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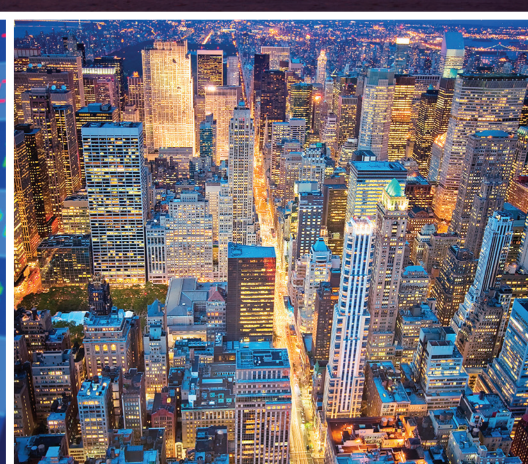
2017 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry



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ANNUAL REPORT OF THE U.S. INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2017 Financial Review is a comprehensive source for critical financial data covering 43 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on six additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms. These 49 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 94 for a list of these companies.

Contents

Highlights of 2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2017	2016r	% Change
Total Operating Revenues	364,009	350,596	3.8%
Utility Plant (Net)	1,182,722	1,061,891	11.4%
Total Capitalization	989,242	941,482	5.1%
Earnings Excluding Non-Recurring and Extraordinary Items	49,894	46,788	6.6%
Dividends Paid, Common Stock	25,233	23,461	7.6%

r = revised   Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution

Company Categories

Two categories are used throughout this publication that group companies on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: 80% or more of total assets are regulated.

Mostly Regulated: Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a "Diversified" category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a "Diversified" category.

President's Letter

2017 Financial Review

Today the electric power industry continues to lead a profound transformation across the nation. One thing remains constant—our commitment to meeting customers' needs by building and using smarter energy infrastructure, by providing even cleaner energy, and by creating the energy solutions customers want. This commitment guides us, and also provides opportunities to collaborate and make progress on key policy priorities.

While many changes are underway, the Edison Electric Institute's (EEI's) member companies—America's investor-owned electric companies—are transitioning to even cleaner generation and are leading the way on renewables. Since 2007, the mix of resources used to generate electricity has changed dramatically and is increasingly clean. Today, more than one-third of U.S. electricity comes from zero-emissions sources (nuclear energy and hydropower and other renewables). In addition, natural gas surpassed coal as the main source of electricity in the United States for the second year in a row in 2017. Electric companies are the nation's largest investors in renewable energy, providing virtually all of the wind and geothermal in the country—and the majority of installed solar and hydropower capacity.

Today, EEI's member companies connect millions of Americans in their homes, communities, businesses, and industries, and around the nation. We are an integral and robust component of our nation's economy. As a whole, the electric power industry contributes $880 billion to our nation's economy and supports more than 7 million jobs in communities across the United States—this includes nearly 2.7 million directly provided jobs that result from the industry's operations and investments. We also are creating long-term solutions to address the ongoing need for a skilled, diverse workforce in the future.

To better serve customers and investors, EEI launched a pilot environmental, social, governance, and sustainability-related (ESG/sustainability) reporting template in December 2017, with the goal of helping our member companies provide investors with more uniformity and better consistency for ESG/sustainability reporting. The EEI ESG Template enables our members to tell their very positive ESG story to investors and all key stakeholders.

In 2017, tax reform legislation was a top industry priority. Final passage of the Tax Cuts and Jobs Act in December was a win for electricity customers and enables our industry to continue to make needed investments in our nation's energy infrastructure. We believe passage of tax reform legislation provides a solid foundation for one of 2018's major policy initiatives: infrastructure investment.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the fourth straight year in 2017, after increasing from the BBB average that had previously held since 2004. Ratings upgrades were nearly identical to the previous year: a very favorable 73.6 percent of total credit actions, resulting from companies' increased focus on regulated operations that was achieved largely through asset sales, as well as the effective management of regulatory risk. The improved credit quality greatly supports the continued elevated capital expenditures, which set a new record high of $113.6 billion in 2017.

All but one of the EEI Index companies paid a dividend in 2017, and strong dividend yields continue to support electric company stocks. The industry's dividend yield at the end of 2017 stood at 3.4 percent, and 38 electric companies, or 88 percent of the industry, increased their dividend last year, the second largest percentage on record.

Looking ahead, I am optimistic about our industry. EEI's member companies are committed to providing the safe, reliable, affordable, and increasingly clean energy that drives our nation's economy and powers our everyday lives. By continuing to lead together on the issues driving the industry's transformation, EEI and our member companies are demonstrating Power by Association, and we are delivering America's energy future.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

Thomas R. Kuhn

President
Edison Electric Institute

Industry Financial Performance

Income Statement

Electric Output Decreases 0.9% in 2017

As shown in the table *U.S. Electric Output*, the U.S. electric power industry in 2017 made 3,989,942 gigawatt-hours (GWh) of electricity available for distribution in the continental U.S., a decrease of 0.9% from 2016's 4,026,393 GWh. The 2017 total was virtually identical to 2006's 3,988,868 GWh and nearly 3% below 2007's 4,100,612 GWh. Prior to 2017, U.S. electric output had increased for four consecutive years. The electric output data is compiled by the Edison Electric Institute on a weekly basis and represents all electricity placed on the grid in the contiguous 48 states by investor-owned electric utilities, rural electric cooperatives, government power projects and independent power producers.

Five of the nine U.S. power regions experienced a decrease in electric output in 2017. The Central Industrial and New England regions experienced the largest declines, at -2.7% each. The Mid-Atlantic, West Central and Southeast regions also experienced lower output for the year. The Pacific Northwest re-

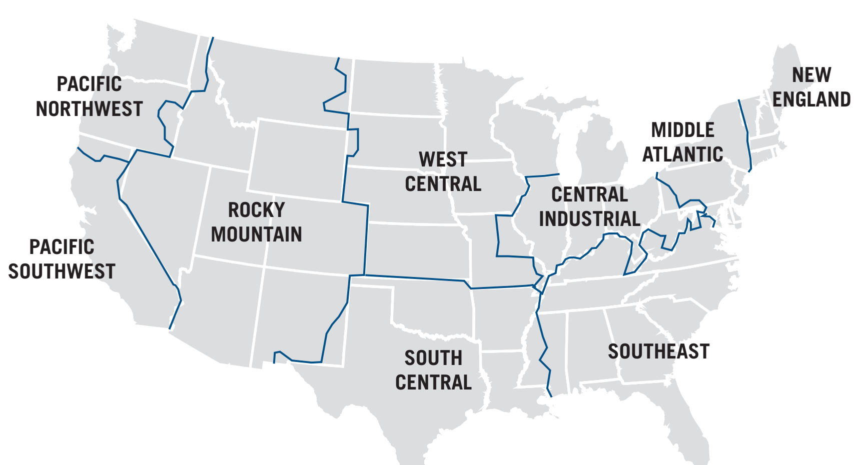
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2017	2016	% Change
New England	120,584	123,972	(2.7%)
Mid-Atlantic	424,973	436,082	(2.5%)
Central Industrial	658,276	676,837	(2.7%)
West Central	325,952	330,754	(1.5%)
Southeast	1,013,044	1,031,963	(1.8%)
South Central	725,643	716,334	1.3%
Rocky Mountain	278,313	275,310	1.1%
Pacific Northwest	159,537	152,220	4.8%
Pacific Southwest	283,621	282,921	0.2%
Total United States	**3,989,942**	**4,026,393**	**(0.9%)**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Information Group.

EEI U.S. Electric Output – Regions



Source: EEI Business Information Group.

gion saw the largest annual gain, at 4.8%, while the South Central region saw a fifth consecutive year-to-year increase. The Rocky Mountain and Pacific Southwest regions also saw gains.

EEI calculates weather-normalized electric output using cooling degree day (CDD) and heating degree day (HDD) data from the National Oceanic and Atmospheric Administration (NOAA) (see table, *U.S. Weather*). On a weather-adjusted basis, electric output increased in 2017 by 0.8%. The South Central region's weather-normalized output increased 3.5%. Other regions experiencing weather-normalized gains were the Southeast, Rocky Mountain and West Central regions. The New England region had the largest year-to-year decrease in weather-normalized output, which fell 1.4%.

The U.S. economy in 2017 extended its recovery from the Great Recession of 2007-2009 to an eighth consecutive year. Real gross domestic product (GDP) increased 2.3% for the year, a notable strengthening from 2016's 1.5% rate. When measured as the annualized percentage change from the preceding quarter, the real GDP growth rate reached 3.1% in Q2 2017 and 3.2% in Q3, the strongest quarterly readings since early 2015. The official unemployment rate continued to fall, ending the year at 4.1%, its lowest level since 2000. Inflation-adjusted U.S. retail sales grew by 3.5%. Industrial production grew by 3.4%, which lifted the national industrial production index to pre-recession levels by mid-year and beyond the pre-recession peak by year end. Nevertheless, the current economic expansion, while long-lived, has been tepid by historical standards. Expansionary annual growth rates routinely reached 3% to 6% during the second half of the 20th century. The strongest annual growth rate in the current expansion is 2015's 2.9% and the average annual growth rate is just 2.2%.

U.S. Weather
January – December 2017

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	572	155	37%	(223)	(28%)
Middle Atlantic	770	114	17%	(269)	(26%)
East North Central	730	22	3%	(279)	(28%)
West North Central	935	7	1%	(157)	(14%)
South Atlantic	2,285	321	16%	(207)	(8%)
East South Central	1,693	145	9%	(355)	(17%)
West South Central	2,766	317	13%	(146)	(5%)
Mountain	1,483	240	19%	6	0%
Pacific	1,010	306	43%	111	12%
United States	**1,410**	**194**	**16%**	**(163)**	**(10%)**
Heating Degree Days					
New England	6,106	(505)	(8%)	280	5%
Middle Atlantic	5,217	(694)	(12%)	32	1%
East North Central	5,684	(813)	(13%)	38	1%
West North Central	5,959	(791)	(12%)	221	4%
South Atlantic	2,318	(535)	(19%)	(162)	(7%)
East South Central	2,846	(758)	(21%)	(221)	(7%)
West South Central	1,635	(652)	(29%)	(136)	(8%)
Mountain	4,391	(818)	(16%)	49	1%
Pacific	2,831	(397)	(12%)	233	9%
United States	**3,881**	**(643)**	**(14%)**	**20**	**1%**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

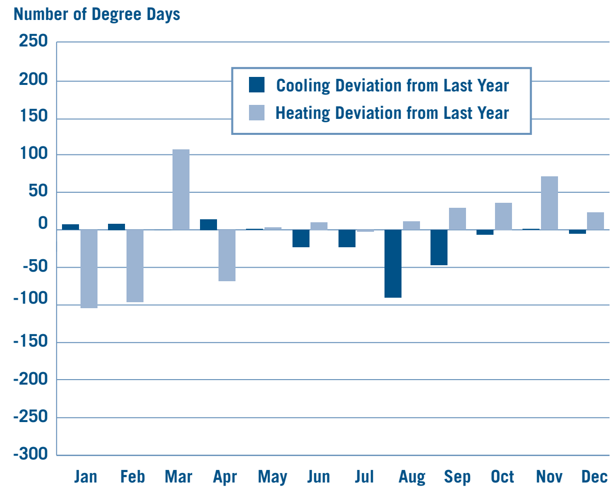
Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

Industry Revenue Rises 3.8%

As shown in the *Consolidated Income Statement*, the industry's total annual revenue rose by $13.4 billion, or 3.8%, in 2017 compared with the total in 2016. Forty-two of the industry's 49 constituent companies reported higher revenue. Four companies posted a double-digit percentage increase. Of the seven companies that reported a decline in revenue, only one experienced a double-digit percentage decline.

2017 Weather Compared to 2016

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service.

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	7	(104)
Feb	8	(96)
Mar	0	107
Apr	14	(68)
May	1	3
Jun	(23)	10
Jul	(23)	(2)
Aug	(90)	11
Sep	(47)	29
Oct	(6)	36
Nov	1	71
Dec	(5)	23
Total	**(163)**	**(643)**

Heating and Cooling Degree Days and Percent Changes

January—December 2017

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	10	1	7	766	(151)	(104)	11.1%	233.3%	(16.5%)	(12.0%)
Feb	15	7	8	549	(183)	(96)	87.5%	114.3%	(25.0%)	(14.9%)
Mar	25	7	0	556	(37)	107	38.9%	0.0%	(6.2%)	23.8%
First Quarter	**50**	**15**	**15**	**1,871**	**(371)**	**(93)**	**42.9%**	**42.9%**	**(16.5%)**	**(4.7%)**
Apr	51	21	14	249	(96)	(68)	70.0%	37.8%	(27.8%)	(21.5%)
May	107	10	1	157	(2)	3	10.3%	0.9%	(1.3%)	1.9%
Jun	246	33	(23)	29	(10)	10	15.5%	(8.6%)	(25.6%)	52.6%
Second Quarter	**404**	**64**	**(8)**	**435**	**(108)**	**(55)**	**18.8%**	**(1.9%)**	**(19.9%)**	**(11.2%)**
Jul	364	43	(23)	3	(6)	(2)	13.4%	(5.9%)	(66.7%)	(40.0%)
Aug	284	(6)	(90)	14	(1)	11	(2.1%)	(24.1%)	(6.7%)	366.7%
Sep	194	39	(47)	57	(20)	29	25.2%	(19.5%)	(26.0%)	103.6%
Third Quarter	**842**	**76**	**(160)**	**74**	**(27)**	**38**	**9.9%**	**(16.0%)**	**(26.7%)**	**105.6%**
Oct	82	29	(6)	204	(78)	36	54.7%	(6.8%)	(27.7%)	21.4%
Nov	23	8	1	488	(51)	71	53.3%	4.5%	(9.5%)	17.0%
Dec	9	2	(5)	809	(8)	23	28.6%	(35.7%)	(1.0%)	2.9%
Fourth Quarter	**114**	**39**	**(10)**	**1,501**	**(137)**	**130**	**52.0%**	**(8.1%)**	**(8.4%)**	**9.5%**
Full Year	**1,410**	**194**	**(163)**	**3,881**	**(643)**	**20**	**16.0%**	**(10.4%)**	**(14.2%)**	**0.5%**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Heating Degree Days Percentage Change from Historical Norm	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)	(0.6)	1.1	(9.1)	(14.8)	(14.2)
Cooling Degree Days Percentage Change from Historical Norm	5.3	1.6	19.9	21.5	22.4	10.9	5.8	19.2	29.4	16.0

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

Energy Operating Expenses Increase 2.8%

Total energy operating expenses for 2017 rose by $3.0 billion, or 2.8%, slightly less than the percentage increase in revenue. Total energy operating expenses are comprised of two primary elements: total electric generation cost and gas cost. These costs changed in opposite directions in 2017, declining 1.1% and rising 28.7%, respectively. Electric generation cost — which includes the cost of generation fuel and purchased power — was just over 25% of total revenue in 2017, extending a multi-year decline as a percent of revenue. Electric generation cost was 27% of total revenue in 2016, 29% in 2015, 31% from 2012 through 2014, and 34% from 2009 through 2011. This metric reached a high of 37% in 2008.

For the consolidated industry income statement, natural gas transmission and distribution revenue is aggregated with all other revenue sources in the "Energy Operating Revenue" line. However, the cost associated with natural gas distribution (i.e., the delivery of natural gas to homes and businesses primarily for cooking and heating) is broken out separately as "Gas Cost." Gas Cost is typically highest in the first quarter due to winter heating demand and lowest in the third quarter due to the minimal heating needs during summer.

Gas distribution traditionally accounts for a smaller portion of the industry's overall revenue and earnings than do electric operations. However, the relative contribution from gas operations has increased in recent years due to acquisitions.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

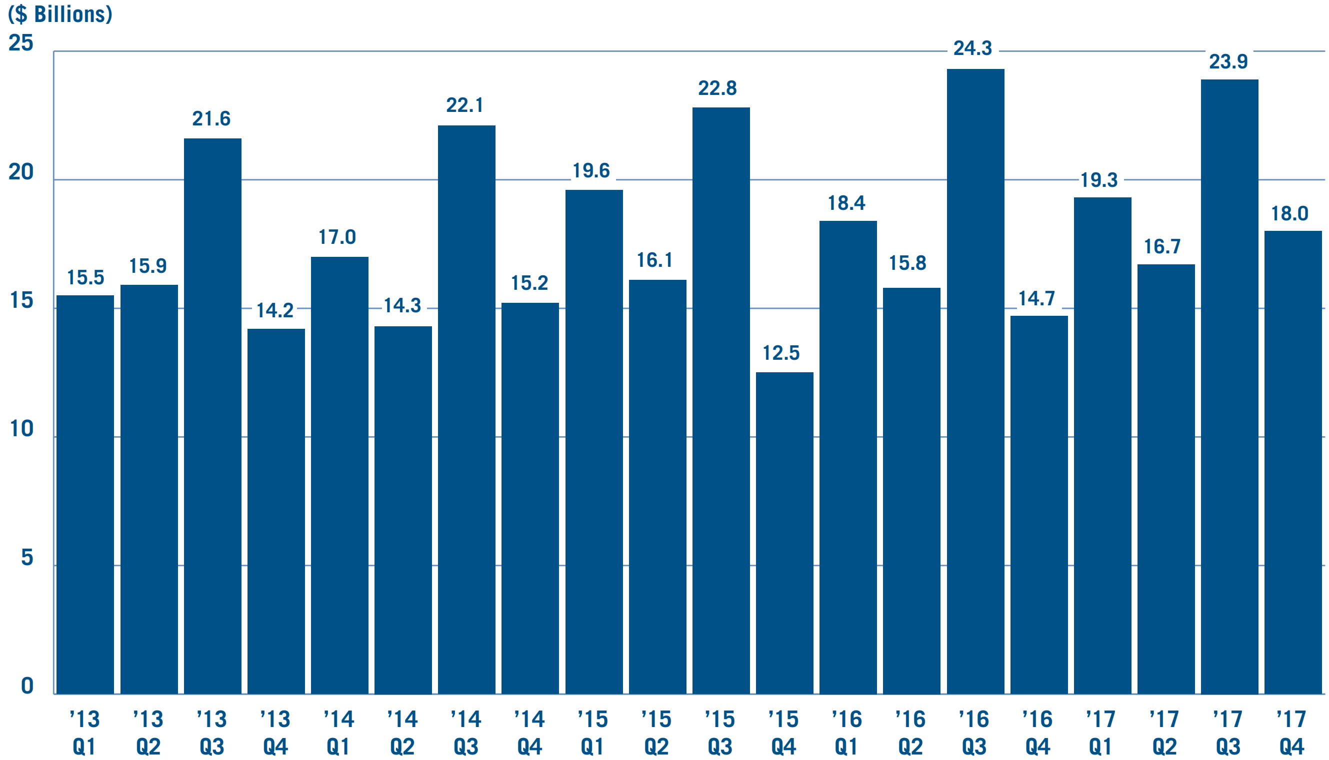
	12 Months Ended		
($ Millions)	**12/31/2017**	**12/31/2016r**	**% Change**
Energy Operating Revenues	$364,009	$350,596	3.8%
Energy Operating Expenses			
Total Electrical Generation Cost	91,907	92,943	(1.1%)
Gas Cost	18,137	14,092	28.7%
Total Energy Operating Expenses	**110,045**	**107,035**	**2.8%**
Revenues less energy operating expenses	**253,964**	**243,560**	**4.3%**
Other Operating Expenses			
Operations & maintenance	93,189	92,867	0.3%
Depreciation & Amortization	47,681	46,138	3.3%
Taxes (not income) - Total	19,321	18,457	4.7%
Other Operating Expenses	15,880	12,890	23.2%
Total Operating Expenses	**286,115**	**277,388**	**3.1%**
Operating Income	**77,894**	**73,208**	**6.4%**
Other Recurring Revenue			
Partnership Income	1,177	1,264	(6.9%)
Allowance for Equity Funds Used for Construction	1,858	1,838	1.1%
Other Revenue	2,850	2,544	12.0%
Total Other Recurring Revenue	**5,884**	**5,646**	**4.2%**
Non-Recurring Revenue			
Gain on Sale of Assets	1,632	767	112.7%
Other Non-Recurring Revenue	493	888	(44.5%)
Total Non-Recurring Revenue	**2,125**	**1,655**	**28.4%**
Interest expense	24,019	22,274	7.8%
Other expenses	569	511	11.4%
Asset Writedowns	7,365	17,487	(57.9%)
Other Non-Recurring Expenses	5,598	3,109	80.1%
Total Non-Recurring Expenses	12,963	20,596	(37.1%)
Net Income Before Taxes	**48,352**	**37,127**	**30.2%**
Provision for Taxes	9,296	9,281	0.2%
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**39,056**	**27,847**	**40.3%**
Discontinued Operations	(25)	(732)	(96.6%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(25)	(732)	(96.6%)
Net Income	**39,031**	**27,114**	**44.0%**
Preferred Dividends Declared	37	17	118.0%
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(4)	(7)	(50.9%)
Net Income Attributable to Noncontrolling Interests	585	606	NA
Net Income Available to Common	**38,403**	**26,482**	**45.0%**
Common Dividends	**25,233**	**23,461**	**7.6%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

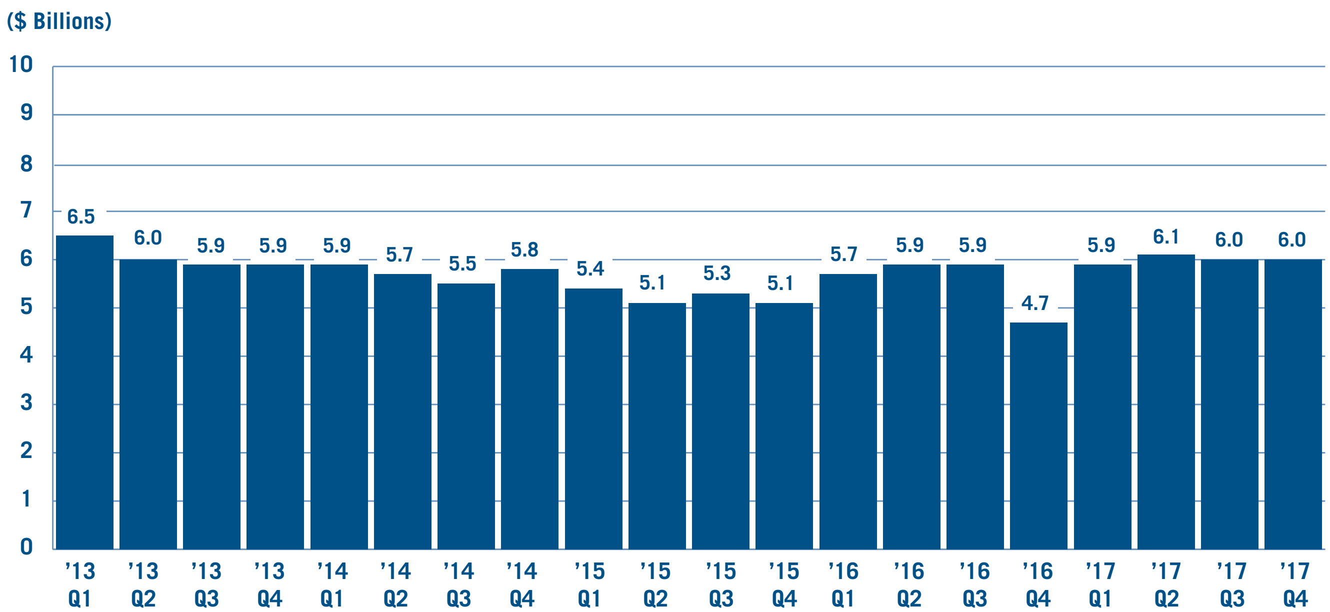
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Gas operations can help balance the earnings stream for combined gas/electric distribution companies since residential gas demand peaks in the cold winter months while electricity demand peaks in the hot summer months for most U.S. utilities.

Operations and Maintenance (O&M) Expenses Rise 0.3%

Operations and maintenance (O&M) expenses increased $321 million, or 0.3%, in 2017. O&M accounted for 33% of the industry's operating expenses for the second consecutive year; this is the highest percentage level of the past ten years. The combination of O&M and Depreciation and Amortization accounted for 49% of total operating expenses in 2017, up from roughly 33% a decade earlier, an increase that is partially attributable to the currently elevated levels of capital spending. The consolidated industry O&M total includes the electric, natural gas and other operating segments and is influenced by plant and business divestitures.

Operating Income Climbs 6.4%

The industry's aggregate operating income rose by $4.7 billion, or 6.4%. More than two-thirds of the companies (34 of 49) showed a year-to-year gain and ten companies posted a double-digit percentage increase. Last year was the fifth consecutive year in which the industry's operating income growth exceeded the 2.0% compound annual rate over the trailing ten years.

Individual Non-Recurring and Extraordinary Items 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2008	2009	2010	2011	2012	2013	2014	2015	2016r	2017
Net Gain (Loss) on Sale of Assets	581	7,176	3,410	891	311	414	996	789	767	1,632
Other Non-Recurring Revenue	1,661	(494)	2,065	946	264	78	296	(4)	888	493
Total Non-Recurring Revenue	**2,243**	**6,682**	**5,475**	**1,837**	**576**	**492**	**1,292**	**785**	**1,655**	**2,125**
Asset Writedowns	(11,256)	(2,022)	(8,805)	(2,743)	(5,646)	4,276	8,762	5,189	17,487	7,365
Other Non-Recurring Charges	(1,525)	(822)	(545)	(851)	(3,136)	3,510	2,675	1,764	3,109	5,598
Total Non-Recurring Charges	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(8,783)**	**7,786**	**11,437**	**6,953**	**20,596**	**12,963**
Discontinued Operations	759	(63)	(476)	(1,011)	(4,317)	(88)	295	(1,148)	(732)	(25)
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	67	(5)	10	960	–	–	–	–	–	–
Total Extraordinary Items	**826**	**(68)**	**(466)**	**(51)**	**(4,317)**	**(88)**	**295**	**(1,148)**	**(732)**	**(25)**
Total Non-Recurring and Extraordinary Items	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,524)**	**(7,381)**	**(9,850)**	**(7,316)**	**(19,674)**	**(10,863)**

r = revised   Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Interest Expense Up 7.8%

Interest expense rose by 7.8%, to $24.0 billion in 2017 from $22.3 billion in 2016. As in 2016, nine companies reported a double-digit percentage increase. However, increases were more evenly distributed among the companies in 2017 than in 2016, when only three accounted for more than 85% of the industry's overall increase. The industry's aggregate interest expense held relatively steady for most of the last decade as declining interest rates offset upward pressure from the rising level of debt needed to fund capital investments.

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported an $8.8 billion year-to-year decrease in the total expense associated with nonrecurring and extraordinary items. The $10.9 billion total in 2017 is close to the industry's 10-year average of $8.0 billion, whereas the $19.7 billion in 2016 is a relatively anomalous amount.

Net Income Higher at Most Companies

The industry's net income was $39.0 billion in 2017, an increase of $11.9 billion, or 44%, over 2016's $27.1 billion. This was the highest annual total of the past decade. About three-quarters of companies reported higher net income in 2017 relative to 2016. Nineteen companies reported a double-digit percentage gain and four companies increased net income by 100% or more.

Top Net Non-Recurring and Extraordinary Gains (Losses) 2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

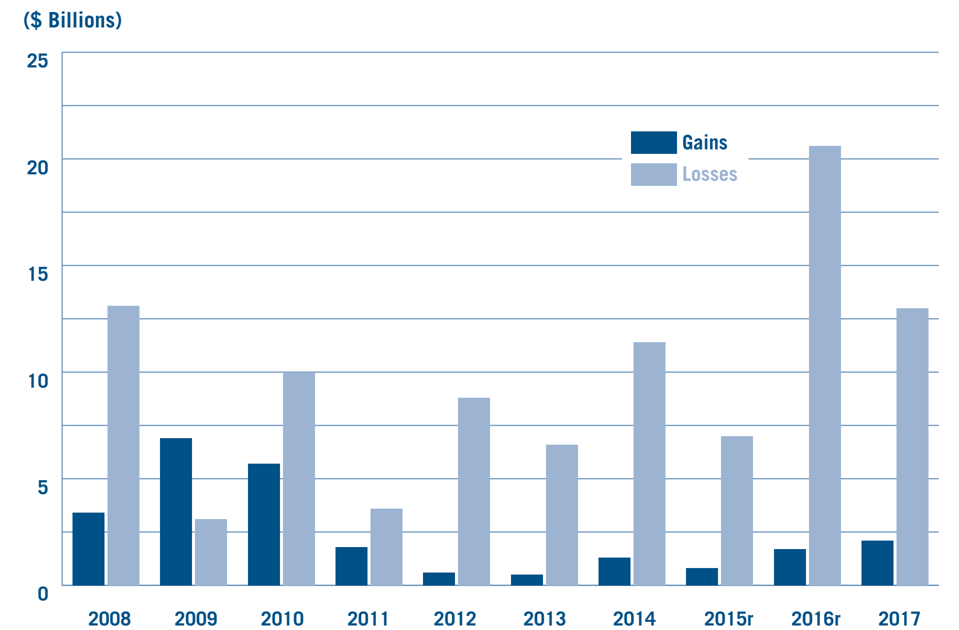
($ Millions)

Company	Gains	Losses	Net Total
Southern Company	–	3,362.0	3,362.0
FirstEnergy Corp.	–	2,406.0	2,406.0
SCANA Corporation	–	1,118.0	1,118.0
Edison International	–	738.0	738.0
AVANGRID, Inc.	–	642.0	642.0
Duke Energy	28.0	645.0	617.0
NextEra Energy	1,225.0	1,770.0	545.0
Entergy Corporation	16.3	538.4	522.1
Sempra Energy	50.0	423.0	373.0
Great Plains Energy	–	239.4	239.4

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



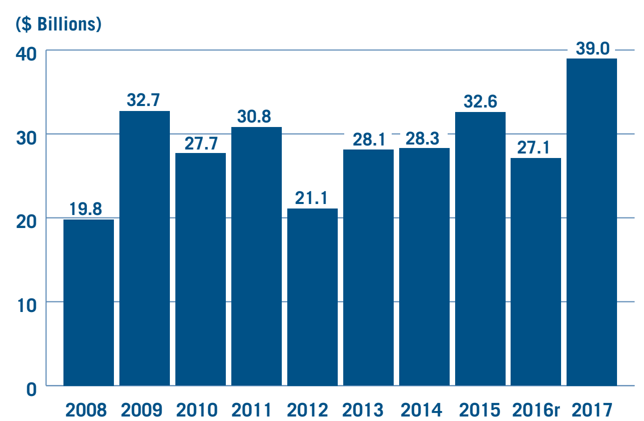
	2008	2009	2010	2011	2012	2013	2014	2015r	2016r	2017	Total
Gains	3.4	6.9	5.7	1.8	0.6	0.5	1.3	0.8	1.7	2.1	24.7
Losses	13.1	3.1	10.0	3.6	8.8	6.6	11.4	7.0	20.6	13.0	97.2
Total	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(8.2)**	**(6.2)**	**(10.1)**	**(6.2)**	**(18.9)**	**(10.8)**	**(72.5)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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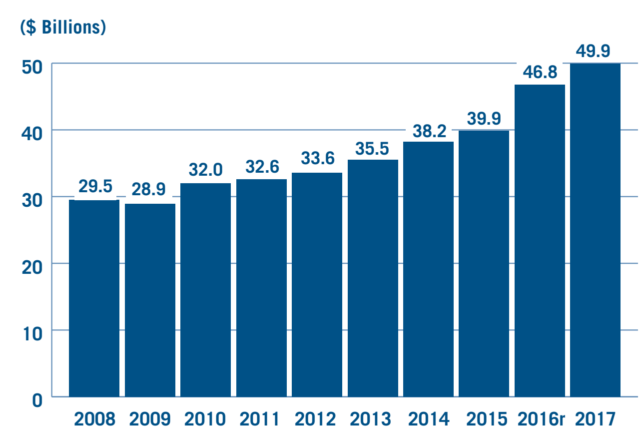
Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2008-2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Balance Sheet

The industry's consolidated balance sheet remained healthy in 2017, although debt as a percent of total capitalization rose for a third consecutive year as long-term debt increased at most companies. The industry's aggregate total long-term debt rose by $30.3 billion, to $551.6 billion at year end from $521.3 billion at year-end 2016. However, the pace of long-term debt growth slowed in 2017 from 2016's $53.4 billion increase, which was driven by the year's merger and acquisition activity and nearly three times the $19 billion average rise from 2008 through 2015. Long-term debt reached 55.8% of the industry's aggregate total capitalization at year-end 2017, up slightly from 55.4% at year-end 2016 and 53.6% at year-end 2015. The two-percentage-point jump from year-end 2015 is less significant when put in the context of the past decade; the level ranged between 53.8% and 56.4% from 2007 through 2013. Rising debt levels over the past ten years have been largely offset with net income and common stock issuance.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)

Capitalization Structure	12/31/2017	12/31/2016r	12/31/2015r
Common Equity	424,209	406,311	396,856
Preferred Equity & Noncontrolling Interests	13,435	13,901	8,492
Long-term Debt (current & non-current)*	551,599	521,270	467,919
Total	**989,242**	**941,482**	**873,268**
Common Equity %	42.9%	43.2%	45.4%
Preferred & Noncontrolling %	1.4%	1.5%	1.0%
Long-term Debt %	55.8%	55.4%	53.6%
Total	**100.0%**	**100.0%**	**100.0%**

* Long-term debt not adjusted for (i.e., includes) securitization bonds.
r = revised
Source: S&P Global Market Intelligence and EEI Finance Department.

Broad Trends Show Little Change

The broad trends that have impacted the industry for the past several years, and that have supported the industry's overall strong financial condition, were little changed in 2017. These include the continuation of a multi-year migration toward regulated business strategies, generally constructive regulation, moderate and steady profitability and, importantly, accommodating financial markets characterized by very low interest rates and a hunger for yield — whether in the form of dividends or bond interest — on the part of investors worldwide.

The favorable financial market environment for companies seeking to raise capital through bond offerings continued in 2017. U.S. interest rates remained very low by historical standards. The 10-year U.S. Treasury yield began the year at 2.5% and fell to 2.1% by early September as inflation remained subdued; year-to-year gains in the U.S. consumer price index (excluding the volatile food and energy components) fell to 1.7% during the summer from readings just above 2.0% in January and February. While inflation remained under 2.0% in the year's second half, the pace of economic growth strengthened and the 10-year Treasury yield rose during the final months of the year, holding above 2.3% during the fourth quarter. Corporate credit spreads (the difference between risk-free Treasury yields and yields on comparable maturity corporate bonds) generally tightened during the year. Credit spreads for Moody's Aaa-rated corporate bonds ranged from 140 to 150 basis points through August, then fell steadily to 100 basis points by late December. Likewise, spreads for Moody's Baa-rated corporate bonds narrowed from a range of 220 to 230 basis points in the year's first half to 180 basis points by year-end.

Bond investors worldwide again turned to the U.S. for income in 2017 as interest rates in Europe and Japan remained at very low levels, suppressed by lethargic economies and aggressive asset purchase programs at both the European Central Bank and the Bank of Japan. The 10-year German government yield held under 0.4% for much of the year. The yield for a broad index of Eurozone 10-year government bonds declined from 1.4% early in 2017 to under 1.0% by December. Japan's 10-year government yield remained below 0.1% throughout the year. Compared with these paltry yields, the interest income available from U.S. government and corporate bonds was attractive indeed. The industry's high-quality debt securities hold strong appeal for global investors seeking income without an uncomfortable level of financial risk. U.S. high-grade electric utilities issued $59 billion in corporate bonds in 2017, according to Bank of America Merrill Lynch research, only slightly below 2016's record $61 billion issuance. By comparison, annual issuance ranged between roughly $30 billion and $45 billion from 2007 through 2015. The industry's aggregate short-term debt also rose, edging higher to $37.4 billion at year-end 2017 from $34.1 million at the end of 2016.

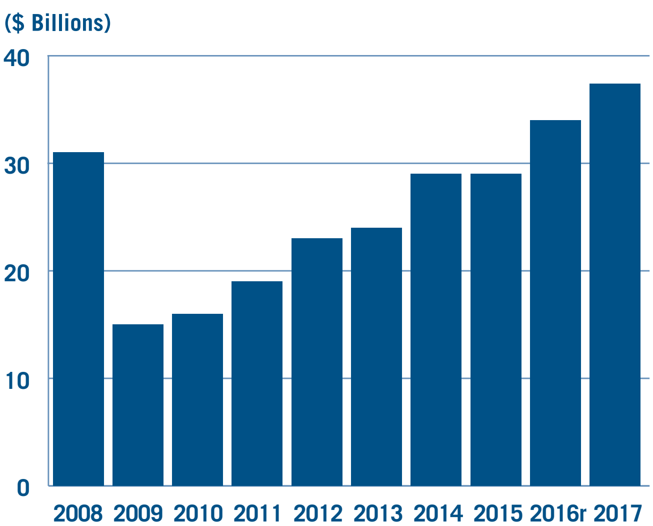
Minority of Companies Drive Slight Leverage Increase

The slight increase in the industry's aggregate balance sheet leverage in 2017 was driven by a minority of companies. Only 15 companies, or 31% of the industry, saw long-term debt rise as a percent of total capitalization. Twenty-two companies, or 45% of the industry, showed no change. Twelve companies showed a decrease for this metric. These figures are roughly comparable to those of 2016, when leverage increased for 18 companies, or 35% of the industry. Twenty-one companies, or 41 of the industry, saw no change in 2016 while twelve showed a decrease in leverage.

The industry's aggregate total common equity rose by $17.9 billion, or 4.4%, from $406.3 billion at year-end 2016 to $424.2 billion at year-end 2017. The rise in balance sheet equity was supported by aggregate net income of $38.4 billion and $5.7 billion in net stock issuance (proceeds from stock offerings

Short-term Debt 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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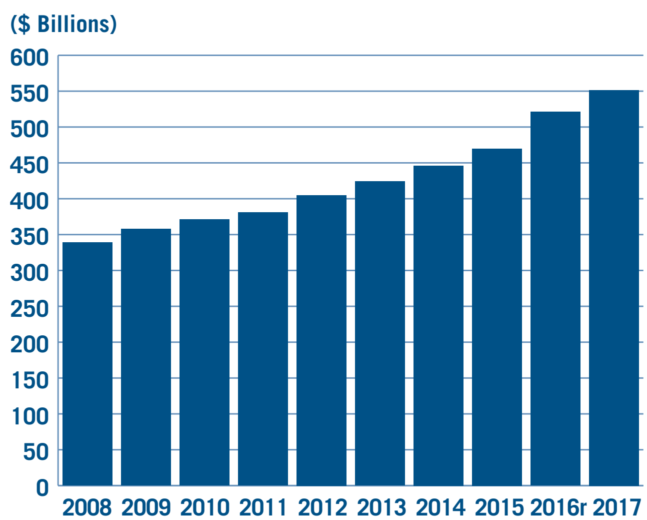
Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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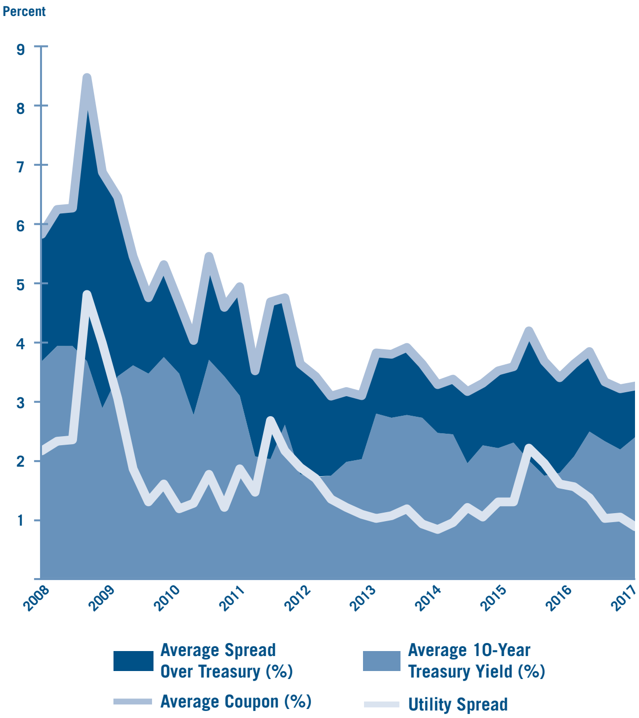
Source: S&P Global Market Intelligence and EEI Finance Department.

