0	8.7	0.0	8.5	0.0	8.5
2011	0.0	9.1	0.0	8.8	0.0	8.8
2012	0.0	9.4	0.0	9.1	0.0	9.1
2013	17.5	9.8	0.0	9.5	0.0	9.5
2014	135.	10.2	3.8	9.9	0.3	9.9
2015	332.	10.6	61.0	10.3	7.5	10.3
2016	510.	11.0	179.	10.7	34.8	10.6

Table 1 – Example deferring substation upgrade using PV (R stands for substation rating)

The estimated deferral value is based on avoided cost of capital upgrades only. The paper will not attempt to compare cost-effectiveness of other alternatives to address the overload; however it attempts to provide enough information to allow for consideration of PV as options in the planning process.

ANALYSIS FOR DEFERRAL VALUE OF STORAGE AND PV

In cases where PV generation does not reduce the peak load sufficiently, adding energy storage could be considered as part of the solution. Some advantages of using PV with energy storage are PV generation reduces energy storage discharge time (energy drawn from storage), and can reduce Power Conditioning System (inverter) size requirements. The ideal synergy between the energy storage and PV generation takes place when PV deployment offsets load growth (Figure 6). This is because an energy storage system can be used to avoid overloads for multiple years. In addition to analyzing a PV only solution, the paper will provide some examples scenarios where energy storage may be effective. Analyses to determine a reasonable size of the energy storage will be discussed.

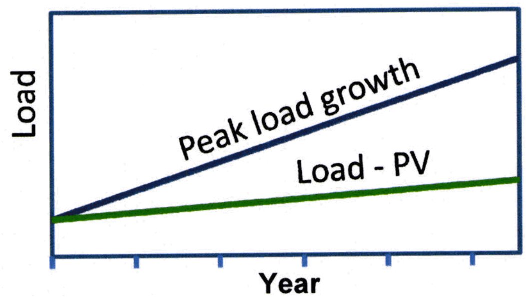

Figure 6 – Effect of PV deployment on load growth

Figure 7 shows the effect of adding energy storage to a substation. A reasonable energy management strategy would be to recharge the energy storage during off-peak outs, just after midnight in this example. The system with PV would be able to complete the charge process earlier because less energy is required from the storage system during the day. This means that a smaller energy storage capacity and a smaller grid interface (inverter) would be needed.

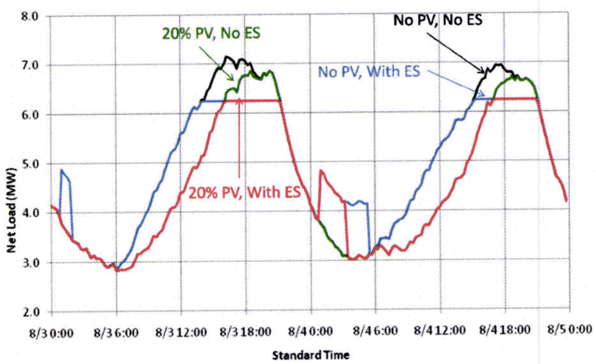

Figure 7 – Substation Load (black) with PV and Energy Storage (red), with PV (green), and Energy Storage (blue)

Technical considerations for the energy storage include the capacity (kW) of the power conditioning system, useful energy storage capacity (kWh), the energy storage technology available and portability if the storage is to be moved to another location after the deferment period. In addition, operating strategy and locations for the energy storage must also be considered. Another consideration is that the deferral horizon for storage is optimal for a 1-2 year period. This avoids the possibility of underutilizing energy storage capacity and makes a strong case for a mobile storage system.

The paper will describe the methodology was as applied to two test cases, a substation serving commercial load and a substation serving residential load. The basic results of these two cases are shown in Table 2. For both cases, the size of the required energy storage and the size of the power conditioning systems are reduced. With the commercial load, the reductions are larger than the residential case because the commercial load profile peaked earlier in the day (compared to the residential load profile) when the solar resource was much better.

Case	Energy (MW-h)		PCS Rating (MW)	
	No PV	20% PV	No PV	20% PV
Commercial	12.0	2.0	1.2	0.3
Residential	4.5	2.5	1.0	0.8

Table 2 – Example deferring substation upgrade using PV with Storage

Energy storage can cost-effectively defer upgrades over a couple of years. The deferral value is based on avoided cost of capital upgrades only. Energy storage is likely to be a utility-owned asset; thus it could be treated as an option among other alternatives. Other value opportunities should be considered in a full evaluation (voltage support, etc). These value streams have a lesser impact on station deferral, but can significantly improve the value proposition for a utility.

MONETIZING DEFERMENT VALUE

In order to compare deferment to upgrade alternatives, it is useful to monetize the deferral period. Deferment value is considered to be equivalent to the annual fixed charge rate multiplied by upgrade cost. Utilities earn a rate of return to cover the cost of equipment in service. The annual revenue requirement ranges from 8% to 15% of equipment costs, which reflects principal, interest, dividend, taxes, and insurance. An example calculation is as follows:

A 12 MVA station transformer is upgraded with a new 16 MVA unit for a cost of $1,200,000. Assume that the annual fixed charge rate is 11%, and that there is no residual value.

- The annual cost to own the new transformer is
  0.11 X $1,200,000 = $132,000
- The deferral value for 1 year is also $132,000
- In this case, the marginal cost of the T&D upgrade is
  $1,200,000 / 4 MVA = $300,000 per MVA

ACKNOWLEDGEMENT

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Rocky Mountain Power assisted in this study by providing circuit and load information that was used in the technical analysis.

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Economic Effects of Distributed PV Generation on California's Distribution System

M.A. Cohen, P.A. Kauzmann, D.S. Callaway

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http://ei.haas.berkeley.edu

Economic Effects of Distributed PV Generation on California's Distribution System

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Abstract

The economic value of distributed photovoltaic (PV) electricity is affected both by its correlation with transmission level energy prices and by a host of effects it may have on distribution systems. In this study we combine detailed physical simulation of distribution circuits with budgetary information provided by Pacific Gas & Electric (PG&E) to estimate PV's value with respect avoided transmission-level energy expenditures, avoided distribution system capacity upgrades, and increased expenditures to manage voltage magnitudes. We find that favorable timing of generation and the potential to defer capacity investments both increase PV's value on average by a small amount. We use circuit-level loading and load growth data to show that distribution circuit capacity value is very heterogeneous: PV shows very little capacity value on most circuits but substantial (over \$60/kW-yr, nearly half of the near-term targets for the cost of distributed PV) on a limited number of circuits. We examine some other distribution system impacts of PV, including voltage regulator operations and voltage quality, and find that they are also likely to be very small on average, with the caveat that there are some impacts (such as the effect of reverse power flow on protection equipment) that we have insufficient data to assess. In much the same way that dynamic pricing tariffs capture PV's value in time, our results point toward the importance of tariffs that recognize the heterogeneity of PV's impacts on distribution systems across different locations.

Keywords: electric distribution, photovoltaic generation, valuation

1. Introduction

Distribution systems were designed to deliver power from high voltage transmission networks to customers. When photovoltaics (PV) are embedded in distribution systems, they fundamentally change power flow conditions: power transfer could go from one customer to another, or from customers back to the transmission system. This has created concern among distribution engineers, regulators and researchers as to whether distribution systems will be able to accommodate very high penetrations of PV – and if so, what the associated costs will be. There are a number of areas where PV could have important impacts, including: resistive losses, peak load (which impacts capacity investments), and voltage levels

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at the point of utilization, transformer aging, voltage regulator mechanical wear, and the ability of protection systems to properly identify fault conditions.

