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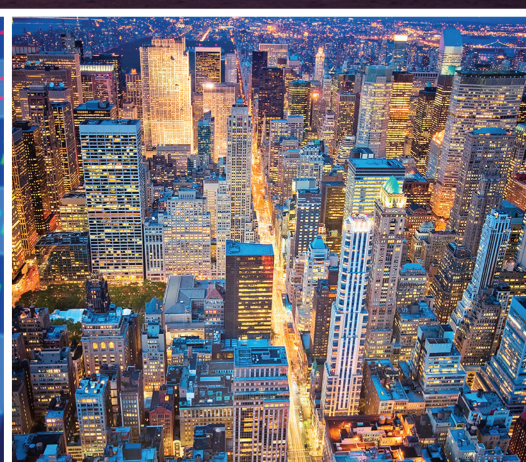
2016 Financial Review

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



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Edison Electric
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2016 FINANCIAL REVIEW

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 2016 Financial Review is a comprehensive source for critical financial data covering 44 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 50 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 101 for a list of these companies.

Contents

Highlights of 2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2016	2015r	% Change
Total Operating Revenues	350,630	352,160	(0.4%)
Utility Plant (Net)	1,061,974	989,309	7.3%
Total Capitalization	941,396	873,268	7.8%
Earnings Excluding Non-Recurring and Extraordinary Items	46,716	39,949	16.9%
Dividends Paid, Common Stock	23,461	21,938	6.9%

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

Three 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: Greater than 80% of total assets are regulated.

Mostly Regulated: 50% to 80% of total assets are regulated.

Diversified: Less than 50% of total assets are regulated.

EEI

WISHING

David K. Owens

THE BEST IN HIS RETIREMENT

For nearly four decades, David has provided pioneering leadership to EEI and to our member companies. David will be sorely missed by his colleagues and by a legion of friends and admirers throughout the electric power industry and beyond.

President's Letter

2016 Financial Review

Last year, I wrote to you about the profound transformation that our industry is leading across the nation. As our industry continues to evolve, 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 they want. This commitment guides us, and also provides opportunities to collaborate and make progress on key policy priorities.

To meet customers' changing needs, we are transitioning to even cleaner generation sources and are leading the way on renewables. In just 10 years, the mix of sources used to generate electricity has changed dramatically and is increasingly clean. In 2016, natural gas use surpassed coal as a main source of electricity in the U.S.—the first time that a fuel other than coal has supplied the bulk of the nation's power. Electric companies also are the largest investors in renewable energy in the U.S. Virtually all of the wind, geothermal, and hydropower in the country—and the majority of installed solar capacity—is provided by electric companies.

We are building smarter energy infrastructure, and our investments are creating additional jobs and are making the energy grid more dynamic and more secure for all customers. We are investing in energy efficiency and are providing customers the energy solutions they want. We also are partnering with leading innovative companies and start-ups to shape the future using technology.

Today, the Edison Electric Institute's (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 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.

As you will see in this year's Financial Review, EEI's investor-owned electric company members continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the third straight year in 2016, after increasing from the BBB average that had previously held since 2004. Ratings upgrades were a very favorable 73.1% of total credit actions, resulting from companies' increased focus on regulated operations, achieved through spin-offs and divestitures, as well as the effective management of regulatory risk. The improved credit quality greatly supports the continued surge in capital expenditures, which rose by $8.5 billion, or 8.2%, to a new record high of $112.5 billion in 2016.

For the sixth consecutive year, all of the EEI Index companies paid a dividend in 2016, and strong dividend yields continue to support utility stocks. The industry's dividend yield at the end of 2016 stood at 3.4%, and 40 electric companies, or 91% of the industry, increased their dividend last year, the largest percentage on record.

Looking ahead, I am optimistic about our industry's future. EEI's member companies are committed to providing reliable, affordable, secure, and increasingly clean energy to drive our nation's economy and power our everyday lives. By continuing to lead together on the issues driving the electric power industry's transformation, EEI and our member companies will demonstrate Power by Association, and we will deliver 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 Increases 0.2% in 2016

As shown in the table *U.S. Electric Output*, the U.S. electric power industry in 2016 made 4,026,393 gigawatt-hours (GWh) of electricity available for distribution in the continental U.S., an increase of 0.2% over 2015's total of 4,019,387 GWh. While 2016 was the fourth consecutive year in which U.S. electric output increased, the year's total was only about 1% above 2006's 3,988,868 GWh and nearly 2% below 2008's 4,062,716 GWh. 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 an increase in electric output in 2016. The South Central region saw one of the largest year-to-year gains for a fourth consecutive year, with the Southeast, Central Industrial, West Central, and Pacific Northwest regions also showing growth. The New England

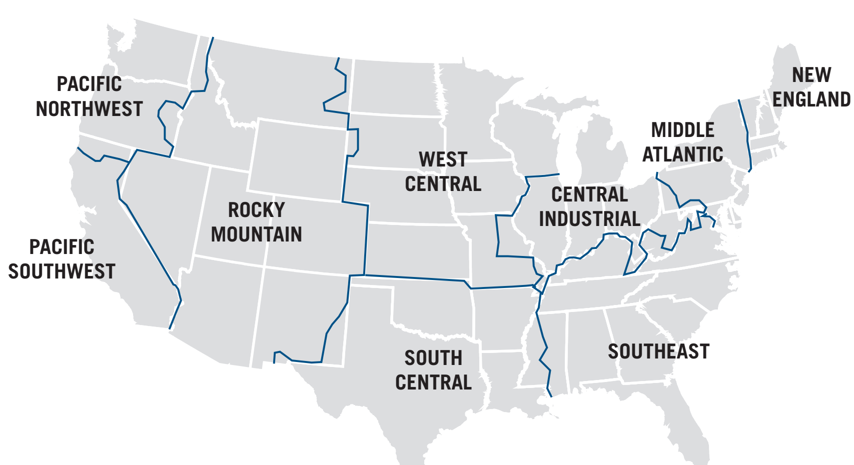
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2016	2015	% Change
New England	123,972	126,894	(2.3%)
Mid-Atlantic	436,080	444,359	(1.9%)
Central Industrial	676,832	674,318	0.4%
West Central	330,753	329,835	0.3%
Southeast	1,031,965	1,020,773	1.1%
South Central	716,334	709,227	1.0%
Rocky Mountain	275,312	276,813	(0.5%)
Pacific Northwest	152,226	152,141	0.1%
Pacific Southwest	282,919	285,027	(0.7%)
Total United States	**4,026,393**	**4,019,387**	**0.2%**

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.

region saw the largest decrease in output, at -2.3%. The Mid-Atlantic, Pacific Southwest, and Rocky Mount regions also experienced decreases in output for the year.

EEI also calculates weather-normalized 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 decreased in 2016 by 0.1%. The weather-normalized data shows that, similar to the prior year, the New England region had the largest decrease in output, at -2.1%, followed by the Mid-Atlantic region at -1.7%, while the Southeast region had the highest year-to-year increase, at 1.1% (weather-normalized).

U.S. real gross domestic product (GDP) grew 1.6% in 2016, below the 2.6% and 2.4% rates in 2015 and 2014, respectively. While the official unemployment rate fell below 5% in 2016, for the third straight year the percentage of working-age (i.e., aged 16 or above) U.S. citizens in the labor force was below 63%, a level not seen since the late 1970s and more than three percentage points below the 66% level that preceded the recession of 2008/2009. While due in part to demographic factors (e.g., an aging workforce), the lower labor participation rate probably also reflects the fact that some workers have been unable to get back into the labor force since the last economic downturn and are therefore not counted in the unemployment rate. Total U.S. retail sales grew by 2% last year, but industrial production declined by 1%. The drop in industrial production was mirrored by a decline in industrial electricity sales of nearly 4%.

U.S. Weather
January – December 2016

	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	794	377	90%	175	28%
Mid-Atlantic	1,039	383	58%	172	20%
East North Central	1,009	301	43%	284	39%
West North Central	1,092	164	18%	121	12%
South Atlantic	2,493	528	27%	98	4%
East South Central	2,048	500	32%	286	16%
West South Central	2,916	465	19%	160	6%
Mountain	1,476	233	19%	68	5%
Pacific	899	195	28%	(141)	(14%)
United States	**1,575**	**358**	**29%**	**123**	**8%**
Heating Degree Days					
New England	5,845	(800)	(12%)	(758)	(11%)
Mid-Atlantic	5,204	(739)	(12%)	(504)	(9%)
East North Central	5,669	(862)	(13%)	(531)	(9%)
West North Central	5,762	(1,022)	(15%)	(359)	(6%)
South Atlantic	2,491	(377)	(13%)	(37)	(1%)
East South Central	3,075	(548)	(15%)	(159)	(5%)
West South Central	1,776	(523)	(23%)	(355)	(17%)
Mountain	4,358	(874)	(17%)	(80)	(2%)
Pacific	2,608	(635)	(20%)	84	3%
United States	**3,875**	**(672)**	**(15%)**	**(268)**	**(6%)**

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.

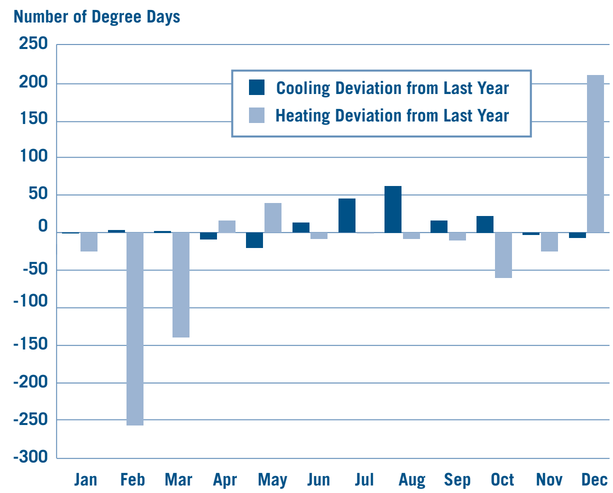
Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

Industry Revenue Fell 0.4%

As shown in the *Consolidated Income Statement*, the industry's total revenue fell by $1.5 billion, or 0.4%, in 2016. However, roughly half the companies reported higher revenue and the equal-weight, average change was a 0.1% increase. Four companies posted a double-digit percent increase and five experienced a double-digit percent decrease. A total of 70 new rate cases were filed in 2016; this was the second-highest number of new cases filed in a year over the last three decades (see *Rate Case*).

2016 Weather Compared to 2015

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	(1)	(25)
Feb	3	(256)
Mar	2	(139)
Apr	(9)	16
May	(20)	39
Jun	13	(8)
Jul	45	(1)
Aug	62	(8)
Sep	16	(10)
Oct	22	(60)
Nov	(3)	(25)
Dec	(7)	209
Total	**123**	**(268)**

Heating and Cooling Degree Days and Percent Changes

January—December 2016

	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	4	(5)	(1)	870	(47)	(25)	(55.6%)	(20.0%)	(5.1%)	(2.8%)
Feb	7	(2)	3	659	(96)	(256)	(22.2%)	75.0%	(12.7%)	(28.0%)
Mar	24	6	2	450	(143)	(139)	33.3%	9.1%	(24.1%)	(23.6%)
First Quarter	**35**	**(1)**	**4**	**1,979**	**(286)**	**(420)**	**(2.8%)**	**12.9%**	**(12.6%)**	**(17.5%)**
Apr	38	8	(9)	317	(28)	16	26.7%	(19.1%)	(8.1%)	5.3%
May	106	9	(20)	154	(5)	39	9.3%	(15.9%)	(3.1%)	33.9%
Jun	269	56	13	19	(20)	(8)	26.3%	5.1%	(51.3%)	(29.6%)
Second Quarter	**413**	**73**	**(16)**	**490**	**(53)**	**47**	**21.5%**	**(3.7%)**	**(9.8%)**	**10.6%**
Jul	387	66	45	5	(4)	(1)	20.6%	13.2%	(44.4%)	(16.7%)
Aug	374	84	62	3	(12)	(8)	29.0%	19.9%	(80.0%)	(72.7%)
Sep	241	86	16	27	(50)	(10)	55.5%	7.1%	(64.9%)	(27.0%)
Third Quarter	**1,002**	**236**	**123**	**35**	**(66)**	**(19)**	**30.8%**	**14.0%**	**(65.3%)**	**(35.2%)**
Oct	88	35	22	168	(114)	(60)	66.0%	33.3%	(40.4%)	(26.3%)
Nov	23	8	(3)	418	(121)	(25)	53.3%	(11.5%)	(22.4%)	(5.6%)
Dec	14	7	(7)	785	(32)	209	100.0%	(33.3%)	(3.9%)	36.3%
Fourth Quarter	**125**	**50**	**12**	**1,371**	**(267)**	**124**	**66.7%**	**10.6%**	**(16.3%)**	**9.9%**
Full Year	**1,575**	**358**	**123**	**3,875**	**(672)**	**(268)**	**29.4%**	**8.5%**	**(14.8%)**	**(6.5%)**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Heating Degree Days Percentage Change from Historical Norm	(5.6)	(0.8)	(0.9)	(1.7)	(4.5)	(16.6)	(0.6)	1.1	(9.1)	(14.8)
Cooling Degree Days Percentage Change from Historical Norm	14.5	5.3	1.6	19.9	21.5	22.4	10.9	5.8	19.2	29.4