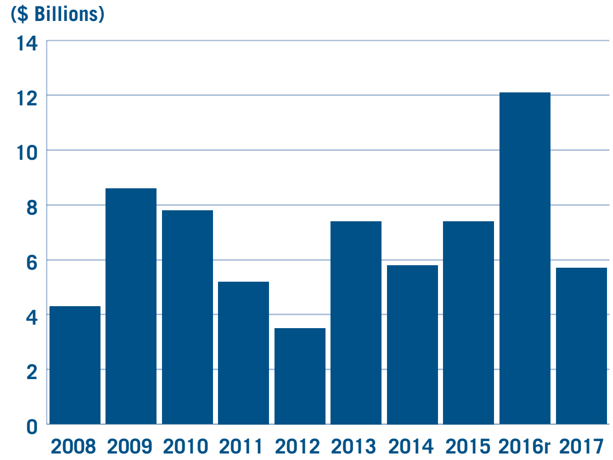
Utilities' Cost of Debt: 10-Year Treasury Yields and Bond Spreads (New Offerings)



Source: S&P Global Market Intelligence and EEI Finance Department.

Proceeds from Issuance of Common Equity 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

less buybacks), although payment of $25.5 billion in common stock dividends constrained the total income retained as equity on the balance sheet. The balance sheet shows changes in equity resulting from public stock offerings, which increase equity, and retained earnings or losses, which increase or decrease equity (see chart, *Proceeds from Issuance of Common Equity*). Industry credit quality — tied closely in recent years to the management of capital spending, merger and acquisition activity, and related financing strategies — remained at BBB+ in 2017 for a fourth straight year after improving in 2014 to an average BBB+ from BBB. The improvement in 2014 was the first change since 2004, when the average rating rose to BBB from BBB-.

Date	PP&E in Service, Net ($MM)	% Change from 12/31/2013
12/31/2017	$1,082,229	35%
12/31/2016r	$969,737	21%
12/31/2015r	$898,152	12%
12/31/2014	$839,351	5%
12/31/2013	$803,007	

Source: S&P Global Market Intelligence and EEI Finance Department.

Total long-term debt (current and non-current) has risen from $314.9 billion at year-end 2007 to $551.6 billion at year-end 2017, a 75% increase, driven higher mostly by the need to finance consistently high levels of capital expenditures (capex). Industry capex climbed from a cyclical low of $40.2 billion during the 12-month period that ended September 30, 2004, to a record high of $113.6 billion in 2017, and is expected to remain at an elevated level for at least the next few years.

Impact of Elevated Capex

The impact of historically high levels of capital spending is evident in the industry's consolidated balance sheet. Total net property, plant and equipment in service (shown in the adjacent table) jumped 35% from year-end 2013 to year-end 2017.

A rising level of construction work-in-progress (CWIP) also reflects the industry's elevated capital spending. CWIP jumped from $62.4 billion at year-end 2012 to $80.9 billion at year-end 2017. CWIP, along with adjustment clauses, interim rate increases and the use of projected costs in rate cases, is especially important during large construction cycles because it helps minimize regulatory lag.

Deferred taxes fell by $62.0 billion, or 39.1%, to $96.4 billion at year-end 2017 from a revised $158.3 billion at year-end 2016. Deferred taxes had risen nearly 30% from year-end 2012 to year-end 2016 due to persistently high capital spending and the impact of accelerated depreciation. The very large decrease in deferred taxes in 2017 is largely due to revaluation adjustments made as a result of the Tax Cuts and Jobs Act of 2017.

Debt-to-Cap Ratio by Category 2017 vs. 2016r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	6	17.1%	6	42.9%	12	24.5%
No Change*	19	54.3%	3	21.4%	22	44.9%
Higher	10	28.6%	5	35.7%	15	30.6%
Total	**35**	**100.0%**	**14**	**100.0%**	**49**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2017 vs. December 31, 2016. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category 2017 vs. 2016r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
($ Millions)	2017	2016r	Change	2017	2016r	Change
Common Equity	281,164	275,659	5,505	143,045	130,652	12,392
Total Preferred Equity	4,675	6,095	(1,420)	8,760	7,806	954
Long-term Debt (current & non-current)*	378,652	359,020	19,632	172,947	162,250	10,697
Total Capitalization	664,491	640,774	23,717	324,751	300,708	24,043
Common Equity %	42.3%	43.0%	-0.7%	44.0%	43.4%	0.6%
Preferred Equity %	0.7%	1.0%	-0.2%	2.7%	2.6%	0.1%
Long-term Debt %	57.0%	56.0%	1.0%	53.3%	54.0%	-0.7%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Note: Long-term debt not adjusted for (i.e., includes) securitization bonds.

Source: S&P Global Market Intelligence and EEI Finance Department.

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2017	12/31/2016r	% Change	$ Change
PP&E in service, gross	1,528,906	1,378,601	10.9%	150,305
Accumulated depreciation	446,677	408,864	9.2%	37,813
PP&E in service, net	1,082,229	969,737	11.6%	112,492
Construction work in progress	80,863	74,326	8.8%	6,537
Net nuclear fuel	16,542	16,054	3.0%	487
Other property	3,088	1,774	74.1%	1,314
PP&E, net	1,182,722	1,061,891	11.4%	120,831
Cash & cash equivalents	14,439	12,323	17.2%	2,115
Accounts receivable	39,566	38,251	3.4%	1,315
Inventories	23,080	24,060	(4.1%)	(979)
Other current assets	43,367	43,704	(0.8%)	(337)
Total current assets	120,451	118,338	1.8%	2,114
Total investments	96,490	86,237	11.9%	10,253
Other assets	166,376	255,894	(35.0%)	(89,518)
Total Assets	**1,566,039**	**1,522,360**	**2.9%**	**43,679**
Common equity	424,209	406,311	4.4%	17,897
Preferred equity	0	851	(100.0%)	(851)
Noncontrolling interests	13,435	13,050	2.9%	385
Total equity	437,643	420,212	4.1%	17,431
Short-term debt	37,439	34,141	9.7%	3,297
Current portion of long-term debt	35,150	28,276	24.3%	6,874
Short-term and current long-term debt	72,589	62,417	16.3%	10,171
Accounts payable	67,714	66,965	1.1%	750
Other current liabilities	35,849	35,451	1.1%	398
Current liabilities	176,152	164,833	6.9%	11,319
Deferred taxes	96,369	158,337	(39.1%)	(61,968)
Non-current portion of long-term debt	516,449	492,994	4.8%	23,454
Other liabilities	338,642	285,258	18.7%	53,384
Total liabilities	1,127,611	1,101,421	2.4%	26,190
Subsidiary preferred	754	553	36.3%	201
Other mezzanine	31	173	(82.2%)	(142)
Total mezzanine level	784	726	8.0%	58
Total Liabilities and Owner's Equity	**1,566,039**	**1,522,360**	**2.9%**	**43,679**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

Net Cash Provided by Operating Activities

Net Cash Provided by Operating Activities increased by $3.4 billion, or 3.4%, to $101.6 billion in 2017 from $98.3 billion in 2016. As shown in the *Statement of Cash Flows*, an $11.9 million or 44.0% increase in Net Income, from $27.1 million in 2016 to $39.0 million in 2017, was the primary reason for the increase. A distant secondary contributor was the $1.3 billion, or 2.6%, rise in the cash provided from Depreciation and Amortization, to $50.4 billion from $49.2 billion. Together, these two sources of cash were strong enough to offset a $4.5 billion, or 38.6%, reduction in cash provided by Other Operating Changes in Cash from $11.6 billion in 2016 to $7.1 billion in 2017 and a $5.9 billion reduction in cash from Change in Working Capital, which swung from a $2.9 billion contribution in 2016 to a $3.0 billion deficit in 2017.

Cash provided by Deferred Taxes and Investment Credits rose to $9.3 billion in 2017 from $8.9 billion in 2016. This metric remained at a historically high level for a tenth straight year. In combination with the industry's elevated capital expenditures, the use of bonus depreciation has created a significant increase in deferred taxes over the period. The Tax Cuts and Jobs Act, which passed in late 2017, will significantly impact deferred taxes on a prospective basis. Going forward, the current portion of deferred taxes will be relatively lower, all things being equal, due to the reduction in the corporate income tax rate from 35% to 21%.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12 Months Ended		
	12/31/2017	12/31/2016r	% Change
Net Income	$39,031	$27,114	44.0%
Depreciation and Amortization	50,445	49,155	2.6%
Deferred Taxes and Investment Credits	9,333	8,923	4.6%
Operating Changes in AFUDC	(1,296)	(1,409)	(8.0%)
Change in Working Capital	(2,991)	2,925	NM
Other Operating Changes in Cash	7,123	11,600	(38.6%)
Net Cash Provided by Operating Activities	**101,644**	**98,284**	**3.4%**
Capital Expenditures	(113,610)	(112,516)	1.0%
Asset Sales	14,684	15,444	(4.9%)
Asset Purchases	(15,529)	(43,567)	(64.4%)
Net Non-Operating Asset Sales and Purchases	(845)	(28,123)	(97.0%)
Change in Nuclear Decommissioning Trust	(415)	(414)	0.3%
Investing Changes in AFUDC	153	114	34.5%
Other Investing Changes in Cash	1,832	(4,309)	NM
Net Cash Used in Investing Activities	**(112,886)**	**(145,248)**	**(22.3%)**
Net Change in Short-term Debt	3,965	3,419	16.0%
Net Change in Long-term Debt	31,017	44,466	(30.2%)
Proceeds from Issuance of Preferred Equity	1,274	1,157	10.2%
Preferred Share Repurchases	(2,133)	(494)	331.8%
Net Change in Prefered Issues	(858)	663	NM
Proceeds from Issuance of Common Equity	5,668	12,123	(53.2%)
Common Share Repurchases	(194)	(267)	(27.4%)
Net Change in Common Issues	5,474	11,855	(53.8%)
Dividends Paid to Common Shareholders	(25,534)	(23,828)	7.2%
Dividends Paid to Preferred Shareholders	(76)	(62)	21.6%
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(25,610)	(23,891)	7.2%
Other Financing Changes in Cash	(617)	3,947	NM
Net Cash (Used in) Provided by Financing Activities	**13,370**	**40,459**	**(67.0%)**
Other Changes in Cash	50	421	(88.1%)
Net increase (decrease) in cash and cash equivalents	$2,179	$(6,083)	NM
Cash and cash equivalents at beginning of period	$12,260	$18,407	(33.4%)
Cash and cash equivalents at end of period	$14,439	$12,323	17.2%

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

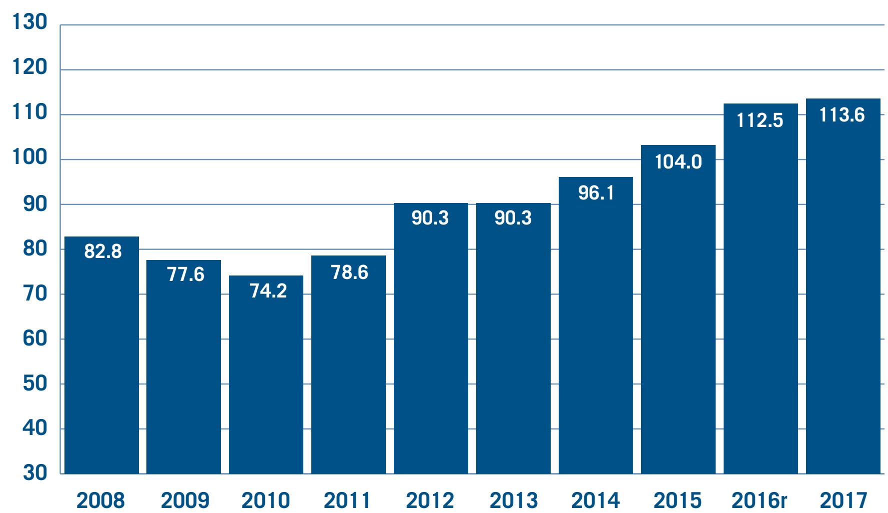
Net Cash Used in Investing Activities

Net Cash Used in Investing Activities decreased by $32.4 billion, or 22.3%, to $112.9 billion in 2017 from $145.2 billion in 2016. The decrease was caused by a $28.0 billion, or 64.4%, drop in Asset Purchases. In 2016, asset purchases surged by $25.5 billion, or 141.2%, from $18.1 billion in 2015 to 2016's $43.6 billion total. However, the jump was driven by merger and acquisition activity at just a handful of companies; asset purchases increased by about $9.0 billion at Southern Company, $6.9 billion at Exelon, $4.6 billion at Duke and $3.7 billion at Dominion in 2016.

Cash used for Capital Expenditures rose only 1.0%, as industry capex in 2017 marginally increased to $113.6 billion from $112.5 billion in 2016. However, the 2017 total was another record high. The elevated level of capex is depicted in the *Capital Spending –Trailing 12 Months* chart. One of the principle drivers of rising capex has been the industry's considerable investment in clean energy generation, including natural gas, nuclear, wind and solar. The industry has also sustained a high level of transmission and distribution investment for grid modernization and system expansion. Finally, investment in natural gas supply pipelines and gas distribution utilities has driven capital spending in the industry's natural gas infrastructure segment. The $113.6 billion spent on capex in 2017 is 183% greater than the $40.2 billion invested during the 12-month period that ended September 30, 2004, which marked the cyclical low following the competitive generation build-out that peaked in 2001.

Capital Expenditures 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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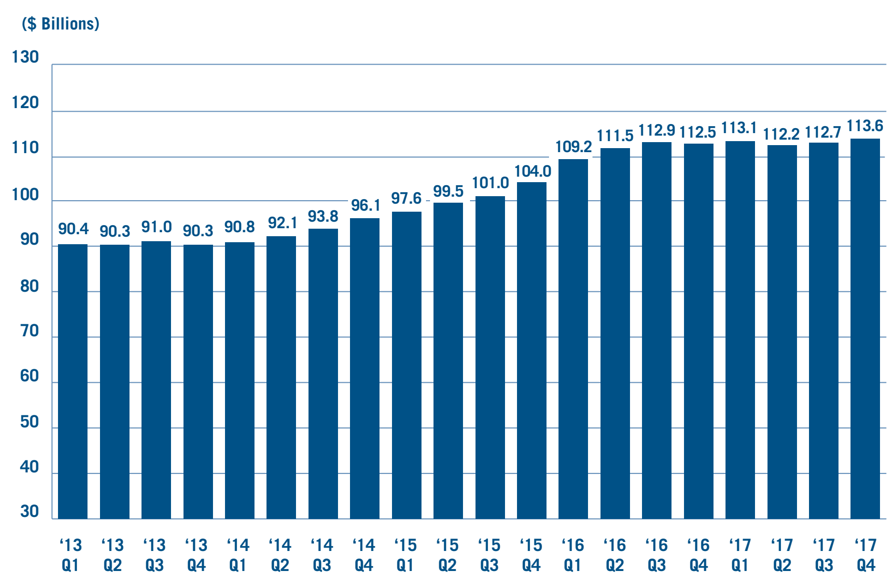
Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Spending—Trailing 12 Months

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Net Cash Provided by Financing Activities

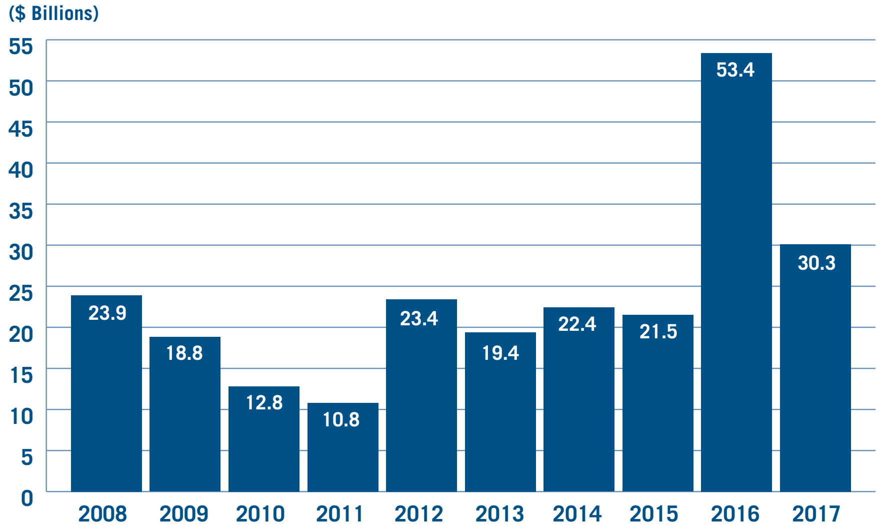
Net Cash Provided by Financing Activities decreased by $27.1 billion, or 67.0%, to $13.4 billion in 2017 from $40.5 billion in 2016. The primary reason was a $13.5 billion decrease in the Net Change in Long-term Debt as the group of companies that were active asset purchasers in 2016 issued debt to fund these purchases. The industry's long-term debt increased annually at an average of $19.1 billion per year between 2008 and 2015. In 2016, however, long-term debt jumped by $53.4 billion.

Given the industry's extended period of elevated capital spending, it is not surprising that long-term debt has risen continuously since the sizeable debt pay-downs that took place from 2003 through mid-year 2006. Total long-term debt fell from $349.7 billion at the end of 2003 to $322.8 billion at June 30, 2006 and has since risen to $551.6 billion (including securitized debt) at December 31, 2017.

Proceeds from the Issuance of Common Equity fell 53.2%, to $5.7 billion in 2017 from $12.1 billion in 2016. The 2017 total was near the middle of the $3.5 billion to $8.6 billion range that includes most years since 2007; 2016's $12.1 billion was a relative outlier. Stock issuance was slightly higher from 2001 to 2006, ranging from $6.6 to $13.1 billion. The industry's strong stock market performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, has supported

Net Change in Long-term Debt 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

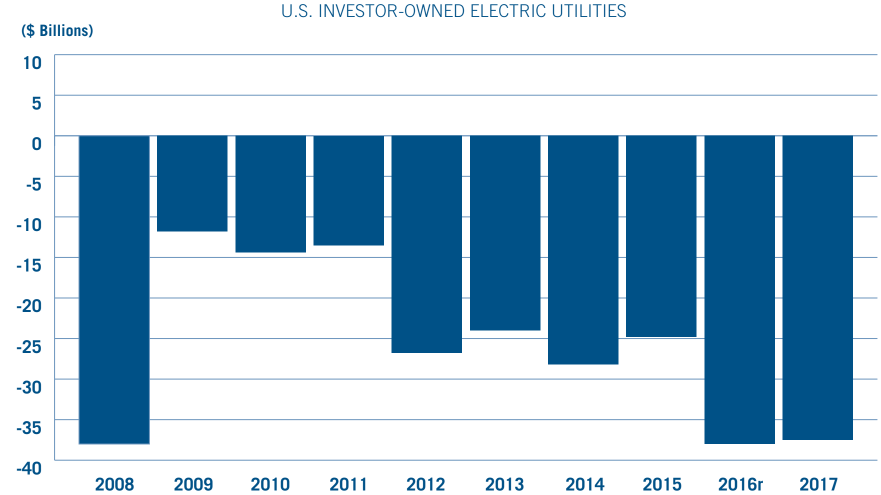


Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF) 2008–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2008	2009	2010	2011	2012	2013	2014	2015	2016r	2017
Net Cash Provided by Operating Activities	61.3	82.9	77.7	84.4	84.0	87.1	89.0	101.6	98.3	101.6
Capital Expenditures	(82.8)	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)	(113.6)
Dividends Paid to Common Shareholders	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)
Free Cash Flow	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.8)**	**(24.0)**	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**

r = revised

Note: Totals may not equal sum of components due to rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

annual common stock offerings. Bonus depreciation has also helped finance the industry's significant capital needs in recent years.

Free Cash Flow Deficit Continues in 2017

Free cash flow was negative $37.5 billion in 2017 compared to negative $38.1 billion in 2016. The three line-item contributors were similar in each year. Net Cash Provided by Operating Activities edged higher to $101.6 billion in 2017 from $98.3 billion in 2016. Capital Expenditures increased marginally from $112.5 billion to $113.6 billion. Dividends paid rose to $25.5 billion in 2017 from $23.8 billion in 2016. The industry's calendar-year free cash flow was last positive in 2004. There is a strong association on the regulated side of the business between rising capex, declining free cash flow and regulatory lag (defined as the time between a rate case filing and decision). Regulatory lag delays the recovery of costs associated with capital investment and can result in utilities significantly under-earning their allowed return on equity (ROE).

From 2003 through 2017, total industry-wide cash dividends more than doubled, to $25.5 billion from $12.3 billion. While some analysts define free cash flow as the difference between cash flow from operations and capital expenditures, we also deduct common dividends due to the utility industry's strong tradition of dividend payments.

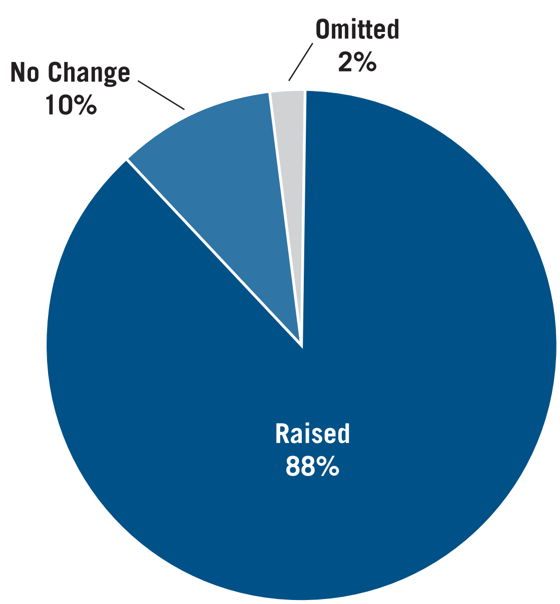
Dividends

The investor-owned electric utility industry added to its long-term trend of widespread dividend increases during 2017. A total of 38 companies increased or reinstated their dividend in 2017 as a whole compared to 40 in 2016, 39 in 2015, 38 in 2014 and 36 in both 2013 and 2012. Only 27 of the 65 companies tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates.

The percentage of companies that raised or reinstated their dividend in 2017 was 88%, the second-highest on record after 2016's 91%. This followed results of 85% in 2015, 79% in 2014, 74% in 2013, 73%

2017 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

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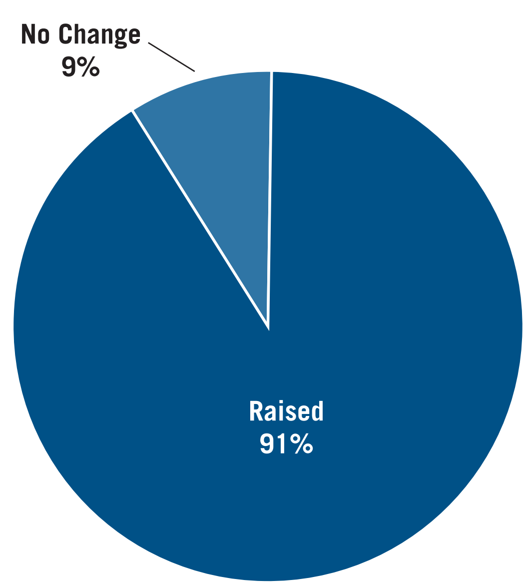


Source: EEI Finance Department.

in 2012, 58% in 2011 and 60% in 2010. The 2016 record high is based on data going back to 1988. The 15% dividend tax rate has supported the high number of increases in recent years.

As of December 31, 2017, 42 of the 43 publicly traded companies in the EEI Index were paying a common stock dividend. The *Dividend Patterns* table shows the industry's dividend paying patterns over the past 24 years. Each company is limited to one action per year. For example, if a company raised its dividend twice during a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, with the first quarter being the most common for electric utilities.

2017 Increases Average 5.6%

The industry's average dividend increase per company during 2017 was 5.6%, with a range of 1.4% to 12.9% and a median increase of 5.6%. NextEra Energy (12.9% in Q1), Edison International (11.5% in Q4) and OGE Energy (9.9% in Q3) posted the largest percentage increases.

Dividend Patterns 1993–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1993	65	29	1	–	1	4	100	80.5%
1994	54	37	6	–	–	3	100	79.8%
1995	52	40	3	–	–	3	98	75.3%
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%**
2001	21	40	3	2	–	3	69	64.1%
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%
2014	38	9	1	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%
2016	40	4	–	–	–	–	44	62.9%
2017	38	4	–	1	–	–	43	64.0%

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Average of the Increased Dividend Actions ***	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%	5.7%	5.8%	5.6%	5.6%
Average of the Declining Dividend Actions ***	(45.7%)	(46.4%)	NA	(100.0%)	NA	(41.0%)	(34.5%)	NA	NA	NA

* Omitted in current year. This number is not included in the Not Paying column.
** Prior to 2000 = total industry dividends/total industry earnings, starting in 2000 = average of all companies paying a dividend.
*** Excludes companies that omitted or reinstated dividends.
Note: Dividend percent changes are based on year-end comparisons.
Source: EEI Finance Department and S&P Global Market Intelligence.

NextEra Energy, headquartered in Juno Beach, Florida, raised its quarterly dividend from $0.87 to $0.9825 per share in Q1. The increase is consistent with the company's plan, announced in 2015, to target 12% to 14% annual growth in dividends per share through at least 2018, off a 2015 base. NextEra also had the highest percentage increase in 2016 (tied at 13.0% with Edison International and DTE Energy).

Edison International, based in Rosemead, California, announced an increase in its quarterly dividend from $0.5425 to $0.605 per share in Q4, marking the fourth straight year of a $0.25 per share annual increase. The company called this another meaningful step in raising its dividend payout ratio toward the upper end of its targeted range of 45% to 55% of subsidiary Southern California Edison's earnings.

OGE Energy, based in Oklahoma City, announced an increase of $0.03 per share in Q3, from $0.3025 to $0.3325. The company affirmed its commitment to 10% dividend growth annually through 2019.

In December, PG&E Corporation announced that it would suspend its dividend beginning with the fourth quarter of 2017, citing uncertainty related to causes and potential liabilities associated with the extraordinary October 2017 Northern California wildfires.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/17

Sector	Payout Ratio (%)
EEI Index Companies*	**54.3%**
Energy	95.1%
Utilities	63.3%
Consumer Staples	59.1%
Industrial	42.0%
Materials	39.1%
Consumer Discretionary	30.8%
Technology	30.6%
Health Care	28.0%
Financial	27.7%

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Assumptions:

1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2017E dividends and earnings per share (estimates as of 12/31/2017).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 54.3% for the calendar year 2017, remaining among the highest of all U.S. business sectors. The broader Utilities sector (consisting of electric, gas and water utilities) was somewhat higher at 63.3%. The industry's payout ratio was 64.0% when measured as an un-weighted average of individual company ratios; 54.3% represents an aggregate figure.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. From 2000 through 2017, the industry's annual payout ratio ranged from 60.4% to 69.6% (see *Dividend Patterns* Table). We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 3.4% on December 31, 2017, higher than all other business sectors except the broader Utilities sector's average 3.5% yield. The industry's yield was 3.3% on September 30, 3.3% on June 30 and 3.4% on March 31. This follows yields of 3.4% at year-end 2016, 3.8% at year-end 2015, 3.3% at year-end 2014, 4.0% at year-end 2013 and 4.3% at year-end 2012.

We calculate the industry's aggregate dividend yield using an unweighted average of the EEI Index companies that are paying a dividend. The strong dividend yields prevalent among most electric utilities have helped support their share prices over the past decade, especially given the period's historically low interest rates. The industry's dividend yield was unchanged over the last year as the rise in utility stock prices was offset by strong dividend increases.

The EEI Index delivered a positive total shareholder return of 11.7% in 2017 but underperformed the broad market. This followed a 17.4% return in 2016, a negative 3.9% return in 2015 and positive returns from 2014 back to 2009, respectively, of 28.9%, 13.0%, 2.1%, 20.0%, 7.0% and 10.7%. The EEI Index has produced a positive total return in 13 of the last 15 years.

Sector Comparison, Dividend Yield
As of December 31, 2017

Sector	Dividend Yield (%)
EEI Index Companies	**3.4%**
Utilities	3.5%
Consumer Staples	2.7%
Energy	2.6%
Industrial	1.9%
Materials	1.8%
Financial	1.6%
Health Care	1.6%
Technology	1.5%
Consumer Discretionary	1.3%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2017); S&P sector yields based on 2017E cash dividends (estimates as of 12/31/2017).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

Business Category Comparison

As shown in *Category Comparison, Dividend Yield* table, at year-end 2017 the Regulated and Mostly Regulated categories each had a 3.4% average dividend yield. The Diversified category no longer exists, as the only two remaining companies from 2016 were merged into the Mostly Regulated category at the start of 2017. The yields for the Regulated and Mostly Regulated categories were 3.4% and 3.5%, respectively, on December 31, 2016.

The Regulated category had a dividend payout ratio of 68.7% in 2017 compared to 53.3% for the Mostly Regulated group (see *Category Comparison, Dividend Payout Ratio* table). The Regulated category produced the highest annual payout ratio in 2015, 2011 and 2010 and in each year from 2003 through 2008. It was exceeded by the Mostly Regulated category in 2016, 2014, 2013, 2012 and 2009; it's likely that the weaker earnings from the competitive power business contributed to the higher payout ratio among Mostly Regulated companies in those years.

Share Repurchases Remain Low After 2007 Spike

Twelve of the industry's publicly traded companies repurchased an aggregate $182 million of common shares during 2017 as an alternate way of returning cash to shareholders. This compares to ten companies and $267 million in 2016, 11 companies and $1.9 billion in 2015, 12 companies and $668 million in

Category Comparison, Dividend Payout Ratio

Category[1]	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
EEI Index	**66.8**	**69.6**	**62.0**	**62.8**	**64.2**	**61.5**	**60.4**	**67.0**	**62.9**	**64.0**
Regulated	71.2	68.2	64.1	63.4	62.1	60.5	59.4	68.7	61.1	68.7
Mostly Regulated	66.7	72.2	60.7	63.1	69.7	64.7	63.8	62.6	68.0	53.3
Diversified[2]	44.6	69.2	49.7	54.7	53.4	44.7	56.4	64.9	64.6	–

[1] Refer to page v for category descriptions.
[2] Starting January 1, 2017, the Diversified Category will no longer exist due to the dwindling number of companies.

Note: In addition to the impact of dividend strategies and company earnings, the dividend payout ratios for each category are also affected by the movement of companies between categories and by dividend reinstatements and cancellations.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

Category Comparison, Dividend Yield
As of December 31, 2017

Category[1]	Dividend Yield
EEI Index	**3.4%**
Regulated	3.4%
Mostly Regulated	3.4%

[1] Refer to page v for category descriptions.
Source: EEI Finance Department and S&P Global Market Intelligence.

2014, ten companies and $410 million in 2013, 14 companies and $821 million in 2012, 15 companies and $1.8 billion in 2011, 13 companies and $2.7 billion in 2010, 11 companies and $908 million in 2009, and 18 companies and $2.4 billion in 2008 — all levels far below the $11.9 billion of 2007. The industry's common share repurchases exceeded $6.0 billion in 2004, 2005 and 2006 after rising from only $120 million in 2003.

Dividend Tax Treatment Unchanged

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, maintaining pre-existing tax rates for dividends and capital gains. Continued low dividend tax rates remain an important element in the industry's ability to attract capital for investment. Maintaining parity between dividend and capital gains tax rates is crucial to avoid creating a disadvantage for companies that rely on a strong dividend to attract investors.

The top tax rate for both dividends and capital gains is 20% for couples earning more than $479,000 ($425,800 for singles). For taxpayers below these income thresholds, dividends and capital gains will continue to be taxed at the current rates of 15% and 0%, depending on a filer's income level. A 3.8% Medicare tax that was included in the 2010 health care legislation is also applied to all investment income for couples earning more than $250,000 ($200,000 for singles).

Dividend Summary
As of December 31, 2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	MR	$2.14	63.4%	2.9%	Raised	$2.14	$2.08	2017 Q1
Alliant Energy Corporation	LNT	R	$1.34	61.9%	3.1%	Raised	$1.34	$1.26	2017 Q4
Ameren Corporation	AEE	R	$1.83	81.5%	3.1%	Raised	$1.83	$1.76	2017 Q4
American Electric Power Company, Inc.	AEP	R	$2.48	67.1%	3.4%	Raised	$2.48	$2.36	2017 Q4
AVANGRID, Inc.	AGR	MR	$1.73	52.2%	3.4%	Raised	$1.73	$1.69	1996 Q1
Avista Corporation	AVA	R	$1.43	79.8%	2.8%	Raised	$1.43	$1.37	2017 Q1
Black Hills Corporation	BKH	R	$1.90	42.2%	3.2%	Raised	$1.90	$1.78	2017 Q4
CenterPoint Energy, Inc.	CNP	MR	$1.11	25.7%	3.9%	Raised	$1.11	$1.07	2017 Q4
CMS Energy Corporation	CMS	R	$1.33	78.5%	2.8%	Raised	$1.33	$1.24	2017 Q1
Consolidated Edison, Inc.	ED	R	$2.76	52.7%	3.2%	Raised	$2.76	$2.68	2017 Q1
Dominion Energy, Inc.	D	MR	$3.08	64.8%	3.8%	Raised	$3.08	$3.02	2017 Q4
DTE Energy Company	DTE	MR	$3.53	51.3%	3.2%	Raised	$3.53	$3.30	2017 Q4
Duke Energy Corporation	DUK	R	$3.56	66.4%	4.2%	Raised	$3.56	$3.42	2017 Q3
Edison International	EIX	R	$2.42	50.3%	3.8%	Raised	$2.42	$2.17	2017 Q4
El Paso Electric Company	EE	R	$1.34	54.3%	2.4%	Raised	$1.34	$1.24	2017 Q2
Entergy Corporation	ETR	R	$3.56	66.4%	4.4%	Raised	$3.56	$3.48	2017 Q4
Eversource Energy	ES	R	$1.90	60.5%	3.0%	Raised	$1.90	$1.78	2017 Q1
Exelon Corporation	EXC	MR	$1.31	31.4%	3.3%	Raised	$1.31	$1.27	2017 Q1
FirstEnergy Corp.	FE	R	$1.44	93.7%	4.7%	Lowered	$1.44	$2.20	2014 Q1
Great Plains Energy Inc.	GXP	R	$1.10	176.2%	3.4%	Raised	$1.10	$1.05	2016 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.24	80.7%	3.4%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$2.36	53.1%	2.6%	Raised	$2.36	$2.20	2017 Q4
MDU Resources Group, Inc.	MDU	MR	$0.79	53.1%	2.9%	Raised	$0.79	$0.77	2017 Q4
MGE Energy, Inc.	MGEE	MR	$1.29	44.8%	2.0%	Raised	$1.29	$1.23	2017 Q3
NextEra Energy, Inc.	NEE	MR	$3.93	31.5%	2.5%	Raised	$3.93	$3.48	2017 Q1
NiSource Inc.	NI	R	$0.70	93.3%	2.7%	Raised	$0.70	$0.66	2017 Q1
NorthWestern Corporation	NWE	R	$2.10	62.2%	3.5%	Raised	$2.10	$2.00	2017 Q1
OGE Energy Corp.	OGE	R	$1.33	40.0%	4.0%	Raised	$1.33	$1.21	2017 Q3
Otter Tail Corporation	OTTR	R	$1.28	70.2%	2.9%	Raised	$1.28	$1.25	2017 Q1
PG&E Corporation	PCG	R	$-	59.8%	0.0%	Omitted	$-	$2.12	2017 Q4
Pinnacle West Capital Corporation	PNW	R	$2.78	57.1%	3.3%	Raised	$2.78	$2.62	2017 Q4
PNM Resources, Inc.	PNM	R	$1.06	63.1%	2.6%	Raised	$1.06	$0.97	2017 Q4
Portland General Electric Company	POR	R	$1.36	63.1%	3.0%	Raised	$1.36	$1.28	2017 Q2
PPL Corporation	PPL	R	$1.58	95.0%	5.1%	Raised	$1.58	$1.52	2017 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.72	54.9%	3.3%	Raised	$1.72	$1.64	2017 Q1
SCANA Corporation	SCG	MR	$2.45	34.4%	6.2%	Raised	$2.45	$2.30	2017 Q1
Sempra Energy	SRE	MR	$3.29	104.3%	3.1%	Raised	$3.29	$3.02	2017 Q1
Southern Company	SO	R	$2.32	53.7%	4.8%	Raised	$2.32	$2.24	2017 Q2
Unitil Corporation	UTL	R	$1.44	70.3%	3.2%	Raised	$1.44	$1.42	2017 Q1
Vectren Corporation	VVC	R	$1.80	65.7%	2.8%	Raised	$1.80	$1.68	2017 Q4

Dividend Summary (cont.)
As of December 31, 2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
Westar Energy, Inc.	WR	R	$1.60	66.3%	3.0%	Raised	$1.60	$1.52	2017 Q1
WEC Energy Group, Inc.	WEC	R	$2.21	54.6%	3.3%	Raised	$2.21	$2.08	2017 Q4
Xcel Energy Inc.	XEL	R	$1.44	62.8%	3.0%	Raised	$1.44	$1.36	2017 Q1
Industry Average				**64.0%**	**3.4%**				

NOTES

Business Segmentation: Assets as of 12/31/2016

Categories:

R = Regulated: 80% or more of total assets are regulated.

MR = Mostly Regulated: Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2017.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2017 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2017. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.

“NM” applies to companies with negative earnings or payout ratios greater than 200%.

Dividend Yield: Annualized Dividends Per Share at 12/31/2017 divided by stock price at market close on 12/31/2017.

By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

Rate Case Summary

Electric utilities filed 56 new rate cases in 2017, less than the 70 filed in 2016 but consistent with the increased pace of filings since the industry’s period of restructuring nearly 20 years ago. Average awarded return on equity (ROE) was 9.74%, the lowest annual average in our nearly 30-years of data. Average requested ROE was 10.28%, also a record low. The long-term decline in interest rates since the early 1980s is the primary reason for the corresponding long-term declines in requested and approved ROEs. Average regulatory lag, at 8.6 months, was near the ten-month average for the years following restructuring. Average regulatory lag will likely continue to hold near ten months unless state commissions accelerate the speed of rate case decisions.

Filed Cases 2017

Broadly speaking, the primary reason utilities file rate cases is to recover for the many forms of required capital expenditures (capex), such as new generation, plant upgrades, transmission and distribution expansion and upgrades, environmental compliance, system hardening and reliability improvements. The second most common reason is electric utilities’ desire to establish rate mechanisms. Recovery of operation and maintenance (O&M) expenses is typically third. All three reasons were evident in 2017. Other drivers of the year’s filings included utilities’ desire to recover for flat and declining sales and to adjust return on equity. Following is a discussion of specific themes within these broad categories.