A number of studies quantify various engineering impacts of PV in distribution systems, e.g. Quezada et al. (2006); Shugar (1990); Woyte et al. (2006); Thomson and Infield (2007); Navarro et al. (2013); Widén et al. (2010); Paatero and Lund (2007); Hoke et al. (2013); Cohen and Callaway (2013), but relatively little research has been done to translate the full range of engineering impacts into economic values. Indeed, the California Public Utilities Commission (CPUC) rejected the possibility of valuing PV's non-energy economic impacts, especially its possible deferral of generation, transmission and distribution capacity, on the basis of limited evidence (California Public Utilities Commission, 2011, p. 34). This paper aims to address this gap with new estimates of the economic impacts that PV could have on distribution systems, with a focus on conditions in California.

The contribution we make in this paper is to apply previously reported physical results from Cohen and Callaway (2013, 2015) to an economic framework that quantifies distributed PV's impact on distribution system operation and maintenance costs. We do this with a combination of (1) assumptions about growth in demand and PV capacity, and their interactions with one another, (2) a model of how PV capacity defers investment in distribution capacity infrastructure and (3) a unique set of data on distribution capacity expenditures and feeder-level growth rates from Pacific Gas and Electric.

Our key findings are as follows: First, PV provides distribution circuit capacity deferral value of up to \$6/kW-yr when averaged across the potential impact on *all* feeders in PG&E's service territory. This is a very small fraction of the installed cost of PV (approximately \$380/kW-yr using historical cost estimates, or \$110/kW-yr if near-term DOE projections are met). However roughly 90% of these feeders receive no capacity benefit from PV because their peak load is much less than their peak capacity or their load growth is low – therefore those feeders do not require capacity upgrades over the horizon we investigate. We find that PV's capacity value on the 10% of feeders that would otherwise require capacity upgrades ranges from \$10/kW-yr to more than \$60/kW-yr at very low penetrations. This range suggests that the value on some circuits could be a significant fraction of the installed cost of PV. We also find that these benefits decline relatively quickly as additional PV is installed on each circuit; at 50% penetration capacity value is half of its value at low penetrations.

Second, based on our engineering simulations of PV impacts on distribution circuits, we find PV's impacts on voltage magnitudes and voltage regulator operations are relatively small (Cohen and Callaway, 2013, 2015). If we assume that voltage regulator maintenance scales linearly with the frequency of operation, results in this paper indicate that distributed PV would increase PG&E's annual costs by \$442,000 if *all* circuits in PG&E territory had 100% PV penetration – an extremely small amount of PG&E's roughly \$6 billion operations and maintenance budget. Because we do not have circuit-level data from PG&E on voltage maintenance, we are not able to accurately quantify the heterogeneity of PV's impacts on the cost to address voltage issues. However our earlier engineering simulations showed feeder location and design can significantly impact the likelihood that PV will create voltage problems, suggesting that proactive distribution planning may serve to avoid these voltage problems altogether at relatively low cost.

1.1. Overview of PV economics

Distributed PV's value has three main components. The first, and simplest, is avoided cost of energy. Distributed PV offsets electricity purchases that the supplying utility would otherwise make. The second component has to do with PV's impact on the performance and requirements of generation, transmission and distribution infrastructure. At the distribution level these impacts can be both positive and negative, including reducing line losses, avoiding the need to build distribution system capacity and also increasing voltage regulation problems. Third, PV reduces pollution and possibly other negative externalities associated with conventional generation. We also note that incentives for PV capacity may have *positive* externalities; incentivizing deployment might lead to otherwise unattainable economies of scale and technology learning.

Ideally, the price paid to PV owners would include accurate assessments of all of the above components of PV's value. Unfortunately, the second and third components are difficult to measure or estimate, and this uncertainty leads to controversy over the appropriate magnitude of incentives. This paper addresses these uncertainties by providing new estimates of the value of PV's energy and its effects on distribution systems.

Our analysis relies on simulated distribution system impacts. This approach has advantages and limitations. On the positive side, our detailed physical simulation allows us to study high levels of PV penetration while taking into account important factors such as the smoothing of aggregate generation profiles due to small-scale geographic diversity of PV production. It also allows us to examine effects that cannot be addressed without a detailed physical model, such as voltage quality. On the other hand, the detailed nature of the simulations limits our scope – in this case to one utility's territory, to a small but representative set of engineering models of distribution systems, and to one year of PV production and weather data. We note, however, that by using locational marginal prices for electricity, we implicitly capture both the energy and transmission value of PV.

1.2. Prior studies on system-level economics of PV

Three recent studies examined the how PV capacity might affect distribution capacity upgrades in California: Darghouth et al. (2010); Energy and Environmental Economics (2013); Beach and McGuire (2013). Darghouth et al. (2010) used existing estimates of PV's transmission and distribution capacity value but noted that capacity value is highly uncertain (ranging between \$0.001/kWh to \$0.10/kWh). They also noted that accounting for avoided line losses increases the value of PV above wholesale generation costs, though not by a significant amount (Darghouth et al., 2010, pp. 40-42). The Crossborder Energy study (Beach and McGuire, 2013) allocates capacity value to distributed PV by examining its output during the hottest hours of the year, which generally correspond roughly to the hours with the most energy usage. These capacity savings are multiplied by an estimated marginal cost of T&D capacity from utility rate cases to find a total capacity value (Beach and McGuire, 2013, pp. 23-28 of appendix B-2). E3 Energy and Environmental Economics (2013) uses a more granular method that estimates distribution capacity upgrade costs from specific projects forecasted by PG&E. They estimate the present value of PV for deferring those capacity projects by crediting PV production in any hour that a generic substation load profile is within one standard deviation of its peak (Energy and Environmental Economics, 2013, pp. C-40–C-44). None of these studies investigate the distribution capacity value of PV at the circuit level and for different quantities of PV installed on each circuit.

In addition to these California-based studies, we are aware of a several other studies that address the economic impacts of distributed PV on distribution systems. These address the value of deferred capacity upgrades and to a lesser degree avoided energy purchases: Woo et al. (1994); Gil and Joos (2006, 2008); Piccolo and Siano (2009).

This paper builds on prior work in several important ways. First, by working with circuit-level load growth assessments for each of PG&E's 3,000 feeders, we are able investigate the full range of capacity benefits on a feeder-by-feeder basis. Second, because we build our economic assessments up from a distribution power flow model that uses real PV production data as inputs, we are able to assess the economics of other engineering impacts of PV in distribution systems (most notably voltage impacts). Third, we investigate the impacts of PV on distribution circuits at a large range of penetrations (PV capacity ranging from 7.5% to 100% of feeder peak demand); this allows us to quantify the declining distribution capacity benefits of PV as circuit-level net load peaks get pushed later in the day when PV production is low.

2. Simulation and utility data inputs

Our study focuses on climate, photovoltaic production and infrastructure representative of PG&E's territory (Northern California). We chose this region in part for the prominence of distributed photovoltaics there and its and ongoing policy debates on issues of net metering and retail tariff design. We also chose this region due to our ability to access unique information (in particular, feeder-level load growth rates) under the terms of a non-disclosure agreement. For reference, in 2012 PG&E accounted for 38.3% of California's total energy consumption (California Energy Commission, 2013).

GridLAB-D models. We generated simulation results – summarized in the next section and described in detail in other papers (Cohen and Callaway, 2013, 2015) – with GridLAB-D, developed by Pacific Northwest National Laboratory (PNNL). GridLAB-D simulates distribution system operation over time and captures load variation due to varying building occupancy patterns and ambient conditions. It models major distribution system equipment including capacitors, voltage regulators, on-load tap changing transformers, and secondary distribution transformers. We used GridLAB-D version 2.3 with the forward-backward sweep power flow solver.