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 Decline 9.9%

Total energy operating expenses fell by $11.7 billion, or 9.9%, from the prior year's level, declining significantly more than revenue. The two components of total energy operating expenses — total electric generation cost (-10.1%) and gas cost (-8.1%) — each contributed to the decrease. Electric generation cost, which includes electric generation fuel expense and the cost of purchased power, was just over 26% of total revenue in 2016. This represents a continued decrease compared to recent years: electric generation cost was 29% of total revenue in 2015, 31% from 2012 through 2014, and 34% from 2009 through 2011, down from 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 heating demand and lowest in the third due to the minimal heating needs during the 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)	**12/31/2016**	**12/31/2015r**	**% Change**
Energy Operating Revenues	$350,630	$352,160	(0.4%)
Energy Operating Expenses			
Total Electrical Generation Cost	92,906	103,368	(10.1%)
Gas Cost	14,092	15,337	(8.1%)
Total Energy Operating Expenses	**106,998**	**118,705**	**(9.9%)**
Revenues less energy operating expenses	**243,631**	**233,455**	**4.4%**
Other Operating Expenses			
Operations & maintenance	92,912	90,436	2.7%
Depreciation & Amortization	46,174	42,188	9.4%
Taxes (not income) - Total	18,466	17,911	3.1%
Other Operating Expenses	12,951	11,934	8.5%
Total Operating Expenses	**277,502**	**281,174**	**(1.3%)**
Operating Income	73,128	70,986	3.0%
Other Recurring Revenue			
Partnership Income	1,264	1,113	13.6%
Allowance for Equity Funds Used for Construction	1,810	1,587	14.1%
Other Revenue	2,530	1,898	33.3%
Total Other Recurring Revenue	**5,604**	**4,598**	**21.9%**
Non-Recurring Revenue			
Gain on Sale of Assets	767	789	(2.8%)
Other Non-Recurring Revenue	888	(4)	NM
Total Non-Recurring Revenue	**1,655**	**785**	**110.8%**
Interest expense	22,271	20,966	6.2%
Other expenses	511	501	2.1%
Asset Writedowns	17,480	5,189	236.8%
Other Non-Recurring Expenses	3,110	1,764	76.3%
Total Non-Recurring Expenses	20,590	6,953	196.1%
Net Income Before Taxes	**37,015**	**47,949**	**(22.8%)**
Provision for Taxes	9,234	14,168	(34.8%)
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	**27,780**	**33,781**	**(17.8%)**
Discontinued Operations	(668)	(1,148)	(41.8%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(668)	(1,148)	(41.8%)
Net Income	**27,112**	**32,633**	**(16.9%)**
Preferred Dividends Declared	17	2	652.1%
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(7)	(4)	101.6%
Net Income Attributable to Noncontrolling Interests	606	412	NA
Net Income Available to Common	**26,480**	**32,214**	**(17.8%)**
Common Dividends	**23,461**	**21,938**	**6.9%**

r = revised NM = not meaningful

Note: Statement items for both periods have been adjusted due to M&A-related activity. Data for Empire District Electric Company and TECO Energy include only the first three quarters of 2016.

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

The gas contribution can help balance the seasonal earnings stream for combined gas/electric distribution companies due to the fact that residential gas demand peaks in the colder months while electricity demand peaks in the hot summer months for most U.S. utilities.

Operations and Maintenance (O&M) Expenses Rise 2.7%

Operations and maintenance (O&M) expenses for the industry increased 2.7% in 2016, in-line with the median company increase of 2.8%. O&M accounted for 33% of the industry's operating expenses, which is the highest percentage over the last decade. The combination of O&M and Depreciation and Amortization accounted for half of operating expenses in 2016, up from roughly one-third of operating expenses a decade earlier.

The consolidated industry O&M total includes not only the electric but also the natural gas and other operating segments and is influenced by plant and business divestitures.

Operating Income Climbs 3.0%

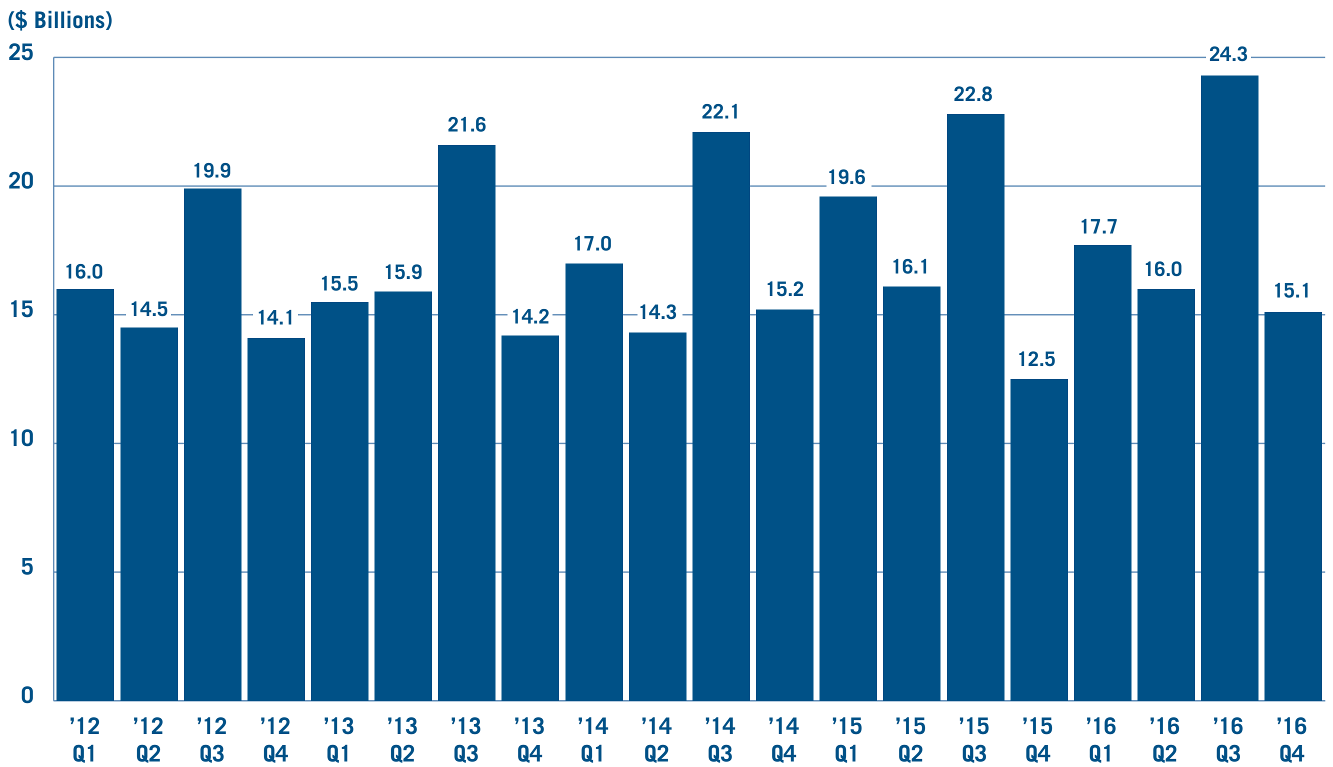
The industry's aggregate operating income rose by $2.1 billion, or 3.0%, with a median increase of 5.4%; 75% of companies showed a year-to-year gain. Last year was the fourth consecutive year in which the industry's operating income increase exceeded the 2.0% compound annual growth rate over the trailing 10 years.

Interest Expense Up 6.2%

Interest expense rose by 6.2%, to $22.3 billion from $21.0 billion in 2015. Nine companies recorded double-digit percent increases while only three accounted for more than 85% of the overall increase. The median change was an increase of 2.0%. Interest expense has held relatively steady for most of the last decade as upward pressure from ris-

Quarterly Net Operating Income

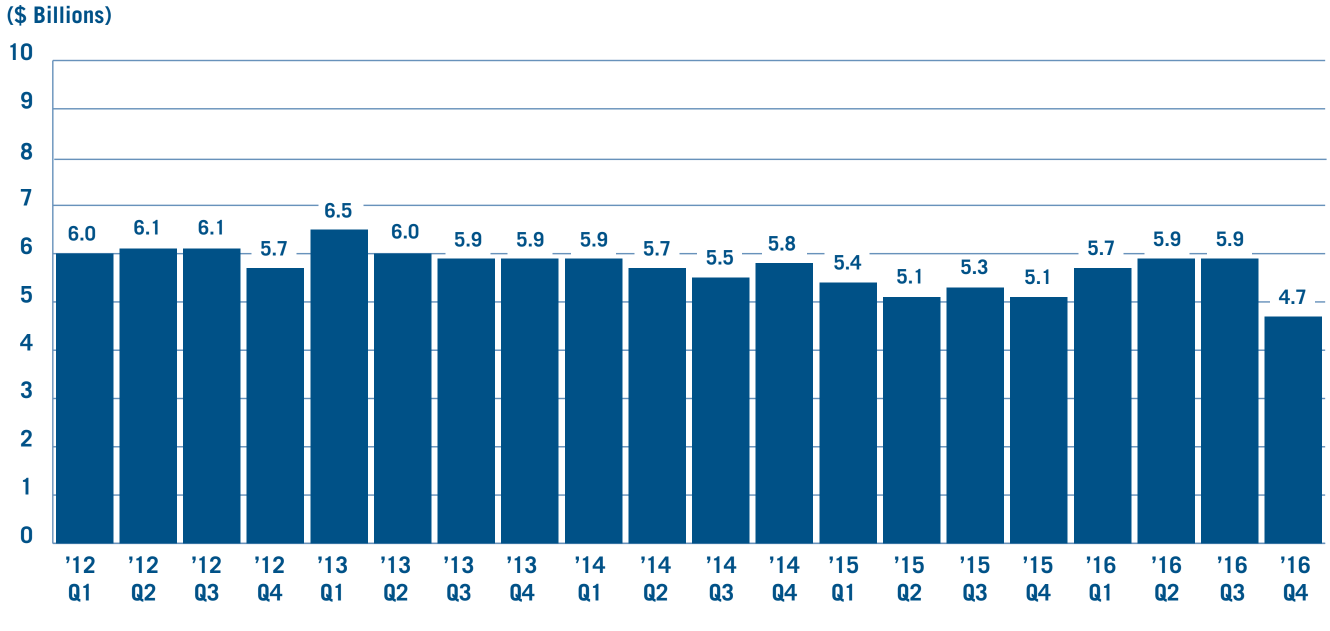
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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.

ing debt needed to fund capital investment has been offset by declining interest rates. The movement of the quarterly average coupon rates for newly issued 10-year utility bonds closely mirrored that of 10-year Treasuries in 2016; however, the utility spread was above the Treasury yield for two quarters in 2016, which is only the third time this has occurred during the last decade (see *Balance Sheet*).

Non-Recurring and Extraordinary Activity

As shown in the table *Individual Non-Recurring and Extraordinary Items*, the industry reported a $12.3 billion year-to-year increase in the total expense associated with non-recurring and extraordinary items, mostly due to a $12.3 billion increase in "Asset Writedowns".

The cost of "Asset Writedowns" increased from $5.2 billion in 2015 to $17.5 billion in 2016; however only 12 companies reported write-downs and the majority of the industry's total increase was attributable to a single company.

Net Income Higher at Most Companies

The industry's net income declined from $32.6 billion in 2015 to $27.1 billion in 2016, a $5.5 billion or 17% decrease. However, net income rose for about three-quarters of the industry and 21 companies reported a double-digit percentage gain.