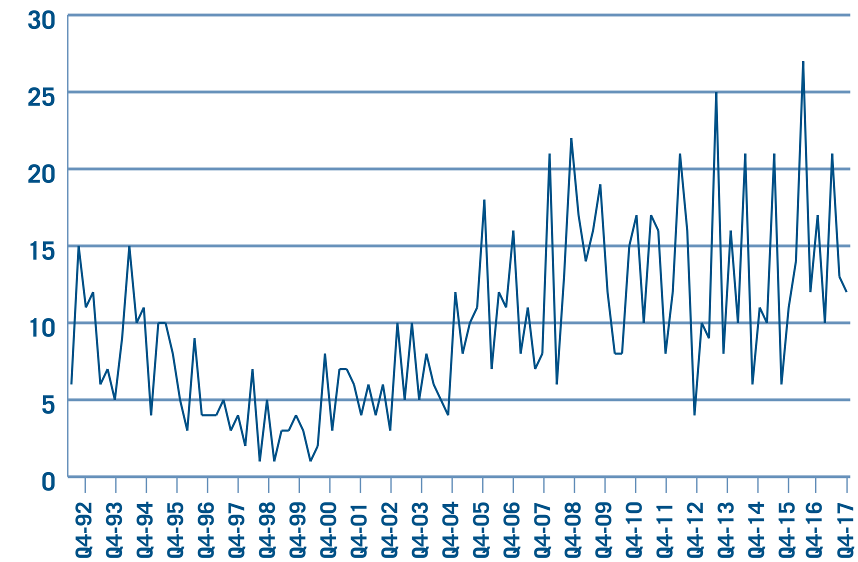
Grid Modernization

NSTAR Electric and Massachusetts Electric each filed in Massachusetts to implement performance-based ratemaking (PBR) mechanisms. The companies are proposing a grid modernization base commitment of a combined $400 million in capital investment over the next five years "to enable clean energy initiatives, including the development of electric vehicle infrastructure and electric storage capabilities, as well as the implementation of technologies such as remote sensing and switching that will assist in integrating distributed energy resources . . . and maintaining top tier service reliability."

Public Service Colorado has embarked on an Advanced Grid and Intelligence Initiative, which includes infrastructure investments, other spending to improve productivity, and costs related to Colorado's Clean Air Clean Jobs Act. The Act requires the state's electric utilities to either convert or retrofit coal plants to gas, or retire them up to the lesser of 900 megawatts or 50% of the utility's coal assets, by January 1, 2018. In Q4, the company filed for a four-step increase to recover associated costs, explaining that the rate increases would "fund investments to better integrate renewable energy, boost grid reliability, offer customers more information for greater control over their energy budget, reduce system fuel and energy costs, and put in place technology to keep costs low over the long term."

Number of Rate Cases Filed 1992–2017

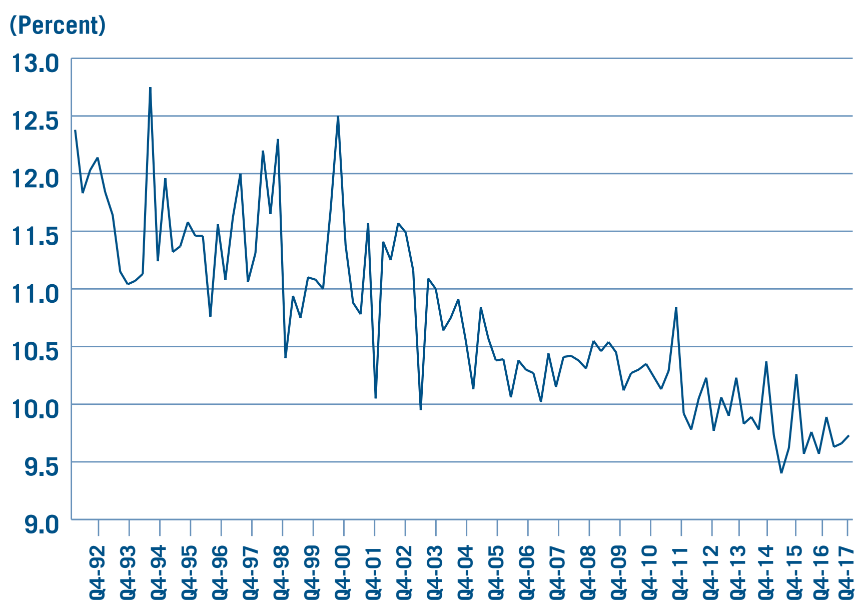
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Rate Department.

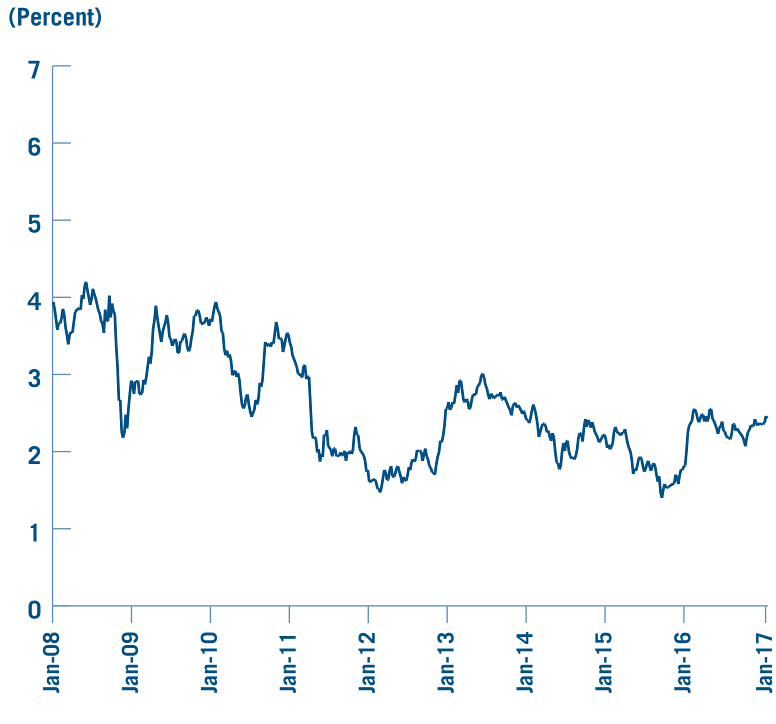
Average Awarded ROE 1992-2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Rate Department.

10-Year Treasury Yield
1/1/08 through 12/31/17



Source: U.S. Federal Reserve.

Similarly, Narragansett Electric in Rhode Island proposed a Power Sector Transformation Plan (PSTP) consistent with the state's Power Sector Transformation Initiative (PSTI). The PSTI responds to the state governor's directive that stakeholders collaborate to create a "more dynamic regulatory framework" that enables a "cleaner, more affordable, and more reliable energy system for the 21st century and beyond." A report issued by stakeholders proposes shifting the traditional electric utility business model to a more performance-based model to better-align incentives with customer demand and public policy. The report recommends adoption of multi-year rate plans along with budget and revenue caps to incentivize cost savings. Narragansett's PSTP proposes four main areas for investment: advanced metering, grid modernization, electric vehicle infrastructure, and energy storage and solar demonstration projects. In its initial comment on the company's proposal, the commission said, "As Rhode Island navigates the transition from an old one-way energy system to a new one, based as much on information as infrastructure, we need to consider fresh solutions, new partners and bring the best know-how in the world to our doorstep."

Return on Equity

In its Maryland filing, Delmarva Power said it "has a well-documented history of earning less than the ROE that has been authorized by [the commission]. . . . [T]he company has realized unadjusted ROEs lower than those authorized by the commission over each of the last five years and, on average, has earned 372 basis points less than its authorized ROE during that period." The company said it earned an ROE of 4.04% versus an authorized 9.6% in the test period; it cited a Maryland rule that requires use of a historical test year for rate setting as one reason for its struggle. Consequently, the company requested a year-end, reliability-related rate base valuation covering known and measurable reliability-related plant additions from the end of the test year through October 2017. It also requested that reliability-related construction work-in-progress be placed in service through April 2018.

Duke Energy Kentucky's ROE from electric operations is only 2.58%, which the company's filing describes as "inadequate to enable the company to continue providing safe, reasonable and reliable service to its customers and is insufficient to afford Duke Energy Kentucky a reasonable opportunity to earn a fair return on its investment property that is used to provide such service while attracting necessary capital at reasonable rates."

Emera Maine filed in Q4 to remove a 50-basis-point ROE reduction, ordered in its last rate case, for management inefficiencies associated with its billing system, customer service and reliability. The company says it has made improvements that address these issues.

Commission Rulings On Customer Charges: 2017

Company	State	Previous	Requested	Allowed
Delmarva Power & Light	Delaware	$11.70	$17.47	$11.70
Delmarva Power & Light	Delaware	$11.70	$13.51	
Potomac Electric Power	District of Columbia	$13.00 $10.25 (master metered apartments)		$15.09 $11.84 (master metered apartments)
Indiana Michigan Power	Indiana	$7.30	$18.00	
Interstate Power & Light	Iowa	$10.50	$13.50	
Kentucky Utilities	Kentucky	$10.75	$22.00	$12.25
Louisville Gas & Electric	Kentucky	$10.75	$22.00	$12.25
Delmarva Power	Maryland	$7.94	$12.00	$8.17
Indiana Michigan Power	Michigan	$7.25	$18.00	
Union Electric	Missouri	$8.00	$8.00	$9.00
Liberty Utilities Granite State	New Hampshire	$11.80		$14.50
Unitil Electric Systems	New Hampshire	$10.27	$15.00	$15.24
Atlantic City Electric	New Jersey	$4.44	$6.44	$5.00
Duke Energy Progress	North Carolina	$11.15	$19.50	
Duke Energy Carolinas	North Carolina	$11.80	$17.79	
Otter Tail Power	North Dakota	$8.00	$17.70	
Oklahoma Gas and Electric	Oklahoma	$13.00	$26.54	$13.00
Metropolitan Edison	Pennsylvania	$10.25	$17.42	$11.25
Pennsylvania Power	Pennsylvania	$10.85	$13.41	$11.00
West Penn Power	Pennsylvania	$5.81	$13.98	$7.44
El Paso Electric	Texas	$6.90	$10.85	$8.25

Commonwealth Edison and Ameren Illinois in Q4 completed their seventh rate case under their formula rate plans. The Illinois commission granted each company an 8.4% ROE, among the lowest ROEs awarded U.S. utilities in the last 35 years.

Recovering for Lower Sales

Several electric utilities filed in 2017 to recover for shortfalls associated with declining customer sales and load, including Atlantic City Electric in New Jersey and Northern States Power in Wisconsin. Interstate Power & Light in Iowa filed partly to recover for declining residential consumption; two-thirds of its service territory is rural and growing more slowly than its urban areas. Avista in Idaho filed partly to adjust for decreased usage. On the other hand, Oncor Electric Delivery filed in Texas partly to address improving growth prospects resulting from an expanding economy and growing population in its service territory.

Rate Design

Electric utilities' attempts to increase residential customer charges were evident in several rate cases in 2017. As one example, Indiana Michigan Power in Indiana filed to raise the residential customer charge from $7.30 to $18, saying the proposed increase "better reflects the fixed, customer specific nature of these customer costs and provides increased customer rate stability. The proposed increase . . . also brings [the company's] rates more in line with the principles of cost causation, thereby eliminating subsidies within the residential class."

Several electric utilities filed partly to make rate design changes beyond simple attempts to increase the customer charge.

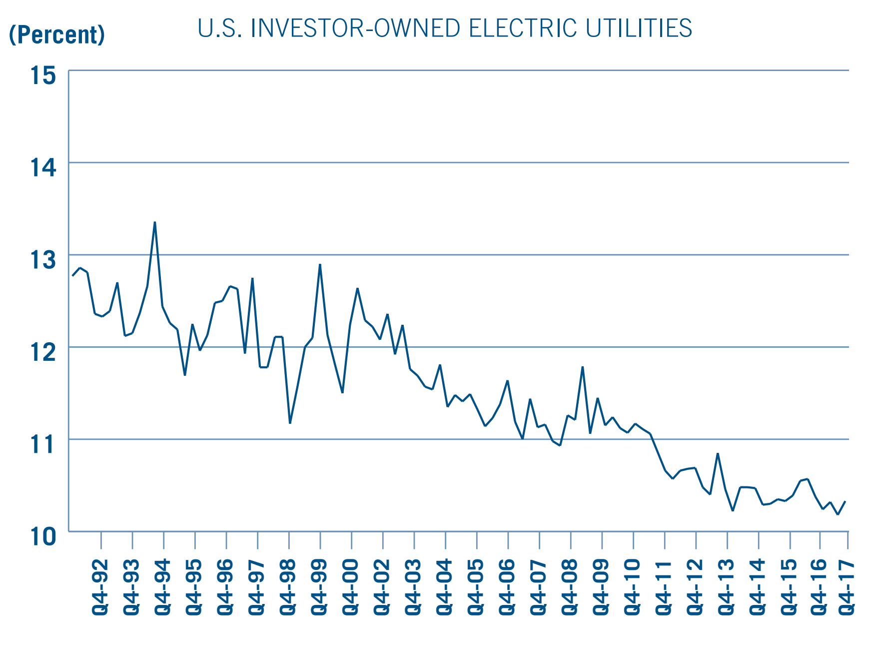
In El Paso Electric's filing in Texas, the company asked to establish a new rate class for grid-connected customers who self-generate. These customers create two-way power flows and other expenses that other customers do not create. As a result, rates designed for non-generating customers, when applied to generating customers, result in extraordinary cost shifts between customer groups. El Paso's proposed three-part rate structure incorporates a customer charge, a charge based on the customer's demand (usage at a specific instant), and an energy charge (covering the total amount of electricity the customer uses).

Duke Energy in Ohio filed partly to implement "straight fixed variable" rates for certain customers. Straight fixed variable rates employ a higher customer charge in order to more efficiently recover the fixed costs imposed by customers on an electric system. The remainder of the rate is a variable energy charge that recovers usage costs. Interstate Power & Light filed to initiate a pilot program for residential and general service demand billing. Otter Tail Power in North Dakota wants to launch a residential time-of-day rate class.

Miscellaneous

Duke Energy Carolinas in North Carolina cancelled a nuclear project after the main contractor went bankrupt. The $53 million per year the utility is seeking extends only to the next dozen years. Despite cancelling the project, the company notes that

Average Requested ROE 1992–2017



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Rate Department.

". . . the license and other investments remain an important asset. Cancelling the project now helps to keep costs lower for customers while also meeting the state's energy needs through use of cost effective natural gas, existing nuclear plants and expanded renewable energy. And it gives us the opportunity to benefit from the lessons learned from other utilities pursuing new nuclear generation, which will ultimately benefit customers when the time comes to build a new nuclear plant. We are also continuing to evaluate options to extend the life of our existing nuclear fleet."

Decided Cases 2017

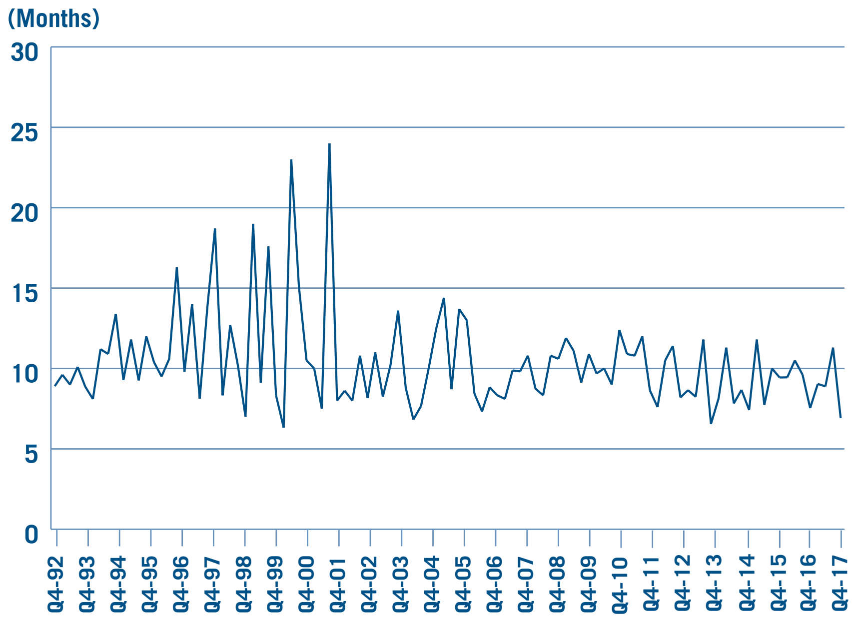
Return on Equity

Delmarva Power in Maryland requested a 10.6% ROE. The commission awarded 9.6%, saying the company's reliance on comparative risk observations in Baltimore Gas and Electric's (BG&E) rate case was misguided. The commission said it commented in that case to distinguish between BG&E's electric and gas distribution operations; combining these to produce a single return would cause a cross-subsidization of services and Delmarva has no gas operations. The commission also said Delmarva's argument that the commission consider the recent change in Federal Reserve-administered interest rates was not persuasive, partly because the change occurred after the evidentiary hearing in the case and it was too small to justify an increase in Delmarva's ROE. The commission said a 9.6% ROE is consistent with the risks facing electric distribution operations in Maryland, capital market conditions at the time of the proceeding, the fact that Delmarva does not issue its own stock, and with other ROEs across the country.

Potomac Electric Power in Maryland requested an ROE of 10.1%, but the Maryland commission awarded 9.5% observing that in each of the company's previous four cases it "requested an ROE of 10.10% or greater. Each time we declined to adopt the Company's recommendation in view of the economic and risk factors faced by the Company at the time. This time is no different. . . . Interest rates have generally declined over the last decade. Once again, the Company predicts that interest rates will increase, however, . . . economists have been forecasting that interest rates would increase for the past ten years, and they have been wrong. . . . interest rates went up and down between Case No. 9418 and this case, and are now somewhat higher. The resultant increase however cannot be correctly described as significant. . . . Thus, although market conditions may have changed, they do not support an increase in authorized ROE. . . . [The 9.5% ROE is] both adequate and appropriate for Pepco, considering the low level of risk associated with its electric distribution service in Maryland and the current capital market environment."

Average Regulatory Lag 1992–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Rate Department.

Kentucky Utilities' and Louisville Gas & Electric's settlements would have awarded the companies ROEs of 9.75%. However, the commission awarded 9.7% saying, "In 2017 the economic environment has shown signs of relative improvement. In response to increased economic growth and low unemployment, the Federal Reserve increased interest rates in March and June 2017, and current outlooks, including comments from government agencies, show that investors anticipate additional interest rate increases. . . . Even with the current uptick in economic conditions, the economy remains in an era of historically low interest rates and slow economic growth. Therefore, irrespective of the agreement by the parties that a 9.75 percent ROE is appropriate for [the companies], the Commission finds that a slightly lower ROE is a better reflection of current economic conditions and investor expectations. Based on the entire record . . . we find that [the companies'] required ROE falls within a range of 9.2 percent to 10.2 percent, with a midpoint of 9.70 percent. . . . While the Commission does not rely on individual returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, the Commission does find it reasonable to expect that other state commissions, each with its own attributes, evaluate expert witness testimony which uses the same or similar cost-of-equity models as those presented by the parties participating in this rate proceeding, and reach conclusions based on the data provided in the records of individual cases. The [Regulatory Research Associates] reports introduced into the record of this proceeding summarize conclusions reached by state utility regulatory commissions, including this Commission, with regard to reasonable ROEs and contain explanatory reference points as to individual circumstances, all of which are available to investors. To the extent that investors' expectations are influenced by such publications, and we believe they are, we also find it appropriate to use that information to put their expectations in context."

Employee Benefits

In Delmarva Power's case in Maryland, the commission excluded 50% of costs associated with the company's senior executive retirement plan; the commission said it found no evidence that the company could not attract highly qualified executives without the plan. In Kentucky Utilities' and Louisville Gas & Electric's settlements in Q2, the commission disallowed certain retirement costs for employees in the categories of exempt, manager, non-exempt, officer and director; the commission said eligible employees participating in the company's defined benefit pension plan "enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts [additional retirement funds] excessive for ratemaking purposes."

New Technologies and Grid Modernization

Potomac Electric Power's settlement in Maryland allows the company to build or buy 700 kilowatts of solar generation, at a price capped at $1,650 per kilowatt, with recovery beginning January 1, 2019, at a 10.5% ROE. The settlement allows the company to initiate a 50-megawatt battery storage pilot program, capped at $2,300 per kilowatt, to be recovered in the next rate case. The settlement further allows the company to deploy a minimum of 530 electric charging stations, at a total investment of up to $8 million, to be recovered over a four-year period after 2021.

Gulf Power's settlement in Florida allows the company to establish electric vehicle (EV) charging stations, on a revenue-neutral basis, as a pilot program for the lesser of five years or until the company files a permanent EV charging station program. Tampa Electric's settlement allows the company to implement a solar base rate adjustment mechanism allowing the company to install and receive recovery for 600 megawatts of photovoltaic solar generation with a maximum $122.3 million revenue requirement (not to exceed $1,500 per kilowatt) by the end of 2021. If the installed cost is less than this amount, the company must share 75% of the savings with customers.

NSTAR Electric's and Western Massachusetts Electric's decisions in Massachusetts allow the companies to recover $45 million in investments made to accelerate the development of electric vehicle infrastructure and up to $55 million made to construct both a five-megawatt and a 12-megawatt energy storage facility. The commission said "grid modernization is vital for maintaining and improving the reliability of the electric system and offers potential savings to customers. . . . The Department remains committed to ensuring that electric distribution companies implement appropriate grid modernization technologies and practices to enhance reliability, reduce costs, empower customers to better manage usage, and support a cleaner, more efficient electric system. . . . These investments should not only enable the market for energy storage in Massachusetts, but also provide data that will be critical in evaluating future energy storage deployments as part of Massachusetts' clean energy future."

Duke Energy Florida's settlement increased rates to reflect $1.1 billion in grid modernization investments intended to enhance reliability, reduce outages, shorten restoration time, support the growth of renewable energy and emerging technologies, install advanced metering infrastructure, and upgrade company systems.

El Paso Electric

El Paso Electric's settlement in Texas allows recovery of decommissioning and retirement costs related to a coal plant, but it includes a mechanism to adjust for changes in corporate income taxes; the mechanism requires the company to record as a regulatory liability the difference between income taxes reflected in the revenue requirement and taxes calculated using the new rate. The company is required to file a tariff within 120 days of the law's enactment for any regulatory liability refund over a 12-month period. The company must update and file the refund factor, within 90 days of the end of each fiscal year, to reflect any over- or under-recovery until reconciliation in the next base rate case.

The settlement also increased El Paso Electric's residential monthly customer charge from $6.90 to $8.25. The company had requested $10.85. New customers with an expected load of greater than 400 kilowatts must take service under the company's time-of-use rates, with a one-time opportunity to opt out after one year. Customers who opt out will pay the lower of time-of-use rates or standard service rates for the introductory year. Residential customers who generate electricity can choose either a $30 monthly minimum bill, a time-of-use rate or a demand charge. Under the time-of-use rate option, the customer would pay the greater of total base rate charges, including the customer charge, or a minimum bill of $26.50. Under the demand charge option, the customer would pay the customer charge, a monthly demand charge of $3.16 per kilowatt-hour based on monthly peak and metered demand, and time-of-use energy charges. The settlement applies similar changes to the rates of generating customers in the small general service class. The company is unable to change rates for generating customers beyond those changes applying to all customers for a minimum of three years. Customers who applied to be generating customers before the order date are exempt from minimum bill provisions for 20 years.

Miscellaneous

Oklahoma Gas and Electric's settlement in Oklahoma prohibits the company from implementing residential demand charges until it conducts "a study and pilot program on demand charges to evaluate customer acceptance, understanding, and ability to respond to a rate design that includes demand charges and appropriate methods for recovering fixed costs."

Delmarva Power requested an increase in the residential customer charge in Maryland from $7.94 to $12. The commission awarded $8.17. The commission said that "determining the appropriate customer charge is not an exact science, but rather requires the balancing of several important considerations," such as energy conservation and efficiency, and that ". . . maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges." The commission expressed concern about the effect of larger customer charges on low-income customers and observed that low customer charges provide value to net metering customers.

In the same case, the commission found that the benefits of Advanced Metering Infrastructure (AMI) exceeded the costs, and therefore approved recovery. However, it expressed concern about the effect of that recovery on customers and admonished Delmarva "to demonstrate and communicate to its customers that the AMI program will result in direct monetary benefits and continue to develop ways to increase" those benefits. Kentucky Utilities and Louisville Gas & Electric are conducting collaborative efforts on AMI to explore related merits and appropriate rate treatments.

Liberty Utilities Granite State's settlement in New Hampshire stipulates that the company's customer service performance be measured between 2017 and 2019 based on call answer time, billing and customer satisfaction. If performance does not meet certain levels, the company must provide a $1 credit to each customer.

Business Strategies

Business Segmentation

Revenue increased for all four of the industry's primary business segments in 2017. Overall, industry revenue rose by $13.4 billion, or 3.8%, from 2016's total. While nationwide electric output decreased by 0.9% after four years of marginal increases, Regulated Electric revenue grew by $2.0 billion, or 0.8%. The industry's Natural Gas Distribution segment experienced the largest revenue growth in both dollar and percentage terms as several natural gas-related acquisitions that closed during 2016 contributed a full year of revenue to 2017.

The industry's three largest business segments all grew assets in 2017, driving a $43.7 billion, or 2.9%, increase in total industry assets. The industry's regulated asset base expanded 2.7%, extending a multi-year trend and providing most of the industry's asset growth in dollar terms. Regulated assets rose to an 80.9% share of industry assets at year end, up from 80.1% at year-end 2016; a record-high $113.6 billion of capital expenditures and a generally constructive regulatory environment supported the increase. The Competitive Energy segment showed a 5.5% revenue gain and a 4.0% increase in assets.

2017 Revenue by Segment

Regulated Electric revenue increased modestly in 2017, rising by $2.0 billion, or 0.8%, to $254.9 billion from $252.9 billion in 2016. The segment's share of industry revenue fell to 68.0% from 70.0% in 2016, yet remained well above the 52.1% level of 2005.

Natural Gas Distribution revenue rose by $6.6 billion, or 17.6%, to

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2017	2016r	Difference	% Change
Regulated Electric	254,935	252,903	2,032	0.8%
Competitive Energy	55,367	52,472	2,895	5.5%
Natural Gas Distribution	44,117	37,519	6,598	17.6%
Natural Gas Pipeline	4,578	3,975	603	15.2%
Natural Gas and Oil Exploration & Production	—	34	(34)	(100.0%)
Other	15,871	14,141	1,730	12.2%
Discontinued Operations	(0)	(2)	2	(97.2%)
Eliminations/Reconciling Items	(10,854)	(10,412)	(442)	4.2%
Total Revenues	**364,014**	**350,630**	**13,384**	**3.8%**

r = revised

Note: Difference and Percent Change columns may reflect rounding. Totals may reflect rounding.

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2017	12/31/2016r	Difference	% Change
Regulated Electric	1,107,753	1,086,483	21,270	2.0%
Competitive Energy	192,764	185,383	7,381	4.0%
Natural Gas Distribution	196,212	183,089	13,124	7.2%
Natural Gas Pipeline	25,678	27,203	(1,526)	(5.6%)
Natural Gas and Oil Exploration & Production	797	1,022	(225)	(22.0%)
Other	88,677	101,390	(12,713)	(12.5%)
Discontinued Operations	5	211	(206)	(97.7%)
Eliminations/Reconciling Items	(45,832)	(62,418)	16,586	(26.6%)
Total Assets	**1,566,054**	**1,522,363**	**43,691**	**2.9%**

r = revised

Note: Difference and Percent Change columns may reflect rounding. Totals may reflect rounding.

$44.1 billion from $37.5 billion in 2016. This followed an 8.9% increase in 2016, a 19.2% drop in 2015, and double-digit percentage increases during the three previous years (10.8% in 2014, 12.2% in 2013, and 15.6% in 2012). The significant growth over the last two years is due to the completion in 2016 of four acquisitions that were focused on natural gas distribution assets.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — increased by $8.6 billion, or 3.0%, to $299.1 billion in 2017. Over the past decade, the year-to-year change for this metric has fluctuated between gains of 5% to 8% and declines of 5% to 7%. However, revenue from regulated operations has steadily grown as a percentage of industry revenue. Regulated revenue accounted for 79.8% of industry revenue in 2017, extending a steady upward trend from 65.3% in 2005. The *Business Segmentation–Revenues* table presents the industry's revenue breakdown by business segment. Eliminations and reconciling items were added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2017 and 2016.*

2017 Assets by Segment

Regulated Electric assets edged up to 68.7% of industry assets at December 31, 2017 from 68.6% at December 31, 2016, rising in dollar terms by $21.3 billion, or 2.0%, over the year-end 2016 level. Competitive Energy assets increased by $7.4 billion, or 4.0%, from year-end 2016. Natural Gas Distribution assets showed the highest percentage growth for the second consecutive year, jumping $13.1 billion, or 7.2%. Natural Gas Pipeline assets experienced a drop of $1.5 billion, or 5.6%. The asset total in the very small Natural Gas and Oil Exploration & Production segment fell 22.0%, to $797 million.

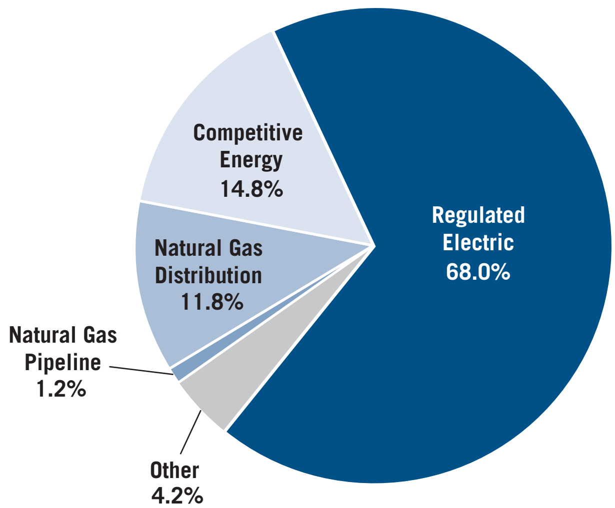
Total regulated assets (Regulated Electric plus Natural Gas Distribution) grew to 80.9% of total industry assets at year-end 2017 from 80.1% on December 31, 2016. This aggregate measure has risen steadily from 61.6% at year-end 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period. During 2017, 65% of companies increased regulated assets as a percent of total assets (or maintained a 100% regulated structure).

Regulated Electric

Regulated Electric segment operations include the generation,

Revenue Breakdown 2017

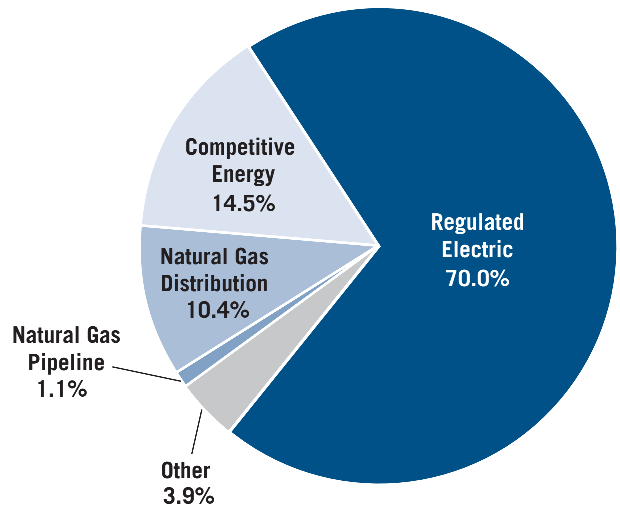
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2016r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

transmission and distribution of electricity under state regulation for residential, commercial and industrial customers. Thirty-nine companies, or 80% of the industry, experienced an increase in Regulated Electric revenue in 2017.

The year's 0.8% increase in Regulated Electric revenue followed modest declines in 2016 (-0.1%) and 2015 (-2.6%), solid gains in 2014 (+4.9%) and 2013 (+4.7%) and declines in the two preceding years (-2.8% in 2012 and -0.6% in 2011). U.S. electric output decreased by 0.9% in 2017 following four years of only marginal increases that ranged from 0.1% to 0.5%. This came after declines of 1.8% in 2012, 0.6% in 2011, 3.7% in 2009 and 0.9% in 2008. During the 2008 through 2012 period, output rose only in 2010 (+3.7%). Until recently, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percentage growth. Energy efficiency initiatives, demand-side management programs and the off-shoring of formerly U.S.-based manufacturing and heavy industry continue to constrain growth in electricity demand.

Competitive Energy

Competitive Energy segment revenue increased 5.5% to $55.4 billion from $52.5 billion in 2016. Revenue declined $6.9 billion (-11.4%) in 2016 and $7.4 billion (-10.3%) in 2015, after increasing $1.6 billion (+2.3%) in 2014 and $984 million (+1.5%) in 2013. Revenue fell by $22.4 billion, or 26.0%, in 2012. The Competitive Energy segment's 2016 revenue was its lowest annual total in data going back to 2000. The segment's peak annual revenue during the previous decade was $113.2 billion in 2008. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically electric utilities seeking to supplement generation capacity along with regional power pools and large industrial customers. Competitive Energy also includes the trading and marketing of natural gas. Of the 24 companies that have Competitive Energy operations, just over half (13 companies, or 54%) grew these assets during 2017 while 58% had revenue gains.

Natural Gas

Natural Gas Distribution revenue surged $6.6 billion, or 17.6%, the largest gain in both dollar and percentage terms of all business segments. This followed an increase of $3.0 billion (+8.9%) in 2016, a decline of $7.8 billion (-19.2%) in 2015 and gains of $4.0 billion (+10.8%) in 2014 and $3.9 billion

(+12.2%) in 2013 after four years of declines. The large gas acquisitions that were completed in 2016 — Southern Company's purchase of AGL Resources, Dominion Energy's purchase of Questar, Duke Energy's acquisition of Piedmont Natural Gas and Black Hills' acquisition of SourceGas Holdings — drove the segment's revenue growth in 2017 and 2016. Total gas distribution revenue for these four acquiring companies increased more than six-fold in two years, rising to $7.67 billion in 2017 from $1.26 billion in 2015. Overall, 27 of the 29 companies (93%) that report gas distribution revenue showed a year-to-year increase in 2017. This followed a decrease for 61% of companies in 2016 and 90% in 2015 and an increase for 91% in 2014 and 88% in 2013.

Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers. Added together, Natural Gas Distribution and Natural Gas Pipeline activities produced revenue of $48.7 billion in 2017, up from $41.5 billion in 2016. In percentage terms, the contribution to total industry revenue from these two natural gas activities increased to 13.0% in 2017 from 11.5% in 2016.

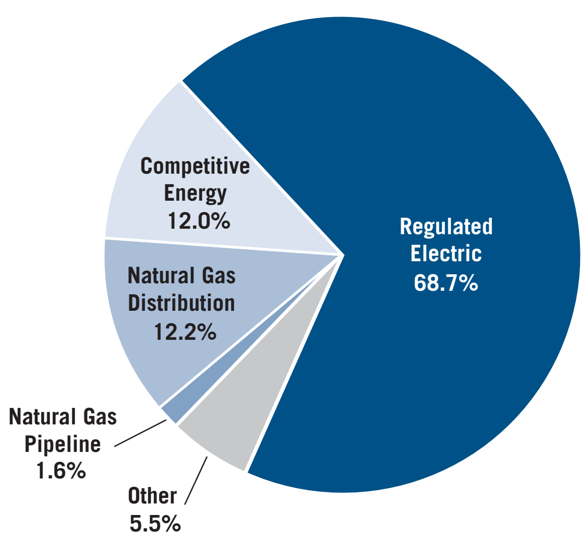
The Natural Gas and Oil Exploration & Production segment has undergone a steady decline over the past decade; Black Hills was the last in our universe of companies to exit the business. No companies reported revenue for this business segment in 2017. Only two companies carried a small amount of related assets as of December 31, 2017.

2017 Year-End List of Companies by Category

Early each calendar year, EEI updates our list of investor-owned electric utility holding companies organized by business category. The list is based on previous year-end business segmentation data presented in 10-K's and supplemented by discussions with parent companies. Our categories are as follows: Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated). Starting January 1, 2017, the Diversified category, which represented companies with

Asset Breakdown
As of December 31, 2017

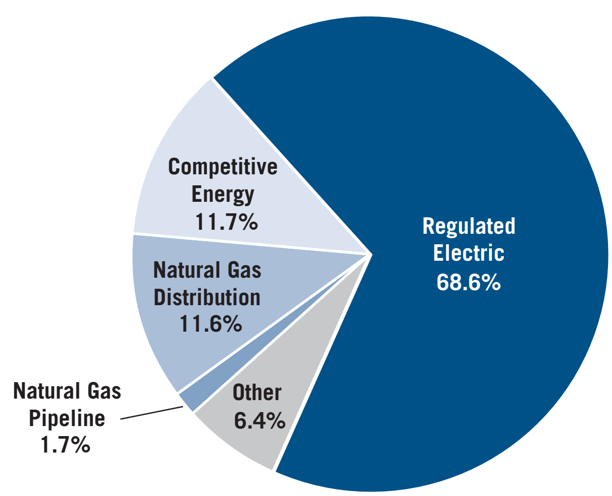
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2016r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

List of Companies by Category at December 31, 2017

Regulated (36)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
*Cleco Corporation**
CMS Energy Corporation
Consolidated Edison, Inc.
*DPL Inc.**
Duke Energy Corporation
Edison International
El Paso Electric Company
Entergy Corporation
Eversource Energy
FirstEnergy Corp.
Great Plains Energy Inc.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
*Oncor Electric Delivery Company**
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
*Puget Energy, Inc.**
SCANA Corporation
Southern Company
Unitil Corporation
Vectren Corporation
WEC Energy Group, Inc.
Westar Energy, Inc.
Xcel Energy Inc.

Mostly Regulated (13)

ALLETE, Inc.
AVANGRID, Inc.
*Berkshire Hathaway Energy**
CenterPoint Energy, Inc.
Dominion Energy, Inc.
DTE Energy Company
Exelon Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
Public Service Enterprise Group Incorporated
Sempra Energy

Note:* Non-publicly traded companies.

less than 50% of holding company assets that are regulated, was terminated due to its dwindling number of members.

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends. Fluctuating natural gas and power prices can impact revenue so greatly that a company's strategic approach to business segmentation is distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and indicates the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

There was modest movement between categories in 2017. The Regulated category remained at 36 companies as two additions offset two departures. DPL and SCANA were added as their regulated asset percentages rose above 80%. Berkshire Hathaway Energy fell just below the 80% mark in 2017 and Empire District Electric left the category when it was acquired by Algonquin Power & Utilities, a North American diversified generation, transmission, and distribution utility headquartered in Canada.

The Mostly Regulated category fell from 14 to 13 companies as DPL and SCANA migrated to the Regulated category and Berkshire Hathaway Energy was added.

The total number of companies in the EEI universe fell from 50 at year-end 2016 to 49 at year-end 2017, a result of the Empire District Electric acquisition. At the close of 2017, there were 36 Regulated and 13 Mostly Regulated companies (*see List of Companies by Category at December 31, 2017*).