Table 1 summarizes the feeders we studied. These come from a set of "taxonomy" models provided by PNNL. PNNL assembled the taxonomy set by first collecting 575 distribution feeder models from 151 separate substations from a range of investor- and municipally-owned utilities and rural cooperatives in the United States (Schneider et al., 2008). The taxonomy feeders are the result of a systematic clustering analysis that identified 23 representative models from the set of 575. We simulated taxonomy feeders associated with California climate zones. This left us with five feeders in region 1 (R1, temperate west coast) and three in region 3 (R3, desert southwest). Though the original PNNL sample was neither random nor exhaustive, with these feeders we can explore a broad range of PV's impacts on representative distribution systems. Note that we did not study PV on General Industrial Case (GC) feeders (9-20% of feeders, according to PNNL) because they consist essentially of one large industrial or commercial load and we did not have available an appropriately representative set of commercial and industrial load shapes. The feeder taxonomy also does not include networked urban cores, which represent 5-10% of the distribution system (Schneider et al., 2008). Frequencies for the remaining feeders, taken from Schneider et al. (2008), are listed in Table 2.

Locations and Timeframe. We simulated each of the eight feeders in two locations – Berkeley and Sacramento – during the 366 days between September 25, 2011 and September 24, 2012, inclusive. We chose these locations and time span due to the availability of high-resolution PV and weather data and because Berkeley and Sacramento are representative of PG&E's two major climate regions (coastal and interior, respectively). These data and the feeder placement process are described later in this section. California peak demand during the selected year was fairly typical relative to the past decade, with a peak load of 46,846 MW in 2012 versus a high of 50,270 MW in 2006 (CAISO, 2013b).

PV Generation Data and Assignment to Feeder Locations. The PV integrator SolarCity provided a database of instantaneous power at each inverter they monitor (roughly 7,000 systems, mostly in California) under the terms of a non-disclosure agreement. The majority of inverters provide data on the quarter hour; some have one-minute data. 325 systems in the vicinity of Berkeley and 308 systems in the vicinity of Sacramento passed our data quality checks, with minimal gaps in recording and very few anomalous readings.

We associated PV profiles with GridLAB-D houses to capture diversity in output driven by differences in cloud cover, array orientation, technology and shading. We constructed geographic layouts of the taxonomy models (Cohen and Callaway, 2013; Cohen, 2013), and then used ArcGIS to superimpose the locations of the SolarCity PV systems on the feeder layouts; we ran a "nearest neighbor" query to associate each GridLAB-D distribution transformer with the closest SolarCity profile with acceptable data quality. Roughly 100 PV systems were matched with a GridLAB-D transformer in each location. The matched systems had ratings between 1.6 kW and 13.2 kW. If necessary we reduced the capacity of the assigned PV system on simulated buildings to ensure the array size did not exceed available roof area.

Penetration Levels and PV Placement. We define PV "penetration" relative to a baseline (no PV) loading for each feeder as:

$$\text{PV penetration} = \frac{\sum(\text{PV system ratings})}{\text{Peak feeder load from baseline run}}$$

We populated as many houses with PV as necessary to vary penetration from zero to 100 percent. We placed PV randomly across the available house models. We used the same random number seed in each scenario to ensure that houses populated with PV in the lower penetration scenarios were a strict subset of those populated in the higher penetration scenarios, in order to isolate the effect of penetration from the effect of placement. We used the same random ordering of houses for PV placement in each test location, and modeled PV as a unity power factor "negative load".

Deployment Timelines and Financial Discounting. In our economic calculations we compute the net present cost or value of PV over a ten year horizon using 2012 dollars. In most cases we discount with PG&E's weighted average cost of capital (WACC) of 7.6% less a combined inflation plus project escalation rate of 2.5% (PG&E, 2013a) – yielding a net discount rate of $r = 5.1\%$.

We define penetration scenarios by a function that specifies the amount of PV penetration achieved in a given year:

$$p(t) = \frac{e^{\alpha t} - 1}{e^{\alpha T} - 1} X$$

where $0 < p(t) < 1$ is the penetration in year t, X is the final penetration, T is the year in which to reach the target penetration (ten, in our case) and α is a shape parameter. Figure 1 illustrates how the shape of $p(t)$ changes with varying α. α values above zero and less than 0.4 are likely most reasonable (with installations spread out over ten years), but we present results for several α values for comparison.

Most values of $p(t)$ did not correspond exactly to penetration levels that we modeled; e.g. on the way to 15% penetration in year ten the function passes through 0.7% in year one, 1.5% in year two, and so on. In these cases, we interpolated linearly between the the two nearest penetrations that we had modeled.

Weather Data. We used one-minute temperature, humidity, and solar irradiance data obtained for Berkeley from Lawrence Berkeley National Laboratoray (Fernandes, 2012) and for Sacramento from SOLRMAP at the Sacramento Municipal Utility District(National Renewable Energy Laboratory, 2012). The weather data determined HVAC load in GridLAB-D. Using SolarCity generation data sources near to the weather stations preserved the correlation between air conditioning load and PV generation.

PG&E Feeder Data. We obtained feeder-level capacity and peak loading data (in MW) from 2012 and projected annual load growth percentages for 2013-2017 for 2,987 feeders in the PG&E service territory, provided under the terms of a non-disclosure agreement by PG&E (PG&E, 2013a). 36.3% of these feeders are located in PG&E's coastal region, and we mapped the data from those to temperate west coast taxonomy feeders (region R1). The remaining 63.7% of feeders are located in PG&E's interior region, which we mapped to the desert southwest climate taxonomy feeders (region R3). We used peak demand projections based on one-year-in-two weather data.

3. Summary of Simulation Engineering Results

System Losses. By serving loads locally, system losses decrease with PV penetration. As with prior studies (Quezada et al., 2006; Widén et al., 2010; Navarro et al., 2013; Thomson and Infield, 2007) we found that on some feeders losses begin to increase at very high penetrations due to heavy reverse flow conditions. However on most feeders, losses continued to decrease to the maximum penetration level we studied (100%). In general, feeder type had a stronger influence on the total magnitude of losses than did climate.

Peak Loading. PV reduced peak load by 6-35% (at 100% penetration) over the period we studied. Demand reductions are well below the penetration level because peak demand occurs in late afternoon or early evening, later in the day than peak PV production. In general we found that location (which drove load and PV production profiles) had a stronger influence on peak load reduction than feeder type.

Transformer aging. Transformer aging is driven by thermal degradation; higher loading results in greater losses and accelerated insulation aging. In general, we observed minimal aging in all scenarios and penetration levels, with a mean equivalent aging of up to 0.29 y in one scenario (R3-12.47-3, Sac.) and all other scenarios having mean aging less than 0.001 y. We sized transformers at or just above their baseline peak load (Cohen and Callaway, 2013); aging would have been faster if the transformers were undersized.

Voltage regulators. Voltage magnitude on a conductor typically declines in the direction of power flow, and as power flow increases, voltage declines further. There are three basic types of equipment that maintain voltage within prescribed bounds in a distribution circuit: on-load tap changers (LTC) located at distribution substations, capacitor banks and voltage regulators. LTCs and voltage regulators automatically adjust voltage by changing the "turns ratio" on an in-line transformer to maintain voltage within a prescribed range. We only studied voltage regulator impacts. We neglected LTC impacts because their operation is a strong function of transmission level voltage and because GridLAB-D does not model transmission impedance (meaning LTC output voltage is minimally affected by PV variability); we neglected capacitor bank switching because, to the extent it occurs, is often scheduled (rather than based on a voltage measurement). See (Cohen and Callaway, 2013) for more discussion. Overall we found that the change in the number of tap changes on the regulators ranged from negative 10 percent to positive 30 percent.