Individual Non-Recurring and Extraordinary Items 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2007	2008	2009	2010	2011	2012	2013	2014	2015r	2016
Net Gain (Loss) on Sale of Assets	5,240	581	7,176	3,410	891	311	414	996	789	767
Other Non-Recurring Revenue	130	1,661	(494)	2,065	946	264	78	296	(4)	888
Total Non-Recurring Revenue	**5,370**	**2,243**	**6,682**	**5,475**	**1,837**	**576**	**492**	**1,292**	**785**	**1,655**
Asset Writedowns	(215)	(11,256)	(2,022)	(8,805)	(2,743)	(5,646)	4,276	8,762	5,189	17,480
Other Non-Recurring Charges	(1,091)	(1,525)	(822)	(545)	(851)	(3,136)	3,510	2,675	1,764	3,110
Total Non-Recurring Charges	**(1,306)**	**(12,781)**	**(2,844)**	**(9,350)**	**(3,594)**	**(8,783)**	**7,786**	**11,437**	**6,953**	**20,590**
Discontinued Operations	599	759	(63)	(476)	(1,011)	(4,317)	(88)	295	(1,148)	(668)
Change in Accounting Principles	(158)	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	(79)	67	(5)	10	960	–	–	–	–	–
Total Extraordinary Items	**362**	**826**	**(68)**	**(466)**	**(51)**	**(4,317)**	**(88)**	**295**	**(1,148)**	**(668)**
Total Non-Recurring and Extraordinary Items	**4,426**	**(9,713)**	**3,771**	**(4,341)**	**(1,808)**	**(12,524)**	**(7,381)**	**(9,850)**	**(7,316)**	**(19,604)**

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

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

Top Net Non-Recurring and Extraordinary Gains (Losses) 2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

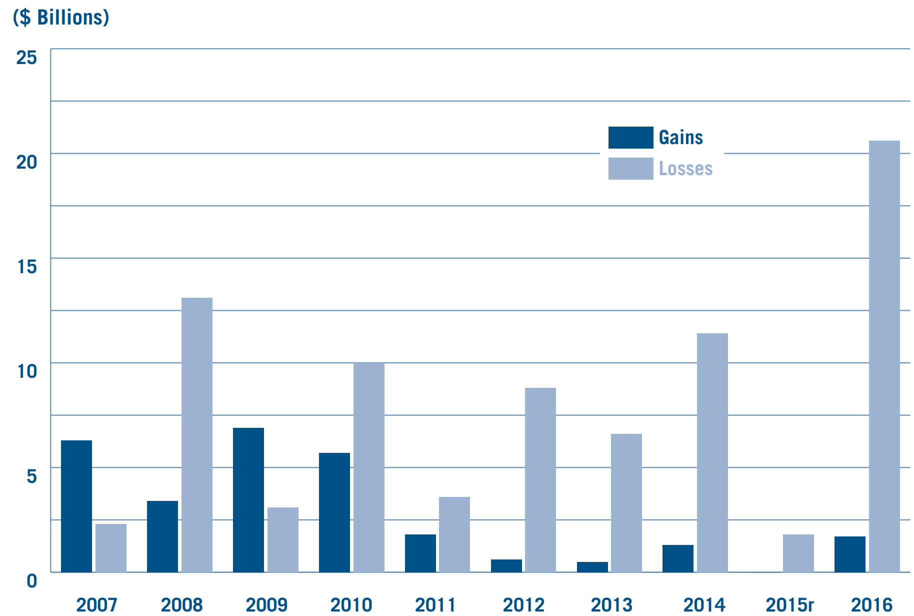
($ Millions)

Company	Gains	Losses	Net Total
FirstEnergy	–	10,665	10,665
Entergy	–	2,836	2,836
AEP	–	2,268	2,268
Duke	27	999	972
Exelon	(48)	850	898
DPL	–	862	862
Sempra	719	153	566
NextEra	675	135	540
Southern	–	539	539
PG&E	–	507	507

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

Aggregate Non-Recurring and Extraordinary Items 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



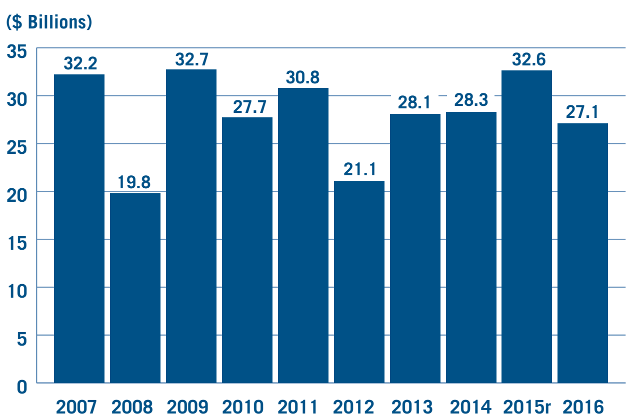
	2007	2008	2009	2010	2011	2012	2013	2014	2015r	2016	Total
Gains	6.3	3.4	6.9	5.7	1.8	0.6	0.5	1.3	0.0	1.7	28.1
Losses	2.3	13.1	3.1	10.0	3.6	8.8	6.6	11.4	1.8	20.6	81.3
Total	**4.0**	**(9.7)**	**3.8**	**(4.3)**	**(1.8)**	**(8.2)**	**(6.2)**	**(10.1)**	**(1.8)**	**(18.9)**	**(53.2)**

r = revised Note: Totals may reflect rounding.

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

Net Income 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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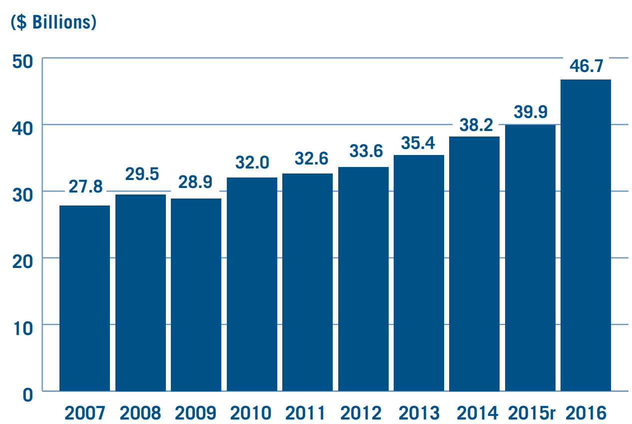
Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2007-2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Balance Sheet

The industry's consolidated balance sheet remained generally healthy in 2016, although rising debt associated in part with the year's merger and acquisition activity caused debt as a percent of total capitalization to rise for a second straight year. Long-term debt was 55.4% of total capitalization at yearend 2016, up from 53.6% at yearend 2015 and 53.1% at yearend 2014. However the jump is less significant when put in the context of the past decade as the level ranged between 53.8% and 56.4% from 2007 through 2013. Rising debt levels during the period have been largely offset with net income and common stock issuance, although 2016's $53.4 billion increase in long-term debt was about double the more gradual $19.1 billion average rise from 2008 through 2015.

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 also little changed in 2016. 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 2016. U.S. interest rates remained very low by historical standards, although yields were somewhat volatile; the 10-year U.S. Treasury yield began the year at 2.3% and fell to 1.4% by early July on concern over the strength of global economic growth and weak inflation indicators. The year's second half produced rising confidence in both domestic U.S. and global economic conditions and the U.S. 10-year yield rose back to 2.5% by yearend. 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 A rated corporate utility bonds declined from about 210 basis points early in the year to under 170 basis points by yearend.

Bond investors worldwide turned to the U.S. for income in 2016 as government yields in the Eurozone and Japan were near zero due to very lethargic economies and to aggressive asset purchase programs at both the European Central Bank and the Bank of Japan. U.S. electric utilities were able to take advantage of strong investor demand to issue debt at historically very favorable yields; the industry's high-quality debt securities hold strong appeal for global investors seeking income without an uncomfortable level of financial risk. The industry's aggregate short-term debt also rose, reaching $34.1 billion at yearend 2016 from $28.7 at the end of 2015.

All three company categories saw long-term debt rise as a percent of total capitalization, however the industry's steady multi-year migration back to a regulated focus has greatly diminished the meaningfulness of analysis by company category. During 2016, 36 of the industry's 50 companies were in the Regulated category and 12 were in the Mostly Regulated category. The Diversified category contained

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2016	12/31/2015r	12/31/2014r
Common Equity	406,225	396,856	386,292
Preferred Equity & Noncontrolling Interests	13,901	8,492	7,399
Long-term Debt (current & non-current)*	521,270	467,919	446,283
Total	**941,396**	**873,268**	**839,974**
Common Equity %	43.2%	45.4%	46.0%
Preferred & Noncontrolling %	1.5%	1.0%	0.9%
Long-term Debt %	55.4%	53.6%	53.1%
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.

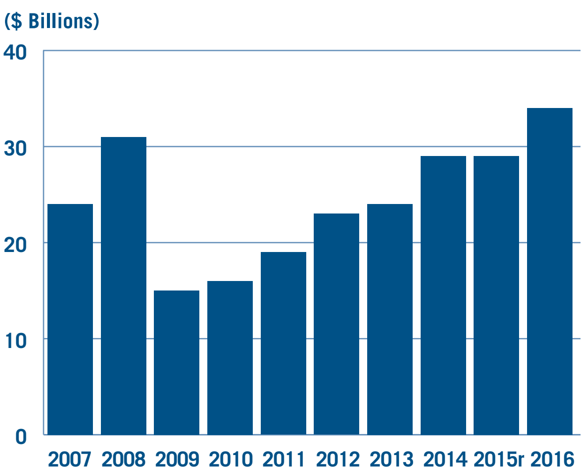
only two companies. Nevertheless, the year's jump in debt was evident across all three categories. The Regulated category's long-term debt as a percent of total capitalization rose from 53.8% at yearend 2015 to 55.1% at yearend 2016, the Mostly Regulated's percentage climbed from 54.3% to 56.1% and the Diversified category's two companies showed a combined jump from 48.4% to 55.1%. While those totals are category aggregates, activity within each shows the increase was fairly narrowly focused. In the Regulated category only 13 of the 36 companies saw the ratio rise more than one percentage point. In the Mostly Regulated category it was only four of 12 companies and in the Diversified category only one of the two. In total, only 18 of the industry's 50 companies saw debt as a percent of total capitalization rise more than one percentage point.

The industry's aggregate total common equity rose by $9.4 billion in 2016, or 2.3%, from $396.9 billion to $406.2 billion. The rise in balance sheet equity was supported by aggregate net income of $27.1 billion and $11.9 billion in net stock issuance (proceeds from stock offerings less buybacks), although payment of $23.8 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 2016 for a third 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-.

Total long-term debt (current and non-current) has risen from $314.9

Short-term Debt 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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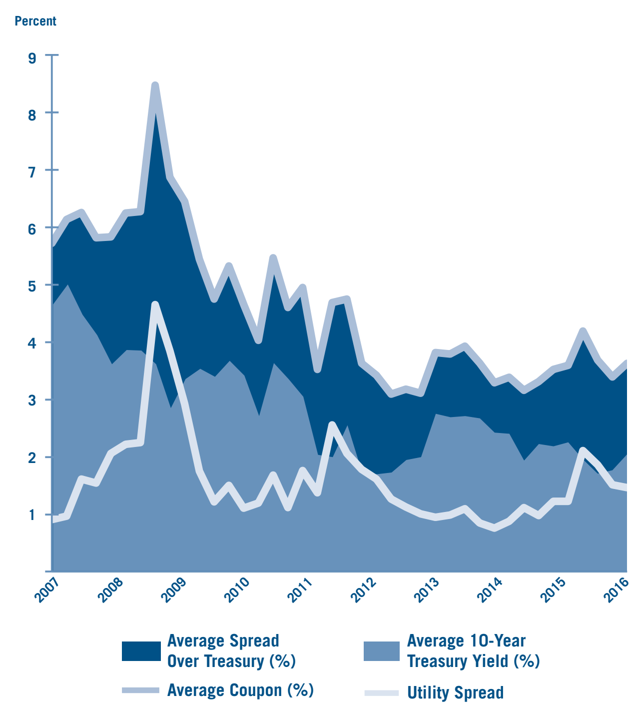
Source: S&P Global Market Intelligence and EEI Finance Department.

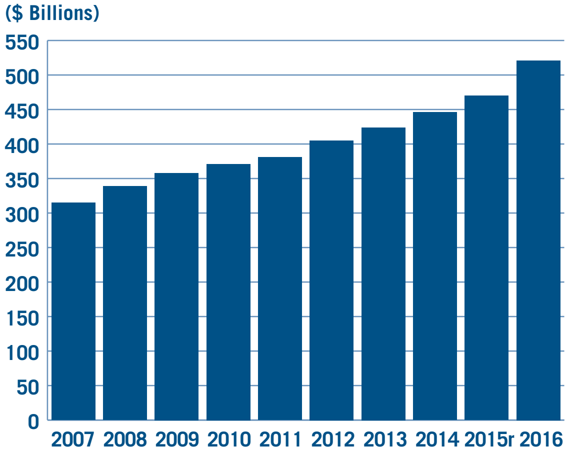
Utilities' Cost of Debt: 10-Year Treasury Yields and Bond Spreads (New Offerings)



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

Long-term Debt 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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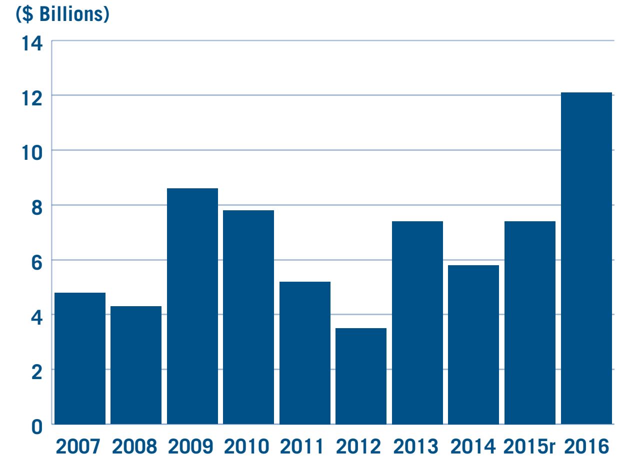
Source: S&P Global Market Intelligence and EEI Finance Department.