Mergers and Acquisitions

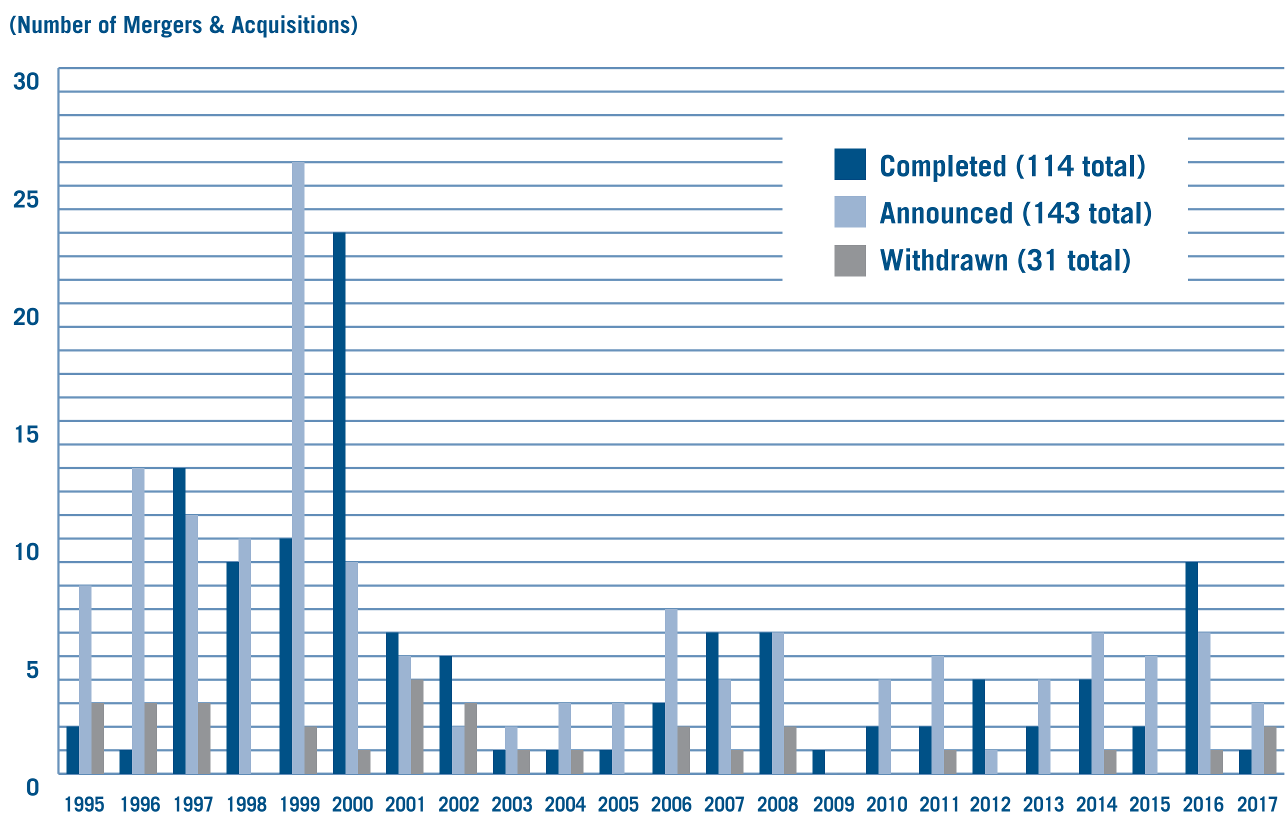
Merger and acquisition (M&A) activity slowed in 2017 from 2016's fast pace. Only three whole-company transactions involving regulated utilities were announced compared with six in 2016. One deal closed versus nine completions in 2016. The year's slower pace was perhaps to be expected as utilities navigated and consolidated the 21 deals announced from 2013 through 2016, of which all but four have been completed (one of those four is still pending, the others were withdrawn).

The fundamental motivations for M&A across the industry were little changed from recent years. Stagnant nationwide power demand makes M&A a potential route to faster earnings growth for larger utilities through synergies and cost reductions as well as acquisition of smaller utilities with relatively better growth outlooks. Teaming up with a larger partner can give smaller utilities access to balance sheet strength for elevated capex programs. And long-term investors view regulated utilities' steady cash flows and sturdy dividends as attractive, particularly given the very low interest rates in global capital markets since the 2008/2009 financial crisis. All three themes were evident in 2017's action. A fourth theme colored deal activity on the competitive power side of the industry: persistently low share prices led to Calpine's acquisition by a private investor group and to a proposed merger between Vistra and Dynegy, motivated by synergies and cost reductions.

Deal action in 2017 among regulated utilities included Sempra's announced acquisition of Oncor, Canadian utility Hydro One's bid for Avista, and Dominion's offer to buy SCANA. Great Plains and Westar revised the terms of their pending

Status of Mergers & Acquisitions 1995–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

combination in response to Kansas state regulators' concerns. Finally, Canadian utility Algonquin completed its purchase of Missouri-based Empire District Electric.

Announced Deals in 2017

Sempra Acquires Oncor

On August 20, San Diego-based Sempra announced a bid for Texas regulated transmission and distribution utility Oncor — whose parent company, privately held Energy Futures Holdings (EFH), filed for bankruptcy in April 2014. EFH was created with the 2007 buyout of vertically integrated Texas utility TXU. Sempra offered $9.45 billion in cash for EFH and its 80% interest in Oncor for an enterprise value of $11.2 billion, including assumption of Oncor's debt. Sempra's bid was the fourth attempt to acquire the profitable transmission and distribution utility, which serves 10 million customers across much of northern Texas. The Texas Hunt brothers tried to buy Oncor in the summer of 2014 with a plan to convert the utility into a real estate investment trust (REIT) but withdrew the bid in May 2016 after state regulators imposed conditions the Hunts said were too onerous. The second bid was NextEra's July 29, 2017 offer to buy EFH and its Oncor stake for a combination of cash and stock with an enterprise value of $18.7 billion. NextEra's plans also encountered resistance from Texas regulators, who rejected the offer in April 2017 and again in July 2017; commissioners cited concern about potential financial risk emanating from NextEra's merchant and nuclear generation fleet and demanded safeguards that included ring-fencing and an independent board of directors for Oncor. Third was Warren Buffet's Berkshire Hathaway Energy, which sought to add Oncor to its portfolio of U.S., Canadian and British gas and electric utilities with a $9 billion cash offer and tentative agreement to the ring-fencing provisions demanded by Texas regulators. Berkshire Hathaway withdrew its bid in August.

Interest in Oncor from four separate bidders highlights a multi-year theme in utility M&A: the appeal of strong and profitable regulated utilities in regions benefitting from growing demand and attractive rate base investment opportunities. While nationwide power demand has been stagnant for nearly a decade, Texas' load grew 23% between 2006 and 2016.

Sempra called Oncor an excellent strategic fit for its portfolio of utility and energy infrastructure businesses and said the acquisition would expand its regulated utility footprint, meaningfully increase its earnings from domestic utilities, be accretive to corporate earnings in 2018, and serve as a platform for future growth in the Texas and Gulf Coast regions; the addition of Oncor's $11.0 billion rate base will nearly double Sempra's $12.8 billion rate base. Sempra also committed to support Oncor's plan to invest $7.5 billion over a five-year period in transmission and distribution infrastructure. Sempra also agreed to ring fence Oncor and maintain an independent board of directors for the utility, meeting Texas regulator's demands, and said the acquisition would improve Oncor's underlying financial strength and credit ratings. Texas approved the transaction on March 8, 2018 and Sempra completed the deal the following day.

Sempra Energy is a Fortune 500 energy services holding company with 2016 revenues of more than $10 billion. Sempra Energy includes San Diego Gas & Electric, Southern California Gas Co., Sempra South American Utilities, Sempra Mexico, Sempra Renewables and Sempra LNG & Midstream. Sempra Energy formerly owned and operated 10 power plants in the Texas electric market.

Canada's Hydro One Bids for Avista

On July 19, Ontario's dominant transmission and distribution utility, Hydro One, joined the list of Canadian utilities seeking to boost growth through acquisition of U.S. utilities with its agreement to buy Spokane, Washington-based Avista for $53 in cash per common share, a 24% premium to Avista's closing price on July 18. The price represents an equity value of $3.4 billion and an enterprise value of $5.3 billion, including assumption of Avista's debt. Canadian utilities Emera, Fortis, Algonquin Power and Gaz Metro have all been buyers of U.S. utilities since 2009. In addition, Alberta-based AltaGas said in January 2017 it would seek to acquire Washington, D.C.-area gas distribution utility WGL. Avista is a vertically integrated, regulated electric and natural gas utility serving customers in Washington, Idaho, Oregon and Alaska; about 40% of its generation is hydro and 35% natural gas. The Pacific Northwest has seen load growth over the past decade while nationwide demand has been flat.

Hydro One said the acquisition offers geographic and regulatory diversification while adding complementary and growing natural gas distribution operations and exposure to regulated and predominantly clean generation. It said the transaction should be accretive to earnings per share in the mid-single digits in the first full year of operation through synergies and reduced costs, and that Avista's capital investment program will further enhance scale, strengthen the quality of its asset mix and reinforce its growth profile. The companies said the combined entity would grow rate base by about 6% annually from 2017 through 2021. Hydro One affirmed its long-term intention of maintaining a dividend payout ratio at 70 to 80 percent of earnings.

Avista said the agreement enables it to define and control its future in a consolidating industry through greater scale and financial flexibility; it plans to maintain its current management team, employees, Spokane headquarters and its own board of directors. Avista said no workforce reductions are anticipated due to the merger.

The Canadian province of Ontario owns nearly half of Hydro One after selling down its 100% stake since 2015 to enable more efficient capital raising through public markets. It noted the transaction represents a form of growth available through broadened share ownership. The companies hope to close the transaction in the second half of 2018, subject to approval by state regulators in Washington, Oregon, Idaho, Alaska and Montana.

Status of Announced Mergers & Acquisitions
1995–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	4	–
2014	4	6	1
2015	2	5	–
2016	9	6	1
2017	1	3	2
Totals	**114**	**143**	**31**

Source: EEI Finance Department.

Calpine Goes Private

Publicly held competitive power producers' stock prices were cut in half or worse from 2014 to mid-2017; low natural gas prices and growing wind generation have depressed wholesale power prices in many regions while energy efficiency measures and sluggish economic growth have kept nationwide power demand flat for 10 years. Merchant power plants have also faced off against subsidies for baseload coal and nuclear generators in some markets. Industry analysts and company managements noted a growing gap between private market values for merchant generators and the much lower public market valuations.

Independent power producer Calpine, which owns 26,600 megawatts of mostly natural gas generation across 25 states, Canada and Mexico, in April 2017 said it would welcome private buyers who would value the company more highly than public shareholders. On May 10, Calpine's stock jumped after *The Wall Street Journal* reported the company had retained advisers to arrange a possible sale. On August 18, Calpine announced it would be sold to a private investor group for a cash price of $15.25 per share, a 51% premium to Calpine's May 9 price. The price valued the equity portion of the deal at $5.3 billion, for total value of $17.3 billion including debt. Canadian buyers made an appearance in this transaction too; the Canadian Pension Plan Investment Board along with New York private infrastructure firm Access Industries led the buyout group. Buyers said they had no plans to change the way Calpine operates its business, its financial policies or its ongoing debt reduction plan, and noted they saw value in Calpine's "operational excellence and strong and stable cash flows." The deal was completed on March 8, 2018.

Vistra and Dynegy to Merge

Publicly traded merchant generator Dynegy took a different route to combat its depressed share price. In a move long-telegraphed by industry-wide speculation, Dallas-based Dynegy announced on October 30, 2017 an agreement to merge with Houston-based Vistra, an IPP carved out of the former Texas integrated utility TXU. Vistra's shares were listed on the New York Stock exchange in May 2017.

Synergies, enhanced scale and cost reduction were the deal's drivers. The companies said the combination of Vista's retail and commercial operations with Dynegy's combined cycle gas turbine (CCGT) fleet and geographically

Merger Impacts 1995–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	–
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)
12/31/14	48	(2.04%)
12/31/15	47	(2.08%)
12/31/16	44	(6.38%)
12/31/17	43	(2.27%)

Number of Companies Declined by 56% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

diverse portfolio would create a company with the lowest cost structure in the industry and enhanced diversification across earnings sources, fuel, weather and market exposure. The companies said they hope to create $4 billion in equity value from enhanced cash flow, tax synergies and operational improvements. The combined company would be the nation's largest IPP with approximately 40 gigawatts of installed generation capacity — over 60 percent natural gas-fired and 84 percent in the ERCOT, PJM, and ISO-NE competitive power markets. Dynegy noted that Vistra's strong balance sheet would support and accelerate its own debt reduction plans. Dynegy's shares traded as high as $33 in late 2014, but fell to $6 in April 2017 before climbing to $12 in October on news of the proposed merger. Under the terms of the agreement, Dynegy shareholders will receive 0.652 shares of Vistra common stock for each share of Dynegy; if the deal is completed, Vistra and Dynegy shareholders will own approximately 79 percent and 21 percent, respectively, of the combined company. Based on Vistra's October 27 closing price of $20.30, Dynegy shareholders would receive $13.24 per share. The companies hope to close the transaction in the second quarter of 2018 following federal and state regulatory approvals, including the Federal Energy Regulatory Commission and state regulators in New York and Texas. If the merger is completed, NRG, AES and the combined Vistra/Dynegy will be the remaining publicly held U.S. IPPs.

Dominion Offers to Buy SCANA

While the announcement was dated January 3, 2018, the deal was all but done in 2017. Virginia's Dominion Energy and South Carolina-based SCANA said they hope to merge in a stock-for-stock transaction that would pay SCANA shareholders 0.669 shares of Dominion's common stock, producing an equity value of $7.9 billion and total value of $14.6 billion including assumption of debt. The price represents an approximate 31 percent premium for SCANA shareholders, who would own about 13 percent of the combined company.

Dominion called the merger a "strategic combination" and termed SCANA "a natural fit", noting that Dominion's presence in the Carolinas — through its Dominion Energy Carolina Gas Transmission, electric utility Dominion Energy North Carolina, and Atlantic Coast Pipeline operations — complements those of SCANA's South Carolina regulated electric and gas subsidiary SCE&G and North Carolina gas utility PSNC Energy. Dominion said the deal supports new expansion opportunities in the southeast U.S. and can boost its earnings growth rate through 2020 to eight percent or higher. SCANA has bucked flat nationwide power demand with its customer count and weather-normalized energy sales growing at about two percent annually. Dominion said the merger would be accretive to earnings upon closing, which the companies hope to achieve during 2018.

The companies said a key benefit for SCANA is Dominion's ability — given its larger size and financial strength — to fully resolve the July 2017 decision to cease construction of two new nuclear units at the V.C. Summer Nuclear Station in Jenkinsville, South Carolina. SCANA was part owner of the project, which it deemed prohibitively expensive to continue following the bankruptcy of the nuclear plants' contractor (Westinghouse) and a venture partner's move to abandon the project. Low natural gas prices have made the costly nuclear plants far less profitable than what was expected when the construction process began ten years ago. The companies said the merger agreement seeks to offset project costs borne by SCANA's SCE&G electric customers through a $1,000 payment to the average residential electric ratepayer, an estimated additional five percent rate reduction from current levels, an accelerated write-off of project costs and the purchase of natural-gas fired power station, at no cost to ratepayers, to meet generation needs. SCANA said a merger with Dominion Energy would strengthen the company and enable it to once again focus on core operations. SCANA would operate as a wholly owned subsidiary of Dominion Energy, maintaining its local management structure and the headquarters of its SCE&G utility in South Carolina. The merger needs approval from state regulators in South Carolina, North Carolina and Georgia in addition to Federal Energy Regulatory Commission (FERC) and Nuclear Regulatory Commission (NRC).

Mergers & Acquisitions Announcements Updated through December 31, 2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
8/21/2017	Sempra Energy	Oncor Electric Delivery Company	PN					$9.5B cash	9,450.0
7/19/2017	Hydro One Limited	Avista Corporation	PN					$5.3B cash (per share value of $53.00, roughly 24% premium)	5,300.0
7/7/2017	Berkshire Hathaway Energy	Oncor Electric Delivery Company	W		8/21/2017			$9.0B cash	9,000.0
9/28/2016	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	C		10/20/2016	1	EG	Undisclosed	1,300.0
7/29/2016	NextEra Energy	Oncor Electric Delivery Company	W		10/31/2017			$9.5B debt + additional cash and common stock	11,178.0
5/31/2016	Great Plains Energy	Westar Resources	PN					$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/2016	Fortis Inc.	ITC Holdings Corp.	C		10/14/2016	8	EE	$4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium)	11,300.0
2/9/2016	Algonquin Power & Utilities	Empire District Electric Company	C		1/1/2017	11	EE	$1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium)	2,400.0
2/1/2016	Dominion Energy	Questar Corporation	C		9/16/2016	8	EG	$1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium)	4,400.0
10/26/2015	Duke Energy	Piedmont Natural Gas	C		10/3/2016	12	EG	$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/2015	Emera	TECO Energy, Inc.	C		7/1/2016	10	EE	$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/2015	Southern Company	AGL Resources	C		7/1/2016	10	EG	$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/2015	Black Hills Corporation	SourceGas Holdings	C		2/12/2016	10	GG	$760M debt + $1.13B cash	1,890.0
2/25/2015	Iberdrola USA	UIL	C	AVANGRID, Inc.	12/16/2015	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/2014	NextEra Energy	Hawaiian Electric	W		7/18/2016			NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/2014	Macquarie-led Consortium	Cleco	C		4/13/2016	18	EE	$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/2014	Winsconsin Energy	Integrys	C	WEC Energy Group, Inc.	6/30/2015	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/2014	Berkshire Hathaway Energy	AltaLink (Canadian)	C		12/1/2014	7	ET	BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/2014	Exelon	Pepco	C		3/23/2016	24	EE	EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,337.0
3/3/2014	UIL Holdings	Philadelphia Gas Works	W		12/4/2014			UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/2013	Fortis Inc.	UNS Energy	C		8/15/2014	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/2013	Avista	Alaska Energy & Resources Company	C		7/1/2014	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
5/29/2013	MidAmerican Energy Holdings Co.	NV Energy	C	Berkshire Hathaway Energy	12/19/2013	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/2013	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	C		9/2/2014		EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/2012	Fortis Inc.	CH Energy Group	C		6/27/2013	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,609.7
5/27/2011	Fortis Inc.	Central Vermont Public Service Corp	W		7/11/2011		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/2011	Duke Energy	Progress Energy	C		7/3/2012	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/2011	Gaz Metro LP	Central Vermont Public Service Corp	C		6/27/2012	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2
10/16/2010	Northeast Utilities	NSTAR	C		4/10/2012	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/2011	Exelon Corp.	Constellation Energy Group Inc.	C		3/12/2012	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2
4/19/2011	AES Corporation	DPL Inc.	C		11/28/2011	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2

4/28/2010	PPL Corp.	E.ON U.S.	C		11/1/2010	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/2010	Emera Inc	Maine & Maritimes	C		12/21/2010	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/2010	FirstEnergy	Allegheny Energy	C		2/25/2011	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/2008	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/2008		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/2008	Sempra Energy	EnergySouth Inc.	C		10/1/2008	3	EG	$499 million cash + 283 million debt	771.9
7/1/2008	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/2008	3	EG	$245 million cash + $82 million debt	327.0
6/25/2008	Duke Energy	Catamount Energy Corp.	C		9/15/2008	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/2008	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	C		12/1/2008	10	EG	$160 million cash	160.0
1/12/2008	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/2008		EE	$202.5 million	202.5
10/26/2007	Macquarie Consortium	Puget Energy	C		2/6/2009	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/2007	Iberdrola S.A.	Energy East Corp.	C		9/16/2008	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/2007	KKR & Texas Pacific Group	TXU Corp.[1]	C	Energy Future Holdings Corp.	10/10/2007	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/2007	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/2008	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/2006	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/2007	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/2006	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/2007	7	EG	$2.47 billion	2,472.4
7/5/2006	Macquarie Consortium	Duquesne Light Holdings	C		5/31/2007	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/2006	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/2007	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/2006	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/2006	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/2006	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/2007		EE	$2.2 billion cash	2,200.0
2/27/2006	National Grid	KeySpan Corp.	C		8/24/2007	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/2005	FPL Group Inc.	Constellation Energy Inc.	W		10/25/2006		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/2005	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/2006	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/2005	Duke Energy Corp.	Cinergy Corp.	C		4/3/2006	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/2004	Exelon Corp.	Public Service Enterprise Group	W		9/14/2006		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/2004	PNM Resources	TNP Enterprises	C		6/6/2005	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/2004	Ameren Corp	Illinois Power[3]	C		10/1/2004	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/2003	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/2004		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/2003	Exelon Corp.	Illinois Power	W		11/22/2003		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/2002	Aquila Inc	Cogentrix Energy Inc	W		8/2/2002		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/2002	Ameren Corp	CILCORP[4]	C		1/31/2003	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/2001	Northwest Natural Gas	Portland General	W		5/16/2002		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/2001	Duke Energy	Westcoast Energy	C		3/14/2002	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/2001	Dominion Energy	Louis Dreyfus Natural Gas	C		11/1/2001	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/2001	Energy East	RGS Energy	C		6/28/2002	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/2001	PEPCO	Conectiv	C		8/1/2002	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/2000	PNM	Western Resources[5]	W		1/8/2002		EE	Stock transfer	4,442.0
10/2/2000	NorthWestern	Montana Power[6]	C		2/15/2002	16	EE	$1.1 billion in cash	1,100.0
9/5/2000	National Grid Group	Niagara Mohawk	C		1/31/2002	16	EE	$19 per share	8,900.0
8/8/2000	FirstEnergy	GPU Inc.	C		11/7/2001	15	EE	$35.60 per share	12,000.0
7/31/2000	FPL Group	Entergy	W		4/2/2001		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/2000	AES Corporation	IPALCO	C		3/27/2001	8	IPPE	$25 per share	3,040.0
6/30/2000	NS Power	Bangor Hydro	C	Emera	10/10/2001	16	EE	$26.50 per share	206.0

[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007.
TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

[3] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[4] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[5] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[6] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

Source: EEI Finance Department, S&P Global Market Intelligence.

C = Completed	E = Electric
W = Withdrawn	G = Gas
PN = Pending	O = Oil
	IPP = Independent Power Producer
	P = Privatized

Great Plains, Westar Revise Deal Terms

Kansas-based Great Plains Energy's attempt to buy neighboring utility Westar, announced in May 2016, faced resistance from Kansas regulators, who said a merger of the two companies made sense but that the purchase price was too high. On May 31, 2016 Great Plains Energy announced it reached an agreement to purchase Westar Energy in a combined cash and stock transaction with an enterprise value of approximately $12.2 billion, including $8.6 billion in stock and cash and assumption of $3.6 billion in Westar's debt. The commission said those deal terms required Great Plains to take on too much debt and could negatively impact the companies' credit ratings. It also said the companies' cost reduction plans were ambiguous and rate benefits to customers were unclear. The commission rejected the proposed deal in April 2017.

In response, the companies in July 2017 proposed a revised transaction structured as a stock-for-stock merger of equals with no premium paid or received, no transaction debt and no exchange of cash. The companies also quantified cost savings from synergies and operating efficiencies at about $35 to $45 million in 2018 (growing to $140 to $170 million by 2021), offered a $50 million rate credit to customers and said there would be no layoffs from the merger. Westar shareholders would own 52.5 percent and Great Plains shareholders 47.5 percent of the new combined entity. The companies said the merger would be accretive to their standalone earnings per share in the first year and thereafter, and the combined company would target compounded annual earnings per share growth of six to eight percent from 2016 to 2021. The new company would maintain the current dividend for Great Plains Energy shareholders, resulting in a 15 percent dividend increase for Westar shareholders.

If the merger is completed, the new company will have 1.6 million customers in Kansas and Missouri and nearly 13,000 megawatts of generation capacity, including one of the largest wind generation portfolios in the country. Wind would represent nearly one-third of its retail sales and, including nuclear output, nearly half of the utility's retail sales would be produced with zero emissions. The two companies hope to complete a transaction in the first half of 2018.

Completed Transactions in 2017

Algonquin Acquires Empire District Electric

On January 1, 2017 Ontario-based Algonquin Power and Utilities Corp. (APUC) announced it completed its purchase of U.S. utility Empire District Electric (EDE) for $34.00 per share, implying a purchase price of approximately $2.3 billion including the assumption of $0.8 billion of EDE debt. The offer represented a 21% premium to EDE's closing price on February 8, 2016 (the day before the deal was announced) and a 50% premium to EDE's price before news emerged that it was seeking a buyer. The Canadian acquirer said that acquisition represents a continuation of its growth strategy, which seeks to strengthen and diversify its existing businesses and strategically expand its regulated utility footprint in the Midwest United States. Algonquin said the transaction would provide additional support to its annual dividend growth target of 10% and that it expected to finance the transaction in a way that maintains its credit profile and strong investment grade credit ratings.

Empire District Electric is a regulated utility with approximately 90% of its on-system revenue from Missouri and Arkansas, regulatory jurisdictions that Algonquin (through its Liberty Utilities subsidiary) has operated in for many years. APUC said the transaction further diversifies Liberty Utilities' electric, gas, and water utility operations and provides an entry into two new markets in Oklahoma and Kansas.

Construction

New Capacity

The electric utility industry brought 26,225 MW of new capacity online in 2017, an 8% decrease from 2016. Natural gas capacity was the dominant contributor with 11,990 MW of new capacity added (46% of the total), a 30% increase over 2016, and double the amount added in 2015. This contrasts with 2016 when natural gas and solar tied for first place in new generation capacity. In 2017, wind and solar together comprised 51% of the total new capacity added. Wind capacity was at 7,275 MW (28% of the total), while solar accounted for 6,002 MW (23% of the total). The investor-owned utilities that brought the most capacity online, either as new plants or expansions at existing facilities, were Exelon (2,552 MW), NextEra Energy (1,298 MW), TECO Energy (1,195 MW) and Alliant Energy (683 MW).

Natural gas

Natural gas generation dominated capacity additions in 2017. Abundant supply of natural gas and low natural gas prices make gas-fired generation cost competitive with coal while environmental regulations favor cleaner fuels. Combined-cycle projects accounted for 9,795 MW, or 82% of total gas capacity added. Simple-cycle turbines contributed 1,827 MW, or 15% of the total. Exelon expanded capacity at two combined cycle plants in Texas, adding 1,231 MW at its Wolf Hollow facility and 1,230 MW at the Colorado Bend Energy Center. TECO added 1,195 MW through an expansion at Polk Station in Florida. Florida Power & Light added 879 MW of simple-cycle natural gas capacity at its Ft. Lauderdale facility.

Although not counted in capacity additions, two coal-fired plants were converted to equal capacity natural gas-powered steam turbines: South Carolina Electric & Gas Company's 294 MW McMeekin plant and a 381 MW Public Service Company of Colorado plant owned by Xcel Energy. The combined total of 674 MW was down 84% from 2016.

Plant expansions dominated new capacity additions at 67% of the total. New builds accounted for 3,799 MW, just under 33% of the total. Fuel-switching and rerated plants were a distant third. New-build projects ranged from 1 MW steam turbines in Iowa to an 832 MW combined-cycle plant in Ohio.

Wind

Wind accounted for 28% of capacity additions, second after natural gas. Although total wind capacity added to the grid dropped 10% from 2016, some regions saw an increase. The total wind added in the Western Electricity Coordinating Council

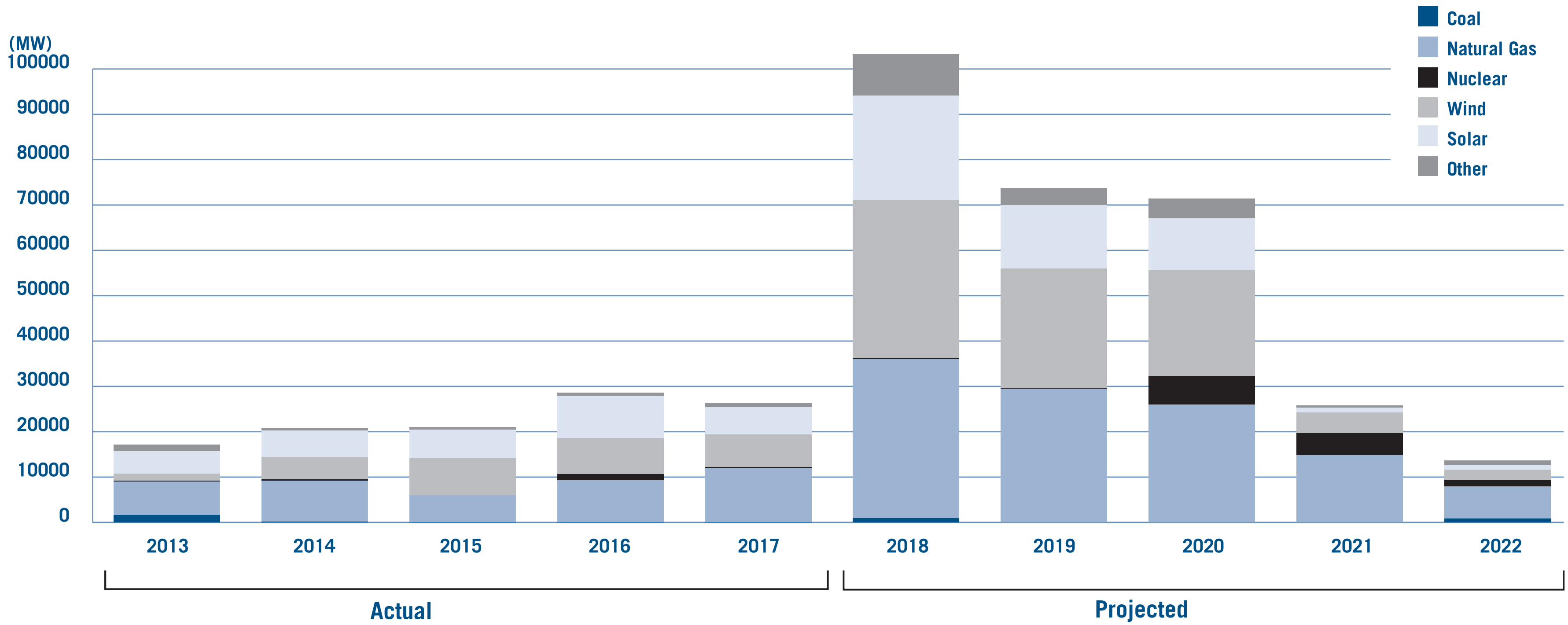
New Capacity Online (MW) 2013–2017

	Entire Industry
2017	
New Plant	15,549
Plant Expansions	10,676
Total	**26,225**
2016	
New Plant	18,804
Plant Expansions	9,818
Total	**28,622**
2015	
New Plant	14,917
Plant Expansions	6,108
Total	**21,025**
2014	
New Plant	12,719
Plant Expansions	8,130
Total	**20,849**
2013	
New Plant	9,920
Plant Expansions	7,243
Total	**17,163**

Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municpals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

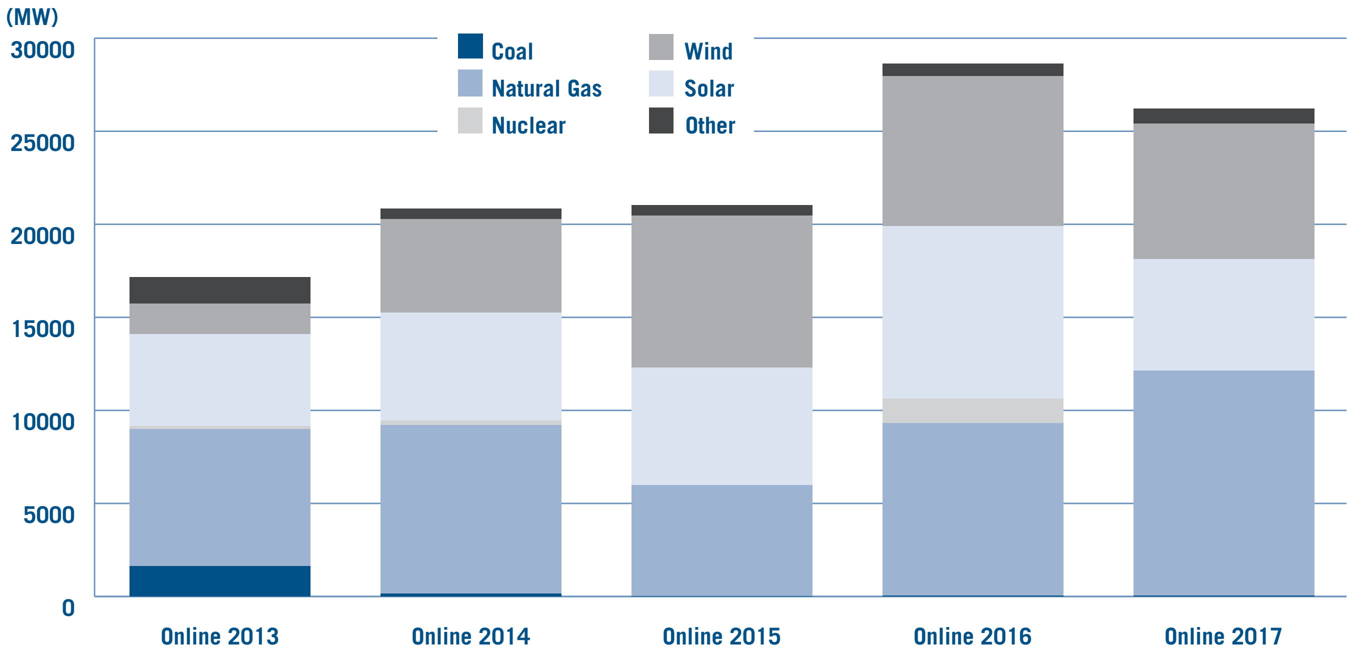
Actual and Projected Capacity Additions 2013–2022



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	1,618	136	3	45	45	912	—	—	—	850
Natural Gas	7,370	9,081	5,971	9,282	11,990	35,089	29,504	25,968	14,782	7,056
Nuclear	172	227	0	1,291	102	227	107	6,363	4,938	1,460
Wind	1,646	5,041	8,179	8,045	7,275	34,923	26,384	23,278	4,528	2,263
Solar	4,936	5,808	6,316	9,287	6,002	22,995	13,912	11,427	1,032	1,068
Other	1,421	557	556	672	811	9,094	3,810	4,361	566	953
Total	**17,163**	**20,849**	**21,025**	**28,622**	**26,225**	**103,239**	**73,717**	**71,396**	**25,846**	**13,650**

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates. Data does not include projects with an expected online date beyond 2022.
Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.
2013-2017 is actual plants brought online. 2018-2022 is projected based on projects announced as of March 2018.
Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

New Capacity Online by Fuel Type 2013–2017



Fuel Type	2013	2014	2015	2016	2017
Coal	1,618	136	3	45	45
Natural Gas	7,370	9,081	5,971	9,282	11,990
Nuclear	172	227	0	1,291	102
Solar	4,936	5,808	6,316	9,287	6,002
Wind	1,646	5,041	8,179	8,045	7,275
Other	1,421	557	556	672	811
Total	**17,163**	**20,849**	**21,025**	**28,622**	**26,225**

Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

New Capacity Online by Region (MW) 2017

Region	Online	Announced	Announced as % of Total Announced
ASCC	2	2.8	0.0%
FRCC	2,400	5,276	10.3%
HCC	48	111	0.2%
MRO	1,840	5,528	10.8%
NPCC	399	2,881	5.6%
RFC	4,972	9,918	19.4%
SERC	3,518	8,042	15.8%
SPP	3,404	4,244	8.3%
TRE	6,603	2,290	4.5%
WECC	3,038	12,707	24.9%
Total	**26,225**	**50,999**	**100%**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

region jumped 170%, additions in Electric Reliability Council of Texas territory rose 60%, and the ReliabilityFirst region added 5%.

NextEra Energy, Southern Company and Sempra Energy together accounted for 14% of added wind capacity. NextEra added 555 MW from projects in Nebraska, California, Texas, Indiana and North Dakota — all new facilities except for a 200 MW expansion in Texas. Southern Company added 401 MW from two Texas projects. Sempra Energy added 100 MW in Michigan. Black Hills Corporation expanded its Busch Ranch wind farm with 28.8 MW of additional capacity.

Solar

Large-scale solar-photovoltaic represented almost one-quarter of 2017's total new solar capacity, but capacity added fell 35% year-to-year. Continuing the solar build-out momentum seen in 2016, NextEra brought on the most capacity, at 1,652 MW. Exelon was second with 1,263 MW. Southern Company was third at 397 MW. Seven new-build projects larger than 50 MW came online in 2017. Southern Company built the largest, at 102 MW in Texas. NextEra in Florida brought three projects online, each about 75 MW. Dominion Energy built two 71 MW solar farms in South Carolina, while Duke activated a 59 MW solar farm in North Carolina.

Cancellations

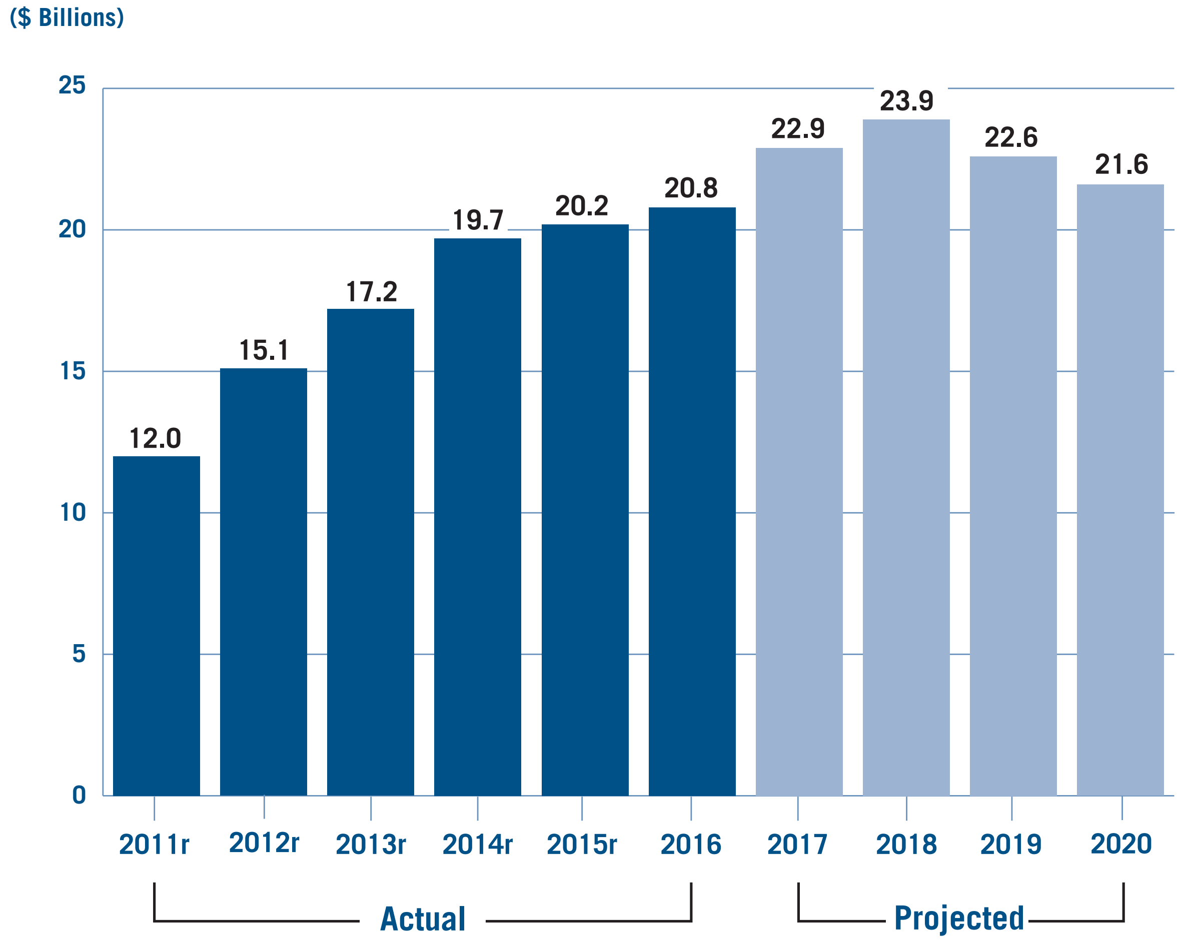
Cancelled or postponed capacity associated with projects in the preconstruction stage totaled 34,155 MW, down 44% from 2016. The decision to halt construction of units 2 and 3 due to cost overruns at SCANA's V.C. Summer nuclear power station, representing 2,234 MW of planned new nuclear capacity was the most notable. Although cancellations dropped across all fuel types, total wind and natural gas capacity that was either cancelled or postponed fell 41% relative to 2016, while coal-related cancellations dropped 70%.