Voltage quality. In general, across all penetrations and feeders, we found voltages to be relatively well-controlled, with most runs having less than 0.002% of readings out of the ANSI standard range (virtually unchanged from the base case), and the worst case (R3-12.47-3, Sac.) having 0.32% of readings out of range at 100% penetration. This is consistent with prior work suggesting that many feeders can support high penetrations of PV without voltage violations (Hoke et al., 2013). Across the scenarios we investigated, the propensity for voltage excursions to occur was most strongly driven by location, with the most occurring in Sacramento.

Reverse power flow. We studied the incidence of negative real power flow ("backflow") through the substation, which can be a proxy for protection equipment problems and higher interconnection costs. At 50% penetration, 8 of the 16 scenarios exhibited occasional backflow, but no more than 1% of the time in any one scenario. At 100% penetration, all scenarios experienced backflow at least 4% of the time.

4. Economic Results

4.1. Energy and Transmission Value of PV

PV's energy and transmission value is increased by PV production's positive correlation with electricity prices, and its tendency to reduce system losses.[1] In this paper we will inves-

[1]Note that PV may *increase* end-use demand slightly by causing voltage-dependent loads to consume more power in high voltage conditions. GridLAB-D captures this effect, though we did not disaggregate it from other effects that tend to reduce net load.

tigate this value using locational marginal prices from the study area; because these prices include energy, transmission congestion and transmission loss components they implicitly capture both the energy and transmission value of PV at specific locations. However given the "lumpy" nature of transmission investments, the LMP is only a rough proxy for the value of deferred transmission infrastructure upgrades.

We calculated the net LMP benefit for each feeder as the difference between the cost to supply energy at the substation at 0% PV penetration and the cost to serve the substation at the given PV penetration:

$$\begin{aligned} C_j(X) =& (\text{feeder } j \text{ energy cost without PV}) \\ & - (\text{feeder } j \text{ energy cost with X\% PV}) \\ =& \sum_t \lambda_{j,t} D_{j,t}(0) - \lambda_{j,t} D_{j,t}(X) \end{aligned} \tag{1}$$

where j indexes the taxonomy feeder, D is simulated hourly demand at the feeder head, and $\lambda_{j,t}$ is the hourly locational marginal price (LMP) for the feeder's location.[2] We obtained hourly LMPs from the California Independent System Operator's (CAISO) day-ahead market for nodes CLARMNT_1_N001 (Berkeley locations) and WSCRMNO_1_N004 (Sacramento locations) (CAISO, 2013a).[3]

We calculated a weighted average energy benefit within and across regions as follows:

$$C_{\text{av}}(X) \;=\; p_{\text{R1}} \sum_{j \in R1} f_j C_j(X) + p_{\text{R3}} \sum_{j \in R3} f_j C_j(X), \tag{2}$$

where X denotes the penetration level, R denotes region (R1, coastal; R3, interior), j indexes the taxonomy feeders, f_j denotes the frequency of feeders within each region (see Table 2), and we used $p_{\text{R1}} = 0.363$ and $p_{\text{R3}} = 0.637$ to define the frequency of feeders in PG&E's coastal and interior zones, respectively (see Section 2). This provides a representative estimate of the energy benefit across all penetration levels. We computed PV energy for the representative sample, $E_{\text{PV,av}}(X)$ in the same way.

For each feeder, we calculated end-use consumption by subtracting system losses from substation energy at 0% PV penetration and we then computed a weighted average end-use consumption for the sample using the same weighted average approach as in Eq.(2).

We factored in future load growth by scaling consumption to the 2012-2022 projections for PG&E published by the California Energy Comission (CEC) (California Energy Commission, 2012, p. 6, California Energy Commission, 2013, pp. 36-40). These projections include net load reductions due to customer sited PV, since the CEC assumes that a higher percentage of generation will come from this source over time. The CEC provides high and low estimates of customer PV generation, with a midrange of 1% of PG&E's consumption in 2012 and 2%

[2]LMP patterns will very likely change over ten years, depending on fuel and carbon prices and generation infrastructure. A thorough investigation of these future scenarios is very important, but outside the scope of this paper, whose key focus is distribution systems.

[3]We compared several nodes in the general area of Berkeley and Sacramento and chose these two arbitrarily after confirming that differences in price relative to neighboring nodes were very small.

in 2022 (California Energy Commission, 2012, p. 6, 28). To convert the CEC consumption figures to end-use consumption, we multiplied the CEC's "CED 2011 Revised-Mid" forecasts by one plus the solar generation ratio, scaled linearly from 1-2% over the 10 year period.

Next, we calculated the ratio of PG&E consumption to that in our sample, denoted s_y with y indexing years. The ratio ranged from $s_1 = 5{,}720$ to $s_{10} = 6{,}453$. We multiplied the representative feeder energy benefit by s_y to scale it to the PG&E system.[4] Then, using the same method as PG&E (2011), we levelized the energy benefits by dividing the net present value of C_{av} by the sum of discounted PV generation, $E_{\text{PV,av}}$:

$$\text{levelized energy value} = \frac{\sum_{y=1}^{10} \frac{s_y C_{\text{av}}(X_y)}{(1+r)^y}}{\sum_{y=1}^{10} \frac{s_y E_{\text{PV,av}}(X_y)}{(1+r)^y}}. \tag{3}$$

In all scenarios we found the average levelized energy value to be between \$0.0349/kWh and \$0.0351/kWh. The weighted average LMP between Berkeley and Sacramento during our test year was \$0.0297/kWh[5] , meaning PV was about 18% more valuable than a resource with constant production and no effect on losses or voltage-dependent loads. This percentage is consistent with prior work, e.g. Borenstein (2008). The relative insensitivity of the average value to penetration occurs because cost and energy benefits are roughly linear functions of penetration. The small variation across scenarios was due to random variations in which PV generation profiles were chosen and where they were placed on the feeders (see Section 2).

4.2. Distribution Capacity Value of PV

Growth in distribution feeder peak load creates a need for investment in higher capacity distribution equipment such as transformer banks and conductors. To the extent PV reduces peak net load, it can defer these investments. In this section we combine our simulation results with PG&E distribution system data to estimate the system-wide distribution capacity benefit of distributed PV.

4.2.1. Projects and Feeder Data

Figure 2 illustrates how we calculate the capacity benefit of distributed PV. The approach, similar to Gil and Joos (2006); Piccolo and Siano (2009); Energy and Environmental Economics (2013); Woo et al. (1994), involves first establishing a baseline estimate of the year in which distribution capacity projects would occur in the next ten years. Then, based on peak load reduction simulation results, we compute the year in which the same project would occur in the presence of PV. Though we limited the pool of initial projects to a ten

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[4]While the calculated multiplier was on the order of 6,000, there are approximately 3,000 feeders in PG&E's system. This implies that the average PG&E feeder uses about twice as much energy annually as our weighted average simulated feeder. Since the sample is being scaled to the full system size this discrepancy does not affect the overall magnitude of the results.

[5]\$0.0297/kWh is roughly half the levelized cost of energy from combined cycle gas fired generators (U.S. Energy Information Administration, 2014), suggesting that the market is not in long-run equilibrium. This is likely because natural gas prices in the the U.S. in late 2011 and 2012 were extremely low. But it may also reflect the fact that a portion of generators' levelized costs are paid for via resource adequacy capacity contracts. This highlights the fact that both the basic energy value and the size of the PV "premium" depend on energy market conditions; they may be larger or smaller in future years.

year horizon, we continued to account for the cost of deferred projects for 25 years. We considered projects deferred beyond 25 years to be completely avoided.[6]

We used feeder-level capacity and peak loading data for 2012-2017 described in Section 2, and carried the 2017 growth rates forward for a rough prediction of future trends. We assumed that each feeder project occurs in the year that its peak load reaches 100% of rated capacity.[7]

Before running the PG&E feeders through the model, we eliminated the following categories:

- Feeders operating at or below 4.16 kV (2.4% of PG&E capacity). These are smaller, older, idiosyncratic parts of the distribution system that PG&E engineers felt would not be appropriate to include in a general analysis of this kind (PG&E, 2013a).