Proceeds from Issuance of Common Equity 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

billion at yearend 2007 to $521.3 billion at yearend 2016, a 66% increase, driven higher mostly by the need to finance consistently high levels of capital expenditures (capex). Industry capex climbed from a cyclical low of $41.1 billion in 2004 to a record high of $112.5 billion in 2016 and is expected to rise to $119.7 billion in 2016, based on EEI estimates.

Date	PP&E in Service, Net ($Mil)	% Change from 12/31/2012
12/31/2016	$969,838	28%
12/31/2015r	$898,171	18%
12/31/2014r	$839,351	10%
12/31/2013	$803,007	6%
12/31/2012	$760,105	

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

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 28% from yearend 2012 to yearend 2016.

A rising level of construction work-in-progress (CWIP) also reflects the industry's elevated capital spending. CWIP jumped from $62.4 billion at yearend 2012 to $74.3 billion at yearend 2016. 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 rose by $13.3 billion, or 9.2%, to $158.4 billion at yearend 2016 from a revised $145.1 billion at yearend 2015. Deferred taxes have risen nearly 30% since yearend 2012 as a result of persistently high capital spending and the impact of accelerated depreciation (see *Cash Flow Statement*).

Debt-to-Cap Ratio by Category 2016 vs. 2015r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Diversified		Total Industry	
	Number	%	Number	%	Number	%	Number	%
Lower	8	22.2%	3	25.0%	1	50.0%	12	24.0%
No Change*	15	41.7%	5	41.7%	0	0.0%	20	40.0%
Higher	13	36.1%	4	33.3%	1	50.0%	18	36.0%
Total	**36**	**100.0%**	**12**	**100.0%**	**2**	**100.0%**	**50**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2016 vs. December 31, 2015. Refer to page v for category descriptions.

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

Capitalization Structure by Category 2016 vs. 2015r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Total Industry			Regulated		
	2016	2015r	Change	2016	2015r	Change
Common Equity	406,225	396,856	9,369	278,429	267,833	10,596
Total Preferred Equity	13,901	8,492	5,409	6,583	4,589	1,994
Long-term Debt (current & non-current)*	521,270	467,919	53,351	350,426	317,147	33,279
Total Capitalization	941,396	873,268	68,128	635,438	589,569	45,869
Common Equity %	43.2%	45.4%	(2.3%)	43.8%	45.4%	(1.6%)
Preferred Equity %	1.5%	1.0%	0.5%	1.0%	0.8%	0.3%
Long-term Debt %	55.4%	53.6%	1.8%	55.1%	53.8%	1.4%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

	Mostly Regulated			Diversified		
	2016	2015r	Change	2016	2015r	Change
Common Equity	99,893	101,303	(1,410)	27,904	27,721	183
Total Preferred Equity	5,543	2,402	3,141	1,775	1,501	274
Long-term Debt (current & non-current)*	134,479	123,308	11,171	36,365	27,464	8,901
Total Capitalization	239,915	227,013	12,902	66,044	56,686	9,358
Common Equity %	41.6%	44.6%	(3.0%)	42.3%	48.9%	(6.7%)
Preferred Equity %	2.3%	1.1%	1.3%	2.7%	2.6%	0.0%
Long-term Debt %	56.1%	54.3%	1.7%	55.1%	48.4%	6.6%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Refer to page v for category descriptions.

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)	12/31/2016	12/31/2015r	% Change	$ Change
PP&E in service, gross	1,379,716	1,290,264	6.9%	89,452
Accumulated depreciation	409,878	392,093	4.5%	17,785
PP&E in service, net	969,838	898,171	8.0%	71,668
Construction work in progress	74,326	73,077	1.7%	1,249
Net nuclear fuel	16,054	16,111	(0.4%)	(57)
Other property	1,755	1,950	(10.0%)	(195)
PP&E, net	1,061,974	989,309	7.3%	72,665
Cash & cash equivalents	12,323	18,389	(33.0%)	(6,066)
Accounts receivable	38,253	35,530	7.7%	2,723
Inventories	24,057	25,380	(5.2%)	(1,323)
Other current assets	43,705	38,008	15.0%	5,697
Total current assets	118,338	117,307	0.9%	1,031
Total investments	86,181	80,421	7.2%	5,760
Other assets	255,871	226,662	12.9%	29,209
Total Assets	**1,522,363**	**1,413,698**	**7.7%**	**108,665**
Common equity	406,225	396,856	2.4%	9,369
Preferred equity	851	54	1470.8%	797
Noncontrolling interests	13,050	8,438	54.6%	4,611
Total equity	420,126	405,349	3.6%	14,777
Short-term debt	34,141	28,697	19.0%	5,444
Current portion of long-term debt	28,226	25,418	11.0%	2,808
Short-term and current long-term debt	62,367	54,115	15.2%	8,252
Accounts payable	66,407	58,725	13.1%	7,682
Other current liabilities	36,009	34,842	3.3%	1,166
Current liabilities	164,783	147,683	11.6%	17,100
Deferred taxes	158,426	145,085	9.2%	13,342
Non-current portion of long-term debt	493,044	442,501	11.4%	50,543
Other liabilities	285,258	272,134	4.8%	13,123
Total liabilities	1,101,511	1,007,403	9.3%	94,108
Subsidiary preferred	553	686	(19.4%)	(133)
Other mezzanine	173	260	(33.3%)	(87)
Total mezzanine level	726	946	(23.3%)	(220)
Total Liabilities and Owner's Equity	**1,522,363**	**1,413,698**	**7.7%**	**108,665**

r = revised

Note: Balance items for all three periods have been adjusted due to M&A-related activity. Data for Empire District Electric Company and TECO Energy include only the first three quarters of 2016.

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 decreased by $3.3 billion, or 3.3%, to $98.3 billion in 2016 from $101.6 billion in 2015. This metric decreased for about half of the industry at the holding company level. As shown in the *Statement of Cash Flows*, a year-to-year decline of $5.0 billion in cash provided by Deferred Taxes and Investment Credits and a $5.5 billion drop in cash provided by Net Income were only partially offset by a $3.8 billion increase in cash from rising Depreciation and Amortization and a $4.2 billion increase from Other Operating Changes in Cash.

Although the cash provided by Deferred Taxes and Investment Credits was lower, at $8.9 billion in 2016 versus $13.8 billion in 2015, it remained at a historically high level for the ninth 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. On December 18, 2015, Congress passed the Protecting Americans from Tax Hikes (PATH) Act of 2015, which extended bonus deprecation for five additional years (it had expired at the end of 2014). The previous 50% level of bonus depreciation continues for property placed in service during 2015, 2016 or 2017, then phases down to 40% in 2018 and 30% in 2019. Bonus depreciation has been in place most of the time since September 11, 2001 at levels that have varied from 30% to 100%. Although potential comprehensive tax reform was in its early stages at year end, it should be noted that both the Trump and House GOP Blueprint tax reform proposals included components of 100% expensing.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

$ Millions	12 Months Ended		
	12/31/2016	12/31/2015r	% Change
Net Income	$27,112	$32,663	(16.9%)
Depreciation and Amortization	49,166	45,342	8.4%
Deferred Taxes and Investment Credits	8,879	13,829	(35.8%)
Operating Changes in AFUDC	(1,409)	(1,275)	10.5%
Change in Working Capital	3,015	3,688	(18.3%)
Other Operating Changes in Cash	11,581	7,425	56.0%
Net Cash Provided by Operating Activities	**98,320**	**101,643**	**(3.3%)**
Capital Expenditures	(112,536)	(103,990)	8.2%
Asset Sales	15,422	15,226	1.3%
Asset Purchases	(43,606)	(18,076)	141.2%
Net Non-Operating Asset Sales and Purchases	(28,184)	(2,849)	889.1%
Change in Nuclear Decommissioning Trust	(414)	(400)	3.4%
Investing Changes in AFUDC	114	101	12.2%
Other Investing Changes in Cash	(4,265)	3,353	NM
Net Cash Used in Investing Activities	**(145,285)**	**(103,785)**	**40.0%**
Net Change in Short-term Debt	3,419	519	559.2%
Net Change in Long-term Debt	44,373	24,138	83.8%
Proceeds from Issuance of Preferred Equity	1,157	68	NM
Preferred Share Repurchases	(494)	(472)	4.6%
Net Change in Prefered Issues	663	(404)	NM
Proceeds from Issuance of Common Equity	12,123	7,381	64.2%
Common Share Repurchases	(267)	(1,947)	(86.3%)
Net Change in Common Issues	11,855	5,434	118.2%
Dividends Paid to Common Shareholders	(23,828)	(22,478)	6.0%
Dividends Paid to Preferred Shareholders	(62)	(105)	(40.9%)
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(23,891)	(22,583)	5.8%
Other Financing Changes in Cash	4,062	(85)	NM
Net Cash (Used in) Provided by Financing Activities	**40,481**	**7,020**	**476.7%**
Other Changes in Cash	443	1,419	(68.8%)
Net increase (decrease) in cash and cash equivalents	$(6,042)	$6,296	NM
Cash and cash equivalents at beginning of period	$18,365	$12,093	51.9%
Cash and cash equivalents at end of period	$12,323	$18,389	(33.0%)

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 rose by $41.5 billion, or 40.0%, to $145.3 billion in 2016 from $103.8 billion in 2015. The increase was caused primarily by a $25.5 billion, or 141.2%, surge in Asset Purchases, which increased from $18.1 billion in

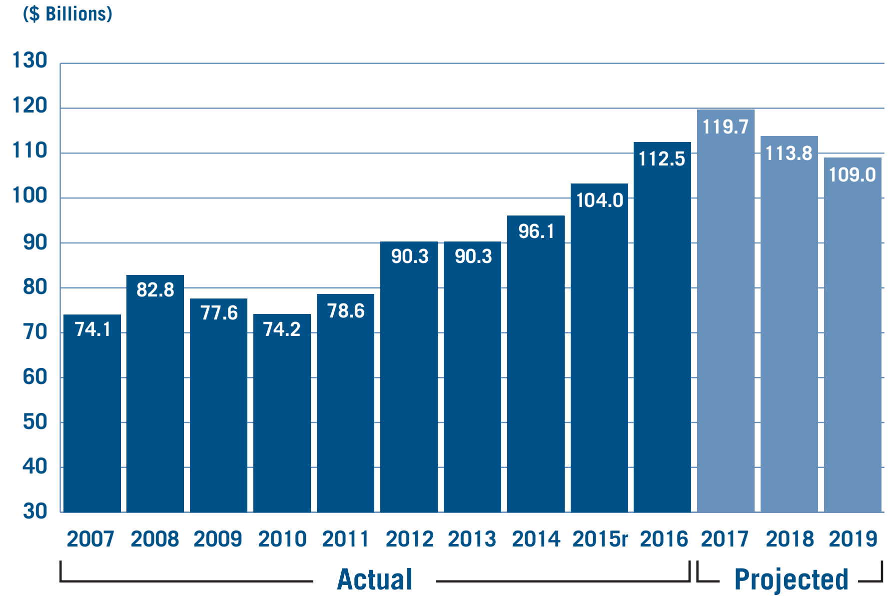
2015 to $43.6 billion in 2016. The surge was driven by just a handful of companies; asset purchases increased by about $9.0 billion at Southern Company, $6.9 billion at Exelon, $4.6 billion at Duke and $3.7 billion at Dominion as all were active in the M&A space (*please see Mergers & Acquisitions section for more details*).

The industry experienced an 8.2% increase in Capital Expenditures, which rose from $104.0 billion in 2015 to $112.5 billion in 2016 for a fifth consecutive annual 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 $112.5 billion spent on capex in 2016 is 180% 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.