Announcements

In 2017, the electric industry announced plans to build 60 GW of new capacity. While this was 10% below 2016's total, it was largely in line with the 48 GW average from 2013 through 2016. One-quarter of the year's newly announced capacity was in the Western Electricity Coordinating Council (WECC) region, followed by the ReliabilityFirst (RF) region at 19%, the Southeastern Electric Reliability Council (SERC) region at 16%, the Midwest Reliability Organization (MRO) region at 11%, the Florida Reliability Coordinating Council (FRCC) region at 10%, the Southwest Power Pool (SPP) region at 8%, the Northeast Power Coordinating Council (NPCC) region at 6%, and the Texas Reliability Entity (Texas RE) region at 5%, with Hawaii and Alaska rounding out the remainder.

Wind accounted for 36% of announced new capacity, solar was one-third and natural gas was 28%.

Actual and Planned Transmission Investment* 2011–2020



r = revised

*Investment of investor-owned electric utilities and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Budget & Forecast Survey supplemented with data obtained from company 10-K reports and investor presentations. Please note that the investment totals are shown in nominal dollars and are not wholly comparable with previous versions of this chart which showed investment in Real dollars.

Source: Edison Electric Institute Economics, Statistics, and Industry Research Group.

Updated September 2017.

Hawaii's announcements were all solar whereas Alaska's were all oil. After Hawaii, the regional leader in solar as a percent of total announcements was NPCC at 64%. WECC was second at 61%. The SPP region showed the highest wind percentage, at 89% of total announced new capacity. MRO followed at 77% with the RF region close behind at 66%. While no new wind capacity was announced in the FRCC, gas announcements were 73% of the total and solar the remaining 27%. No new natural gas capacity was announced in Alaska, Hawaii or the SPP region. Natural gas showed the highest penetration in the RF region, at 58% of total announced capacity. In Texas, 42% of announcements were natural gas capacity; this was on par with wind's 43%.

While not all announced projects will be built, 7,043 MW, or 14%, is under construction and set to be completed in 2018, 2019 or 2020. Of that, 63% is wind capacity, 22% is natural gas and 14% is solar. There are no new coal plants under construction in the U.S., however an inactive FirstEnergy 1,728 MW coal plant in Pennsylvania is scheduled to restart in 2021.

New vs. Canceled Capacity by Fuel Type (MW)

Fuel Type	Online 2013	Canceled 2013	Online 2014	Canceled 2014	Online 2015	Canceled 2015	Online 2016	Canceled 2016	Online 2017	Canceled 2017
Coal	1,618	4,645	136	279	3	100	45	2,190	45	675
Natural Gas	7,370	4,278	9,081	3,549	5,971	9,090	9,282	12,045	11,990	7,090
Nuclear	172	10,813	227	3,583	0	0	1,291	1,600	102	—
Solar	4,936	6,651	5,808	11,741	6,316	5,800	9,287	10,191	6,002	10,475
Wind	1,646	16,497	5,041	21,414	8,179	10,212	8,045	15,304	7,275	9,033
Other	1,421	9,974	557	4,850	556	1,946	672	7,869	811	4,648
Total	**17,163**	**52,858**	**20,849**	**45,415**	**21,025**	**27,148**	**28,622**	**49,199**	**26,225**	**31,921**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

Stage of Projected Capacity Additions (MW)

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	—	—	—	1745	—	17	—	1,762
Natural Gas	34,015	1,630	28,632	20,716	3,276	24,761	3,674	116,703
Nuclear	10,540	4,436	3,366	3,740	—	2,200	—	24,282
Wind	53,145	5,737	13,507	12,772	403	9,618	2,143	97,325
Solar	35,197	202	7,577	5,047	13	2,944	923	51,904
Other	4,999	10,244	4,004	2,762	5	598	104	22,716
Total	**137,898**	**22,249**	**57,085**	**46,781**	**3,698**	**40,138**	**6,843**	**314,692**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data does not include projects with an expected online date beyond 2022.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

Proposed New Nuclear Plants

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company	Site (State)	Early Site Permit	Design (# of units)	Construction & Operating License	# Units	Status
Southern Co.	Vogtle (GA)	Approved August 2009	AP1000	Approved February 2012	2	Under Construction
DTE Energy Co.	Fermi (MI)	—	ESBWR	Approved May 2015	1	COL Issued
Nuclear Innovation North America	Matorga County (TX)	—	ABWR	Approved February 2016	2	COL Issued
Duke Energy Corp.	Levy County (FL)	—	AP1000	Approved October 2016	2	COL Issued
Duke Energy Corp.	William States Lee (SC)	—	AP1000	Approved December 2016	2	COL Issued
Dominion Energy Inc.	North Anna (VA)	Approved November 2007	ESBWR	Approved June 2017	1	COL Issued
Florida Power & Light	Turkey Point (FL)	—	AP1000	Submitted June 2009	2	Under Active NRC Review
Exelon Corp.	Clinton (IL)	Approved March 2007	TBD	TBD		Eary Site Permit
PSEG	Lower Alloways Creek (NJ)	Approved May 2016	TBD	TBD		Early Site Permit

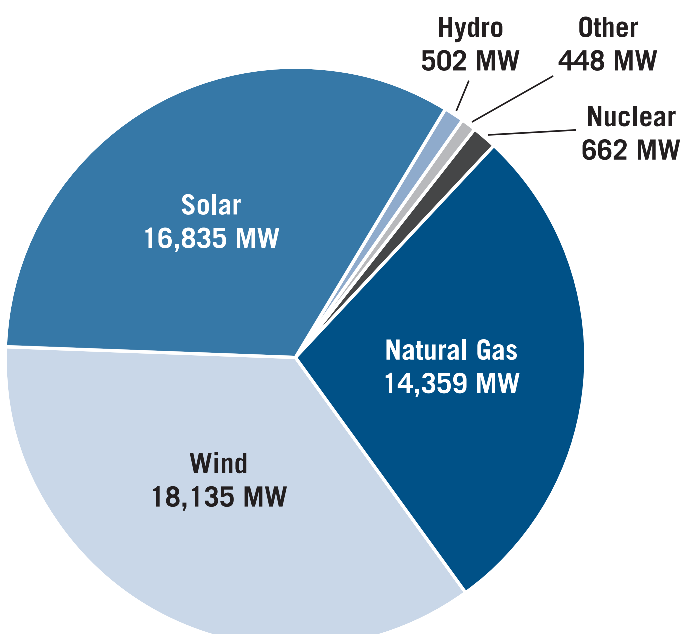
Legend:
TBD: To Be Determined
ABWR: Advanced Boiling Water Reactor
AP1000: Reactor designed by Westinghouse
ESBWR: Economic Simplified Boiling Water Reactor

Source: Nuclear Energy Institute, EEI Finance Department. Last updated March 2018.

For updates, please visit: http://www.nei.org/resources/statistics/new-nuclear-plant-status.

2017 New Capacity Announcements by Fuel Type

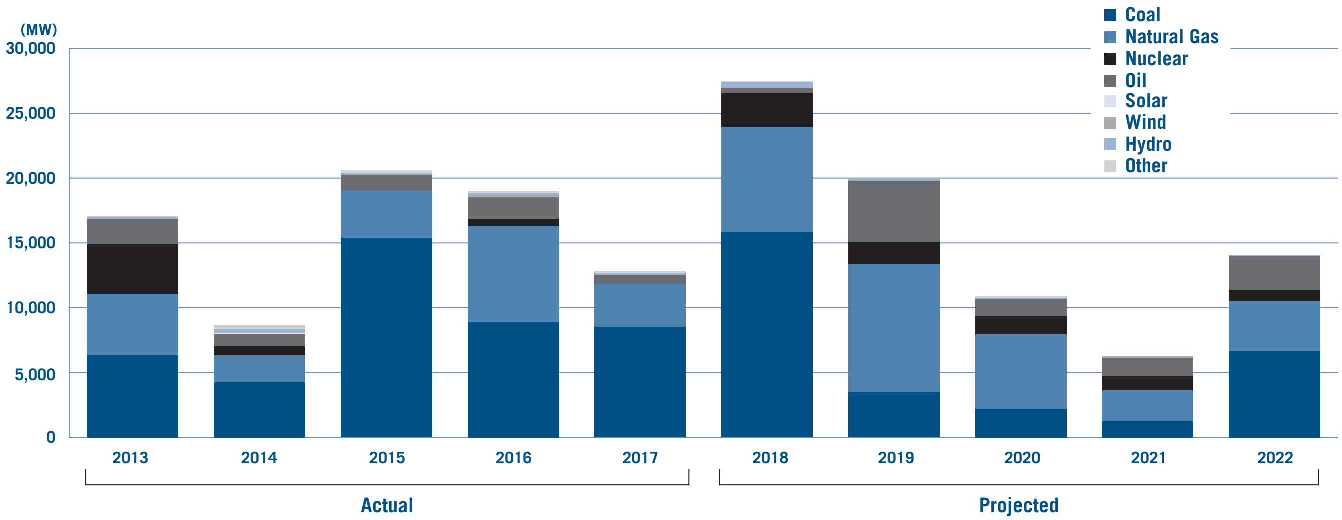
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Other includes biomass, diesel/fuel oil, energy storage, fuel cells, geothermal, landfill gas, pet coke, solar/PV, waste heat, water, and wood. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

Actual and Projected Retirements 2013–2022



	Actual					Projected				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	6,333	4,259	15,380	8,919	8,514	15,845	3,470	2,222	1,236	6,651
Gas	4,747	2,071	3,647	7,380	3,319	8,120	9,926	5,733	2,411	3,850
Nuclear	3,781	676	0	577	0	2,572	1,641	1,371	1,074	823
Oil	1,954	997	1,215	1,648	698	412	4,717	1,343	1,420	2,626
Solar	0	5	34	0	1	2	0	0	0	0
Wind	0	64	37	116	44	68	0	0	0	0
Hydro	165	270	138	127	118	391	219	96	95	130
Other	79	330	160	230	166	41	129	152	23	2
Total	**17,058**	**8,672**	**20,576**	**19,029**	**12,860**	**27,450**	**20,103**	**10,917**	**6,259**	**14,082**

Notes: Data includes new plants and expansions of existing plants. Data does not include projects with an expected online date beyond 2022. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

2013-2017 is actual plants retired. 2018-2022 is projected based on announced retirements.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

Retirements

Approximately 12,860 MW of capacity was retired in 2017, and coal capacity accounted for 66% of the total retired, a 5% decrease from 2016. The electric power industry is moving ahead with coal plant retirements driven by a number of economic and regulatory factors, including the competitive pricing and abundant supply of natural gas, the declining costs of renewable energy technologies, customer demands and environmental regulations.

Transmission

According to EEI's 2017 *Annual Property & Plant Capital Investment Survey*, investor-owned electric utilities and stand-alone transmission companies invested a record $20.8 billion in transmission in 2016, up 2.8% from the $20.2 billion invested in 2015. The increase is attributable to the industry's efforts to meet changing customer expectations while providing low-cost, reliable service. EEI members continue to invest in the transmission system in order to maintain and improve its safety and security from both physical and cyber threats. Over the last 10 years, companies have invested more than $141 billion in the U.S. high-voltage network.

The *EEI Transmission Capital Budget & Forecast Survey* indicates that transmission investment will continue to increase in the short term, peaking in 2018 before leveling off in 2019 and 2020. EEI forecasts its members will invest $91 billion (nominal dollars) in transmission from 2017 to 2020. It should be noted that the projected total is an estimate subject to changing market conditions and customer demand.

The survey shows that most of the projected investment will fund expansion of the transmission network and construction of new lines that connect new energy resources to the grid, enabling an evolving energy mix. The remainder is focused primarily on replacement of existing transmission lines and system improvements such as hardening, physical security and cyber security that improve and maintain the grid's resilience.

Distribution

EEI's 2017 *Annual Property & Plant Capital Investment Survey* shows the industry invested $26.7 billion in distribution during 2016, a 3.4% increase over 2015's level. While companies cited many reasons for the increase, the primary drivers were increased spending on smart grid technology, storm hardening, and improved reliability through replacement of aging lines and equipment. Over the past 10 years, electric companies have invested $205 billion in the distribution network. Since 2001, combined transmission and distribution investment in the U.S. electric grid has amounted to almost a half-trillion dollars.

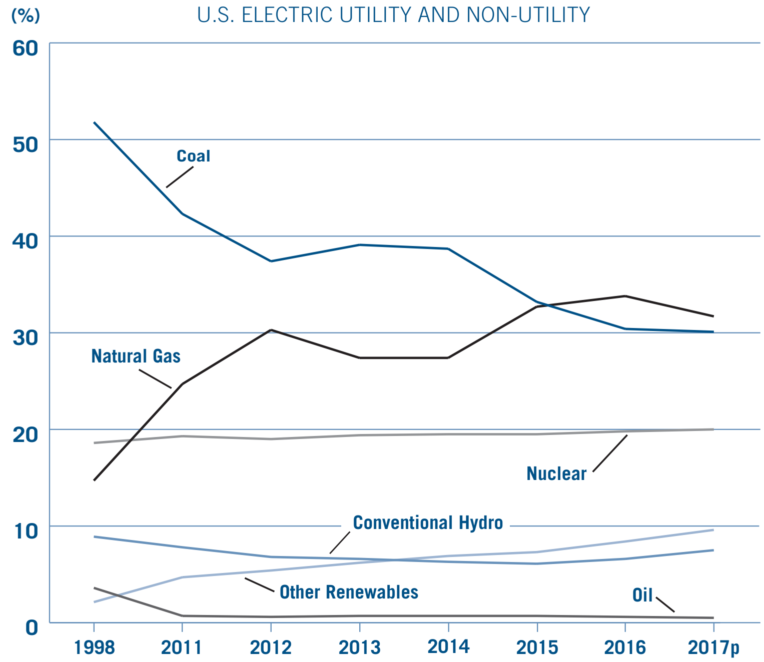
Distribution investment is driven primarily by the continuous need to replace end-of-life assets, serve new load, preserve reliability, improve system resiliency and restoration capabilities, and increasingly, to accommodate distributed resources. Investment in utility infrastructure tends to be cyclical; large investments are made to support major development projects, investment levels off as the focus shifts to maintenance and incremental upgrades, then investment rises again to support load growth and/or adoption of new technologies. Distribution upgrades encompass not only poles and wires but, increasingly, advanced metering infrastructure (AMI) and smart inverters that enable a two-way power flow between the grid and distributed resources such as rooftop solar and battery storage. The rate and breadth of implementation of these smart technologies, however, continues to vary by region and electric utility territory.

Fuel Sources

The primary trends impacting industry fuel use over the last decade continued in 2017. Electricity demand remained flat, natural gas prices remained low, and renewable generation capacity continued to grow. Electric generation from all fuels fell 1.5% in 2017 relative to 2016, the largest annual drop since 2009 when generation declined 4.1% year-to-year. Over the last ten years, year-to-year growth in net generation has averaged only one-third of one percent, while the most recent seven years show a net decline. Demand has been flat, in part as a result of the nation's ongoing shift to a service-based economy and by residential, commercial, and industrial energy efficiency measures, such as increased installation of energy efficient appliances and energy-saving Light Emitting

Fuel Sources for Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY



p = preliminary

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA).

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2017p	2016
Coal	30.1%	30.4%
Gas	31.7%	33.8%
Nuclear	20.0%	19.8%
Oil	0.5%	0.6%
Hydro	7.5%	6.6%
Renewables	9.6%	8.4%
Biomass	1.6%	1.5%
Geothermal	0.4%	0.4%
Solar	1.3%	0.9%
Wind	6.3%	5.6%
Other fuels	0.5%	0.5%
Total	100%	100%

Note: Totals may not equal 100.0% due to rounding.
p: preliminary

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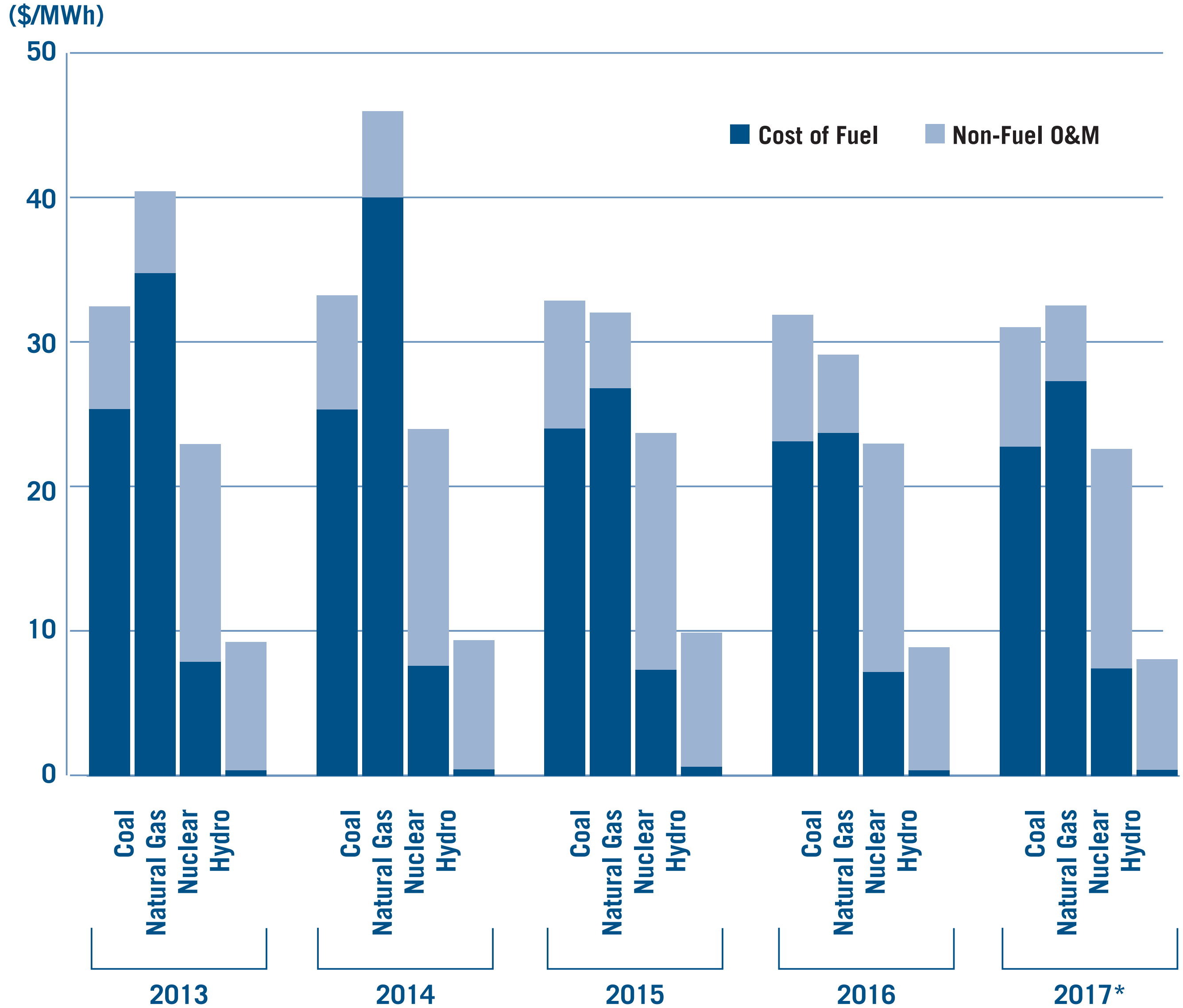
Source: U.S. Department of Energy, Energy Information Administration (EIA).

Average Cost to Produce Electricity 2013–2017

U.S. ELECTRIC UTILITY AND NON-UTILITY



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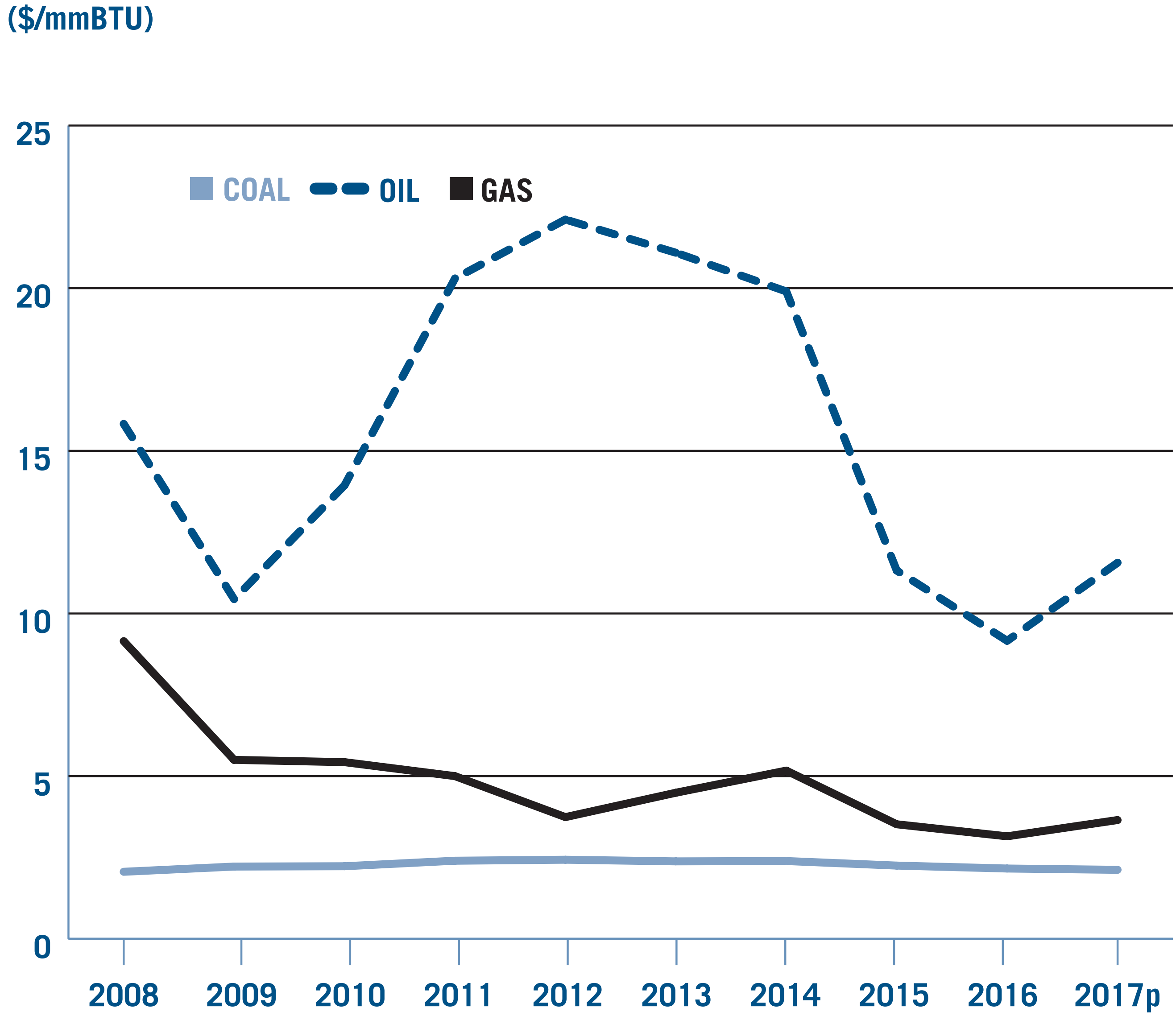
* 2017 results are preliminary and based on modeled data from ABB's Velocity Suite.

Source: Velocity Suite, ABB Enterprise Software.

Average Cost of Fossil Fuels 2008–2017

U.S. ELECTRIC UTILITIES



p = preliminary

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Source: U.S. Department of Energy, Energy Information Administration (EIA).

Diode (LED) lighting. In 2017, mild weather resulted in fewer heating and cooling degree days, dampening electric generation.

Natural gas maintained the lead it established in 2016 as the nation's primary generation fuel, although its contribution to total generation fell 2.1% to 31.7% from 33.8% in 2016. The contribution from coal and nuclear generation remained virtually unchanged, at 30.1% and 20.0% of the total, respectively. Due in part to California's record year for precipitation, hydroelectricity's share increased from 6.6% to 7.5%. Other renewables — wind, solar, geothermal, and biomass — saw their collective share rise 1.3% year-to-year, and together they accounted for 9.6% of total generation in 2017. In fact, zero-carbon fuel sources produced 37.2% of the nation's electric generation in 2017, up 2.5% from 2016 and a notable 10% increase since 2007.

Coal

Coal fueled 30.1% of U.S. generation in 2017, a 0.3% drop from 2016, the year coal lost its longstanding lead as the country's primary electricity generation fuel. Total coal-fired generation fell 2.5% year-to-year, extending a downward trend caused by the abundant supply of low-cost natural gas from the shale revolution. State and federal efforts to support coal have not prevailed against the powerful effects of low natural gas production costs and prices. Driven by these market fundamentals, flexible and cleaner natural gas generation will likely continue to erode coal's market share.

Nonetheless, coal demand from other countries remains strong, and in 2017 U.S. coal production rose 6% from 2016. Electric utilities paid an average $2.12 per million British Thermal Units (mmBTU) for coal in 2017 — the lowest price since 2008 and a 12% drop since 2012, when coal prices were the highest in a decade.

Average coal spot prices from Central and Northern Appalachia went in opposite directions in 2017. The average spot price for Central Appalachia coal rose 13.4% year-to-year to $52.21 per ton, just below the 2015 average price. The average spot price for Northern Appalachia coal dropped 2%, to $47.98 per ton, adding to a 15.8% decline in 2016. The Powder River Basin price reversed its two-year decline with an average price of $9.55 per ton in 2017, up 12.5% year-to-year and just five cents below the average seen in both 2012 and 2009. Nonetheless, the average cost of producing electricity from coal decreased to $31.05 per MWh, a 2.7% drop from $31.92 per MWh in 2016.

Natural Gas

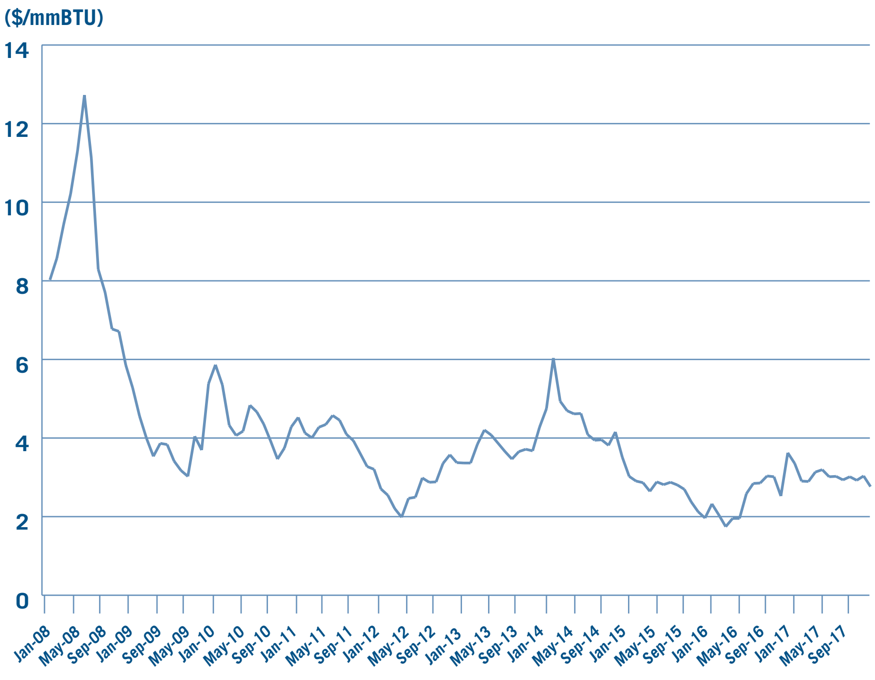
The share of total electricity generation fueled by natural gas dropped to 31.7%, a 2.1% year-to-year decrease from 2016, due to slightly higher natural gas prices. Nevertheless, natural gas maintained its lead over coal as the main fuel source for electricity generation in the U.S.

Continued growth in natural gas production from the Appalachian region's Marcellus and Utica shales drove a 1.2% year-to-year increase in total marketable production, to 28,810 billion cubic feet (Bcf), reversing the 1.0% production decline in 2016. However, warm winter temperatures and fewer total heating and cooling degree days throughout the year caused consumption to fall 1.4% year-to-year, to 27,090 Bcf, the first annual decline since 2009. Mild weather also prompted a 7.3% drop in the amount of natural gas used for power generation, which now accounts for 34.2% of total U.S. natural gas consumption, 2.1% less than in 2016. Demand for natural gas by the industrial and residential sectors grew 2.3% and 1.8% year-over-year, respectively. The industrial sector's share of total gas consumption increased to 29%, second after the electric generation sector. Residential sector's use trailed at 16.3% of the total.

The average benchmark Henry Hub (HH) spot price in 2017 was $2.98 per mmBTU, up 18% from $2.51 in 2016. As a result, the cost to produce electricity from natural gas jumped 11%, to $32.54 per MWh in 2017 from $29.17 per MWh in 2016.

For the first time since 1957, the U.S. exported more natural gas than it imported. Nevertheless, imports grew for the third consecutive year; total volume increased 1.1% with 97% of imports entering via pipelines. Canada remained the main source of imported natural gas, producing 97% of the total imported via pipelines. Mexico contributed a mere 0.4%. Liquified natural gas imports declined 11.8% versus 2016 levels.

NYMEX-Henry Hub Natural Gas Close Prices
2008–2017



Source: U.S. Department of Energy, Energy Information Administration (EIA).

Natural gas exports increased for the second consecutive year, rising about 35.6% from 2016, with pipeline flows dominating, at 78% of the total. Pipeline exports to Mexico were almost half of total exports, at 48.7%, with a 12% year-over-year increase. Exports to Canada were about 28% of total exports, up 19% year-to-year.

In 2016, pipeline exports to Canada and Mexico accounted for 92% of U.S. natural gas exports. This dropped 16% to 76% of the total in 2017, as vessel-based exports increased three-fold with notable growth in shipments to Brazil, China, Jordan, Japan, Kuwait, Portugal and South Korea. Mexico, followed by South Korea, and then China were the top three liquified natural gas (LNG) importers.

LNG exports from the U.S. to Mexico quadrupled year-over-year at 20% of the total LNG exports, comprising 4% of total natural gas exports in 2017. Total U.S. natural gas exports to Mexico via pipeline and vessel amounted to 53% of total U.S. natural gas exports.

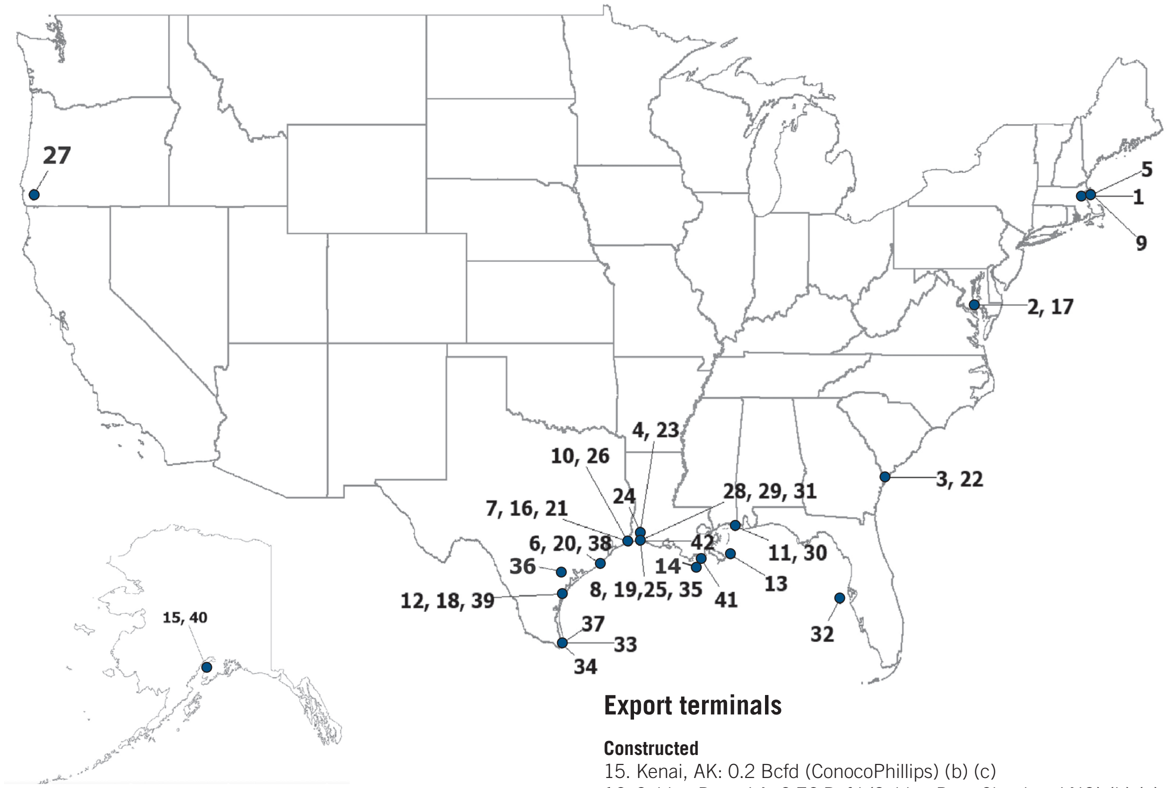
The spike in pipeline and vessel export volume to Mexico is attributable to growing demand from the country's power generation sector, which is adding new capacity in response to energy market reform. Mexico is using LNG exports to supplement pipelined gas because gridlock has slowed construction of U.S. export pipeline connections. Growth in LNG exports is attributable to new export capacity resulting from expansions at Dominion Energy's Cove Point, Maryland terminal and Cheniere's Sabine Pass facility in Louisiana, which came online in 2017.

Nuclear

Nuclear power generates approximately 5% of the world's electricity, with 30 U.S. states producing about one-third of the world's nuclear generation. In the U.S., nuclear power has fueled between 17.8% and 20.6% of total U.S. electric generation since 1988. In 2017, nuclear power accounted for 20% of the electricity used in the U.S., down less than one tenth of a percent (0.09%) from 2016, but up from 2015. In fact, 2016 and 2017 saw the highest nuclear generation levels since 2010. Due to high construction costs and lengthy permitting and building processes, year-to-year changes in nuclear output are driven largely by the length of downtime due to refueling and maintenance.

The Nuclear Regulatory Commission (NRC) has granted a 20-year operational life extension to 85% of the 99 reactors originally scheduled to operate 40 years. Almost all U.S. reactors have been uprated — received NRC-approved expansions of original capacity, totaling more than 7 GW. This includes a 2012 approval to add two new units, scheduled for completion in 2021 and 2022 to the two existing pressurized water reactors at Southern Company's Vogtle facility in Georgia, augmenting nameplate capacity by 2,320 MW.