- Feeders already having greater than 10% PV penetration (7.6% of PG&E capacity). Because peak load growth forecasts for these feeders are likely affected by existing PV, their forecasted growth rates do not provide a good "control" against which to apply further peak load reductions due to PV. These feeders are relatively similar to the population (2012 peak demand average of 7.0 MW versus 7.7 MW for the population; average voltage of 14.5 kV versus 14.1 kV for the population; and 31.4% coastal / 68.6% interior versus 36.3% / 63.7% for the population).

- Feeders already loaded over their rated capacity (1.7% of total capacity).

We used demand growth data to estimate which of the remaining feeders would require a capacity project in the next ten years. This left us with 296 feeders totalling 4,143 MVA (roughly 10% of the 2,987 feeders, and 20% of the total 20,600 MVA of capacity, for which we received data). This equates to roughly 30 distribution projects per year, which is approximately the number of PG&E feeders that actually reach capacity in a given year (PG&E, 2013a).

4.2.2. Applying Model Runs to PG&E Feeders

We permuted each R1 result that was simulated with Berkeley weather data with the loading and load growth data for each feeder in PG&E's "coastal" service territory, and each R3 result that was simulated with Sacramento weather data with each feeder in PG&E's "interior" service territory. For each combination of taxonomy feeder and PG&E feeder that would require a capacity project within ten years, we computed savings in net present value as a ratio (ρ) between the savings and the original project cost:

$$\begin{aligned}\rho_{i,j}(X,\alpha) &= \frac{(\text{present value of original project}) - (\text{present value of deferred project})}{\text{present value of original project}} \\ &= \frac{(\text{real project cost})(1+r)^{-y^0_{i,j}} - (\text{real project cost})(1+r)^{-y^d_{i,j}(X,\alpha)}}{(\text{real project cost})(1+r)^{-y^0_{i,j}}} \\ &= 1-(1+r)^{(y^0_{i,j}-y^d_{i,j}(X,\alpha))}\end{aligned} \tag{4}$$

[6]Using a WACC of 7.6% (our nominal case), a project deferred from year 1 to year 25 would decrease in present cost by 71%.

[7]In practice, other factors can affect project timing; see section 4.2.6 for further discussion.

where i indexes the PG&E feeder and j indexes the simulation results of each GridLAB-D taxonomy feeder (in the appropriate climate), r is the discount rate, and $y^0_{i,j}$ is the originally estimated year of the capacity project. $y^d_{i,j}(X, \alpha)$, the deferred year, depends on the year ten penetration level X and deployment scenario α.[8]

We then calculated $\rho_{\text{aggregate}}$, the total weighted average normalized savings in net present value across all GridLAB-D taxonomy feeders in the coastal and interior zones:

$$\rho_{\text{aggregate}} = \frac{\sum_{i \in \text{R1}, j \in \text{R1}} f_j \rho_{i,j} + \sum_{i \in \text{R3}, j \in \text{R3}} f_j \rho_{i,j}}{N}, \tag{5}$$

where $N = 296$ is the total number of feeders we estimate will require a capacity project in the next ten years, R denotes region (R1 / coastal; R3 / interior), f_j is the regional taxonomy feeder frequency from Table 2, and N is the total number of feeders across all regions.

4.2.3. Scaling to PG&E's Distribution Capacity Budget

We calculated the system-wide financial benefit of project deferral by multiplying $\rho_{\text{aggregate}}$ by the fraction of PG&E's distribution budget that could reasonably be affected by PV. PG&E records and forecasts all line and substation capacity upgrade expenditures in major work categories (MWC) 06 and 46, respectively (PG&E, 2012, Workpaper Table 12-5). In consultation with PG&E (PG&E, 2013a), we assumed the following MWC subcategories would be influenced by PV's contribution to peak loading: MWC 06A (Feeder Projects Associated with Substation Work), MWC 06D (Circuits Reinforcements (DE Managed)), MWC 06E (Circuits Reinforcements (PS Managed)) and MWC 46A (all projects). We excluded some smaller distribution expenses that would not likely be influenced by PV's peak load reduction: 06B (Overloaded Transformers), 06E (Reinforce Circuit > 6000 customers per feeder), 06E (Complete Mainline Loops per Standard), 06G (Voltage Complaints (Includes PEV)), and Line Voltage Regulator Revolving Stock.

In total, the categories deemed sensitive to PV impacts on peak loading constitute 93% of PG&E's 2012 distribution capacity budget in MWC 06 and 46, or approximately \$133 million. For 2013-2016 we used nominal budget projections directly from PG&E (2012, Workpaper Table 12-5) and found that 83–89% of the budget in those years is projected to be sensitive to PV peak load reduction[9]. For 2017-2022 we used the average PV-sensitive budget for 2013-2016. The total net present cost of the budget that we deemed PV-sensitive is \$1.2 billion (using $r = 5.1\%$).

Note that we did not explicitly model all measures that can be implemented to deal with a capacity shortfall. Instead, by normalizing the model's results and applying them to the entire distribution budget, the approach we use implicitly captures all measures in the historical budget and forecasts. That is, the distribution budget may include shortfalls that were solved through less expensive means than full replacement of equipment, such as switching loads to different feeders. In other words, this analysis assumes that while the *number* of capacity shortfalls may change with increasing PV penetration, the distribution of actions taken in response will not change.

[8] Note that the real project cost, assumed to be independent of time, cancels from the ratio.

[9] The percentages are lower than in 2012 because the excluded work categories are projected to grow somewhat more quickly than the included categories.

4.2.4. Value of Capacity Deferral

Figure 3 displays the net present value of distribution capacity project deferral, computed by multiplying $\rho_{\text{aggregate}}$ by the estimated peak-load-sensitive PG&E distribution budget, for a range of penetration levels and deployment ramps. The total value of deferral increases at a decreasing rate, because as PV capacity is added the feeder peak gets pushed later in the day, when PV production is lower. One can also see that the value increases with the rate of deployment, but there is relatively little difference between immediate deployment of PV and intermediate deployment rates. The total NPV of deferral is substantial, up to half of the estimated 10 year distribution capacity budget. Note also that if the large industrial ("GC") feeders accrue PV-related capacity benefits similarly to the weighted average of the feeders we modeled, the total benefit across all penetration levels and deployment trajectories would be about 19% higher (see Section 2 for discussion of the treatment of GC feeders).

Energy-levelized capacity benefit. To put the overall capacity benefit into perspective, we can levelize the capacity benefit across the kWh of PV generated throughout the ten year horizon. As with other levelized statistics we discount future energy production in addition to costs:

$$\text{Energy-levelized capacity benefit} = \frac{\text{net present value of deferral}}{\sum_{y=1}^{10} \frac{s_y E_{\text{PV,av}}(X_y)}{(1+r)^y}}, \tag{6}$$

where we compute energy production in year y as the *total* PG&E-wide PV production associated with each particular deployment and final penetration scenario.

Figure 4 shows the result of this calculation. As with the total benefit, capacity benefit rises with PV penetration but with diminishing returns. Overall the range of levelized benefits is between 0.05¢/kWh and 0.7¢/kWh; this is roughly 0.3% to 5% of the average retail tariff in PG&E. These numbers are similar to the range reported by Darghouth et al. (2010) (0.1¢/kWh - 10¢/kWh).

Recall, however, that we evaluated the present value of capacity deferral only on those feeders identified as having a capacity project in the first ten years of analysis. This subset of feeders is 10% of the number of feeders, and 20% of total capacity, in PG&E. Therefore if one assigned the capacity value only to those PV systems on feeders with deferred projects, the levelized value of those systems would be roughly five times greater (1/0.2) than the numbers reported in Figure 4, or 0.25¢/kWh to 3.5¢/kWh (roughly 1.8% to 25% of the average retail tariff).