EEI currently projects industry capex at $119.7 billion in 2017, $113.8 billion in 2018 and $109.0 billion in 2019. The 2017 projection, if realized, will be another record high for the industry, although a year's actual total has typically been

Capital Expenditures 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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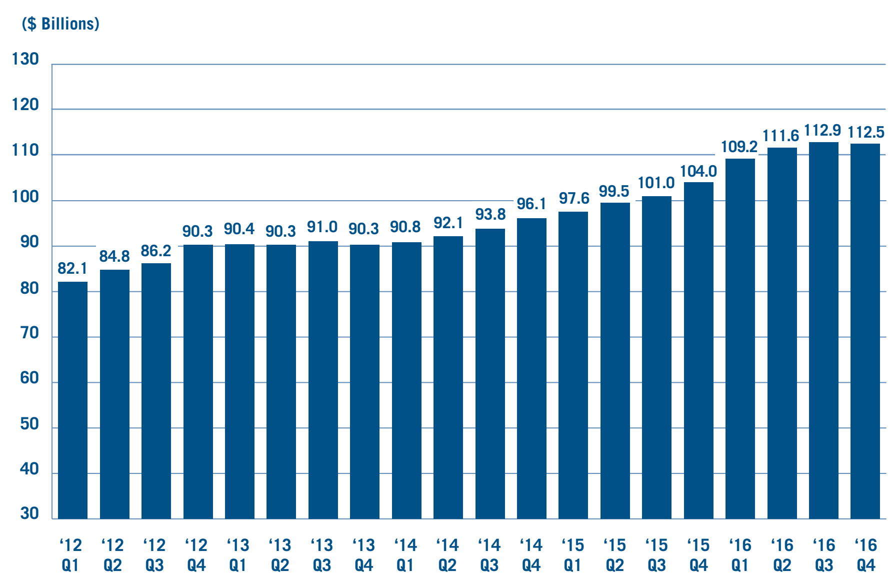
Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Spending—Trailing 12 Months

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

slightly lower than the amount projected early in the year. In contrast, the projections for two years and three years ahead have usually been somewhat understated. EEI will update the industry's capex projection by business function (transmission, distribution, generation, natural gas-related and environment) during the summer of 2017.

Net Cash Provided by Financing Activities

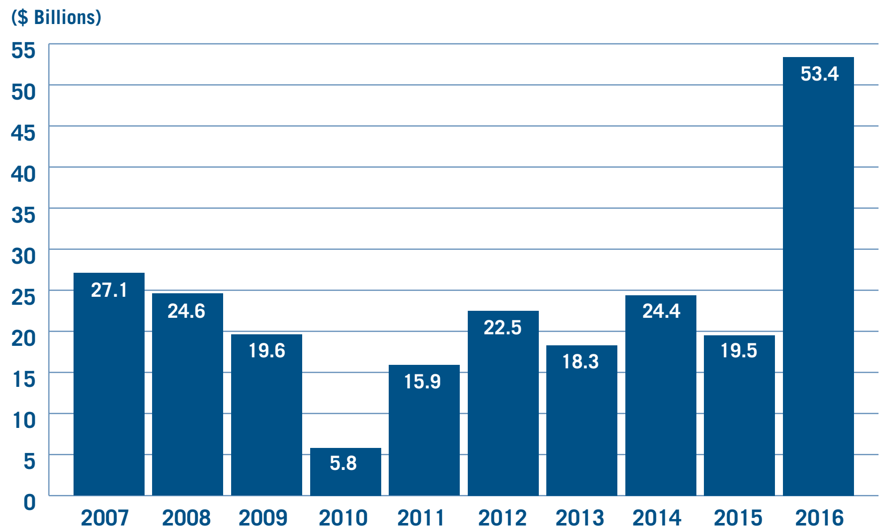
Net Cash Provided by Financing Activities increased by $33.5 billion, or nearly 500%, to $40.5 billion in 2016 from $7.0 billion in 2015. The primary reason was a $20.2 billion increase in the Net Change in Long-term Debt as the group of companies that were active asset purchasers in 2016 issued debt 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, as noted on the *Net Change in Long-term Debt* graph, which is based on data from the industry's consolidated balance sheet.

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 $555.4 billion (including securitized debt) at December 31, 2016.

Proceeds from Issuance of Common Equity rose 64.2%, to

Net Change in Long-term Debt 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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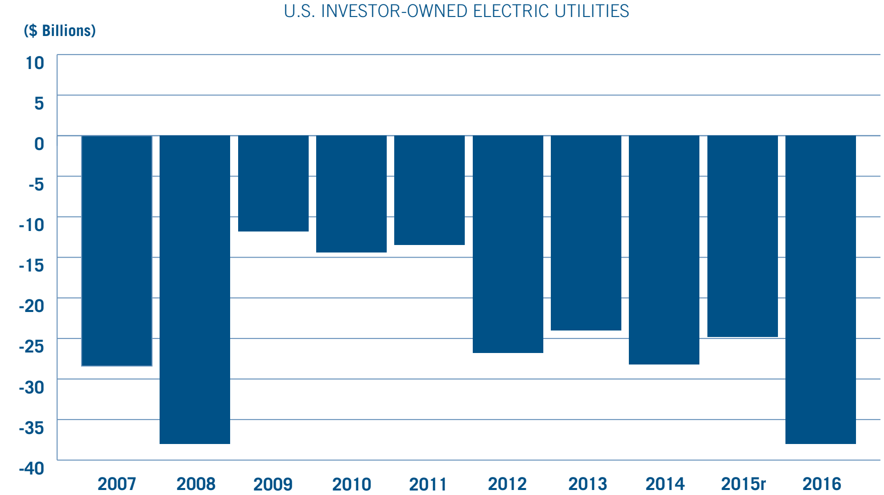
Note: Based on data from industry's consolidated balance sheet.

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

Free Cash Flow (FCF) 2007–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2007	2008	2009	2010	2011	2012	2013	2014	2015r	2016
Net Cash Provided by Operating Activities	61.1	61.3	82.9	77.7	84.4	84.0	87.1	89.0	101.6	98.3
Capital Expenditures	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)
Dividends Paid to Common Shareholders	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)
Free Cash Flow	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.8)**	**(24.0)**	**(28.2)**	**(24.8)**	**(38.0)**

r = revised

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

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

$12.1 billion in 2016 from $7.4 billion in 2015. The industry's strong stock market performance over the last decade, in addition to a widespread desire to strengthen debt-to-capitalization ratios, led to relatively higher stock issuances over the period.

Free Cash Flow Deficit Continues in 2016

Free cash flow was negative $38.0 billion in 2016 compared to negative $24.8 billion in 2015 and negative $28.2 billion in 2014. The change in 2016 related to the $3.3 billion decrease in Net Cash Provided by Operating Activities paired with the $8.5 billion increase in Capital Expenditures. 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).

Total aggregate industry-wide cash Dividends Paid to Common Shareholders rose $1.4 billion, or 6.0%, in 2016 from 2015's level. From 2003 through 2016, total industry-wide cash dividends grew by 93.5%, to $23.8 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.

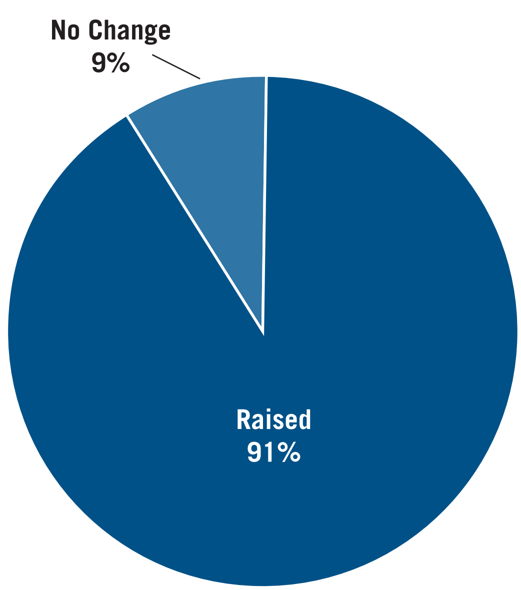
Dividends

The investor-owned electric utility industry extended its long-term trend of widespread dividend increases during 2016. A total of 40 companies increased or reinstated their dividend in 2016; this was the highest number since 43 did so in 2007. During 2016, twenty companies increased their dividend in Q1, seven in Q2, four in Q3 and nine in Q4. This follows the usual trend of the first quarter being the most active for dividend changes.

The percentage of companies that raised or reinstated their dividend in 2016 was 91%, up from 85% in 2015, 79% in 2014, 74% in 2013, 73% in 2012, 58% in 2011 and 60% in 2010. The 2016 result is the high-

2016 Dividend Patterns

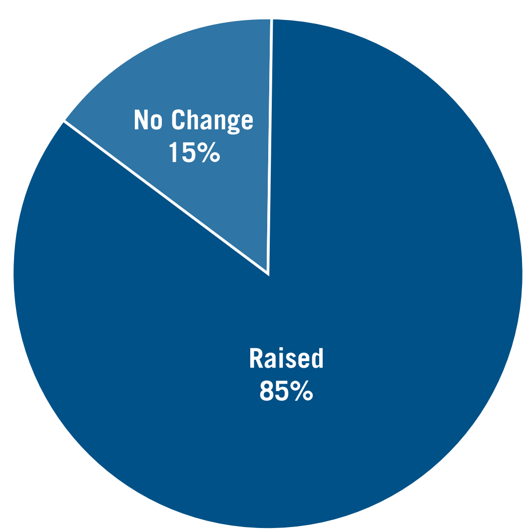
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2015 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

est on record, based on data going back to 1988. In 2003, only 27 of the 65 companies (42%) increased their dividend. The 15% dividend tax rate has supported the high number of increases in recent years.

At December 31, 2016, all 44 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.

2016 Increases Average 5.6%

The average dividend increase per company during 2016 was 5.6%, with a range of 0.7% to 13.0% and a median increase of 5.1%. Coincidentally, three companies tied for the largest annual percentage increase at 13.0%; Next Era Energy raised its dividend in Q1, Edison International in Q4 and DTE Energy reached 13.0% after two increases, in Q2 and Q4.

Dividend Patterns 1993–2016

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%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average of the Increased Dividend Actions ***	7.4%	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%	5.7%	5.8%	5.6%
Average of the Declining Dividend Actions ***	NA	(45.7%)	(46.4%)	NA	(100.0%)	NA	(41.0%)	(34.5%)	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, based in Juno Beach, Florida, raised its quarterly dividend from $0.77 to $0.87 per share in the first quarter. The increase is consistent with the company's plan, announced in 2015, to target 12% to 14% annual growth in dividends per share (off a 2015 base) and a 65% payout ratio (relative to adjusted earnings per share) by 2018.

Edison International, headquartered in Rosemead, California, announced in Q4 an increase in its quarterly dividend from $0.48 to $0.5425 per share, marking a third straight year of a $0.25 per share annual increase. The company also said it would like to increase its payout ratio (within a range of 45% to 55% of earnings of Southern California Edison).

DTE Energy, base in Detroit, announced a $0.04 per share increase in Q2 and $0.055 per share in Q4; together these produced an aggregate 13.0% increase. The company said it is targeting an annual dividend increase of approximately 7% through 2019 — higher than the 5.6% average dividend increase over the past five years — in order to bring its dividend payout ratio in line with industry peers.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/16

Sector	Payout Ratio (%)
EEI Index Companies*	**61.5%**
Energy	392.4%
Utilities	61.1%
Consumer Staples	54.9%
Materials	42.0%
Industrial	39.1%
Technology	32.7%
Consumer Discretionary	30.9%
Financial	28.8%
Health Care	27.2%

* 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 2016E dividends and earnings per share (estimates as of 12/31/2016).

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 61.5% for the year ended December 31, 2016, remaining among the highest of all U.S. business sectors. The broader Utilities sector (consisting of electric, gas and water utilities) was slightly lower, at 61.1%. The industry's payout ratio was 62.9% when measured as an un-weighted average of individual company ratios; 61.5% 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 2016, the annual payout ratio ranged from 60.4% to 69.6%, with the highest result in 2009 due to the weak economy and the weather's negative impact on earnings. 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, 2016, higher than that of all other business sectors except the broader Utilities sector's 3.8%. The industry's yield was 3.4% at September 30, 3.2% at June 30 and 3.4% at March 31. This follows yields of 3.8% at year-end 2015, 3.3% at year-end 2014, 4.0% at year-end 2013, 4.3% at year-end 2012, 4.1% at year-end 2011, 4.5% at year-ends 2010 and 2009, and 4.9% at year-end 2008.

We calculate the industry's aggregate dividend yield using an un-weighted average of the 44 publicly traded EEI Index companies' yields. 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 decline in yield over the last year is due to the rise in utility stock prices. The EEI Index gained 17.4% in 2016, outperforming the broader market indices. This follows a negative 3.9% return in 2015 and positive returns of 28.9%, 13.0%, 2.1%, 20.0%, 7.0% and 10.7% in 2014, 2013, 2012, 2011, 2010 and 2009, respectively. The EEI Index produced a positive total return in 12 of the last 14 years.