Existing and Proposed U.S. LNG Terminals
As of December 31, 2017



Export terminals

Constructed
15. Kenai, AK: 0.2 Bcfd (ConocoPhillips) (b) (c)
16. Sabine Pass, LA: 2.76 Bcfd (Sabine Pass Cheniere LNG) (b) (c)

Under Construction
17. Cove Point, MD: 1.0 Bcfd FTA & 0.77 Bcfd non-FTA (Dominion – Cove Point LNG) (b) (c)
18. Corpus Christi, TX: 2.1 Bcfd (Cheniere – Corpus Christi LNG) (b) (c)
19. Hackberry, LA: 1.7 Bcfd (Cameron LNG – Sempra Energy) (b) (c)
20. Freeport, TX: 1.4 Bcfd FTA & 0.4 Bcfd non-FTA (Freeport LNG Dev./FLNG Liquefaction) (b) (c)
21. Sabine Pass, LA: 1.4 Bcfd (Sabine Pass Liquefaction) (b) (c)
22. Elba Island, GA: 0.35 Bcfd (Southern LNG) (b) (d)

Approved
23. Lake Charles, LA: 2.0 Bcfd (Trunkline LNG) (b) (d)
24. Lake Charles, LA: 1.07 Bcfd (Magnolia LNG) (b) (d)
25. Hackberry, LA: 1.3 Bcfd (Cameron LNG – Sempra Energy) (b) (d)
26. Golden Pass, TX: 2.1 Bcfd (Golden Pass – ExxonMobil) (b) (d)

Proposed
27. Coos Bay, OR: 1.2 Bcfd FTA & 0.9 Bcfd non-FTA (Jordan Cove Energy Project) (b) (c)
28. Plaquemines Parish, LA: 3.40 Bcfd (Venture Global LNG) (b) (d)
29. Calcasieu Parish, LA: 4.0 Bcfd (Driftwood LNG)
30. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (b) (d)
31. Cameron Parish, LA: 1.41 Bcfd (Venture Global) (b) (d)
32. Jacksonville, FL: 0.132 Bcfd (Eagle LNG Partners) (d)
33. Brownsville, TX: 0.55 Bcfd (Texas LNG Brownsville) (b) (d)
34. Brownsville, TX: 0.9 Bcfd (Annova LNG Brownsville) (b)
35. Gulf of Mexico, Cameron Parish, LA: 1.8 Bcfd (Delfin LNG) (b) (d)
36. Port Arthur, TX: 1.86 Bcfd (Port Arthur LNG) (b) (d)
37. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade)
38. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev)
39. Corpus Christi, TX: 1.4 Bcfd (Cheniere – Corpus Christi LNG)
40. Nikiski, AK: 2.55 Bcfd (ExxonMobil, ConocoPhillips, BP, TransCanada and Alaska Gasline)
41. LaFourche Parish, LA: 0.65 Bcfd (Port Fourchon LNG)
42. Cameron Parish, LA: 1.18 Bcfd (Commonwealth, LNG)

Import terminals

Constructed
1. Everett, MA: 1.035 Bcfd (Distrigas of Massachusetts)
2. Cove Point, MD: 1.8 Bcfd (Dominion – Cove Point LNG)
3. Elba Island, GA: 1.6 Bcfd (El Paso – Southern LNG)
4. Lake Charles, LA: 2.1 Bcfd (Southern Union – Trunkline LNG)
5. Offshore Boston, MA: 0.8 Bcfd (Northeast Gateway – ExcelerateEnergy)
6. Freeport, TX: 1.5 Bcfd (Freeport LNG Dev.) (a)
7. Sabine Pass, LA: 4 Bcfd (Sabine Pass Cheniere LNG) (a)
8. Hackberry, LA: 1.8 Bcfd (Cameron LNG – Sempra Energy) (a)
9. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG)
10. Golden Pass, TX: 2.0 Bcfd (Golden Pass – ExxonMobil)
11. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC, TRC Companies)

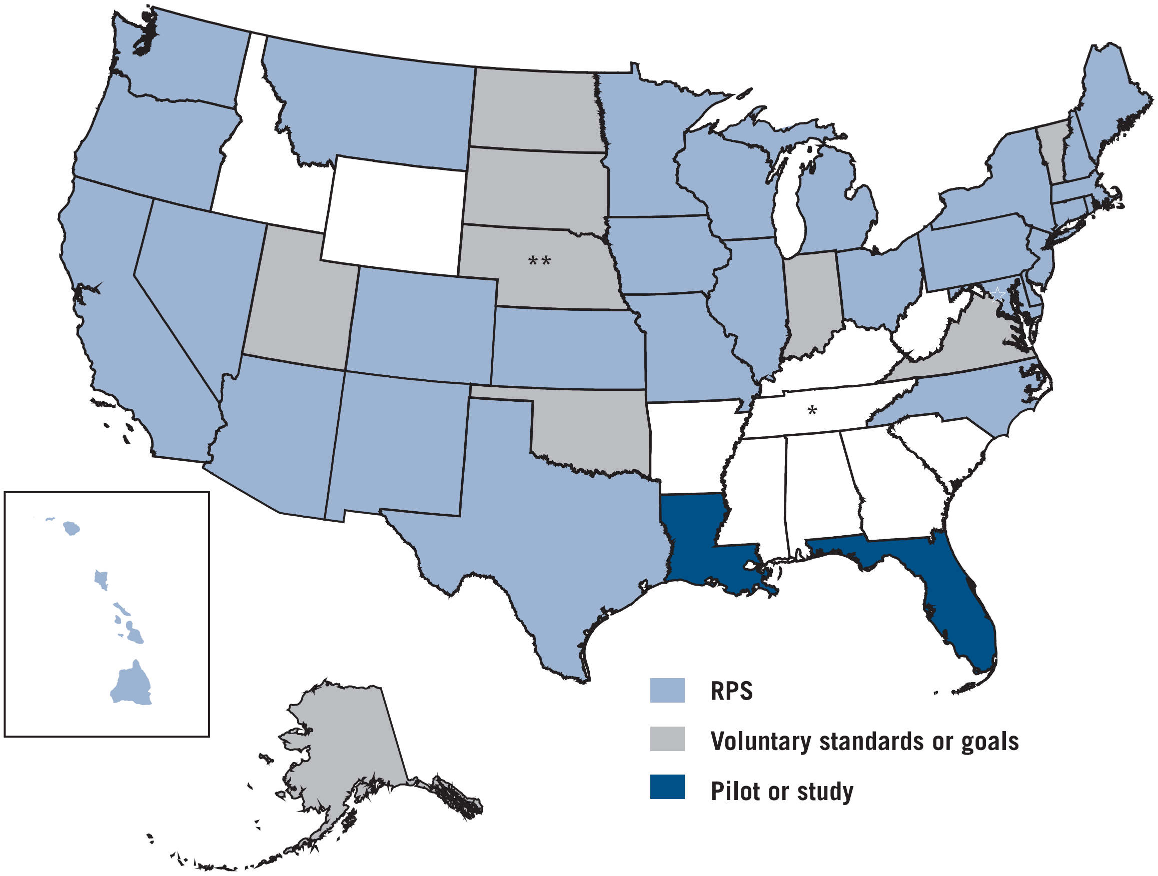
Under Construction
12. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG)

Approved
13. Main Pass, LA: 1.0 Bcfd (Main Pass McMoRanExp.)
14. TORP LNG, AL: 1.4 Bcfd (Bienville Offshore Energy Terminal – TORP)

(a) Authorized to re-export
(b) Approved by DOE to export to FTA countries
(c) Approved by DOE to export to non-FTA countries
(d) Under DOE review for exports to non-FTA countries

Sources: U.S. Department of Energy, Office of Fossil Energy; Federal Energy Regulatory Commission; Velocity Suite, ABB Enterprise Software.

29 States and D.C. have Renewable Electricity Portfolio Standards (RES)



AZ: 15% by 2025; 4.5% DG
CA: 50% by 2030
CO: 30% by 2020 (10% co-ops, munis), 3% DG and 1.5% customer sited.
CT: 27% by 2020
DC: 50% by 2032, 2.5% solar by 2023
DE: 25% by 2026, 3.5% PV. Triple credit for PV
HI: 100% by 2045
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2026; wind 75%, 1.5% PV and 0.25% DG
IN: 10% by 2025 (goal)
KS: 20% by 2020
MA: 15% by 2020 (new resources); 2 GW wind and 400 MW PV
MD: 25% by 2020, 2.5% solar by 2020
ME: 40% by 2017; 8 GW wind goal by 2030
MI: 15% by 2021. 3.2 multiplier for solar electric
MN: 26.5% by 2025 (31.5% by 2020 Xcel). 1.5% solar and 0.15% PV DG by 2020.
MO: 15% by 2021, 0.3% solar
MT: 15% by 2015
NC: 12.5% by 2021, 0.2% solar by 2018. (10% by 2018 co-ops, munis)
ND: 10% by 2015 (goal)
NH: 24.8% by 2025. 0.3% solar electric by 2014
NJ: 20.38% by 2021 and 4.1% solar by 2028
NM: 20% by 2020 (10% - co-ops), 4% solar electric, 0.6% DG.
NV: 25% by 2025, 1.5% solar by 2025. 2.4 multiplier for PV
NY: 50% by 2030, 0.58% customer sited by 2015
OH: 12.5% by 2026, 0.5% solar by 2027
OK: 15% by 2015 (goal)
OR: 50% by 2040 (5-10% - smaller utilities). 20 MW PV by 2025. Double credit for PV
PA: 18% by 2021, 0.5% PV by 2021
RI: 38.5% by end 2035
SC: 2% by 2021. 0.25 % DG by 2021 (goal).
SD: 10% by 2015 (goal)
TX: 5,880 MW by 2015, 500 MW non-wind goal, double credit for non wind
UT: 20% by 2025, 2.4 multiplier for solar electric (goal)
VA: 15% by 2025 (goal)
VT: 75% by 2032; 1% DG by 2017 + 3/5 of 1% per year until 10% by 2032
WA: 15% by 2020, double credit for DG, 2 MW DG
WI: 10% by 2015

Updated March 2018.

Abbreviations: EE - Energy Efficiency; RE - Renewable Energy.

Notes: An RPS requires a percent of an electric provider's energy sales (MWh) or installed capacity (MW) to come from renewable resources. Most specify sales (MWh). Map percents are final years' targets. * TVA's goal is not state policy; it calls for 50% zero- or low-carbon generation by 2020. ** Nebraska's two largest public power districts have renewable goals.

Source: Database of State Incentives for Renewables and Efficiency, http://www.dsireusa.org.

Although nuclear power's contribution to the U.S. generation mix has been steady for decades, the sector has been affected by broader changes in U.S. energy supply and demand. Since 2013, six reactors, amounting to more than 5 GW of total capacity, have been decommissioned. An additional eight reactors amounting to 7.5 GW capacity are slated for retirement by 2025. Specifically, the scheduled retirement of the Three Mile Island and Pilgrim nuclear power plants by the end of 2019 will likely reduce nuclear power's share in the years ahead. Construction of SCANA's NRC-approved V.C. Summer power plant in South Carolina was scrapped in 2017 after significant delays and cost overruns. Pressure on utilities to transition to a more flexible power grid have also forced some plant retirements, including PG&E's Diablo Canyon that will sunset by 2025, to be replaced by renewables, energy efficiency and battery energy storage.

Renewables

Renewable fuel sources, including hydro, continue to break records; collectively, they accounted for 17.1% of total U.S. electric generation in 2017, a 2.1% increase from 2016. Non-hydro renewables accounted for a record high 9.6% of the total, up 1.3% from 2016. However, growth in non-hydro generation slowed slightly from 2016.

Solar generation continues to be the fastest growing source of electricity in percentage terms, although its share of total nation-wide output remains small, at just 1.3%. Solar generation had a record-breaking year, with year-over-year growth of 47%, though this was 2% less than the growth rate in 2016. Solar now accounts for 13.7% of total non-hydro renewable generation, up 2.9% from 2016, representing the highest annual contribution on record. Wind generation rose 12% year-to-year, a pace 7% less than in 2016. Wind power accounted for 65.7% of total non-hydro renewable generation, 0.7% less than in 2016.

Biomass and geothermal generation continued to account for less than one quarter of the country's non-hydro renewable generation, at 16.5% and 4.1% of the total non-hydro renewable generation, respectively.

Oil

Oil generation powered only 0.5% of U.S. electric output in 2017, down from 0.6% in 2016. Located away from continental U.S. rail infrastructure, Hawaii and Alaska (the country's two non-contiguous states) account for more than 60% of oil-fueled generation in the country. Hawaii, which accounts for about half of all oil used for power generation, plans to generate 100% of the state's electricity from renewables by 2045. Some regions, such as Florida and New England, have significant oil-fueled capacity; this is mostly in the form of dual-fuel power plants built years ago to hedge the lack of natural gas infrastructure. Neither of these areas, however, generates a significant amount of electricity from oil.

Oil as an electricity generation fuel carries multifaceted risks. Oil prices are vulnerable to price volatility from supply disruptions, currency fluctuations and geopolitical risks. West Texas Intermediate benchmark spot prices, for example, ranged from \$15 to \$25 per barrel in the 1990s, then jumped to \$145/barrel in 2008, ahead of the financial crisis.

Capital Markets

Stock Performance

Utility investors began 2017 with the now-perennial fear of rising interest rates, amplified by the Federal Reserve's desire to finally wean markets off the near-zero short-term yields in place since the 2008/2009 financial crisis. The Fed did raise the Federal Funds target rates by 25 basis points three times in 2017 (in March, June and December) and the three-month Treasury Bill rate ended the year at 1.4%, up from 0.5% when 2017 began. But longer-term rates again defied market expectations. The 10-year Treasury began the year at 2.45%. But instead of rising it fell — to almost 2.0% by September — before climbing back to end the year about where it began, at just over 2.4%.

Absolute Strength but Relative Weakness

Viewed in isolation, and separate from the broader markets, utility stocks had a strong year. The EEI Index returned 11.7%, posting a second consecutive year of double-digit gains after 2016's 17.4% return. But unlike last year, when the EEI Index led the broad market averages, this year it lagged. The Dow Jones Industrials returned 28.1%, the Nasdaq Composite gained 28.2% and the S&P

2017 Index Comparison

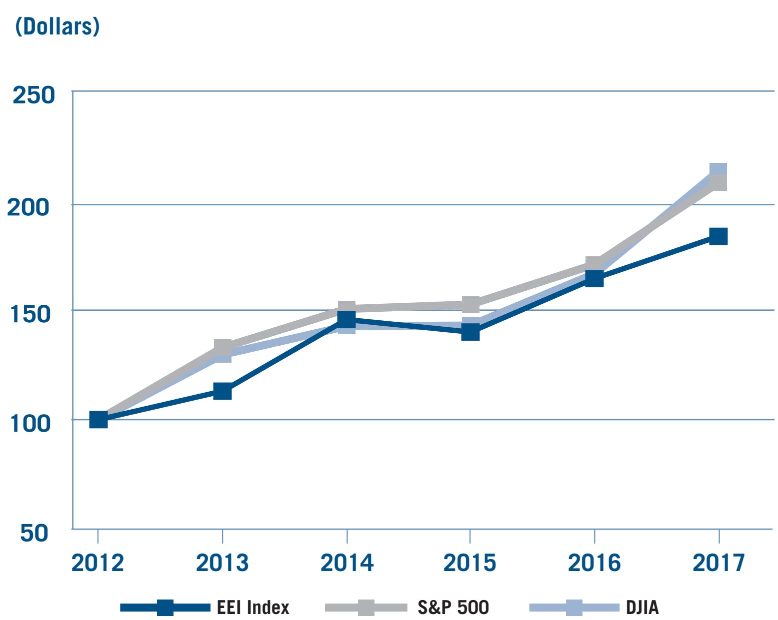
EEI Index	**11.72**
Dow Jones Industrials	28.11
S&P 500	21.83
Nasdaq Composite Index*	28.24

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/13–12/31/17

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2012.

Source: EEI Finance Department and S&P Global Market Intelligence.

2017 Returns By Quarter

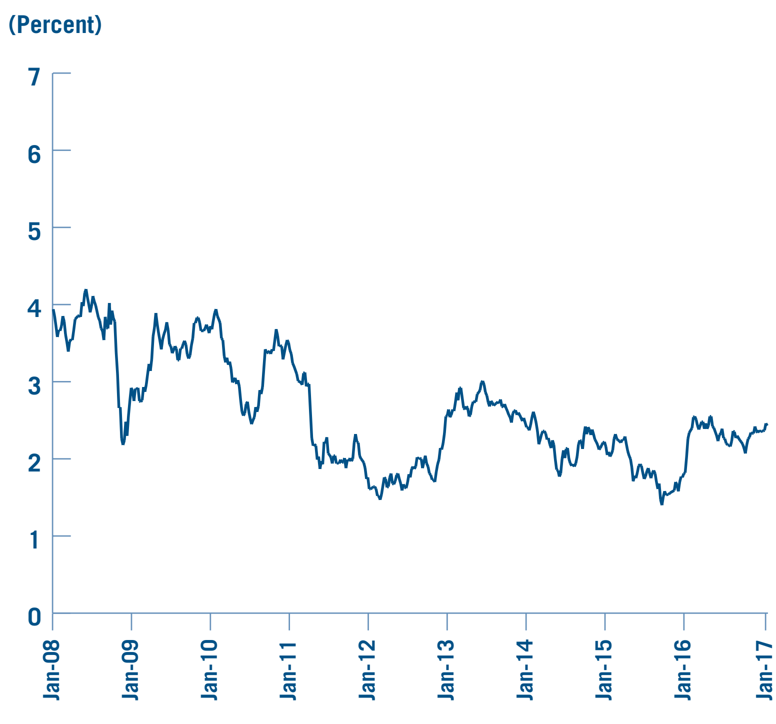
Index	Q1	Q2	Q3	Q4
EEI Index	6.1	2.4	2.7	0.1
Dow Jones Industrial Average	5.2	4.0	5.3	11.3
S&P 500	6.1	3.1	4.5	6.6
Nasdaq Composite*	9.8	3.9	5.8	6.3

Category	Q1	Q2	Q3	Q4
All Companies	5.2	2.5	3.2	0.2
Regulated	5.8	2.7	3.5	(0.7)
Mostly Regulated	3.9	2.0	2.5	2.5

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

10-Year Treasury Yield
1/1/08 through 12/31/17



Source: U.S. Federal Reserve.

500 returned 21.8%. The broad market in 2017 was lifted by optimism about strengthening U.S. and global economic growth. U.S. real gross domestic product (GDP) rose 3.2% in Q3 and 3.1% in Q2 — the highest quarterly readings since Q1 2015 — up from a sluggish 1.2% gain in 2017's first quarter. Markets were also powered higher by improving global growth prospects, which solidified in 2017 following the economic stagnation in Europe and Japan, and broad-based concern about a weak global economy that weighed on markets early in 2016. By late in 2017, economists estimated global growth this year and next at a strong 3.6% to 3.7%. Euro-area economies, in particular, finally experienced an emerging wide-spread confidence after years of near-recessionary conditions, with 2%+ real GDP growth forecast for 2017 and 2018, up from 1.5% when the year began. U.S. corporate earnings are pegged to rise 9% to 10% in 2017 and 2018 while Euro-area corporate profits are set to gain more than 30% in 2017 and about 10% in 2018. Given these trends, most economic sectors outgained the EEI Index for the year with the economically sensitive technology (+37.3%), basic materials (+25.2%) and industrials (+24.6%) sectors as market leaders.

Despite the stronger economic growth, persistently low inflation was one factor that held down interest rates. U.S. and European inflation remained below 2% and in Japan it remained well below 1%. While U.S. longer-term yields failed to rise in 2017, they were still far higher than yields available in Europe and Japan, where bond yields broadly remained below 1% and short-term interest rates were below zero. These very low global yields outside the U.S. may have been one source of support for utility shares, as yield-starved investors sought the income available from utilities' sturdy dividends.

Q4 produced a separation of fortunes between utilities and the major averages. Utilities generally declined in December, partially giving up their year-to-date gains, and the EEI Index rose just 0.1% in Q4 compared to the Dow Jones 11.3% jump and the S&P and Nasdaq's 6%+ gains.

Industry Fundamentals Remain Healthy

The industry's stock performance in 2017 was something of a reflection of its strong fundamentals, which include healthy balance sheets, steady mid-single-digit earnings growth from capital investment programs and an industry average dividend yield just above 3%. Analysts noted several other supportive themes that colored 2017.

Natural gas prices and low-cost renewable power (mostly wind) have helped fuel costs remain low and have reduced pressure on customer bills that might otherwise be required to fund capex programs. Regulation in general remains constructive. Many utilities now have rate mechanisms in place that allow for more timely recovery of capital expenditures and address the impact of very slow to flat sales growth, bad debts and pension costs. Analysts also noted more states are implementing multi-year rate plans with fewer rate cases and better opportunities for utilities to earn their allowed return on equity.

Federal and state policymakers also offered support for baseload coal and nuclear plants through federal energy market reforms set for 2018 along with court rulings and state decisions that supported zero emission credits for nuclear plants, which could improve cash flow and ease concern about decommissioning liabilities. These moves in part supported share prices for select companies within the EEI Index's Mostly Regulated category, which returned 11.3% in 2017, nearly matching the Regulated category's 11.7% return even as natural gas spot prices held at multi-year lows, ranging from $2.50-3.00/mmBTU. And the natural gas futures curve was little changed from year-end 2016, remaining at the lowest levels of the past decade.

Such regulatory and policy support is crucial in an environment where power demand is virtually flat. Driven by the changing nature of the U.S. industrial economy and the impact of energy efficiency programs, nationwide demand in 2016 totaled 3.76 billion megawatthours, nearly the same as that of 2007. And power demand through October of 2017 (latest EIA data available) was down 2.7% year-to-year.

Top Gainers

AVANGRID (+38.1%) was the EEI Index's top gainer for 2017. The company reported profits that beat analysts' estimates for the first three quarters of the year and said it hopes to grow earnings 8% to 10% annually through 2020, mostly through regulated operations. The company said it plans to invest $9 billion in its utilities and competitive renewable operations through 2020. NextEra Energy (+34.4%) was the next-strongest gainer and likewise rose on strong growth prospects driven by a focus on renewable investment. In June 2017, management said it hopes to grow earnings at a 6-8% rate and dividends at a 12-14% rate between

Sector Comparison 2017 Total Shareholder Return

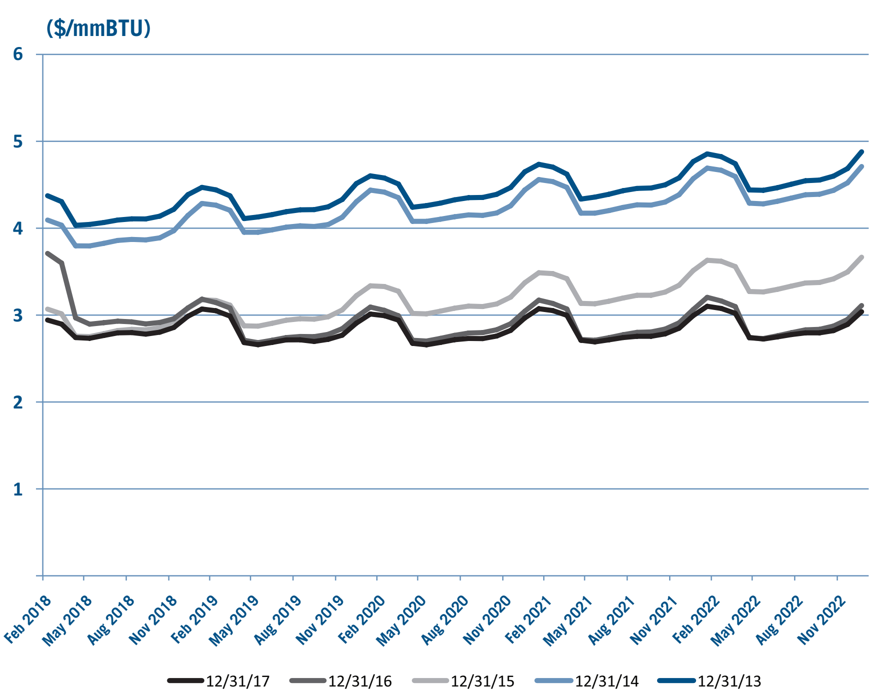
Sector	Total Return %
Technology	37.3%
Basic Materials	25.2%
Industrials	24.6%
Healthcare	22.9%
Consumer Services	20.4%
Financials	20.1%
Consumer Goods	17.1%
Utilities	12.5%
EEI Index	**11.7%**
Telecommunications	(0.2%)
Oil & Gas	(1.5%)

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

Natural Gas Spot Prices - Henry Hub
12/31/13 through 12/31/17

Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2018 through December 2022



Source: S&P Global Market Intelligence.

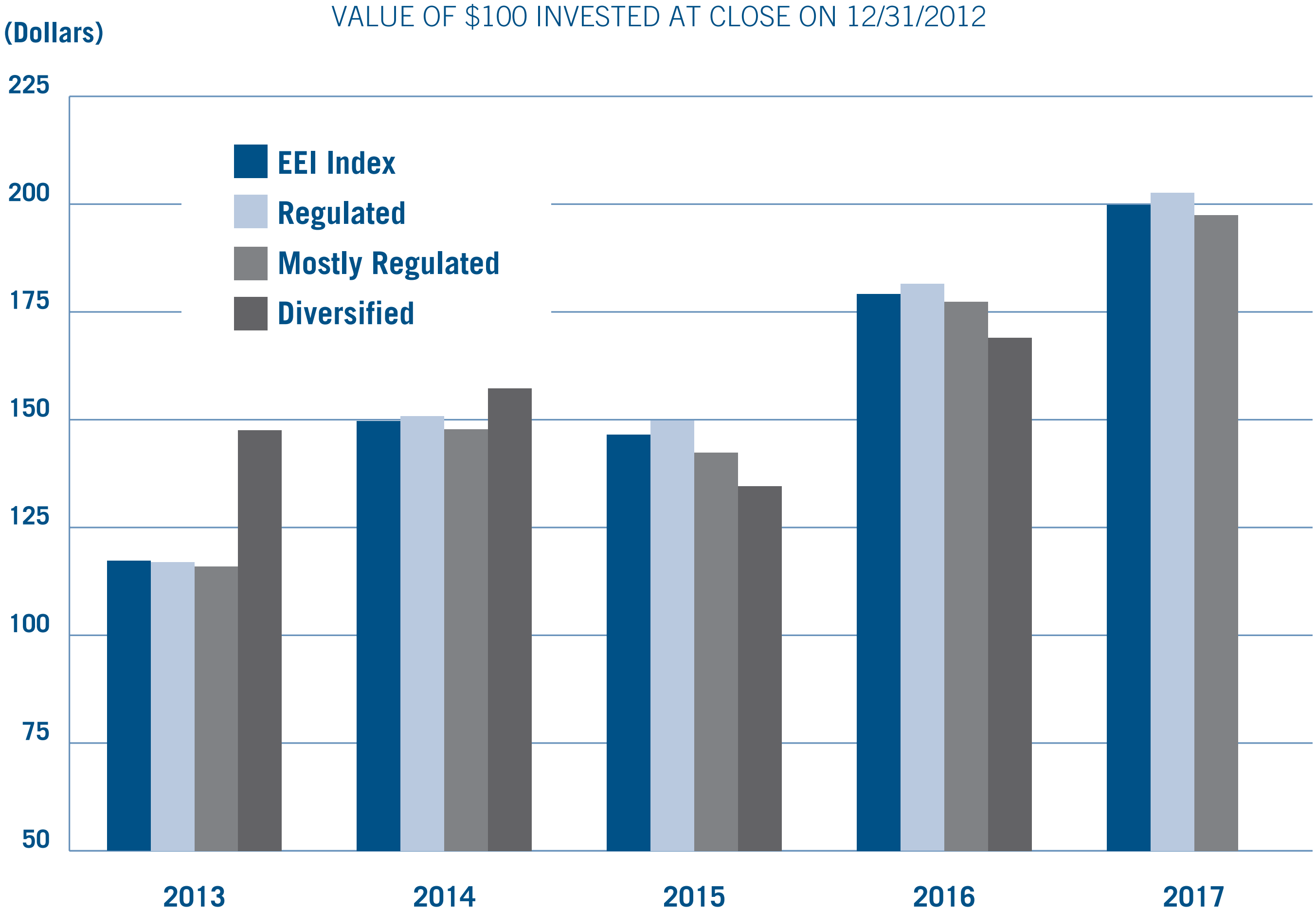
2017 and 2020, investing over $40 billion in its competitive and regulated operations. Avista (+32.9%) shares jumped over 20% in July, adding to strength earlier in the year, on news it would be acquired in an all-cash transaction for $53/share by Canadian utility Hydro One. Midwestern gas and electric utility Vectren (+28.2%) likewise jumped 9% in August on news it was working with a financial adviser in response to takeover interest from at least one potential buyer. Great Plains Energy (+22.2%), which is seeking a no-premium merger of equals with neighboring Westar, beat its Q3 earnings forecast and benefitted from analyst upgrades that cited potential for wind power and distribution system investment provided the companies get regulatory support. El Paso Electric (+22.0%) also gained on rising earnings expectations and, potentially, on the wave of buyout interest in small- to mid-cap utilities with rate base growth prospects.

Outlook Remains Steady

It may be a truism to say that regulated utility growth fundamentals change slowly and are reasonably easy to predict—at least relative to those of most other business sectors. It's the macro calls, such as movement of interest rates and changes in economic growth fortunes, that buffet stocks of other sectors and cause gyrations in utilities' relative performance. The industry continues to execute capital investment programs that are transforming the nation's power system with a focus on clean and renewable generation, transmission investment, reliability and safety enhancements and a mod-

Comparative Category Total Annual Returns 2013–2017

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2012



	2013	2014	2015	2016	2017
EEI Index Annual Return (%)	17.27	27.63	(2.05)	22.21	11.56
EEI Index Cumulative Return ($)	117.27	149.67	146.59	179.15	199.86
Regulated EEI Index Annual Return	16.97	28.92	(0.67)	21.16	11.66
Regulated EEI Index Cumulative Return	116.97	150.80	149.79	181.48	202.64
Mostly Regulated EEI Index Annual Return	15.97	27.46	(3.67)	24.57	11.32
Mostly Regulated EEI Index Cumulative Return	115.97	147.81	142.38	177.36	197.45
Diversified EEI Index Annual Return	47.54	6.61	(14.43)	25.59	–
Diversified EEI Index Cumulative Return	147.54	157.29	134.60	169.04	–

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2012.

Source: EEI Finance Dept., S&P Global Market Intelligence.

2017 Category Comparison

Category	Return (%)
EEI Index	**11.56**
Regulated	11.66
Mostly Regulated	11.32

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2017 Index Comparison table is cap-weighted.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

EEI Index Top 10 Performers

Twelve-month period ending 12/31/2017

Company	Total Return %	Category
AVANGRID, Inc.	38.1	MR
NextEra Energy, Inc.	34.4	MR
Avista Corporation	32.9	R
Vectren Corporation	28.2	R
Great Plains Energy Inc.	22.2	R
El Paso Electric Company	22.0	R
Xcel Energy Inc.	21.9	R
Public Service Enterprise Group Incorporated	21.8	MR
PNM Resources, Inc.	20.9	R
American Electric Power Company, Inc.	20.9	R

Note: Return figures include capital gains and dividends.

ernization of the grid to facilitate potentially more electric vehicles, customer control over power options and increased amounts of distributed renewable generation.

The industry has grown capex from $74.3 billion in 2010 to $113.6 billion in 2017, and industry capex is expected to remain at an elevated level for at least the next few years. Broad longer-term opportunities seem robust for grid modernization, transmission investment and provision of the clean energy demanded by state renewable portfolio standards and by increasing numbers of corporations interested in long-term contracts for renewable power.

Most analysts see the industry set to continue its mid-single-digit earnings growth over the next several years, with growing dividends and healthy balance sheets, and with regional pockets of opportunity for higher growth rates. Of course, this optimism is reliant on continued support from state regulators for utility investment (and the jobs thereby produced); a trend that could be threatened if fuel prices rise and pressure rates upward rather than down. The Trump Administration's tax reform provides an additional benefit for regulated utilities; savings passed to customers are one more measure that can limit bill increases in a time of rising capex. According to EIA data, the average cost of electricity in late 2017 was about 10.58 cents/kilowatt-hour, not too far above the 9.74 cent level ten years ago in 2008.

Utilities' Macro Hedge: Different This Time?

Utilities have been a reliable hedge on broad market weakness almost continuously since the 2008/2009 financial crisis. When stocks have declined so have interest rates, and utility shares have shined on a relative basis versus the broad market, outperforming anywhere from 8% to 15% in market corrections (credit to J.P. Morgan's December 2017 utility industry equity research for mapping this trend). Only the May 2013 "taper tantrum", when the 10-year Treasury yield jumped in response to then-Fed Chief Ben Bernanke's hints at a reduction in Fed support for markets, did utilities lag on a relative basis, but only by about 3%.

Investors have feared rising rates for longer than many professional investors have been in the business. But the 35-year bond bull market has defied all skeptics and yields have fallen rather than risen. At the outset of 2018, the 10-year Treasury yield, at 2.5%, is at the high end of the 1.5% to 2.5% range that has held since late 2011. But if rates do finally begin a rising trend and cause, in part anyway, a stock market correction, it's unclear if utilities will outperform. The industry has no control over such macro forces, only its own business strategies and to some extent its fundamentals. At the beginning of 2018, those look fairly strong and utilities seem poised to offer investors slow and steady earnings growth and rising dividends. What value the market places on that only time will tell and it can't be predicted with any consistency.

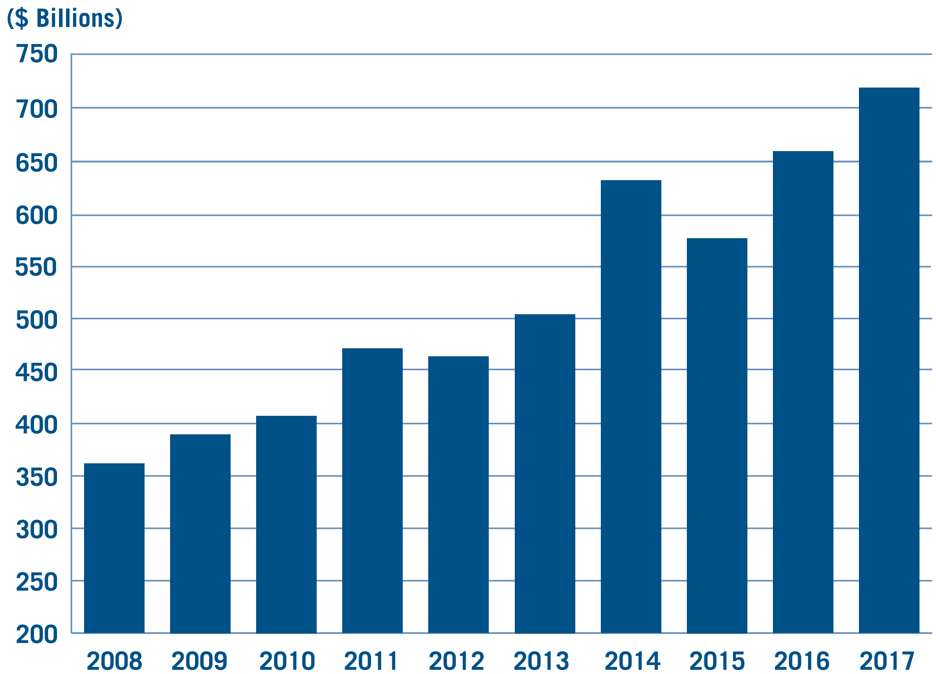
Market Capitalization at December 31, 2017 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	73,316	10.18%
Duke Energy Corporation	DUK	58,877	8.17%
Dominion Energy, Inc.	D	52,081	7.23%
Southern Company	SO	48,234	6.70%
Exelon Corporation	EXC	37,912	5.26%
American Electric Power Company, Inc.	AEP	36,185	5.02%
Sempra Energy	SRE	26,940	3.74%
Consolidated Edison, Inc.	ED	26,148	3.63%
Public Service Enterprise Group Incorporated	PEG	26,008	3.61%
Xcel Energy Inc.	XEL	24,468	3.40%
PG&E Corporation	PCG	22,998	3.19%
PPL Corporation	PPL	21,249	2.95%
WEC Energy Group, Inc.	WEC	20,965	2.91%
Edison International	EIX	20,616	2.86%
Eversource Energy	ES	20,053	2.78%
DTE Energy Company	DTE	19,593	2.72%
AVANGRID, Inc.	AGR	15,654	2.17%
Entergy Corporation	ETR	14,615	2.03%
Ameren Corporation	AEE	14,311	1.99%
FirstEnergy Corp.	FE	13,595	1.89%
CMS Energy Corporation	CMS	13,282	1.84%
CenterPoint Energy, Inc.	CNP	12,224	1.70%
Alliant Energy Corporation	LNT	9,843	1.37%
Pinnacle West Capital Corporation	PNW	9,526	1.32%
NiSource Inc.	NI	8,500	1.18%
Westar Energy, Inc.	WR	7,523	1.04%
Great Plains Energy Inc.	GXP	6,951	0.96%
OGE Energy Corp.	OGE	6,572	0.91%
SCANA Corporation	SCG	5,689	0.79%
Vectren Corporation	VVC	5,397	0.75%
MDU Resources Group, Inc.	MDU	5,250	0.73%
IDACORP, Inc.	IDA	4,601	0.64%
Portland General Electric Company	POR	4,060	0.56%
Hawaiian Electric Industries, Inc.	HE	3,933	0.55%
ALLETE, Inc.	ALE	3,792	0.53%
Avista Corporation	AVA	3,317	0.46%
PNM Resources, Inc.	PNM	3,233	0.45%
Black Hills Corporation	BKH	3,200	0.44%
NorthWestern Corporation	NWE	2,895	0.40%
El Paso Electric Company	EE	2,238	0.31%
MGE Energy, Inc.	MGEE	2,188	0.30%
Otter Tail Corporation	OTTR	1,756	0.24%
Unitil Corporation	UTL	642	0.09%
	Total Industry	**720,427**	**100.00%**

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization 2008–2017

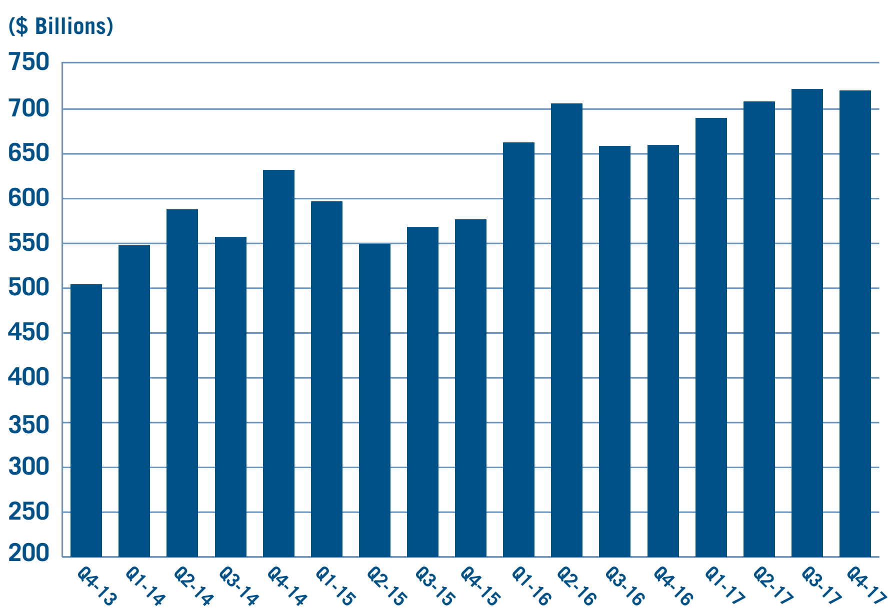


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization

December 31, 2013–December 31, 2017



Source: EEI Finance Department and S&P Global Market Intelligence.

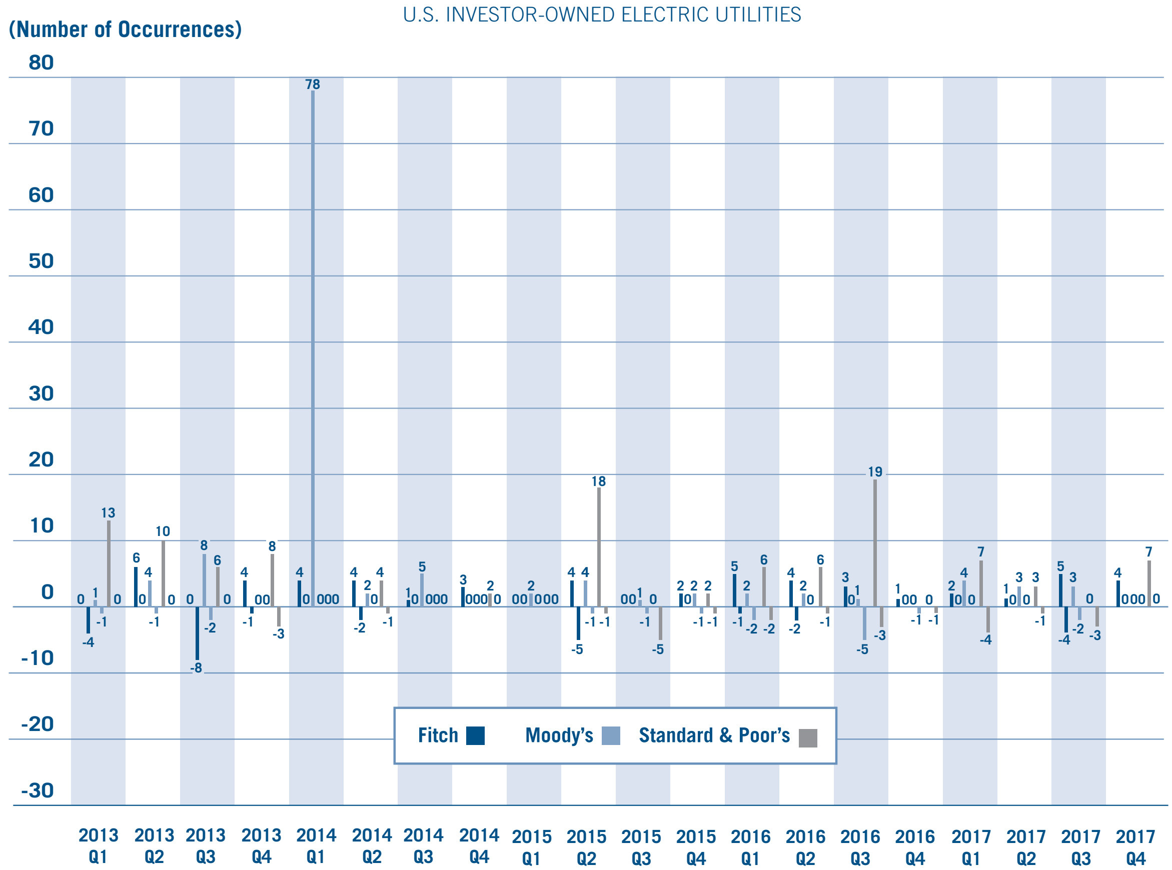
Credit Ratings

The industry's average credit rating in 2017 was BBB+, remaining for a fourth straight year above the BBB average that has held since 2004. Ratings activity, at 53 changes, was below the industry's average for the last decade of 68 changes per year. Upgrades were 73.6% of total actions, the third-highest annual figure in our dataset and just above 2016's 73.1%. In fact, the last five years have produced the five highest upgrade percentages in our historical data. EEI captures upgrades and downgrades at the subsidiary level; multiple actions within a parent holding company are included in the upgrade/downgrade totals. The industry's average credit rating and outlook are based on the unweighted averages of all Standard & Poor's (S&P) parent company ratings and outlooks.