Though earlier deployment always improves the NPV of the capacity benefit, the effect on the energy-levelized benefit is slightly different. As one might expect, levelized benefit is greatest with intermediate rates of deployment, where solar deployment (and energy production) roughly follows the feeder load growth trajectories.

Annualized capacity benefit. An alternative way to put the capacity benefit in context is to normalize per kW of installed PV. We computed the following metric for each target penetration and ramp rate:

$$CV_{\text{av}} = \frac{\text{annualized capacity benefit}}{\text{(per unit of PV capacity)}} = \frac{\frac{\text{net present value of deferral}}{\text{target PV penetration on all feeders}}}{\text{annuity factor}}, \tag{7}$$

where we annualize in order to facilitate comparisons with annual distribution fixed charges as well as generation capacity costs at the conclusion of this section. To compute the annuity factor we used the same discount rate as before ($r = 5.1\%$), and we assumed benefits accrue over $n = 25$ years. We made the second assumption because, although we only compute deferral benefits on feeders that would have projects in the first ten years in the absence of PV, we count the cost of the deferred project for up to as much as 25 years. In this case, with $r = 5.1\%$, the annuity factor is $\frac{1-(1+r)^{-n}}{r} = 13.95$ years.

Figure 5 shows the result, with values ranging from nearly zero to more than \$6/kW-yr As one would expect, the value declines with increasing penetration and increases with the rate of deployment. By comparison, at \$5.30/W (the 2012 average price for residential systems (Barbose et al., 2013), the annualized *cost* of PV was on the order of \$380/kW-yr in 2012. Moreover, if DOE's SunShot 2020 goal of \$1.50/W for residential solar is met (U.S. DOE, 2012), the annualized cost would be roughly \$110/kW-yr, still much greater than the annualized benefit.

However, as mentioned in Section 4.2, we found that only 10 percent of feeders would require a project within ten years. Therefore dividing by PV capacity on *all* feeders dilutes the value of PV on feeders that *would* have projects. We computed the following metric to capture the capacity value on feeders with deferred projects:

$$\begin{aligned} CV_{\text{deferred}} &= \text{deferred feeder annualized capacity benefit} \\ &= \frac{\frac{\text{present value of capacity deferral}}{\text{target PV penetration on \textit{deferred} feeders}}}{\text{annuity factor}}. \end{aligned} \tag{8}$$

We then estimated feeder-specific capacity value as follows, where i and j denote deferred PG&E feeders and GridLAB-D taxonomy feeders, respectively:

$$CV_i = CV_{\text{deferred}} \frac{\sum_{j \in R_i} f_j \rho_{i,j}}{\rho_{\text{aggregate}}} \tag{9}$$

where the normalized NPV of deferral, $\rho_{i,j}$, is defined in Eq. (4), f_j is the regional taxonomy feeder frequency from Table 2, R_i is the subset of taxonomy feeders with the same regional designation (either interior or coastal) as PG&E feeder i, and $\rho_{\text{aggregate}}$ is defined in Eq. (5). This metric weights the average deferral value by the ratio of each feeder's normalized NPV of capacity deferral to the normalized average NPV of capacity deferral – in effect this gives the feeder-specific deferral value. Figure 6 shows percentiles of capacity benefit on the subset of feeders with projects in the first ten years for the fast ramp scenario ($\alpha = -50$). Because we find that roughly 10% of PG&E feeders would require capacity projects within ten years, the percentiles in this figure are roughly ten times larger than they would be if computed across all feeders in PG&E. These numbers compare more favorably to current and and projected annualized costs of PV, though on most feeders (and all in the percentiles we show) the benefits remain well below the cost of PV.

We can also compare these annualized numbers to the size of a possible fixed charge on customer bills. In 2013 California's AB327 authorized its Public Utility Commission to approve up to \$120 per year, in partial recognition of the fact that owners of PV use less energy but still place burdens on infrastructure. However these results suggest that PV systems on deferred feeders could have benefits of the same order as the fixed charge. For example, at a low feeder PV penetration (7.5 percent) a 5 kW system would create \$50 to over \$300 per year benefit in terms of avoided capacity upgrades; even at 100 percent penetration the benefit could be as high as \$100 per year.

Though earlier studies suggested a large range of PV capacity values depending on model assumptions (e.g. Darghouth et al. (2010)), in this case the input data themselves (circuit loading and peak load growth statistics) produce a large range of values, holding model assumptions constant. As we will discuss in the conclusions, this suggests that location-specific compensation for PV capacity benefits may be an effective strategy to minimize utility-wide capacity upgrade costs. Implementing this type of tariff could be challenging from a regulatory and process perspective, though we note that Minnesota's recently approved "Value of Solar Tariff" methodology includes a location-specific capacity value, and it has received both positive (e.g. Draxten, 2013) and negative (e.g. Podratz, 2013) comments from utilities.

4.2.5. Discount Sensitivity Analysis

Because capacity value benefits depend on events that occur in the future, the magnitude of the benefit depends on the assumed WACC (or discount rate). Therefore we ran the model for different values of α (PV deployment rates) and using a WACC of 5.0% and 10.0% (less and greater than the originally assumed WACC of 7.6%). Figure 7 shows the result. As expected, higher discount rates make deferral more desirable. Though immediate deployment (fast ramp) has the highest sensitivity in absolute terms, sensitivities in percent terms (e.g. the percent change in benefit due to increasing or decreasing WACC) are comparable for all WACC / ramp combinations.

4.2.6. Caveats

From a utility perspective, uncertainty in the reliability of distributed solar may prevent some or all of the capacity benefit we measured from being realized during the investment planning process; for instance, utilities may conservatively prefer to provide distribution capacity that would normally not be needed due to PV's reduction of peak load, in order to be prepared for an emergency that temporarily takes PV offline. We also note that in practice capacity projects may be initiated sooner than absolutely necessary to economize on personnel and equipment in the area for other work. To the extent that these phenomena affect distribution capacity costs, they would reduce the capacity value of PV somewhat; we view characterizing this effect as an opportunity for future research. For further discussion of these issues from a utility perspective see PG&E (2013b).

A related concern is that all results are based one year of simulation. We did not directly analyze the impact of cloudy or partly cloudy days (or a lack thereof) on peak feeder loading. However in PG&E's climate zones – especially in the interior region – clouds are infrequent in hours when peak loading occurs. Therefore we believe it is unlikely that other years would have significantly different peak net loading resulting from cloud cover. This may not be the case in other climates.

Finally, we were not able to validate the peak load shapes produced by GridLAB-D against actual feeder-level load shapes in the PG&E service territory. Our analysis in Cohen and Callaway (2015) compares GridLAB-D load shapes against load data from all of PG&E, all of CAISO, and a few isolated substations provided by PG&E under a non-disclosure agreement. Those results suggest that some circuits peak earlier and some peak later than the GridLAB-D load shapes, but that GridLAB-D load shapes are roughly in the middle of the distribution of typical feeder load shapes.

4.3. Voltage Regulators and Voltage Quality

As we indicated in Section 3, PV can impact voltage regulator operation patterns by influencing distribution circuit flow. To the extent this increases or decreases voltage regulator switching, PV could change the maintenance requirements (and therefore cost to distribution companies) for voltage regulators. Using our physical results for voltage regulators (Section 3 and Cohen and Callaway (2013, 2015)) we can make some very general estimates as to how regulator maintenance expenses might change if the trends observed in the simulated taxonomy feeders scaled up to the system.