Sector Comparison, Dividend Yield
As of December 31, 2016

Sector	Dividend Yield (%)
EEI Index Companies	**3.4%**
Utilities	3.8%
Consumer Staples	2.8%
Energy	2.3%
Industrial	2.3%
Materials	2.2%
Financial	2.1%
Health Care	1.9%
Technology	1.9%
Consumer Discretionary	1.6%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2016); S&P sector yields based on 2016E cash dividends (estimates as of 12/31/2016).

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 the *Category Comparison, Dividend Yield* table, the Regulated and Mostly Regulated categories both had dividend yields of 3.4% at yearend 2016, while the Diversified category had a 3.7% yield. Note that Diversified category metrics have become less meaningful indicators of broad industry trends in recent years; category membership fell to just two publicly traded companies in 2016 as industry business models have migrated back to a Regulated emphasis. The yields for all three categories are below their levels at December 31, 2015, when the Regulated, Mostly Regulated and Diversified yields were 3.7%, 3.8% and 4.2%, respectively.

The Regulated category had a dividend payout ratio of 61.1% in 2016, compared to 68.0% and 64.6% for the Mostly Regulated and Diversified categories, respectively (see *Category Comparison, Dividend Payout Ratio* table). The Regulated category produced the highest annual payout ratio in 2015, 2011 and 2010 and each year from 2003 through 2008. It was exceeded by the Mostly Regulated group in 2009 and from 2012 through 2014. It's likely that the weaker earnings from

Category Comparison, Dividend Payout Ratio

Category[1]	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
EEI Index	**62.1**	**66.8**	**69.6**	**62.0**	**62.8**	**64.2**	**61.5**	**60.4**	**67.0**	**62.9**
Regulated	65.0	71.2	68.2	64.1	63.4	62.1	60.5	59.4	68.7	61.1
Mostly Regulated	63.5	66.7	72.2	60.7	63.1	69.7	64.7	63.8	62.6	68.0
Diversified	45.5	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.

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, 2016

Category[1]	Dividend Yield
EEI Index	**3.4%**
Regulated	3.4%
Mostly Regulated	3.4%
Diversified	3.7%

[1] Refer to page v for category descriptions.

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

the competitive power business contributed to the higher payout ratio among Mostly Regulated companies over the last five years.

Share Repurchases Remain Low

Ten of the industry's publicly traded companies repurchased an aggregate $267 million of common shares during 2016 as an alternate way of returning cash to shareholders. This compares to 12 companies and $1.9 billion in 2015, 12 companies and $668 million in 2014, 10 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 that were 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 Summary

As of December 31, 2016

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	$2.08	61.6%	3.2%	Raised	$2.08	$2.02	2016 Q1
Alliant Energy Corporation	LNT	R	$1.18	60.2%	3.1%	Raised	$1.18	$1.10	2016 Q1
Ameren Corporation	AEE	R	$1.76	63.3%	3.4%	Raised	$1.76	$1.70	2016 Q4
American Electric Power Company, Inc.	AEP	R	$2.36	41.3%	3.7%	Raised	$2.36	$2.24	2016 Q4
AVANGRID, Inc.	AGR	MR	$1.73	94.8%	4.6%	Raised	$1.73	$1.69	1996 Q1
Avista Corporation	AVA	R	$1.37	67.3%	3.4%	Raised	$1.37	$1.32	2016 Q1
Black Hills Corporation	BKH	R	$1.68	42.1%	2.7%	Raised	$1.68	$1.62	2016 Q1
CenterPoint Energy, Inc.	CNP	MR	$1.03	55.0%	4.2%	Raised	$1.03	$0.99	2016 Q1
CMS Energy Corporation	CMS	R	$1.24	59.6%	3.0%	Raised	$1.24	$1.16	2016 Q1
Consolidated Edison, Inc.	ED	R	$2.68	68.4%	3.6%	Raised	$2.68	$2.60	2016 Q1
Dominion Resources, Inc.	D	MR	$2.80	80.2%	3.7%	Raised	$2.80	$2.59	2016 Q1
DTE Energy Company	DTE	R	$3.30	60.1%	3.3%	Raised	$3.30	$3.08	2016 Q4
Duke Energy Corporation	DUK	R	$3.42	65.7%	4.4%	Raised	$3.42	$3.30	2016 Q3
Edison International	EIX	R	$2.17	60.8%	3.0%	Raised	$2.17	$1.92	2016 Q4
El Paso Electric Company	EE	R	$1.24	54.4%	2.7%	Raised	$1.24	$1.18	2016 Q2
Empire District Electric Company	EDE	R	$1.04	66.1%	3.1%	Raised	$1.04	$1.02	2014 Q4
Entergy Corporation	ETR	R	$3.48	37.1%	4.7%	Raised	$3.48	$3.40	2016 Q4
Eversource Energy	ES	R	$1.78	62.6%	3.2%	Raised	$1.78	$1.67	2016 Q1
Exelon Corporation	EXC	D	$1.27	57.6%	3.6%	Raised	$1.27	$1.24	2016 Q2
FirstEnergy Corp.	FE	MR	$1.44	50.4%	4.6%	Lowered	$1.44	$2.20	2014 Q1
Great Plains Energy Inc.	GXP	R	$1.10	75.8%	4.0%	Raised	$1.10	$1.05	2016 Q4
Hawaiian Electric Industries, Inc.	HE	D	$1.24	71.6%	3.7%	Raised	$1.24	$1.22	1998 Q1
IDACORP, Inc.	IDA	R	$2.20	53.4%	2.7%	Raised	$2.20	$2.04	2016 Q3
MDU Resources Group, Inc.	MDU	MR	$0.77	81.3%	2.7%	Raised	$0.77	$0.75	2016 Q4
MGE Energy, Inc.	MGEE	MR	$1.23	57.8%	1.9%	Raised	$1.23	$1.18	2016 Q3
NextEra Energy, Inc.	NEE	MR	$3.48	66.7%	2.9%	Raised	$3.48	$3.08	2016 Q1
NiSource Inc.	NI	R	$0.66	69.3%	3.0%	Raised	$0.66	$0.62	2016 Q2
NorthWestern Corporation	NWE	R	$2.00	58.7%	3.5%	Raised	$2.00	$1.92	2016 Q1
OGE Energy Corp.	OGE	R	$1.21	72.7%	3.6%	Raised	$1.21	$1.10	2016 Q3
Otter Tail Corporation	OTTR	R	$1.25	80.3%	3.1%	Raised	$1.25	$1.23	2016 Q1
PG&E Corporation	PCG	R	$1.96	61.3%	3.2%	Raised	$1.96	$1.82	2016 Q2
Pinnacle West Capital Corporation	PNW	R	$2.62	61.0%	3.4%	Raised	$2.62	$2.50	2016 Q4
PNM Resources, Inc.	PNM	R	$0.97	35.2%	2.8%	Raised	$0.97	$0.88	2016 Q4
Portland General Electric Company	POR	R	$1.28	60.1%	3.0%	Raised	$1.28	$1.20	2016 Q2
PPL Corporation	PPL	R	$1.52	55.9%	4.5%	Raised	$1.52	$1.51	2016 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.64	62.5%	3.7%	Raised	$1.64	$1.56	2016 Q1
SCANA Corporation	SCG	MR	$2.30	57.1%	3.1%	Raised	$2.30	$2.18	2016 Q1
Sempra Energy	SRE	MR	$3.02	80.2%	3.0%	Raised	$3.02	$2.80	2016 Q1
Southern Company	SO	R	$2.24	67.1%	4.6%	Raised	$2.24	$2.17	2016 Q2
Unitil Corporation	UTL	R	$1.42	76.3%	3.1%	Raised	$1.42	$1.40	2016 Q1

Dividend Summary (cont.)
As of December 31, 2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
Vectren Corporation	VVC	R	$1.68	64.7%	3.2%	Raised	$1.68	$1.60	2016 Q4
Westar Energy, Inc.	WR	R	$1.52	59.2%	2.7%	Raised	$1.52	$1.44	2016 Q1
WEC Energy Group, Inc.	WEC	R	$2.08	71.0%	3.5%	Raised	$2.08	$1.98	2016 Q4
Xcel Energy Inc.	XEL	R	$1.36	61.6%	3.3%	Raised	$1.36	$1.28	2016 Q1
Industry Average				**62.9%**	**3.4%**				

NOTES

Business Segmentation: Assets as of 12/31/2015

Categories:

R = Regulated: greater than 80% of total assets are regulated.

MR = Mostly Regulated: 50 to 80% of total assets are regulated.

D = Diversified: less than 50% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2016.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2016 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2016. 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 12/31/2016 divided by stock price at market close on 12/31/2016.

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 70 new rate cases in 2016, a number consistent with the long-term trend of rising rate case activity since 2000. Previously, in the industry's period of restructuring, electric utilities typically filed fewer than five new cases per quarter. The average awarded ROE in 2016 was 9.75%, the lowest annual average in our nearly 30 years of historical data and at the low end of the long-term decline in approved ROEs over the entire period. The average requested ROE in 2016 was 10.48%; while not a record low, this was among the lowest levels in our dataset and has declined along with the long-term decline in approved ROEs. Declining interest rates since the early 1980s account for much of the long-term trend in both requested and awarded ROEs. Average regulatory lag in 2016 was 8.8 months, close to the approximate 10-month average over the history of our dataset. Regulatory lag has shown only temporary fluctuations away from its average and will likely continue to remain relatively stable unless state commissions accelerate the speed with which cases are decided.

Filed Cases in 2016

Broadly speaking, the primary reason for rate case filings is the need to recover capital expenditures (capex). Utilities' desire to establish rate mechanisms and to recover operation and maintenance expenses are often the second and third most common reasons for rate case filings. All of these were evident in 2016. Requests for relief from the impact of only very slowly growing (or even declining) sales was the fourth most-cited reason for filings. Successful implementation of energy efficiency programs, slow economic growth in recent years and the de-industrialization of the U.S. economy over recent decades are all likely reasons for the current lack of demand growth facing most utilities. Utilities' attempts to increase the customer charge and adjust the allowed ROE also figured prominently as reasons for filings in 2016.

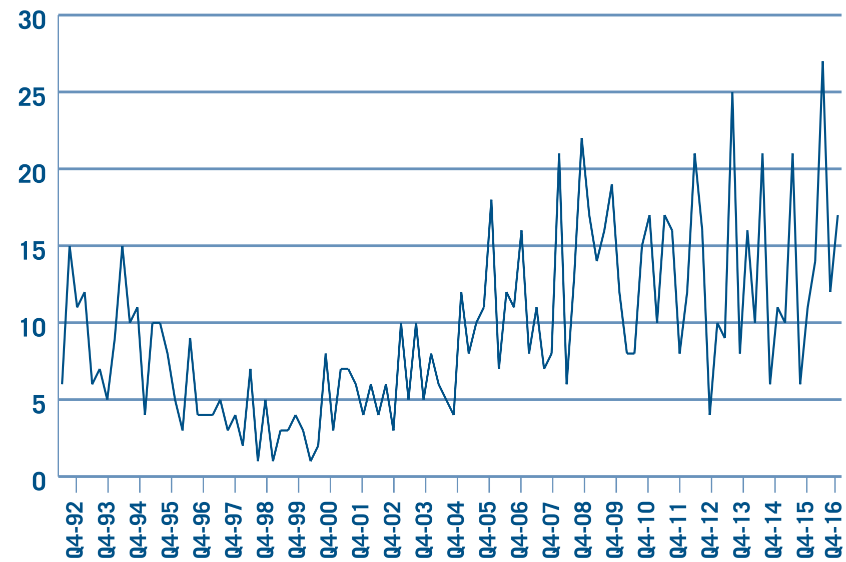
Capital Expenditures

Southwestern Public Service in Texas filed in part for rate recognition of the Texas portion of the company's more than $1 billion in capital investment since June 30, 2014, the end of the test period for its last rate case. Investments included replacements, upgrades and expansions across the company's generation, distribution and transmission systems in order to improve reliability and meet North American Electric Reliability Corporation and environmental requirements. Capital expenditures in 2015 were $590 million and the company hopes to recover planned expenditures that range from $450 million to $790 million annually between 2016 and 2020. Those totals do not include expenditures resulting from the Environmental Protection Agency's Regional Haze Rule or the Clean Power Plan.