While the industry's average credit rating was unchanged at BBB+, the underlying data show a modest strengthening in credit quality. At the parent level, three companies received upgrades and only one received a downgrade. One additional company was downgraded and later upgraded during 2017. Three of the year's upgrades were related to the sale of generation assets. One was the result of favorable rate treatment. Both downgrades were due to regulatory challenges. On December 31, 2017, 73.5% of ratings outlooks were "stable", 20.4% were "positive" or "watch-positive", and only 6.1% were "negative" or "watch-negative".

Credit Rating Agency Upgrades and Downgrades 2013 Q1–2017 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2013 Q1–2017 Q4

	2013		2014		2015		2016		2017	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	0	(4)	4	0	0	0	5	(1)	2	0
Q2	6	0	4	(2)	4	(5)	4	(2)	1	0
Q3	0	(8)	1	0	0	0	3	0	5	(4)
Q4	4	(1)	3	0	2	0	1	0	4	0
Total	**10**	**(13)**	**12**	**(2)**	**6**	**(5)**	**13**	**(3)**	**12**	**(4)**
Moody's										
Q1	1	(1)	78	0	2	0	2	(2)	4	0
Q2	4	(1)	2	0	4	(1)	2	0	3	0
Q3	8	(2)	5	0	1	(1)	1	(5)	3	(2)
Q4	0	0	0	0	2	(1)	0	(1)	0	0
Total	**13**	**(4)**	**85**	**0**	**9**	**(3)**	**5**	**(8)**	**10**	**(2)**
S&P										
Q1	13	0	0	0	0	0	6	(2)	7	(4)
Q2	10	0	4	(1)	18	(1)	6	(1)	3	(1)
Q3	6	0	0	0	0	(5)	19	(3)	0	(3)
Q4	8	(3)	2	0	2	(1)	0	(1)	7	0
Total	**37**	**(3)**	**6**	**(1)**	**20**	**(7)**	**31**	**(7)**	**17**	**(8)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Upgrades Reflect Regulated Focus

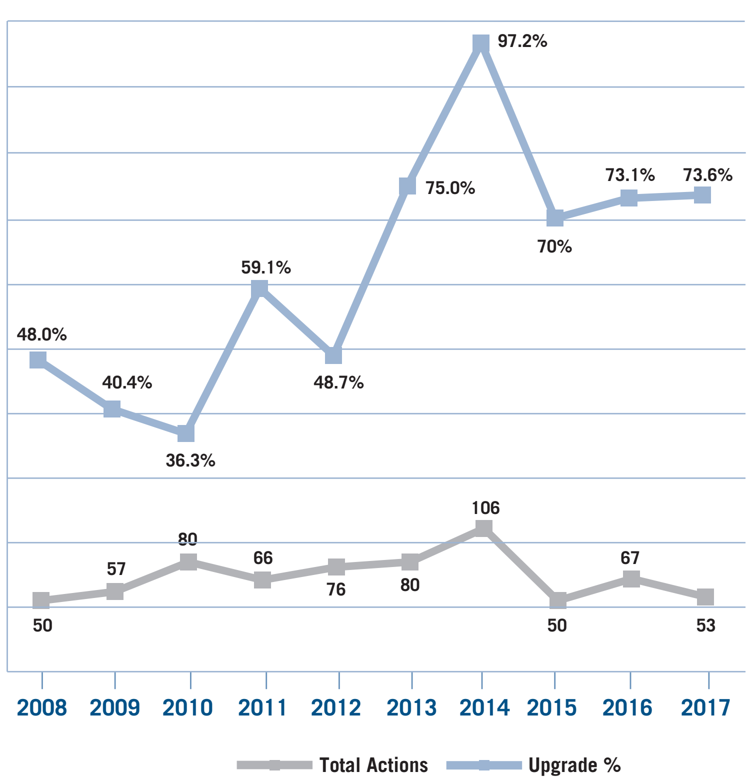
Ratings actions in 2017 included four parent company-level upgrades and only two downgrades, inclusive of both an upgrade and downgrade for one company. Our universe of 49 U.S. "parent" company electric utilities at December 31, 2017 included six that are a subsidiary of an independent power producer, a subsidiary of a foreign-owned company, or that have been acquired by an investment firm.

American Electric Power

On February 2, S&P raised its issuer credit ratings on American Electric Power and all subsidiaries to A- from BBB+. The upgrades reflect AEP's sale of 5,200 MW of merchant generation assets to private equity firms Blackstone Group and ArcLight Capital Partners for $2.1 billion. The asset sale, along with the impairment of AEP's 2,700 MW

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's.

of remaining merchant generation assets in the third quarter of 2016, advances AEP's decision to exit the merchant generation business and focus on regulated utility operations.

DPL Inc.

On March 27, S&P downgraded the issuer credit ratings on DPL Inc. and its subsidiary Dayton Power and Light (DP&L) to BB- from BB. The downgrade was driven by DP&L's decision to retire the 2,308-MW J.M. Stuart and 600-MW Killen Station coal-fired power plants in Ohio. The company retired these plants as part of an agreement reached in early 2017 with the Sierra Club, which is tied to a larger settlement with intervenors in the utility's electric security plan in Ohio.

On December 27, S&P upgraded its issuer credit ratings for DPL and Dayton Power and Light, raising both back to BB from BB-. The upgrades were based on DPL's decision to sell 973 MW of merchant generation capacity. According to S&P, the completed sale supports a stronger business risk profile assessment.

PG&E Corp.

On May 12, S&P raised the issuer credit rating on PG&E Corp. and subsidiary Pacific Gas and Electric to A- from BBB+. The upgrade was driven by the California Public Utilities Commission's approval of a settlement between Pacific Gas and Electric and 14 customers and other interest groups, allowing the utility to implement rate increases of 1.1% in 2017, 5.5% in 2018 and 4.3% in 2019.

SCANA

On September 29, S&P downgraded SCANA and its utility subsidiaries South Carolina Electric & Gas (SCE&G) and Public Service Company of North Carolina as a result of challenges related to SCANA's decision to abandon the V.C. Summer nuclear plant expansion project. Each company received a one-notch downgrade of its issuer credit rating to BBB from BBB+. S&P said the main rationale for the downgrade was a September 26 filing by South Carolina's Office of Regulatory Staff asking regulators to order SCE&G to "immediately suspend" rates collected to finance construction of the now-abandoned project.

Eversource Energy

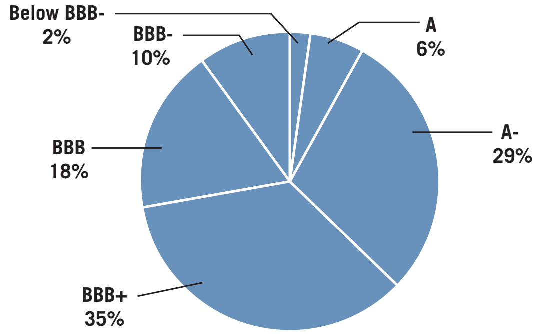
On December 5, S&P upgraded its issuer credit rating on Eversource Energy and all subsidiaries to A+ from A; subsidiaries include Connecticut Light and Power, Yankee Gas Services, Public Service Company of New Hampshire, Western Massachusetts Electric, NSTAR Electric and NSTAR Gas. The upgrades resulted from an improved business risk profile following the sale of Eversource's generation assets. Additionally, S&P expects Eversource's recently closed acquisition of Aquarion Water to be integrated into the utility's long-term growth strategy, consistent with its plan to shift the strategic focus to transmission and distribution.

Few Actions by Moody's and Fitch

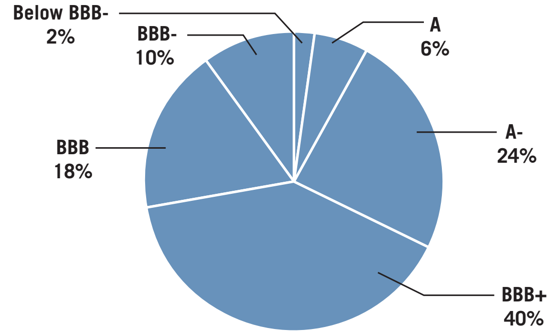
Moody's and Fitch each issued only a modest number of ratings actions in 2017, a third straight year of quiet activity relative to each agency's annual totals since 2001. Moody's issued ten upgrades and two downgrades. Moody's noted a constructive regulatory environment and stronger financial metrics in its two-notch upgrade of AEP subsidiary Ohio Power from Baa1 to A2, in its upgrades of FirstEnergy subsidiaries West Penn Power and Metropolitan Edison from Baa1 to A3 and Penn Electric from Baa2 to Baa1. Exelon subsidiary Commonwealth Edison was upgraded from Baa1 to A3 after an improved regulatory environment in Illinois resulted in approval of a formula rate structure, which Moody's interpreted as a material credit strength. AVANGRID subsidiary Rochester Gas & Electric was upgraded from Baa1 to A3, reflecting sustained improvement in the company's financial metrics compared to its A3-rated sister company New York State Electric and Gas. Entergy was upgraded from Baa3 to Baa2 at the parent company level based on its progress in de-risking; Moody's highlighted a shrinking merchant fleet and improved credit metrics.

Fitch provided 16 actions for the second straight year, inclusive of 12 upgrades and only four downgrades. The positive trend in Fitch's actions reflects the continued strengthening of the industry's credit profile.

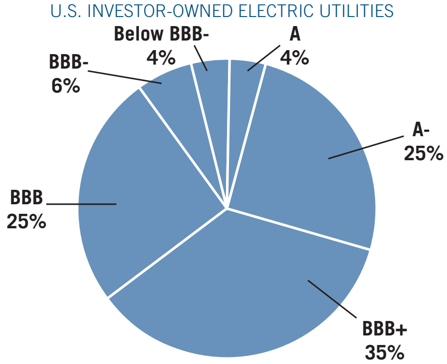
Bond Ratings December 31, 2017
as rated by Standard & Poor's



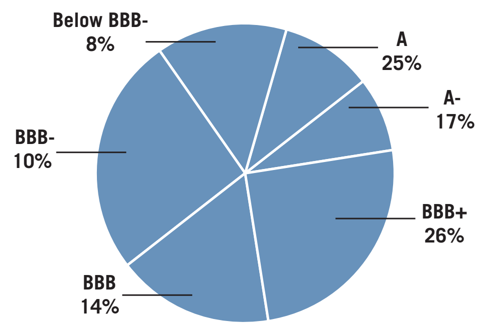
Bond Ratings December 31, 2016
as rated by Standard & Poor's



Bond Ratings December 31, 2015
as rated by Standard & Poor's



Bond Ratings December 31, 2001
as rated by Standard & Poor's



Note: Rating applies to utility holding company entity.

Source: Standard & Poor's, S&P Global Market Intelligence, EEI Finance Department, and company annual reports

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Fitch	17	14	24	25	26	23	14	11	16	16
Moody's	6	23	20	11	20	17	85	12	13	12
Standard & Poor's	27	20	36	30	30	40	7	27	38	25
Total	**50**	**57**	**80**	**66**	**76**	**80**	**106**	**50**	**67**	**53**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

Ratings by Company Category

The table *S&P Utility Credit Rating Distribution by Company Category* presents the distribution of credit ratings over time by company category (Regulated, Mostly Regulated and Diversified) for the investor-owned electric utilities. The Diversified category was eliminated in 2017 due to its dwindling number of companies. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. At December 31, 2017, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2013		2014		2015		2016		2017	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	1	3%	1	3%	1	3%	2	6%	2	6%
A-	7	20%	8	21%	8	22%	10	28%	12	34%
BBB+	6	17%	12	32%	12	33%	13	36%	10	29%
BBB	17	49%	14	37%	12	33%	8	22%	7	20%
BBB-	2	6%	1	3%	1	3%	3	8%	4	11%
Below BBB-	2	6%	2	5%	2	6%	0	0%	0	0%
Total	35	100%	38	100%	36	100%	36	100%	35	100%
Mostly Regulated										
A or higher	1	6%	1	8%	1	8%	1	8%	1	7%
A-	5	29%	4	31%	5	38%	2	17%	2	14%
BBB+	5	29%	4	31%	5	38%	7	58%	7	50%
BBB	3	18%	2	15%	1	8%	0	0%	2	14%
BBB-	3	18%	2	15%	1	8%	1	8%	1	7%
Below BBB-0	0	0%	0	0%	0	0%	1	8%	1	7%
Total	17	100%	13	100%	13	100%	12	100%	14	100%
Diversified										
A or higher	0	0%	0	0%	0	0%	0	0%		
A-	0	0%	0	0%	0	0%	0	0%		
BBB+	1	50%	1	50%	1	50%	0	0%		
BBB	0	0%	0	0%	0	0%	1	50%		
BBB-	0	0%	1	50%	1	50%	1	50%		
Below BBB-	1	50%	0	0%	0	0%	0	0%		
Total	2	100%	2	100%	2	100%	2	100%		

Note: Totals may not equal 100.0% due to rounding.

Refer to page v for category descriptions.

Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Major FERC Initiatives

BUSINESS PRACTICE STANDARDS FOR ELECTRIC UTILITIES

MAJOR PROPOSALS: RM05-5-000

- FERC proposed to incorporate by reference the first set of standards for business practice for electric utilities developed by the Whole Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB). The proposed rule would include OASIS business practice standards, OASIS standards and communications protocols and an OASIS dictionary. FERC also proposed that each electric utility's OATT include the applicable WEQ standards.
- FERC further proposed to incorporate definitions of demand response resources in the definitions of certain ancillary services, and later proposed to incorporate standards that identify operational information and performance evaluation methods.
- FERC did not propose to incorporate NAESB's Standards of Conduct standards.

MAJOR IMPLICATIONS:

- Each electric utility's OATT must include the applicable WEQ standards. For standards that do not require implementing tariff revisions, the utility would be permitted to incorporate the WEQ standard by reference in its tariff.
- Once incorporated, compliance will be mandatory for all jurisdictional utilities and for non-jurisdictional utilities voluntarily following FERC's open access requirements under reciprocity.

FERC MILESTONES

- September 18, 2014, FERC issued Order No. 676-H to incorporate by reference in its regulations Version 003 of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by WEQ of NAESB.
- February 21, 2013, FERC issued Order No. 676-G to incorporate business practice standards for categorizing various products and services for demand response and energy efficiency and to support the measurement and verification of these products and services in organized wholesale electric markets. *Standards for Business Practices and Communication Protocols for Public Utilities*, 142 FERC ¶ 61,131 (2013).
- April 15, 2010, FERC issued Order No. 676-F revising its regulations to incorporate by reference business practice standards for certain demand response services in wholesale markets administered by RTO/ISOs adopted by the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities*, 131 FERC ¶ 61,022 (2010).
- February 18, 2010, FERC issued an Order clarifying aspects of Order No. 676-E and denying rehearing. Standards for Business Practices and *Communications Protocols for Public Utilities*, 130 FERC ¶ 61,116 (2010).
- November 24, 2009, in Docket No. RM05-5-13, FERC issued Order No. 676-E revising its regulations to incorporate by reference the version 2.1 of certain standards adopted by the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities*, 129 FERC ¶ 61,162 (2009).
- On September 30, 2008, in Docket Nos. RM05-5-005 and RM05-5-006, FERC issued Order No. 676-D which clarifies Order No. 676-C. *Standards for Business Practices and Communications Protocols for Public Utilities,* 124 FERC ¶ 61,070 (2008).
- On July 21, 2008, in Docket No. RM05-5-005, FERC issued Order No. 676-C, revising its regulations to incorporate by reference the latest version (Version 001) of certain standards adopted by the WEQ of the NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities,* 124 FERC ¶ 61,070 (2008).
- December 20, 2007, in Docket Nos. RM96-1-028 and RM05-5-001, FERC issued Order No. 698-A clarifying Order No. 698 and denying requests for rehearing. *Standards for Business Practices and Communications Protocols for Public Utilities,* 121 FERC ¶ 61,264 (2007).
- June 25, 2007, in Docket Nos. RM96-1-027 and RM05-5-001, FERC issued Order No. 698, amending its open access regulations governing business practices and electronic communications with interstate gas pipelines and public utilities to improve communications scheduling gas-fired generators and incorporating certain NAESB regulations. *Standards for Business Practices and Communications Protocols for Public Utilities,* 119 FERC ¶ 61,317 (2007).
- April 19, 2007, in Docket No. RM05-5-003, FERC issued Order No. 676-B, amending its regulations to incorporate, by reference, revisions to the Coordinate Interchange business practice standards adopted by WEQ of the NAESB that identify processes and communications necessary to coordinate energy transfers across boundaries between load and generation balancing entities. *Standards for Business Practices and Communications Protocols for Public Utilities,* 119 FERC ¶ 61,049 (2007).
- February 20, 2007, in Docket No. RM05-5-003, FERC issued a NOPR proposing to incorporate the Coordinate Interchange business practice standards adopted by the WEQ of the NAESB into FERC's regulations. The Coordinate Interchange standards identify the processes and communications necessary to coordinate energy transfers between load and generation balancing entities. *Standards for Business Practices and Communications Protocols for Public Utilities,* 118 FERC ¶ 61,135 (2007).
- September 21, 2006, in Docket No. RM05-5-002, FERC issued Order No. 676-A, denying rehearing of Order No. 676. *Standards for Business Practices and Communications Protocols for Public Utilities,* 116 FERC ¶ 61,255 (2006).

- April 25, 2006, FERC issued Order No. 676 that adopts by reference a number of the NAESB WEQ business practices standards. *Standards for Business Practices and Communications Protocols for Public Utilities,* 115 FERC ¶ 61,102 (2006).
- May 9, 2005, FERC issued NOPR to revise it regulations to incorporate by reference standards for business practice for electric utilities developed by WEQ of NAESB. *Standards for Business Practices and Communications Protocols for Public Utilities,* 111 FERC ¶ 61,204 (2005).

CREDIT REFORM IN ORGANIZED WHOLESALE MARKETS: DOCKET NO. RM10-13-000

- FERC issued a Final Rule amending its regulations to improve the management of risk and use of credit in organized wholesale markets.

MAJOR IMPLICATIONS:

- Each RTO and ISO will be required to submit tariff revisions to comply with the following:
- Establish billing periods of no more than seven days after issuance of bills;
  - Reduce extension of unsecured credit to no more than $50 million per market participant, $100 million per corporate family;
  - Eliminate unsecured credit for firm transmission rights positions;
  - Specification of minimum participation criteria to be eligible to participate in the organized wholesale market;
  - Specification of conditions under which the ISO/RTO will request additional collateral due to a material adverse change; and
  - Limit to tie period to post additional collateral.

FERC MILESTONES:

- June 16, 2011, in Docket No. RM10-13-002, FERC issued Order No. 741-B reaffirming its determinations in Order No. 741-A. Credit Reforms In Organized Wholesale Markets, 135 FERC ¶ 61,242 (2011).
- February 17, 2011, in Docket No. RM10-13-001, FERC issued Order No. 741-A denying in part and granting rehearing and clarification of Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).
- October 21, 2010, in Docket No. RM10-13-000, FERC issued Order No. 741. *Credit Reforms in Organized Markets*, 133 FERC ¶ 61,060 (2010).

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

MAJOR PROPOSALS: DOCKET NO. RM16-15-000

- The Fixing America's Surface Transportation Act (FAST Act), enacted in December 2015, added section 215A to the Federal Power Act to improve the security and resilience of energy infrastructure in the face of emergencies.
- The FAST Act directed FERC to issue regulations aimed at securing and sharing sensitive infrastructure information.

MAJOR IMPLICATIONS:

- Adds Section 215A to the Federal Power Act to implement criteria and procedures for designating information as Critical Energy Infrastructure Information (CEII); creates a specific prohibition on unauthorized disclosure of CEII; imposes sanctions for knowing and willful wrongful disclosure of CEII by certain federal personnel; implements a process for voluntary sharing of CEII; and changes the existing process for requesting CEII.

FERC MILESTONES:

- November 17, 2016, in Docket No. RM16-15-000, FERC issued Order No. 833. *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information; Availability of Certain North American Electric Reliability Corporation Databases to the Commission*, 157 FERC ¶ 61,123 (2016).

CYBER SECURITY

MAJOR PROPOSALS: DOCKET NOS. RM15-14-002, RM17-11-000, RM18-2-000 AND AD17-9-000

- As the electric industry incorporates information technology systems into its operations, as part of nationwide efforts to improve reliability and efficiency, there is concern that if these efforts are not implemented securely, the electric grid could become more vulnerable to attacks and loss of service. To address this concern, the Energy Independence and Security Act of 2007 (EISA) gave FERC and the National Institute of Standards and Technology (NIST) responsibilities related to coordinating the development and adoption of smart grid guidelines and standards.

MAJOR IMPLICATIONS:

- Improves mandatory reporting of cyber security incidents, including incidents that might facilitate future attempts to harm reliable operation of the nation's bulk electric system.
- Proposes new cyber security management controls to further enhance the reliability and resilience of the nation's bulk electric system including mandatory controls to address the risks posed by malware from transient electronic devices like laptop computers, thumb drives and other devices used at low-impact bulk electric system cyber systems.
- Requires each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.

FERC MILESTONES:

- December 21, 2017, in Docket Nos. RM18-2-000 and AD17-9-000, FERC issued a Notice of Proposed Rulemaking to direct NERC to submit modifications to broaden the requirement to include mandatory reporting of cyber security incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter or associated Electronic Access Control or Monitoring Systems (EACMS). The proposal would require NERC to: (1) specify the required information in cyber security incident reports to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; and (2) establish a deadline for filing a report once a compromise or disruption, or an attempted compromise or disruption, is identified by a responsible entity. *Cyber Security Incident Reporting Reliability Standards*, 161 FERC ¶ 61,291 (2017).
- October 19, 2017, in Docket No. RM17-11-000, FERC issued a Notice of Proposed Rulemaking proposing to approve Reliability Standard CIP-003-7 which (1) clarifies the obligations pertaining to electronic access control for low impact Bulk Electric System (BES) Cyber Systems and (2) adopts mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems. FERC also proposes to direct NERC to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. *Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls,* 161 FERC ¶ 61,047 (2017).

- July 21, 2016, in Docket No. RM15-14-002, FERC issued Order No. 829 directing NERC to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations and meets the following security objectives: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. *Revised Critical Infrastructure Protection Reliability Standards*, 156 FERC ¶ 61,050 (2016).

DEMAND COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS: DOCKET NO. RM10-17-000

- FERC issued a Final Rule amending its regulations to ensure that when a demand response resources participate in wholesale energy markets administered by RTOs and ISOs has the capability to balance supply and demand and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in the rule, that demand response resource is compensated at the locational marginal price (LMP).

MAJOR IMPLICATIONS:

- The U.S. Supreme Court overturned a lower court's decision to vacate and remand FERC's Order No. 745 affirming FERC's rules on demand response.
- Demand response resources which clear in the day-ahead market will receive the market-clearing LMP as compenstion when it is cost-effective to do so as determined by a net benefits test.
- Each ISO/RTO will implement a net benefits test described in the order to determine if demand response is cost effective.
- ISO/RTOs are directed to review their verification requirements to be sure they can verify that demand response resources have performed.
- Require ISO/RTOs to make compliance filings demonstrating that their current cost allocation methodologies appropriately allocates costs to those that benefit or proposed revisions that conform to this requirement.

FERC MILESTONES:

- February 29, 2012, in Docket No. RM10-17-002, FERC issued Order No. 745-B reaffirming its determinations in Order No. 745-A. *Demand Response Compensation in Organized Wholesale Markets, 138 FERC ¶ 61,148 (2012).*
- December 15, 2011, in Docket No. RM10-17-001, FERC issued Order No. 745-A granting clarification to the limited extent of addressing the applicability of Order No. 745 to circumstances when it is not cost-effective to dispatch demand response resources. Demand Response Compensation in Organized Wholesale Markets, 137 FERC ¶ 61,215 (2011).
- March 15, 2011, FERC issued Order No. 745 in Docket No. RM10-17-000. *Demand Response Compensation in Organized Wholesale Markets*, 134 FERC ¶ 61,187 (2011).

ELECTRICITY MARKET TRANSPARENCY PROVISIONS

MAJOR PROPOSALS: DOCKET NO. RM10-12-000

- The Commission revises its regulations to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce.

MAJOR IMPLICATIONS

- FERC adopted a 4,000,000 MWh de minimis threshold for all non-public utilities, including for non-public utilities that are Balancing Authorities.
- FERC revised the existing EQR filing requirements applicable to market participants in the interstate wholesale electric markets by adding new fields for: (1) reporting the trade date and the type of rate; (2) identifying the exchange used for a sales transaction, if applicable; (3) reporting whether a broker was used to consummate a transaction; (4) reporting electronic tag (e-Tag) ID data; and (5) reporting standardized prices and quantities for energy, capacity and booked out power transactions.
- Requires EQR filers to indicate in the existing ID data section whether they report their sales transactions to an index publisher and, if so, to which index publisher(s), and, if applicable, identify which types of transactions are reported.
- Eliminates the time zone from the contract section and the Data Universal Numbering System (DUNS) data requirement.

FERC MILESTONES:

- April 18, 2013, in Docket No. RM10-12-002, FERC issued Order No. 768-A affirming its determinations in Order No. 768 and providing clarification of certain reporting requirements.
- September 21, 2012, in Docket No. RM10-12-000, FERC issued Order No. 768. *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, 140 FERC ¶ 61,232 (2012).
- April 21, 2011, in Docket No. RM10-12-000, FERC issued a Notice of Proposed Rulemaking to revise its regulations to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports with the Commission. *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, 135 FERC ¶ 61,053 (2011).

ELECTRICITY STORAGE

MAJOR PROPOSALS: DOCKET NOS. RM16-23-000, AD16-20-000, AND PL17-2-000

- Proposes to more effectively integrate electric storage resources into organized wholesale markets to enhance competition and help ensure that these markets produce just and reasonable rates.

MAJOR IMPLICATIONS:

- Proposes to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets.
- Proposes to define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation.
- Because electric storage resources can charge and discharge electricity, provide a variety of grid services in multiple markets or to multiple entities, can almost instantaneously provide multiple services and switch from providing one service to another, these resources may fit into one or more of the traditional asset functions of generation, transmission and distribution. The Policy Statement provides additional guidance for electric storage resources that seek to concurrently recover their costs through cost-based and market-based rates.

FERC MILESTONES:

- January 19, 2017, in Docket No. PL17-2-000, FERC issued a Policy Statement to address (1) the potential for combined cost-based and market-based rate recovery to result in double recovery of costs by the electric storage resource owner or operator to the detriment of cost-based ratepayers; (2) the potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in the wholesale electric markets to the detriment of other competitors who do not receive such cost-based rate recovery; and (3) the level of control in the operation of an electric storage resource by an RTO/ISO that could jeopardize its independence from market participants. *Policy Statement on Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017).
- November 17, 2016, in Docket Nos. RM16-23-000, AD16-20--000, FERC issued a Notice of Proposed Rulemaking to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by RTOs/ISOs. *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operator*, 157 FERC ¶ 61,121 (2016).

ENHANCEMENT OF ELECTRICITY MARKET SURVEILLANCE AND ANALYSIS

MAJOR PROPOSALS: DOCKET NOS. RM11-17-000, AND RM16-17-000

- Amends Commission regulations to establish ongoing electronic delivery of data relating to physical and virtual offers and bids, market awards, resource outputs, marginal cost estimates, shift factors, financial transmission rights, internal bilateral contracts, uplift, and interchange pricing. Such data will facilitate the Commission's development and evaluation of its policies and regulations and will enhance Commission efforts to detect anti-competitive or manipulative behavior, or ineffective market rules, thereby helping to ensure just and reasonable rates.
- Proposes to improve surveillance of wholesale power markets by revising regulations to collect certain data for analytics and surveillance purposes from market-based rate sellers and entities trading virtual products or holding financial transmission rights and to change certain aspects of the substance and format of information submitted for market-based rate purposes.

MAJOR IMPLICATIONS:

- Proposes new data collection to assist FERC in understanding the financial and legal connections among market participants and other entities and their activities in Commission-jurisdictional electric markets.
- Proposes to modify regulations to change certain aspects of the substance and format of information submitted for market-based rate purposes.
- Establishes ongoing electronic delivery of data relating to physical and virtual offers and bids, market awards, resource outputs, marginal cost estimates, shift factors, financial transmission rights, internal bilateral contracts, uplift, and interchange pricing.
- RTOs and ISOs must electronically deliver data to the Commission within seven days after each RTO and ISO creates the datasets in a market run or other procedure.

FERC MILESTONES:

- July 21, 2016, in Docket No. RM16-17-000, FERC issued a Notice of Proposed Rulemaking, *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (2016).
- April 19, 2012, in Docket No. RM11-17-000, FERC issued Order No. 760. *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, 139 FERC ¶ 61,053 (2012).
- October 20, 2011, in Docket No. RM11-17-000, FERC issued a Notice of Proposed Rulemaking proposing to require each RTO and ISO to electronically deliver to the Commission, on an ongoing basis, data related to the markets that it administers. *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, 137 FERC ¶ 61,066 (2011).

FREQUENCY REGULATION COMPENSATION IN THE ORGANIZED WHOLESALE POWER MARKETS

MAJOR PROPOSALS: DOCKET NOS: RM11-7-000 AND AD10-11-000

- Found that current compensation methods for regulation service in RTO and ISO markets fail to acknowledge the inherently greater amount of frequency regulation service being provided by faster-ramping resources. In addition, certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources.
- FERC requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

MAJOR IMPLICATIONS:

- Requires that all RTOs and ISOs with centrally procured frequency regulation resources must provide for marginal resource's opportunity costs in their tariffs. Further, this uniform clearing price must be market-based, derived from market-participant based bids for the provision of frequency regulation capacity.
- RTOs and ISOs are required to calculate cross-product opportunity costs, which reflect the foregone opportunity to participate in the energy or ancillary services markets, and include it in each resource's offer to supply frequency regulation capacity, for use when determining the market clearing price and which resources clear.
- RTOs and ISOs may allow for inter-temporal opportunity costs to be included in a resource's offer to sell frequency regulation service, with the requirement that the costs be verifiable.
- FERC requires use of a market-based price, rather than an administratively-determined price, on which to base the frequency regulation performance payment.
- RTOs and ISOs are required to account for frequency regulation resources' accuracy in following the Automatic Generator Control dispatch signal when determining the performance payment compensation. However, FERC will not mandate a certain method for how accuracy is measured.

FERC MILESTONES:

- February 16, 2012, in Docket No. RM11-7-001 and AD10-11-001, FERC issued Order No. 755-A reaffirming its determinations in Order No. 755. *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* 138 FERC ¶ 61,123 (2012).
- October 20, 2011, FERC issued Order No. 755 in Docket No. RM11-7-000. *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011).

GAS/ELECTRIC COORDINATION

MAJOR PROPOSALS:
DOCKET NOS. RM14-2-000 AND RM13-17-000

- Recognizing increased interdependency of the natural gas and electricity markets, FERC must ensure that outages and reliability problems are not the result of the lack of coordination between the electricity and gas industries.
- Over the last few years, natural gas is being used much more heavily in electricity generation. This trend appears likely to accelerate as coal-powered generation is retired, renewable energy resources require more backup by natural gas plants, and low natural gas prices encourage more use of gas.

- FERC issues Order No. 809 to better ensure the reliable and efficient operations of the interstate natural gas pipelines and the electricity systems. Order No. 809 moves the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1 p.m. CCT and adds a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand.
- FERC issued Order No. 787 which amends the Commission's regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.

MAJOR IMPLICATIONS:

- Allows for better coordination among the natural gas and electricity markets by modifying the scheduling practices used by interstate pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts.
- Provides explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.
- Establishes a "No-Conduit Rule" which prohibits all public utilities and interstate natural gas pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information they receive under this rule to a third party or to its marketing function employees, as that term is defined in § 358.3 of the Commission's regulations.

FERC MILESTONES:

- April 16, 2015, in Docket No. RM14-2-000, FERC issued Order No. 809 moving the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1 p.m. CCT and adding a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand. *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 151 FERC ¶ 61,049 (2015).
- June 19, 2014, in Docket No. RM13-17-001, FERC issued Order No. 787-A affirming its findings in Order No. 787. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 147 FERC ¶ 61,228 (2014).
- March 20, 2014, in Docket No. RM14-2-000, FERC issued a Notice of Proposed Rulemaking (NOPR) to revise the natural gas operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service. The proposed revisions include starting the natural gas operating day earlier, moving the Timely Nomination Cycle later, and increasing the number of intra-day nomination opportunities to help shippers adjust their scheduling to reflect changes in demand.
- November 15, 2013, in Docket No. RM13-17-000, FERC issued Order No. 787 which provides authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 145 FERC ¶ 61,134 (2013).
- July 18, 2013, in Docket No. RM13-17-000, FERC issued a Notice of Proposed Rulemaking regarding the sharing of information between natural gas operators and electric transmission operators to ensure the reliability of service. *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 144 FERC ¶ 61,043 (2013).

GENERATOR INTERCONNECTION AGREEMENTS AND PROCEDURES

MAJOR PROPOSALS: DOCKET NOS. RM13-2-000, RM17-8-000

- Proposes reforms to its large generator interconnection processes aimed at improving the efficiency of processing interconnection requests, removing barriers to needed resource development, and assuring continued reliability of the grid.
- Revises the *pro forma* Small Generator Interconnection Procedures (SGIP) and pro forma Small Generator Interconnection Agreement (SGIA) originally set forth in Order No. 2006.
- Reforms are intended to ensure that the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory.
- Market changes, including the growth of small generator interconnection requests and the growth in solar photovoltaic (PV) installations, driven in part by state renewable energy goals and policies, necessitate a reevaluation of the SGIP and SGIA to ensure that they continue to facilitate Commission-jurisdictional interconnections in a just and reasonable and not unduly discriminatory manner.

MAJOR IMPLICATIONS:

- Proposes to improve certainty by giving interconnection customers more predictability in the interconnection process; improve transparency by providing more information to interconnection customers; and enhance interconnection processes by making use of underutilized existing interconnections, providing interconnection service earlier or accommodating changes in the development process.
- Incorporates into the SGIP and SGIA provisions that provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection.
- Revises the 2 megawatt (MW) threshold for participation in the Fast Track Process included in section 2 of the *pro forma* SGIP.
- Revises the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably.
- Revises the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection.
- Revise the *pro forma* SGIP and the pro forma SGIA to specifically include energy storage devices.

FERC MILESTONES:

- December 15, 2016, in Docket No. RM17-8-000, FERC issued a Notice of Proposed Rulemaking proposing certain reforms to the large generator interconnection procedures to provide more efficiency and consistency in generator interconnection study cycles. *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (2016).
- March 20, 2014, in Docket No. RM13-2-001, FERC issued Order No. 792-A clarifying the reporting requirements under Order No. 792. *Small Generator Interconnection Agreements and Procedures*, 146 FERC ¶ 61,214 (2014).

- November 22, 2013, in Docket No. RM13-2-000, FERC issued Order No. 792. *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013).
- January 17, 2013, in Docket No. RM13-2-000, FERC issued a Notice of Proposed Rulemaking proposing certain reforms to the pro forma SGIA and SGIP to accommodate increasing penetrations of solar PV installations. *Small Generator Interconnection Agreements and Procedures*, 142 FERC ¶ 61,049 (2013).

INTEGRATION OF VARIABLE ENERGY RESOURCES

MAJOR PROPOSALS: DOCKET NO. RM10-11-000

- FERC determined that existing operational procedures may be unduly discriminatory and lead to unjust and unreasonable rates regarding the integration of variable energy resources (VERs) into the bulk electric transmission system. Specifically FERC proposed a limited set of reforms to addresses transmission scheduling practices and VER power production forecasts.

MAJOR IMPLICATIONS:

- FERC amends the *pro forma* Open Access Transmission Tariff (OATT) to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals to allow transmission customers the ability to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour.
- Amends the *pro forma* Large Generator Interconnection Agreement (LGIA) to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting.

FERC MILESTONES:

- September 19, 2013, in Docket No. RM10-11-002, FERC issued Order No. 764-B reaffirming its determinations in Order Nos. 764 and 764-A and offering further technical clarifications. *Integration of Variable Energy Resources*, 144 FERC ¶ 61,222 (2013).
- December 20, 2012, in Docket No. RM10-11-001, FERC issued Order No. 764-A affirming its findings in Order No. 764 and making certain technical clarifications. *Integration of Variable Energy Resources*, 141 FERC ¶ 61,232 (2012).
- June 22, 2012, in Docket No. RM10-11-000, FERC issued Order No. 764 adopting its proposals in the Notice of Proposed Rulemaking with the exception of the generic ancillary serve rate for regulation service. *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012).
- November 18, 2010, in Docket No. RM10-11-000, FERC issued a Notice of Proposed Rulemaking proposing reforms to the OATT to revise scheduling and forecasting requirements and add a generic ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area. *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149 (2010).
- January 21, 2010, in Docket No. RM10-11-000, FERC issued a Notice of Inquiry seeking comment on the extent to which barriers may exist that impede the reliable and efficient integration of VERs into the electric grid, and whether reforms are needed to eliminate those barriers. *Integration of Variable Energy Resources*, 130 FERC ¶ 61,053 (2010).

LONG-TERM TRANSMISSION RIGHTS

MAJOR PROPOSALS: DOCKET NOS. RM06-8-000 AND AD05-7-000

- FERC adopted seven of eight proposed guidelines for independent transmission organizations to follow in developing a framework for providing long-term firm transmission rights (LTFTRs) in organized electricity markets.
- FERC proposed to allow for regional flexibility to account for different market designs and regional differences when developing the framework for LTFTRs.
- FERC proposed that LTFTRs would be required to be available with term lengths sufficient to meet the needs of load-serving entities with long-term power supply arrangements (either existing or planned) used to meet their service obligations.
- FERC required transmission organizations subject to the rule to either file tariff sheets making LTFTRs available which satisfy the seven criteria, or file an explanation of how current tariff sheets and rate schedules meet these criteria.

MAJOR IMPLICATIONS:

- FERC would require that LTFTRs be available to entities that pay for upgrades or build expansions.
- If a transmission organization cannot accommodate all requests for LTFTRs over existing transmission capacity, FERC would require that preference be given to load-serving entities with long-term power supply arrangements used to meet service obligations.