There are several PG&E major work categories (MWC) related to voltage regulators. MWC BK (Distribution Line Equipment Overhauls) is a category that includes needed overhauls for line reclosers and regulators; in 2012 expenses of $2,645,000 were forecast for this purpose (PG&E, 2012, p. 5-34). Regulators constitute about 41% of the total units of line equipment (regulators + reclosers) PG&E (2013a). Under the coarse assumption that the unit cost to overhaul a regulator is the same as the unit cost for a recloser, regulator overhaul expenses are roughly $1,085,000. MWC 48 (Replace Substation Equipment) includes several "Subprograms < $1M", including a line item for regulator replacements projected to be $297,000 in 2012 (PG&E, 2012, Workpaper Table 13-16). Some LTC replacement work also takes place under MWC 54 (Distribution Transformer Replacements) which had an overall forecasted value of $61,005,000 in 2012 (PG&E, 2012, p. 13-14). However, most of this expense is for general substation transformers not LTCs, and projects are usually triggered by factors unrelated to the LTC such as dissolved gas analysis of the transformer oil; in these cases the LTC is replaced in the course of a larger project rather than due to wear on the LTC itself (PG&E, 2013a). Therefore we conclude that MWC 54 expenses are unlikely to be affected by changes in LTC operation triggered by PV. This leaves us with a total projected 2012 regulator budget of $1,382,000 from MWC BK and 48 that could be affected by changes in tap-change activity.

If we assume that substation LTCs will respond similarly to line regulators (this is a strong assumption because LTCs will respond more to transmission level variation in voltage), we can extrapolate our earlier regulator results (Cohen and Callaway, 2013) to the system and estimate how much PV might affect overall regulator expenses. At the high end (100% penetration), PV increased regulator operations by 32%. Assuming line regulator and LTC maintenance requirements increase linearly with the number of tap changes, then maintenance expenses would also increase by 32%, or roughly $442,000 in 2012. In a more optimistic scenario where regulator operations decreased by 8% due to the presence of PV (in line with our "best case" simulation results) across the system, regulator maintenance expenses might decrease by $111,000. In reality both of these scenarios might exist somewhere in the system, in addition to many intermediate cases and a few more extreme ones, likely resulting in an overall expense change somewhere between these bookend values. The overall impact will be more favorable if the reduced current duty brought about by PV also extends regulator lifetime, but the sensitivity of regulator lifetime to reductions in current is heavily dependent on the regulator model and its pre-PV current duty, so we lack the data to estimate the magnitude of this effect. In any case, the clear conclusion of the budgetary analysis is that any regulator maintenance cost changes – whether they are positive or negative – will be very small in comparison to the energy cost and capacity cost effects of PV.

For comparison, PG&E's budget for addressing Voltage Complaint Projects Involving Secondary Distribution (MWC 06G) was forecast to be $2,800,000 in 2012; some fraction of MWC 06E (Circuits Reinforcement – Project Services Managed, forecast at $36,941,000 in 2012) is also dedicated to "primary distribution voltage correction work" (PG&E, 2012, p. 12-20). As noted in Cohen and Callaway (2013, 2015), voltage quality on our simulated feeders was only mildly affected by PV, although we expect that in the field there will be some feeders where it will be a significant issue. Though our data are not sufficient to make a conclusive estimate of how frequently PV will actually trigger complaints or create serious enough problems to require additional work in the above mentioned MWCs, they suggest that the costs will be relatively small.

4.4. Transformer Aging and Backflow/Protection

As noted in Cohen and Callaway (2013, 2015) we observed minimal transformer aging across all of our simulated scenarios, with little change due to PV except with one particular feeder/climate combination. We attribute the lack of aging mainly to conservative sizing of the distribution transformers relative to the loads served. We attempted to locate a data set of distribution transformer loading to ascertain how well this assumption matched California's actual distribution transformers, but utilities do not track the loading of these transformers closely.

We do expect that PV will have some effect on transformer lifetimes in areas where transformers are loaded at or above capacity. In most cases, lifetime is likely to be extended as daytime transformer loading is reduced by generation on the secondary side. In some cases where the installed PV power is much greater than the previous daytime load, transformer lifetime may be decreased by large reverse power flows. Given the uncertainty about existing transformer load shapes and ages it is difficult to estimate the size of the benefit (or cost) that PV could provide.

Similarly, we refrain from drawing any conclusions about the economic effect of backflow caused by high PV penetrations (see Section 3 for physical results). The main concern regarding backflow is that it may require modifications to protection systems that were designed with only one-way power flow in mind. Determining whether such corrections are necessary on any given feeder requires a specialized protection analysis which is beyond the scope of this study.

5. Conclusions and Policy Implications

We found that PV provides a capacity deferral value of up to $6/kW-yr when averaged across the potential impact on all feeders in PG&E's service territory. However, when we disaggregate the result by feeder – some of which are much closer to requiring a capacity upgrade project and have load shapes that are better correlated with PV production – the capacity value can be as much as $60/kW-yr on a small subset of feeders. When viewed against a possible connection fixed charge (proposed to be on the order of $120/yr in California's AB327), the capacity deferral value of PV could be significant in some cases and inconsequential in others. Also when viewed against the cost to install PV ($380/kW-yr at the end of our study period Barbose et al. (2013), but possibly as low as $110/kW-yr if the DOE's SunShot goal of $1.50/W is met), the capacity deferral value of PV could be a significant incentive for some customers to install PV. There is some precedent for recognizing the capacity value of distributed PV (for example Minnesota's "value of solar" tariff), but our findings suggest that the range of distribution capacity benefits is significant enough that a location-specific credit should be considered. Much as the time-value of PV is recognized in time-of-use pricing tariffs, we propose that this spatially heterogeneous value of PV should be recognized in the structure of retail fixed charges. This process could be streamlined with substation-level loading, load growth and capacity data, though a full analysis of equity implications and administrative costs would be needed to determine if locational credits are, on the whole, desirable.

Our earlier results indicate that voltage regulator operations could increase by as much as 32% at high PV penetrations. If voltage regulator maintenance scales linearly with the amount of operation, our results in this paper indicate that distributed PV would increase annual costs by $442,000 – an extremely small amount of PG&E's roughly $6 billion operations and maintenance budget in 2012, and much smaller than the roughly $30-$40 million annual capacity benefit we estimate that PV would provide at the same penetration. Though we do not have sufficient data to assess the heterogeneity of these voltage impacts across PG&E's feeders, our earlier engineering simulations suggest feeder location and design can significantly impact the likelihood that PV will create voltage problems, suggesting that proactive distribution planning may serve to avoid these voltage problems altogether at relatively low cost.

Overall our results suggest that the distribution-level economic impacts we measure are on average very small, and slightly positive. A large part of those positive impacts seem to be concentrated in a small number of circuits. Therefore to the extent these benefits *could* be reflected in incentives to customer-sited PV, we do not anticipate that they would support a significant expansion in total PV capacity in our study region. This suggests that significant PV penetration in distribution systems will be economically justified only when the *energy value* – ideally including environmental externalities such as CO_2 – reaches parity with the levelized cost of PV.

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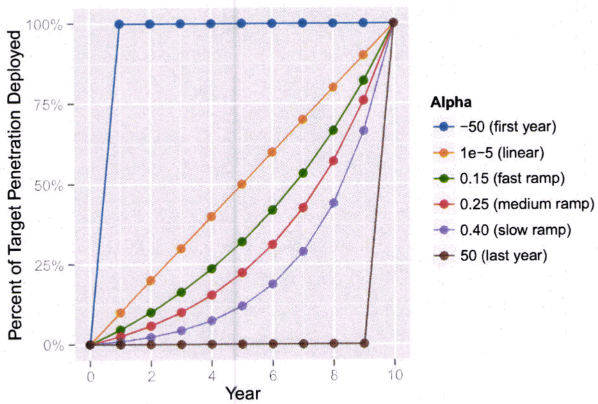

Figure 1: Representative realizations of our deployment ramp up function $p(t)$ for varying α.