Atlantic City Electric in New Jersey filed in part because it believes rates do not provide sufficient revenue to reflect its increased investment in rate base. The company has invested $716 million since 2011 to improve its distribution system, a level it expects to maintain over the next several years. Further, the company is seeking approval of its "Power Ahead" program, which it describes as "a comprehensive plan to advance the modernization of the electric grid through energy efficiency, in-

Number of Rate Cases Filed 1992–2016

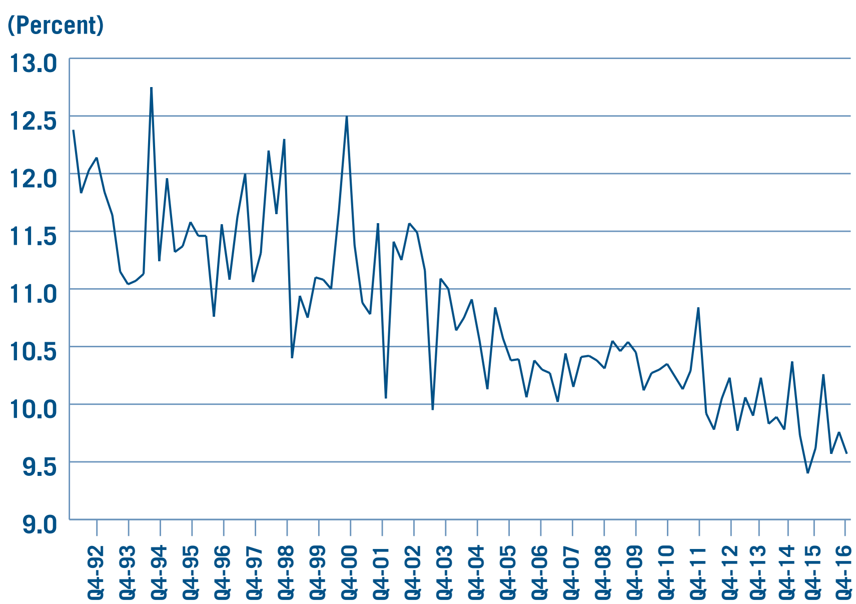
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

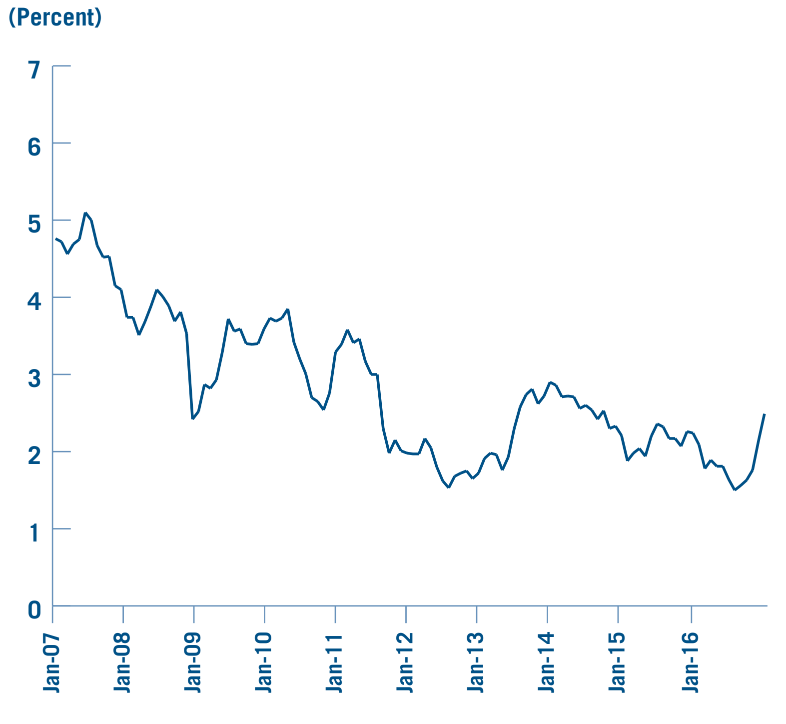
Average Awarded ROE 1992-2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

10-Year Treasury Yield
1/1/07 through 12/31/16



Source: U.S. Federal Reserve.

creased distributed generation, and resiliency, all geared toward improving the distribution system's ability to withstand major storm events." This effort responds to a 2015 commission order encouraging utilities to find ways to harden New Jersey's infrastructure against damage from major storms. The company expects to spend $176 million for the program over the next five years.

Southern California Edison filed in Q3 to recover for a range of capital investments that included replacement of aging equipment, capacity additions in response to customer and load growth, safety and reliability improvements, and enhancement of its system's ability to manage rising amounts of distributed energy resources. The company proposes to spend $2.1 billion in grid modernization between 2018 and 2020, including updating automation systems for the worst-performing distribution circuits, providing communications equipment for these upgrades, and employing analytic tools to advance system planning and grid operations.

Residential Customer and Demand Charges

Avista filed in Washington state in part to increase its residential customer charge from $8.50 to $9.50. KCP&L subsidiaries filed to increase residential customer charges to $14.50 from $10.43 for Missouri Public Service and from $9.54 for Saint Joseph Light & Power. Atlantic City Electric filed in New Jersey in part to raise its residential customer charge from $4 to $6. Delmarva Power in Maryland filed in part to increase the residential customer charge from $7.94 per month to $12 per month. Wisconsin Power and Light filed to increase the residential customer charge from $7.67 per month to $12 per month in 2017 and then to $18 per month in 2018.

In Arkansas, Oklahoma Gas and Electric filed in part to implement a three-component rate for residential and general service customers. [The components of a three-component rate are a customer charge, a demand charge and a usage charge. Most electric rates are currently two-component rates — a customer charge and a usage charge.] The filing would increase the customer charge component of the residential rate from $7.94 to $11.80 and add a demand charge component of $1 per kilowatt. For general service customers, the company proposes to raise the customer charge from $21.75 to $28 and add a demand charge of $1 per kilowatt.

Utilities generally seek to increase the customer charge (a fixed component of a customer's bill) because rate structures typically force recovery of fixed costs through variable, usage-related rates. Customers who are able to dramatically lower usage can avoid paying their share of a utility's fixed costs, shifting the burden to other customers who lack the same ability. A utility's less-affluent customers often have limited control over their usage.

Hawaiian Electric

Among the companies filing for capex recovery in 2016 was Hawaiian Electric, which sought to recover investment in new biofuel and conventional fuel generation. The company said it has increased its wind generation and made "substantial investments to maintain and improve the efficiency, reliability, and resiliency of its systems and grid. This includes new infrastructure and replacement of underground cables and thousands of poles and transformers, as well as implementation of advanced cybersecurity measures."

The filing also sought increased revenue to support and improve service quality and customer service, and to achieve state energy policy goals. The filing discussed the company's significant progress toward clean and renewable energy goals, including exceeding its 2015 renewable portfolio standards goal and lowering greenhouse gas emissions by more than 17% over the past five years.

A third goal of the filing was to make adjustments to the company's alternative regulatory framework (ARF), which consists of a revenue decoupling mechanism, a cost of service recovery mechanism (CSRM) and an earnings sharing mechanism. The CSRM allows for recovery between rate cases of rate base additions, increases in operating and maintenance expenses (subject to certain limitations), and certain depreciation and amortization expenses. The earnings sharing mechanism provides for no sharing if the company earns below its authorized ROE. The requested ARF adjustment asks that baseline plant additions be based on either: 1) the amount approved in the most recent rate case adjusted annually by the gross domestic product price index or 2) an average of the projected baseline plant additions specified in the most recent rate case test year and two subsequent years. The company also asked the commission to initiate a docket on performance-based regulation for all Hawaiian electric utilities.

Kansas City Power & Light Missouri

Kansas City Power & Light filed in Q3 in part to recover (using the company's fuel adjustment clause) forecasted levels of transmission costs associated with independent system operator organizations in which the company participates. The company says such recovery is critical to earning its allowed return. If the commission denies the proposal, the company will attempt to recover through a tracking mechanism costs that vary from projections. The company's previous case disallowed recovery through the fuel adjustment clause of the transmission costs associated with power the company sells into the Southwest Power Pool and repurchases for its native load. The company also hopes to recover infrastructure investments, increased transmission costs and the shortfall caused by lower usage per customer. The company filed to include in revenue requirement forecasted levels of expenses associated with property taxes, critical infrastructure protection and cybersecurity — all in an effort to achieve its allowed return.

Pepco (Maryland)

Pepco's filing in Maryland asked to amortize over ten years its investment in meters retired as a result of Pepco's implementation of an advanced metering infrastructure. The filing also sought to recover costs associated with a commission-ordered electric vehicle pilot program. The company said in its filing that, even if the commission grants the full requested increase, customer bills will still be 9% below the level of five years ago because market power prices have declined. The requested increase also includes two credits of $50 each to residential customers; these were part of the terms for Exelon's acquisition of Pepco.

Pepco (Washington, D.C.)

Pepco filed in D.C. in part to enhance its ability to provide an adequate return to its investors, to sustain reliability, and to support customer service, customer satisfaction and technical innovation. As in its Maryland filing, the D.C. filing reflects a one-time residential bill credit of $54.59 related to Pepco's acquisition by Exelon. Pepco D.C. is also establishing a $72.8 million fund to provide benefits to D.C. customers; the company will use $25.6 million of this to offset any distribution rate increases through March 2019. The full $25.6 million is allocated to this case filing, $4.4 million of which will be used to offset increases for customer in master-metered apartment buildings. Pepco also requests that an incremental $1 million offset to residential rate increases be deferred for recovery in a future year.

Rockland Electric New Jersey

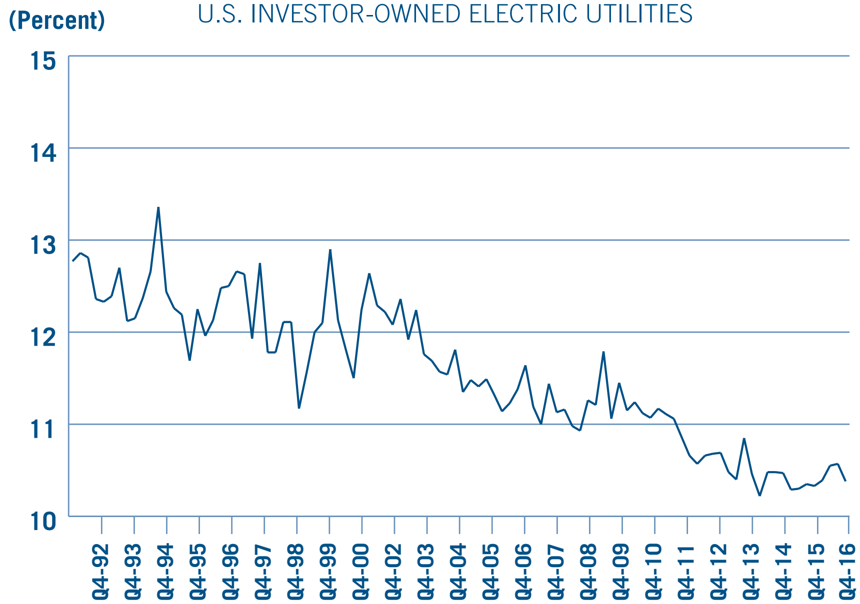
Rockland Electric filed in New Jersey in part to recover costs associated with installing an advanced metering infrastructure (AMI). Rockland's goals for the AMI are to increase operational efficiency and performance; enhance customer service (including outage detection and service restoration); enable customer engagement; and reduce greenhouse gas emissions. Rockland also envisions the AMI as helping it comply with the New Jersey Energy Master Plan, which includes goals such as driving down the costs of energy for all customers, rewarding energy efficiency and energy conservation, reducing peak demand, and capitalizing on emerging technologies for power production.

Union Electric Missouri

Union Electric in Missouri filed in part to recover $81.5 million resulting from reduced sales caused by the failing of an electric supply circuit owned by Noranda Aluminum, the company's largest customer, which filed for bankruptcy. The utility also filed to put into revenue requirements the forecasted transmission costs associated with its participation in the Midcontinent Independent System Operator (MISO), with variations recorded in a tracking mechanism.