FERC MILESTONES:

- March 20, 2009, in Docket No. RM06-8-002, FERC issued Order No. 681-B, granting certain clarifications concerning allocation of long-term firm transmission rights to external load serving entities and deny requests for rehearing. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 126 FERC ¶ 61,254 (2009).
- February 25, 2008, in Docket Nos. ER07-476-000 and RM06-8-000, FERC accepted in part and rejected in part the compliance filing of ISO-NE and New England Power Pool proposing amendments to the ISO-NE OATT. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 122 FERC ¶ 61,173 (2008).
- February 4, 2007, in Docket No. ER07-521-000, the New York Independent System Operator, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- January 29, 2007, in Docket No. ER07-475-000, the California Independent System Operator Corporation submitted a compliance filing in response to Order Nos. 681 and 681-A.
- January 29, 2007, in Docket No. ER07-476-000, the ISO New England, Inc., submitted a compliance filing in response to Order Nos. 681 and 681-A.
- November 16, 2006, in Docket No. RM06-8-001, FERC issued Order No. 681-A, clarifying and denying rehearing of Order No. 681. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 117 FERC ¶ 61,201 (2006).
- July 20, 2006, in Docket No. RM06-8-000, FERC issued Order No. 681 approving seven of the eight proposed guidelines for independent transmission organizations to follow in developing proposals for providing long-term firm transmission rights. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 116 FERC ¶ 61,077 (2006).
- February 2, 2006, FERC issued NOPR, in Docket No. RM06-8-000, proposing eight guidelines for independent transmission organizations to follow in developing a framework for providing long-term firm transmission rights in organized electricity markets. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 114 FERC ¶ 61,097 (2006).

- May 11, 2005, in Docket No. AD05-7-000, FERC issued notice inviting comments on establishing long-term transmission rights in markets with locational pricing. *Notice Inviting Comments On Establishing Long-Term Transmission Rights in Markets With Locational Pricing and Staff Paper, Long-Term Transmission Rights Assessment*, Docket No. AD05-7-000 (May 11, 2005).

MARKET-BASED RATES FOR WHOLESALE SALES OF ELECTRIC ENERGY, CAPACITY AND ANCILLARY SERVICES BY PUBLIC UTILITIES

MAJOR PROPOSALS: DOCKET NOS. RM14-14-000 AND RM04-7-000

- Replaces existing four-prong analysis with a two-part test covering horizontal and vertical market power.
- Current interim market power screens would be made a permanent part of the horizontal (generation) market power analysis.
- Newly-constructed generation would no longer be exempted from the market power analysis.
- Provide for a standard market-based rate tariff of general applicability.
- "Affiliate abuse" would cease to be a separate prong of the market power analysis, but the Commission proposed to codify existing policies governing sales between public utilities and affiliated entities.
- Certain small power sellers would not be required to submit regularly scheduled triennial reviews; other holders of MBR authority would file triennial reviews on a schedule organized by regions.

MAJOR IMPLICATIONS:

- Clarifies that where all generation capacity owned or controlled by sellers and their affiliates in the relevant balancing authority areas (including first-tier balancing authority areas or markets) is fully committed, sellers may explain that their capacity is fully committed in lieu of submitting indicative screens as part of their horizontal market power analyses.
- Removes the requirement that market-based rate sellers file quarterly land acquisition reports and provide information on their control of sites for development of new generation capacity.
- Requires that all long-term firm purchases of capacity and/or energy by market-based rate sellers be reported in their indicative screens.
- Redefines the default relevant geographic market used to analyze market power for an independent power producer with generation capacity located in a generation-only balancing authority area.
- The native load proxy for market power screens would be changed from the minimum peak day in the season to the average peak native load.
- The Delivered Price Test would be retained for companies failing the initial market power screens.
- Maintaining an Open Access Transmission Tariff (OATT) would continue to be sufficient to mitigate any vertical market power; violations of the OATT may be grounds for revocation of MBR authority.
- Consideration of "other barriers to entry" would be considered as part of the vertical market power assessment.
- Both larger and small sellers would remain under the requirement to file change in status reports.
- Corporate entities would have a single, consolidated MBR tariff.

FERC MILESTONES:

- May 19, 2016, in Docket No. RM14-14-001, FERC issued Order No. 816-A denying requests for rehearing and providing clarification to report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligations, unless it is from an exempt qualifying facility. *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 155 FERC ¶ 61,188 (2016).
- October 16, 2015, in Docket No. RM14-14-000, FERC issued Order No. 816 to revise its current standards for market-based rates for sales of electric energy, capacity, and ancillary services to streamline certain aspects of its filing requirements to reduce the administrative burden on applicants and the Commission. *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 153 FERC ¶ 61,065 (2015).
- March 18, 2010, in Docket No. RM04-7-008, FERC issued Order No. 697-D, granting in part and denying in part requests for rehearing of Order No. 697-C. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 130 FERC ¶ 61,206 (2010).
- June 18, 2009, in Docket No. RM04-7-006, FERC issued Order No 697-C, granting in part and denying in part requests for clarification of Order No. 697-B. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 127 FERC ¶ 61,284 (2009).
- December 19, 2008, in Docket No. RM04-7-005, FERC issued Order No. 697-B granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 125 FERC ¶ 61,326 (2008).
- April 21, 2008, in Docket No. RM04-7-001, FERC issued Order No. 697-A granting rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 123 FERC ¶ 61,055 (2008).
- December 14, 2007, FERC issued an order clarifying the effective compliance date, which entities are required to file and what data are required for market power analyses, and details of "seller-specific terms and conditions" for Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 121 FERC ¶ 61,260 (2007).
- June 21, 2007, FERC issued Order No. 697. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295 (2007).
- August 14, 2006, FERC issued notice granting EEI's request for an extension of time to file reply comments.
- May 19, 2006, FERC issued a NOPR proposing to amend its policies regarding the granting of market-base rate authority and to formally incorporate FERC's four-prong market power analysis into the FERC's regulatory code. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 115 FERC ¶ 61,210 (2006).

OATT REFORM

MAJOR PROPOSALS: DOCKET NO. RM05-25-000

- FERC has indicated its preliminary view is that the OATT should be reformed to reflect lessons learned in nearly a decade of experience with open access transmission service.
- FERC has indicated concern that the public utilities' OATTs have been implemented in various ways, and greater clarification and other reforms of the OATT may be necessary to avoid undue discrimination or preferential terms and conditions.

MAJOR IMPLICATIONS:

- The final rule acknowledges that it is best to continue to require functional unbundling rather than corporate unbundling, and FERC declined to entertain proposals that would have required structural changes or that might have required the creation of new market structures.
- The final rule deems that industry consensus is the best means to develop consistent and transparent methods for calculating Available Transfer Capability (ATC) in order to address concerns over denials of transmission service.
- The final rule takes a principled, non-prescriptive approach to open, coordinated, and transparent transmission planning. FERC acknowledged the importance of both regional and local planning processes, and agreed with EEI that a transmission provider must have the ultimate authority on its transmission plan and its commitment to build transmission facilities. Moreover, the final rule recognizes that it is not necessary to impose a third-party entity to conduct transmission planning and that transmission providers must be able to recover the costs of planning.
- The fundamental structure of transmission services (network/point-to-point) is maintained. However, the final rule recognizes that it is not necessary to mandate the provision of hourly firm transmission service and that transmission providers only must provide planning redispatch and conditional firm service when doing so would not impair reliability (or if planning redispatch would interfere with existing firm service).
- The final rule makes transmission planning more rational; transmission customers must take a term of service for five years in order to obtain the right to roll over their service for an additional term of five years. Transmission customers must provide at least one year's notice that they will rollover their service.
- FERC required rules, standards and practices governing transmission service to be included in public utility OATTs, thus subject to FERC filing, notice and comment, and FERC review.

FERC MILESTONES:

- November 19, 2009, in Docket Nos. RM05-17-005 and RM05-25-005, FERC issued Order No. 890-D, affirming its determinations in previous orders and clarifying the requirement to un-designate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 129 FERC ¶ 61,126 (2009).
- March 19, 2009, in Docket Nos. RM05-17-004 and RM05-25-004, FERC issued Order No. 890-C clarification of the degree of consistency required in the calculation of available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).
- June 23, 2008, in Docket Nos. RM05-17-003 and RM05-25-003, FERC issued Order No. 890-B clarifying the degree of consistency required in the calculation of available transfer capability by transmission providers and denies rehearing regarding the requirement to undesignate network resources used to serve off-system sales. *Preventing Undue Discrimination and Preference in Transmission Services*, 123 FERC ¶ 61,299 (2008).
- December 28, 2007, in Docket Nos. RM05-17-001 and 002 and RM05-25-000, FERC issued Order No. 890-A, granting requests for rehearing and clarification to strengthen the pro forma OATT to ensure it prevents undue discrimination, to provide reduced opportunities for undue discrimination, and to increase transparency. *Preventing Undue Discrimination and Preference in Transmission Services*, 121 FERC ¶ 61,297 (2007).
- February 16, 2007, in Docket Nos. RM05-17-000 and RM05-25-000, FERC issued Order No. 890, Final Rule. *Preventing Undue Discrimination and Preference in Transmission Services*, 118 FERC ¶ 61,119 (2007).
- September 19, 2005, in Docket No. RM05-25-000, FERC issued Notice of Inquiry inviting comments (and asking over 100 questions) on the need to reform the Order No. 888 OATT and public utilities' OATTs to ensure the provision of tariffed transmission service is just and reasonable. *Preventing Undue Discrimination and Preference in Transmission Services*, 112 FERC ¶ 61,299 (2005).

PRICE FORMATION

MAJOR PROPOSALS: DOCKET NOS. RM15-24-000, RM16-5-000, RM17-2-000, AND RM17-3-000

- FERC continues to evaluate issues regarding price formation in the energy and ancillary service markets operated by RTOs and ISOs specifically in areas of (1) use of uplift payments; (2) offer price mitigation and offer price caps; (3) scarcity and shortage pricing; and (4) operator actions that affect pricing.

MAJOR IMPLICATIONS:

- Addresses certain practices that fail to compensate resources at prices that reflect the value of the service resources provide to the system, thereby distorting price signals, and in certain instances, creating a disincentive for resources to respond to dispatch signals.

FERC MILESTONES:

- January 19, 2017, in Docket No. RM17-2-000, FERC issued a Notice of Proposed Rulemaking proposing that grid operators that allocate real-time uplift costs to deviations would be required to allocate them only to market participants whose transactions are reasonably expected to have caused the costs. Further, each grid operator must post uplift costs paid and operator-initiated commitments on its website, and to define in its tariff its transmission-constraint penalty factors, including the circumstances under which the penalty factors can set locational marginal prices, and any procedure for temporarily changing the factors. Such allocation efforts should encourage behavior that reduces the need for uplift-creating actions and avoids discouraging market participant behavior that lowers production costs. *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047 (2017).
- December 15, 2016, in Docket No. RM17-3-000, FERC issued a Notice of Proposed Rulemaking proposing to require RTOs/ISOs to: (1) apply fast-start pricing to any resource committed that can start up within 10 minutes or less, has a minimum run time of one hour or less, and submits economic energy offers to the market; (2) incorporate commitment costs, such as start-up and no-load costs, of a fast-start resource in energy and operating reserve prices during the resource's minimum run time; (3) modify its fast-start pricing to relax the economic minimum operating limits of fast-start resources and treat them as dispatchable from zero to the economic maximum operating limits for the purpose of calculating prices; (4) allow an offline fast-start resource to set prices, but only if the resource is feasible and economic for addressing certain system needs; and (5) incorporate fast-start pricing in both the day-ahead and real-time markets. *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (2016).

- November 17, 2016, in Docket No. RM16-5-000, FERC issued Order No. 831 requiring RTOs/ISOs to: (1) cap each resource's incremental energy offer at the higher of $1,000/megawatt-hour (MWh) or that resource's verified cost-based incremental energy offer; and (2) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices. *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,115 (2016).
- June 16, 2016, in Docket No. RM15-24-000, FERC issued Order No. 825 requiring RTOs/ISOs to align settlement and dispatch intervals by: (1) settling energy transactions in its real-time markets at the same time interval it dispatches energy; (2) settling operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (3) settling intertie transactions in the same time interval it schedules intertie transactions. Also requires RTOs/ISOs to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155 FERC ¶ 61,276 (2016).

RELIABILITY: ESTABLISHMENT OF THE ERO, MANDATORY RELIABILITY STANDARDS AND THE DEFINITION OF BULK ELECTRIC SYSTEM

MAJOR PROPOSALS: DOCKET NOS. AD06-6-000, RM05-30-000, RM06-16-000, RM06-22-000, RM09-18-000, RM11-11-000, RM12-6-000 AND RM12-7-000

- Pursuant to EPAct 2005, FERC proposed criteria for the establishment of an Electric Reliability Organization (ERO) that will enforce reliability standards under the regulatory review of FERC.
- FERC accepted the North American Electric Reliability Corporation (NERC) as the ERO and directed NERC to use its compliance registry process to ensure there are no gaps or redundancies among the entities responsible for specific reliability criteria
- FERC and NERC have refined the definition of Bulk Electric System in order to prevent uncertainty in the market.
- FERC and NERC have established mandatory reliability standards that all users, owners and operators of the Bulk Electric System must comply.

MAJOR IMPLICATIONS

- Establishes a new national regime of mandatory reliability standards subject to FERC review and oversight. Compliance with reliability standards become a legal requirement subject to substantial civil penalties.
- Establishes a process for certifying a single, independent ERO. ERO must demonstrate independence from users, owners and operators while assuring fair stakeholder representation in key areas.
- Provides some regional flexibility and variability by allowing "regional entities" to propose reliability standards through the ERO, and allow the ERO to delegate compliance monitoring and enforcement to regional entities. The delegation is subject to FERC approval and periodic review.
- Each proposed reliability standard must be submitted by NERC to FERC for approval on a case-by-case basis. FERC will not defer to NERC or a Regional Entity with respect to the effect of a proposed reliability standard on competition. FERC may remand to NERC for further consideration a proposed reliability standard that FERC disapproves.
- Order No. 672 provides a process for user, owner or operator of the transmission facilities of a transmission organization to notify FERC of a possible conflict for a timely resolution by FERC.
- NERC or a Regional Entity that is delegated enforcement authority may impose a penalty on user, owner or operator of the Bulk Electric System for a violation of a reliability standard. Order No. 672 establishes a single appeal at the NERC or Regional Entity level to ensure internal consistency in the imposition of penalties by NERC or the Regional Entity.
- Order No. 706 approved mandatory reliability standards that require certain users, owners, and operators of the Bulk Electric System to comply with specific requirements to safeguard critical cyber assets.

FERC MILESTONES

- November 22, 2013, in Docket No. RM13-5-000, FERC issued Order No. 791 approving "Version 5" of the CIP reliability standards which identify and categorize Bulk Electric System (BES) Cyber Systems using a new methodology based on whether a BES Cyber System has a Low, Medium, or High Impact on the reliable operation of the bulk electric system. *Version 5 Critical Infrastructure Protection Reliability Standards*, 145 FERC ¶ 61,160 (2013).
- December 20, 2012, in Docket Nos. RM12-6-000 and RM12-7-000, FERC issued Order No. 773 approving certain proposed modifications to the definition of "bulk electric system" and proposed revisions to NERC's Rules of Procedure which create an exception process to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case basis. *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 141 FERC ¶ 61,236 (2012).
- April 19, 2012, in Docket No. RM11-11-000, FERC issued Order No. 761 approving "Version 4" of the CIP reliability standards which includes "bright line" criteria for the identification of critical assets. *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).
- June 18, 2009, in Docket No. RM06-22-006, FERC issued Order No. 706-C denying requests for rehearing of Order No. 706-B regarding nuclear facilities. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 127 FERC ¶ 61,273 (2009).
- March 19, 2009, in Docket No. RM06-22-000, FERC issued Order No. 706-B clarifying that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory CIP reliability standards. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 126 FERC ¶ 61,229 (2009).
- May 16, 2008, in Docket No. RM06-22-001, FERC issued Order No. 706-A which largely affirms its determinations in Order No. 706. FERC offered certain clarifications regarding enforceability, technical feasibility, confidentiality and technical support. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 123 FERC ¶ 61,174 (2008).
- January 18, 2008, in Docket No. RM06-22-000, FERC issued Order No. 706 which established eight Critical Infrastructure Protection (CIP) mandatory reliability standards requiring certain users, owners, and operators of the Bulk Electric System to comply with specific requirements to safeguard critical cyber assets. *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008).
- July 19, 2007, in Docket No. RM06-16-001, FERC issued Order No. 693-A which reaffirmed its determinations in Order No. 693 and offered certain clarifications in the preamble of the rule. *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (2007).

- March 16, 2007, in Docket No. RM06-16-000, FERC issued Order No. 693, Final Rule regarding mandatory reliability standards for the Bulk Electric System which approved 83 of the 107 mandatory reliability standards proposed by NERC. *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218 (2007).
- April 18, 2006, in Docket No. RM06-16-000, FERC issued a notice announcing a rulemaking process for the processing of the proposed reliability standards submitted by NERC. *Mandatory Reliability Standards for the Bulk-Power System*, 115 FERC ¶ 61,060 (2006).
- March 30, 2006, in Docket No. RM05-30-001, FERC issued Order No. 672-A which reaffirmed its determinations in Order No. 672 concerning the rules for the ERO and procedures for electric reliability standards, but clarified certain provisions, and granted rehearing in part regarding transmission organization options in cases of potential conflicts of a reliability standard with a FERC order. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, 114 FERC ¶ 61,328 (2006).
- March 17, 2011, in Docket No. RM09-18-001, FERC issued Order No. 743-A denying requests for rehearing of Order No. 743 and clarifying the discretion of Regional Entities, standard of review and local distribution facilities. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 134 FERC ¶ 61,210 (2011).
- November 18, 2010, in Docket No. RM09-18-000, FERC issued Order No. 743 which directs NERC to revise the definition of "bulk electric system" and consider eliminating the regional discretion in the current definition, maintaining a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establishing an exemption process and criteria for excluding facilities that are not necessary for operating the interconnected transmission network. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 133 FERC ¶ 61,150 (2010).
- February 3, 2006, in Docket No. RM05-30-000, FERC issued Order No. 672 to implement provisions in EPAct 2005 by establishing criteria for ERO qualification. The Final Rule also establishes procedures under which NERC may propose new or modified reliability standards for FERC review and procedures governing an enforcement action for violation of a reliability standard. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, 114 FERC ¶ 61,104 (2006).
- September 1, 2005, in Docket No. RM05-30-000, FERC issued a notice of proposed rulemaking on developing and implementing the process and procedures under EPAct 2005 for FERC to develop and undertake with regard to the formation and functions of the ERO and Regional Entities. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standard*s, 112 FERC ¶ 61,239 (2005).

STANDARDS OF CONDUCT

MAJOR PROPOSALS: DOCKET NO. RM01-10-000; RM07-1-000

- FERC has conducted technical conferences and workshops to discuss Standards of Conduct for Transmission Providers under Order No. 2004.
- FERC has proposed permanent regulations regarding the standards of conduct consistent with the decisions of the U.S. Court of Appeals of the District of Columbia in *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (2006), regarding natural gas pipelines. FERC is soliciting comments regarding comparable changes for electric utility transmission providers: specifically, whether or not the standards of conduct should govern the relationship between electric utility transmission providers and their energy affiliate.

MAJOR IMPLICATIONS:

- Transmission providers are permitted to communicate essential information to affiliated and non-affiliated nuclear power plants to preserve power grid reliability.

FERC MILESTONES:

- April 8, 2011, in Docket No. RM07-1-003, FERC issued Order No. 717-D, clarifying that an employee who perofrms a system impact study re a transmissions service request, that person is a transmission function employee. *Standards of Conduct for Transmission Providers*, 135 FERC ¶ 61,017 (2011).
- April 16, 2010, in Docket No. RM07-1-002, FERC issued Order No. 717-C, further clarifying "marketing function employee." *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,045 (2010).
- November 16, 2009, in Docket No. RM07-1-002, FERC issued Order No. 717-B, clarifying whether an employee who is not making business decisions about contract non-price terms and conditions is considered a "marketing function employee." *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,123 (2009).
- October 15, 2009, in Docket No. RM07-1-001, FERC issued Order No. 717-A, clarifying: 1) the applicability of the Standards of Conduct to transmission owners with no marketing affiliate transactions; 2) whether the Independent Functioning Rule applies to balancing authority employees; 3) which activities of transmission or marketing function employees are subject to the Rule; 4) whether local distribution companies making off-system sales on nonaffiliated pipe pipelines are subject to the Standards; 5) Whether the Standars apply to a pipeline's sale of its own production; 6) applicability of the Standards to asset management agreements; 7) whether incidental purchases to remain in balance or sales of unneeded gas supply subject the company to the Standards; 8) applicability of the No Conduit Rule; and 9) applicability of the Transparency Rule. *Standards of Conduct for Transmission Providers*, 129 FERC ¶ 61,043 (2009).
- October 16, 2008, in Docket No. RM07-1-000, FERC issued Order No. 717, amending its regulations adopted on an interim basis in Order No. 690, in order to make them clearer and to refocus the rules on the areas where there is the greatest potential for abuse. The Final Rule is designed to (1) foster compliance, (2) facilitate Commission enforcement, and (3) conform the Standards of Conduct to the decision of the U.S. Court of Appeals for the D.C. Circuit in *National Fuel Gas Supply Corporation v. FERC*, 468 F. 3d 831 (D.C. Cir. 2006). Specifically, the Final Rule eliminates the concept of energy affiliates and eliminates the corporate separation approach in favor of the employee functional approach used in Order Nos. 497 and 889. *Standards of Conduct for Transmission Providers*, 125 FERC ¶ 61,064 (2008).

- March 21, 2008, in Docket No. RM07-1-000, FERC issued a Notice of Proposed Rulemaking proposing to revise its Standards of Conduct for transmission providers to make them clearer and to refocus the rules on the areas where there is the greatest potential for affiliate abuse. By doing so, we will make compliance less elusive and facilitate Commission enforcement. We also propose to conform the Standards to the decision of the U.S. Court of Appeals for the D.C. Circuit in *National Fuel Gas Supply Corporation v. FERC*, 468 F.3d 831 (D.C. Cir. 2006). *Standards of Conduct for Transmission Providers*, 122 FERC ¶ 61,263 (2008).

- January 18, 2007, FERC issues NOPR in Docket No. RM07-1-000. Standards of Conduct for Transmission Providers, 118 FERC ¶ 61,031 (2007).

- November 17, 2006, in National Fuel Gas Supply Corporation v. Federal Energy Regulatory Commission, the United States Court of Appeals for the District of Columbia vacated Orders 2004, 2004-A, 2004-B, 2004-C, and 2004-D with respect to natural gas suppliers. *National Gas Fuel Supply Corporation v. FERC*, 468 F.3d 831 (November 17, 2006).

- February 16, 2006, FERC issued interpretive order relating to the Standards of Conduct to clarify that Transmission Providers may communicate with affiliated nuclear power plants regarding certain matters related to the safety and reliability of the transmission system on nuclear power plants, in order to comply with the requirements of the Nuclear Regulatory Commission. *Interpretive Order Relating to the Standards of Conduct*, 114 FERC ¶ 61,155 (2006).

THIRD-PARTY PROVISION OF ANCILLARY SERVICES; ACCOUNTING AND FINANCIAL REPORTING FOR NEW ELECTRIC STORAGE TECHNOLOGIES

MAJOR PROPOSALS: DOCKET NO. RM11-24-000 AND AD10-13-000

- FERC revises its *Avista Corp.* policy governing the sale of ancillary services at market-based rates to meet public utility transmission providers and reflect such reforms in Parts 35 and 37 of the Commission's regulations.

- FERC requires each public utility transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response reserve requirements in a manner that takes into account speed and accuracy of resources used.

- FERC also revises the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees and its forms, statements, and reports contained in FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others, FERC Form No. 1-F, Annual Report for Nonmajor Public Utilities and Licensees, and FERC Form No. 3-Q, Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies to better account for and report transactions associated with the use of energy storage devices in public utility operations.

MAJOR IMPLICATIONS:

- FERC allows third-party sellers passing existing market power screens to sell Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service.

- FERC allows third-party sellers passing existing market power screens to sell Operating Reserve-Spinning and Operating Reserve-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another.

- The Final Rule allows applicants to engage in market-based sales of ancillary services to a public utility that is purchasing ancillary services to satisfy its OATT requirements where the sale is made pursuant to a competitive solicitation that meets specific requirements.

- Each public utility transmission provider must add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made "alternative comparable arrangements."

- The Final Rule adds new electric plant and O&M expense accounts to record the installed cost and operating and maintenance cost of energy storage assets and a new account to record the cost of power purchased for use in energy storage operations.

FERC MILESTONES:

- February 20, 2014, in Docket No. RM11-24-001 and AD10-13-001, FERC issued Order No. 784-A clarifying certain reporting requirements and that intra-hour transmission scheduling practices are sufficient to meet the requirements of Order No. 784. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for Electric Storage Technologies*, 146 FERC ¶ 61,114 (2014).

- July 18, 2013, in Docket Nos. RM11-24-000 and AD10-13-000, FERC issued Order No. 784. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 144 FERC ¶ 61,056 (2013).

- June 22, 2012, in Docket Nos. RM11-24-000 and AD-13-000, FERC issued a Notice of Proposed Rulemaking. *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 139 FERC ¶ 61,245 (2012).

THIRD-PARTY PROVISION OF PRIMARY FREQUENCY RESPONSE SERVICE

MAJOR PROPOSALS: DOCKET NO. RM15-2-000

- FERC revises its regulations to foster competition in the sale of primary frequency response service by permitting the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity.

MAJOR IMPLICATIONS:

- Permits voluntary sales of primary frequency response service at market-based rates for entities granted market-based rate authority. The Final Rule does not place any limits on the types of transactions available to procure primary frequency response service as they may be cost-based or market-based, bundled with other services or unbundled and inside or outside of organized markets. The Final Rule focuses solely on how jurisdictional entities can qualify for market-based rates for primary frequency response service in the context of voluntary bilateral sales.

FERC MILESTONES:

- November 20, 2015, in Docket No. RM15-2-000, FERC issues Order No. 819 adopting revisions to its regulations in order to allow sellers with market-based rates to sell primary frequency response service. Third-Party Provision of Primary Frequency Response Service, 153 FERC ¶ 61,220 (2015).

TRANSMISSION PLANNING AND COST ALLOCATION

MAJOR PROPOSALS: DOCKET NO. RM10-23-000

- Reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

MAJOR IMPLICATIONS:

- Establishes three requirements for transmission planning:
  - Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
  - Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
  - Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.
- Establishes three requirements for transmission cost allocation:
  - Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
  - Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.
  - Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.
- Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:
  - This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
  - This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
  - Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
- The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

FERC MILESTONES:

- October 18, 2012, in Docket No. RM10-23-002, FERC issued Order No. 1000-B reaffirming its determinations in Order No. 1000 and Order No. 1000-A. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 141 FERC ¶ 61,044.
- May 17, 2012, in Docket No. RM10-23-001, FERC issued Order No. 1000-A providing certain clarifications to the policies adopted in Order No. 1000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 139 FERC ¶ 61,132 (2012).
- July 21, 2011, FERC issued Order No. 1000 in Docket No. RM11-26-000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011).

TRANSMISSION PRICING REFORMS/INCENTIVES

MAJOR PROPOSALS: DOCKET NOS. EL11-66-000, RM06-4-000 AND RM11-26-000

- FERC established a two-step discounted cash flow (DCF) methodology which incorporates a long-term growth component for determining allowed return on equity (ROE) for transmission investments.
- FERC enacted transmission pricing reforms which identifies incentives which FERC will allow utilities that demonstrate that a project ensures reliability or reduces transmission congestion.
- FERC emphasized that applicants must demonstrate a link between the incentives requested and the investment being made, that the resulting rates are just and reasonable.
- FERC stated that the incentives will only be permitted for investments which benefit consumers by promoting reliability or reducing the cost of delivered power by reducing congestion.

MAJOR IMPLICATIONS:

- Establishes a two-step DCF methodology which includes a long-term growth component, established as gross domestic product (GDP), for determining allowed ROE on transmission investments. The new DCF methodology also uses a national proxy group to measure capital attraction and comparability of risk.
- Incentives available for traditional utilities as well as additional incentives for stand-alone transmission companies, or transcos, that include: (a) a rate of return on equity sufficient to attract new investment; (b) a recovery in rate base of 100% of prudently incurred transmission-related construction work in progress (CWIP) to increase cash flow; (c) allowing hypothetical capital structures to provide the flexibility needed to maintain viability of new capacity projects; (d) accelerating recovery of depreciation expense; (e) recovery of all prudent development costs in cases where construction of facilities may be abandoned or canceled due to circumstances beyond the control of the utility; (f) allowing deferred cost recovery; and (g) providing a higher rate of return on equity for utilities that join transmission organizations.
- A public utility would have to demonstrate that the new facilities would improve regional reliability and reduce transmission congestion in order for it to receive an incentive based rate of return on equity.

- The rule allows for recovery of costs associated with joining a transmission organization, electric reliability organizations and infrastructure development in National Interest Transmission Corridors.
- In order to encourage the formation of transcos, FERC authorized transcos to propose an acquisition premium, and an Accumulated Deferred Income Taxes incentive for companies selling transmission assets to a transco. FERC stated that it would allow a return on equity (ROE) sufficient to encourage transco formation, and that provision of the ROE incentive would not preclude a transco from seeking other approved incentives.

FERC MILESTONES:

- June 19, 2014, in Docket No. EL11-66-001, FERC issued Opinion No. 531 which established a two-step DCF methodology for determining allowed ROEs going forward in response to a complaint filed against the current ROE allowed for transmission owners/utilities in the Northeast.
- November 15, 2012, in Docket No. RM11-26-000, FERC issued its Policy Statement on Promoting Transmission Through Pricing Reform by clarifying that it would no longer rely on the "routine vs. non-routine" analysis as part of its nexus test and thus required applicants to demonstrate that the total package of incentives requested is tailored to address demonstrable risks and challenges. The Commission also expects incentives applicants to seek to reduce the risk of transmission investment not otherwise accounted for in its base ROE by using risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges. *Promoting Transmission Through Pricing Reform*, 141 FERC ¶ 61,129 (2012).
- May 19, 2011, in Docket No. RM11-26-000, FERC issued a Notice of Inquiry given the changes in the electric industry, the Commission's experience to date applying Order No. 679, and the ongoing need to ensure that incentives regulations and policies are encouraging the development of transmission infrastructure. *Promoting Transmission Investment Through Pricing Reform*, 135 FERC ¶ 61,146 (2011).
- December 21, 2010, in Docket Nos. PA11-11-000, PA11-13-000 and PA11-14-000 respectively, FERC announced it would audit compliance with Order Nos. 679, 679-A and 679-B, and the conditions placed when FERC granted incentives.
- April 19, 2007, in Docket No. RM06-4-002, FERC issued Order No. 679-B, denying rehearing and clarifying Order No. 679-A. *Promoting Transmission Investment Through Pricing Reform*, 119 FERC ¶ 61,062 (2007).
- December 22, 2006, in Docket No. RM06-4-001, FERC issued Order No. 679-A, reaffirming in part and granting rehearing in part of Order No. 679.
- July 20, 2006, in Docket No. RM06-4-000, FERC issued Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, 116 FERC ¶ 61,199 (2006).
- November 18, 2005, in Docket No. RM06-4-000, FERC issued a NOPR to amend its regulations to establish incentive-based rate treatments for transmission of electric energy in interstate commerce by public utilities. *Promoting Transmission Investment through Pricing Reform*, 113 FERC ¶ 61,182 (2005).

WHOLESALE COMPETITION IN REGIONS WITH ORGANIZED ELECTRIC MARKETS

MAJOR PROPOSALS: DOCKETS AD07-7, AD07-8, RM07-19

- FERC amends its regulations to improve operation of wholesale electric markets with regards to: (1) demand response and market prices during operating reserve shortages; (2) long-term power contracting; (3) market-monitoring policies; and (4) RTO and ISO responsiveness to stakeholders and customers.

MAJOR IMPLICATIONS:

- Allow RTOs to accept bids from demand response resources for certain ancillary services, to eliminate charges for voluntarily taking less energy in real-time markets than purchased in the day-ahead markets, allow demand response to be bid by a retail customer aggregator, and to allow market-clearing prices to reach levels that allow for rebalances of supply and demand during periods of operating reserve shortages.
- Requires RTOs to support long-term power contracting by allowing market participants to post offers on their website.
- Expands the rules regarding the Market Monitoring Unit's (MMU) interaction with their RT, require the RTO to materially support the MMU, remove the MMU from tariff administration, and reduce time period before energy bid and offer data are released to the public.
- Establishes criteria to ensure RTO responsiveness to customers and stakeholders, such as: inclusiveness, fairness in balancing diverse interests, representation of minority positions and ongoing responsiveness.

FERC MILESTONES:

- December 17, 2009, in Docket No. RM07-19-002, FERC Issued Order No. 719-B affirming its determinations in Orders Nos. 719 and 719-A. *Wholesale Competition in Regions with Organized Electric Markets*, 129 FERC ¶ 61,252 (2009).
- July 16, 2009, in Docket No. RM07-19-001, FERC issued Order No 719-A, affirming and granting clarification of Order No. 719. *Wholesale Competition in Regions with Organized Electric Markets*, 128 FERC ¶ 61,059 (2009).
- October 17, 2008, in Docket Nos. AD07-7-000 and RM07-19-000, FERC issued Order No. 719 amending its regulations under the Federal Power Act to improve the operation of organized wholesale electric markets in the areas of: (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of regional transmission organizations (RTOs) and independent system operators (ISOs) to their customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services. *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 (2008).
- February 22, 2008, FERC issued a Notice of Proposed Rulemaking. *Wholesale Competition in Regions with Organized Electric Markets*, 122 FERC ¶ 61,167 (2008).

Finance and Accounting Division

The Business Services and Finance Division is part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Business Services and Finance Division staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly reports include stock performance, dividends, credit ratings, and rate case summary, as well as the industry's consolidated financial statements.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry. The report also includes an analysis of construction and fuel use trends by electric utilities, as well as an update on major FERC initiatives.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The index, which measures total return and provides company rankings for one- and five-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples. The 2013 edition features updated chapters on Tax Depreciation, Accounting for Asset Retirement Obligations (AROs) and includes a new chapter on Depreciation in an IFRS Environment.

Industry directories published by the Business Services and Finance Division:

- Electric Utility Investor Relations Executives Directory
- Accounting and Internal Audit Directory

For more information, please visit the EEI website at: www.eei.org.

Conference Highlights

Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,100 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Debra Henry for more information.

Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is opened to member company chief financial officers only. Contact Debra Henry for more information.

Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Debra Henry for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Debra Henry for more information.

Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Debra Henry for more information.

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

EEI Accounting Standards Committee

Provides a forum for technical accounting, accounting research, financial reporting, and other interested member-company accounting leaders and staff, to update their knowledge on emerging accounting standards, implementation issues associated with newly issued standards, and other technical and business issues. This Committee meets in conjunction with the Spring Accounting Conference. Contact Randall Hartman for more information.

Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, and the Budgeting & Financial Forecast Committee, and the AGA Accounting Services Committee, the conference provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries – convenes twice a year for two and one-half days. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

Tax School

Provides tax professionals a forum to discuss developing tax issues impacting our member companies. This two and half day training is held every other year. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman or Dave Dougher for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect regulated companies in the changing and increasingly competitive environment of the electric and gas utility industries. Contact Randall Hartman or Dave Dougher for more information.

Accounting for Energy Derivatives

Electricity and gas commercial transacting often involves commodity purchase contracts, hedges, and trading activities that are considered derivatives for accounting purposes. EEI and AGA partner with EY to offer this three-day seminar and workshop that covers the basics of derivatives accounting as well as advanced applications. In 2018, we will fully adopt the course to reflect FASB ASU 2017-12, Derivatives and Hedging. Contact Randall Hartman or Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

This is a 1½-day seminar offered jointly with AGA that provides an introduction to property accounting and depreciation in the electric and natural gas utility industries. Contact Dave Dougher for more information.

Utility Internal Auditor's Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA – convenes for two and one-half days. Contact Randall Hartman or Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Lease and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

The EEI Business Services and Finance Division Staff

Richard McMahon
Vice President, Energy Supply and Finance
(202) 508-5571
rmcmahon@eei.org

Irene Ybadlit
Coordinator, Energy Supply and Finance
(202) 508-5502
iybadlit@eei.org

Accounting Staff

Randall Hartman
Director, Accounting
(202) 508-5494
rhartman@eei.org

Dave Dougher
Manager, Accounting
(202) 508-5570
ddougher@eei.org

Kim King
Administrative Assistant
(202) 508-5493
kking@eei.org

Finance Staff

Mark Agnew
Senior Director, Financial Analysis
(202) 508-5049
magnew@eei.org

Bill Pfister
Director, Financial Analysis
(202) 508-5531
bpfister@eei.org

Michael Buckley
Manager, Financial Analysis
(202) 508-5614
mbuckley@eei.org

Investor Relations Staff

Debra Henry
Manager, Investor Relations &
Conference Services
(202) 508-5496
dhenry@eei.org

Devin James
Senior Investor Relations Specialist
(202) 508-5057
djames@eei.org

Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are finance-related meetings that may be of interest to you. For further details, please contact Debra Henry at (202) 508-5496, Devin James at (202) 508-5057, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

June 5, 2018

Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Conrad Hilton
New York, New York

June 7-8, 2018

Finance Committee Meeting
(Closed meeting, admittance by invitation only)
Manchester Grand Hyatt
San Diego, California

June 10-13, 2018

Accounting Leadership Conference
Loews Minneapolis Hotel
Minneapolis, Minnesota

Chief Audit Executives Conference
(Closed meeting, admittance by invitation only)
Loews Minneapolis Hotel
Minneapolis, Minnesota

August 20-23, 2018

Introduction/Advanced Public Utility Accounting and Internal Auditor's Training Courses
St. Louis Union Station Hotel
St. Louis, Missouri

September 18, 2018

FERC Accounting and Reporting Workshop
Renaissance Chicago O'Hare Suites Hotel
Chicago, Illinois

September 24-26, 2018

Derivative Accounting Workshop
International Chicago Magnificent Mile Hotel
Chicago, Illinois

November 11-14, 2018

EEI Financial Conference
Hilton San Francisco Union Square
San Francisco, California

EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Hilton San Francisco Union Square
San Francisco, California

Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Hilton San Francisco Union Square
San Francisco, California

November 11-14, 2018

Fall Accounting Conference
Omni La Mansion del Rio Hotel
San Antonio, Texas

December 6, 2018

Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

December 7, 2018

Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
Omni Berkshire Place
New York, New York

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2017	2016r
Earnings Excluding Non-Recurring and Extraordinary Items	**49,894**	**46,788**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	1,632	767
Other Non-Recurring Revenues	493	888
Asset Write-downs	(7,365)	(17,487)
Other Non-Recurring Expenses	(5,598)	(3,109)
Total Non-Recurring Items	**(10,838)**	**(18,941)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(25)	(732)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(25)**	**(732)**
Net Income	**39,031**	**27,114**
Total Non-Recurring and Extraordinary Items	**(10,863)**	**(19,674)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

U.S. Investor-Owned Electric Utilities

(At 12/31/2017)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Berkshire Hathaway Energy *
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporation *
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DPL Inc. *
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Entergy Corporation
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Great Plains Energy Inc.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
IPALCO Enterprises, Inc. *
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Oncor Electric Delivery Company *
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
Puget Energy, Inc. *
SCANA Corporation
Sempra Energy
Southern Company
Unitil Corporation
Vectren Corporation
WEC Energy Group, Inc.
Westar Energy, Inc.
Xcel Energy Inc.

Note: Includes the 43 publicly traded electric utility holding companies plus an additional six electric utilities (shown in italics) that are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

EEI | Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
202-508-5000 | www.eei.org