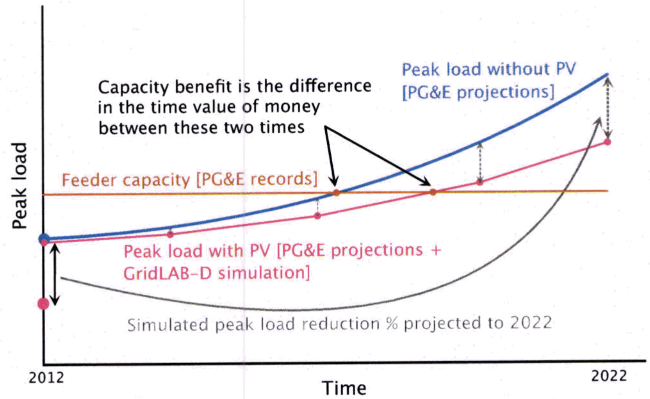

Figure 2: Schematic showing how the value of capacity investement deferral is calculated for an individual feeder at a given PV penetration.

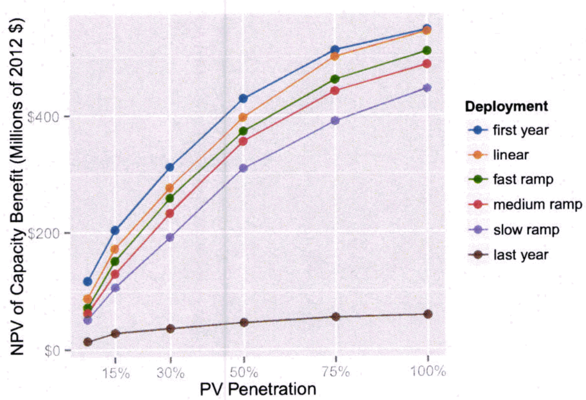

Figure 3: PG&E system-wide capacity benefit.

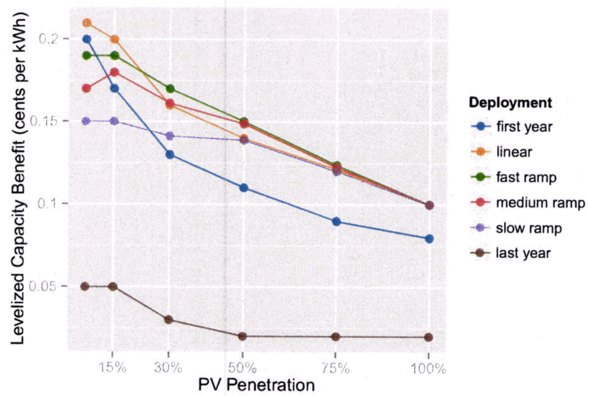

Figure 4: Energy-levelized capacity benefit, computed with Eq. (6) and $r = 5.1\%$.

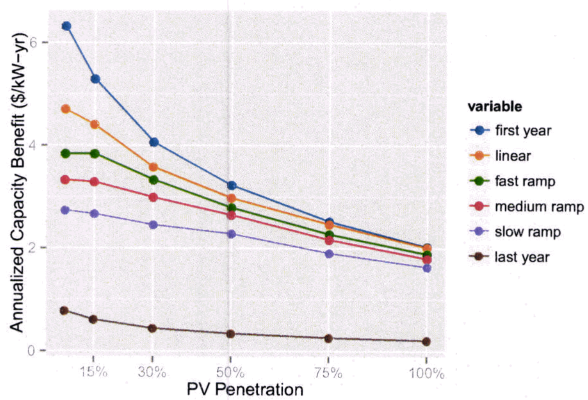

Figure 5: Average annualized capacity benefit, computed using Eq. 7. Note that the benefit is normalized by total PV capacity, rather than PV capacity on only the deferred feeders.

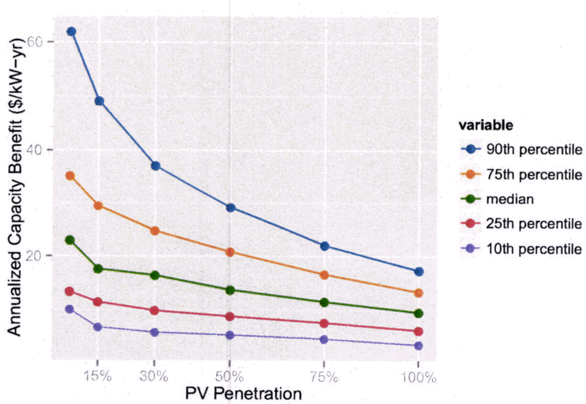

Figure 6: Capacity benefit percentiles on deferred feeders. Because we find that roughly 10% of PG&E feeders would require capacity projects within ten years, the percentiles in this figure are roughly ten times larger than they would be if computed across all feeders in PG&E.

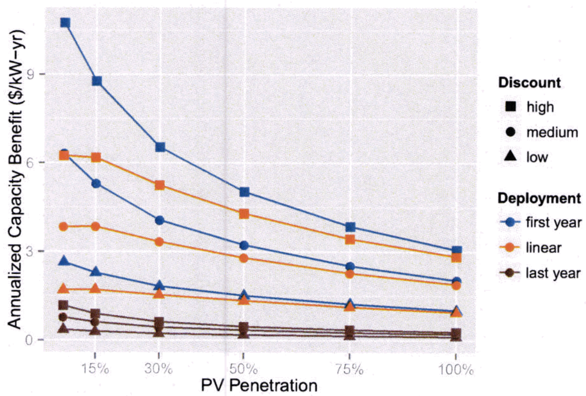

Figure 7: Sensitivity of capacity benefit to discount rate.

Table 1: Summary of Simulated Feeder Characteristics and Figure Legend

Name*	**Serves**[1]	**Nominal Peak Load (MW)**[1]	**Dist. Trans-form-ers**	**Avg House (kW)**[2]	**Approx Length (km)**	**Baseline Peak Load (MW)**		**PV Profiles Selected for Use**	
						Berk.	**Sac.**	**Berk.**	**Sac.**
R1-12.47-1	mod. suburban & rural	7.15	618	4.0	5.5	5.56	7.59	21	26
R1-12.47-2	mod. suburban & lt. rural	2.83	264	4.5	10.3	2.00	2.82	30	30
R1-12.47-3	moderate urban	1.35	22	8.0	1.9	1.27	1.60	10	8
R1-12.47-4	heavy suburban	5.30	50	4.0	2.3	4.31	5.65	12	12
R1-25.00-1	light rural	2.10	115	6.0	52.5	2.35	3.00	28	30
R3-12.47-1	heavy urban	8.40	472	12.0	4.0	6.64	8.70	20	25
R3-12.47-2	moderate urban	4.30	62	14.0	5.7	3.45	4.40	13	18
R3-12.47-3	heavy suburban	7.80	1,733	4.0†	10.4	7.54	9.67	56	55

[1] Schneider et al. (2008)

[2] Pacific Northwest National Laboratory (2012)

* Climate region of origin is indicated by R1 (temperate west coast) or R3 (arid southwest). Nominal voltage is designated by 12.47 or 25.00 (kV).

† Changed from default of 7.0 kW due to an excess of streetlighting. See Schneider et al. (2008); Pacific Northwest National Laboratory (2012) for the relationship between avg. house size and street lighting.

Table 2: Assumed frequency of R1 and R3 feeders, adapted from Schneider et al. (2008)

Feeder	Assumed frequency, f_j
R1-12.47-1	23%
R1-12.47-2	26%
R1-12.47-3	21%
R1-12.47-4	19%
R1-25.00-1	12%
R3-12.47-1	38%
R3-12.47-2	38%
R3-12.47-3	25%