Average Requested ROE 1992–2016

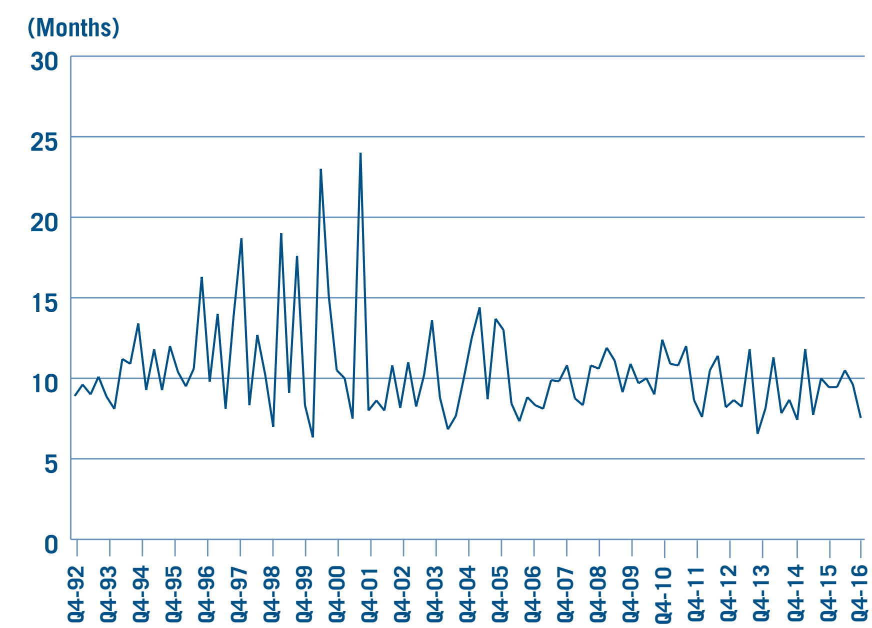
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Average Regulatory Lag 1992–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Alaska Electric Light and Power

Alaska Electric Light and Power's filing in Q3 requested a 13.8% ROE, more than three percentage points above the industry's average requested ROE for the quarter. The utility noted that the high request reflects the challenges of operating in Alaska, which it described as a highly concentrated and geographically isolated service territory with potential for extreme weather. The company also noted its high dependence on a single hydroelectric generating facility, the lack of economies of scale and absence of certain favorable regulatory mechanisms.

Decided Cases 2016

The table below summarizes residential customer charge activities in 2016:

Commission Rulings On Customer Charges: 2016

Company	State	Former Residential Customer Charge	Requested	Awarded
Avista	Washington	$8.50	$14	$8.50
Kentucky Utilities	Kentucky	$12	$15, to increase again to $18 at the beginning of 2017	$12
Northern Indiana Public Service	Indiana	$11	$20	$14
Empire District Electric	Missouri	$12.52	$14.47	$13
El Paso Electric	Texas	$5	$10 $15 for private solar customers	$6.90 $8.40 for customers taking advantage of time-of-use rate offer $15 requested for private solar customers was withdrawn as part of settlement
Atlantic City Electric	New Jersey	$4	$6	$4.44
Missouri Public Service	Missouri	$10.43	$14	$10.43
St. Joseph Light & Power	Missouri	$9.54	$14	$10.43
UNS Electric	Arizona	$10 Time of use: $11.50	$15	$15
Pepco	Maryland	$7.39	$12	$7.60
UNS Electric	Arizona	$10 $11.50 for time-of-use		$15 $12 for customers choosing time-of-use or three-part rates
Wisconsin Power and Light	Wisconsin	$7.67		$15

Residential Customer Charges

Southwestern Public Service in New Mexico had sought to increase customer charges for many classes of service (including the residential class) and to decrease customer charges for others (such as the small municipal and school classes). The company's approved settlement in Q3 modestly increased the customer charges for all classes; this resulted in a much smaller increase for those classes where an increase was sought.

Rate Mechanisms

In Q1, the Indiana Commission had approved a rider for Northern Indiana Public Service to recover certain infrastructure investments. However, intervenors in the case appealed it to the Indiana Court of Appeals. The court remanded the rider back to the commission, saying the plan for the recovery associated with the rider lacked the specificity needed to determine reasonableness. The company made a separate filing that the commission approved and then dismissed the original filing, all following separate procedural efforts before the commission that provided additional information the commission found useful.

Also in Q1, the Indiana Commission approved Indianapolis Power & Light's requested rider to recover non-fuel-related costs that vary from base-level costs associated with the company's participation in the regional transmission organization. The company must true up the rider annually. The company also requested similar treatment for net capacity costs, which the commission also approved finding that, if the company alters its generation mix, the capacity rider will help smooth cost volatility. The commission also approved a company-requested storm tracker rate mechanism and an off-system sales rider that shares shortages or overages equally between customers and shareholders.

In Q3, a settlement in Atlantic City Electric's case in New Jersey implements two economic development riders. One gives customers that construct, lease or purchase at least 8,000 square feet of new space a 20% discount on their monthly bill for five years. The other gives smaller commercial customers who lease or purchase new or vacant space of 2,500 square feet or more a 20% discount. Space must be vacant for at least three months for customers to qualify for the discount and they must hire at least one new full-time employee at the site.

Potomac Electric Power Maryland

In Potomac Electric Power's case in Maryland, the company requested a 10.6% ROE while the commission awarded a 9.55% ROE. The commission said, "We have stated in prior rate cases that we are not willing to rule that there can be only one correct method for calculating an ROE. Indeed, the complexity of this subject cannot be captured by a single mathematical formula. … In its three most recent rate cases, the Company consistently requested an ROE of 10.25% 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. … We have considered Pepco's status as a monopolistic provider of electric distribution service in an economically stable service territory. … We are also mindful of investor perception of utilities constituting low-risk investments. Thus we are once again presented with the question of what has changed since we last established a just and reasonable ROE for Pepco that would now justify a higher return. Our current reality is that interest rates have generally declined since 2008 and have since remained persistently low. Indeed, interest rates have remained at historic lows for nearly a decade and even fallen since the last rate case. … Accordingly, insofar as investors rely on current market data, the data do not support Pepco's proposed increase but, rather, favor a lower cost of capital than Pepco's current authorized ROE of 9.62%. Additionally, we consider Pepco's current state of financial health and note in particular its strong, secured bond rating, which indicates low risk. In this regard … we conclude that Pepco's situation has not changed in a manner that would justify an increase in ROE."

In this case, Pepco also attempted to recover investment in its Advance Metering Infrastructure (AMI). In 2010, the commission approved Pepco's proposed plan to deploy AMI and authorized the company to defer the costs. However, the commission ruled the company could only recover the deferred costs if a cost/benefit analysis and prudence review supported the recovery. In this case, Pepco identified operational costs of the AMI with a present value of $175.5 million and benefits with a present value of $349.6 million; the company proposed to collect the deferred program costs over 10 years. While parties to the case did not agree on the respective values, they did agree AMI was cost beneficial. The commission consequently approved recovery, but warned ". . . Pepco has asserted, and Staff largely agrees, that AMI will result in significant [operation and maintenance] and energy savings. It is imperative that these savings are noticeable and demonstrable to customers over the life of AMI." Further, the commission noted deferred costs include about $26 million in cost overruns related to capital costs for meters, communications infrastructure and information technology. The commission found a portion of these overruns imprudent and lowered revenue requirement by $3 million.

Pepco proposed to include in revenue requirement 50% of its annual supplemental executive retirement plan (SERP) expenses. The commission disallowed these expenses, saying "Although the Company may be correct in noting that the commission has disallowed 50% of SERP expenses in Pepco's two most recent cases, we find that Staff has astutely pointed out that there are some new circumstances to be considered. … after two neighboring jurisdictions recently disallowed 100% of SERP costs … the Company has not performed any analysis to support its continued claim that SERP benefits help the Company to attract and retain qualified executive level talent."

Pepco proposed to extend its Grid Resiliency Program with a surcharge of $31 million over two years. The commission rejected the proposal, saying "We have reserved concurrent cost recovery in the form of a surcharge to exceptional circumstances when we find that immediate improvement to reliability is needed. This is currently no longer the case for Pepco. Its own witness testified that these improvements were not necessary to meet Pepco's reliability targets for 2019."

Pepco proposed to increase the residential customer charge from $7.39 to $12. The commission said, "As with allocating costs between rate classes, determining the proper ratio between customer, volumetric and demand charges requires balancing many competing variables. It is important that customers who cause certain costs incur those costs, but the principle of gradualism applies here as well. Additionally, policy concerns must also guide the commission, such as energy conservation incentives and the effect of an increased surcharge on low income customers. With these principles in mind, we believe the record in this case supports a gradual increase in the customer charges." The commission approved in increase in the residential customer charge to $7.60, saying " … we place emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges. No matter how diligently customers might attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges. Additionally, lower customer charges provide more value to net metering customers."

UNS Electric Arizona

In UNS Electric's case in Arizona, the commission awarded the company a 9.5% return on equity (ROE). The majority of parties to the case supported the decision, however the Alliance for Solar Choice (TASC) advocated for an allowed ROE of 8.75%. In awarding the 9.5% ROE, the commission said "Although [the company's] financial metrics, such as its bond rating and capitalization, have improved since its last rate case … , interest rates are rising, and [the company] faces significant risks from challenging economic conditions in its service area, declining energy sales, and a current rate design that requires substantial modification in order to comply with traditional principles of cost causation. A Cost of Equity of 9.5% is not unreasonable in this case."

UNS proposed a capital structure with a 52.83% equity component; this was based on the company's actual capital structure at the end of the test year. The majority of parties in the case supported the UNS proposal, however TASC advocated for a 50% equity component. The commission accepted the company's proposal.

The company proposed a three-part rate for distributed generation (DG) customers (about 2% of the company's customers), an updated net metering tariff and increased customer charges. The company based the demand portion of the three-part rate on the highest usage in peak periods. The company also proposed paying customers who submitted DG applications after June 1, 2015, 5.84 cents per kilowatt-hour for excess energy sold back to the utility and to adjust this amount annually. The commission deferred ruling on rate design issues to a second phase of the case, which was expected to conclude in March of 2017. However, the commission said it agreed with the approach, rejecting the claims of some intervenors that different treatments for DG and non-DG customers were discriminatory, saying "sending correct price signals to customers, avoiding misaligned subsidies and incentivizing efficiencies and innovation are critical. … requiring the purchase of excess solar DG power whether it is actually needed and compensating excess solar at the retail rate no matter when excess power is received, or treating [kilowatthours] delivered during a system peak may not represent efficient use of system resources or an equitable long-term solution for all ratepayers." The commission also ruled, effective September 1, 2016, that new DG customers must pay a monthly charge of $1.58 to reflect the costs of a secondary meter. Possible additional charges will be considered in Phase 2 of the case.

The commission said it had concerns about the company using a single purchased power agreement as a basis for determining a market price for solar. Further, the commission rejected the June 1, 2015 date for grandfathering, saying it would not allow any date that preceded the date of the commission's order in phase two of the proceeding. The order implements a system benefits rider, to be charged to all customers, designed to collect funds for crediting DG customers for energy exports. The company says it intends to contest the charge and offer an alternative in phase two.

The commission approved the company's request to increase the $10 residential customer charge and the $11.50 residential time-of-use customer charge each to $15 and the $14.50 small general service customer charge and the $16.50 small general service time-of-use customer service charge each to $25. At the conclusion of phase 2 of the proceeding, customers choosing time-of-use or three-part rates will have a lower customer charge of $12. The order also requires the company to increase the customer charges for its larger customers and to consider demand charges for some larger customers who do not currently pay them.

The commission denied the company's request to raise the cap on its large fixed-cost recovery mechanism; it said the company had not met the burden of proving the change was warranted.

The company had proposed an economic development rate, saying shareholders would bear lost non-fuel revenues. The commission adopted the unopposed proposal, saying "If this program is successful, the Company and its ratepayers should benefit from adding high load factor, low-cost customers."

One of the commission's conditions for approving Fortis, Inc.'s purchase of UNS was that UNS implement a pilot tariff allowing large power service customers to select a wholesale generation service provider, limited to a total of ten megawatts of peak load. However in this proceeding the company opposed the proposed tariff. The commission ultimately agreed and did not adopt the proposal, saying "Because of UNSE's small number of large commercial and industrial end users, [this program] may not be appropriate for this utility. … a buy-through tariff may adversely impact [UNS's] other customers by increasing the cost of power. … We understand that the industrial users are frustrated with paying rates that provide subsidies to the Residential Class, but we are taking an incremental step to reducing inter-class subsidies in this case."

Emera Maine

In Emera Maine's case, the company filed for a 10.25% ROE and the commission allowed a 9% ROE, which incorporated a 50-basis-point penalty for management inefficiencies. Part of the reason for Emera's filing was to recognize in rates a customer billing information system that was initially expected to cost $17 million and be implemented by May 2014. The system ultimately cost $31 million and the company did not implement it until June 2015. The commission said the system also generated many billing errors. The commission expressed concern about customer service, saying the company failed to issue refunds to certain customers, and was unable to respond to commission requests for information on the refunds. The commission also expressed concern about transmission and distribution system reliability. In deciding on a 50-basis-point return on equity penalty, the commission apparently accepted the decision by the hearing examiners in the case, who said "there is strong Commission precedent for applying a cost of equity adjustment to penalize a utility for not operating efficiently. When the effect of the inefficient behavior has been difficult to specifically quantify, the Commission has used an adjustment to the allowed equity return as the best ratemaking remedy to protect ratepayers from the inefficiency [in accordance with state law]." The hearing examiners said, "because of the inadequacies identified and the prolonged inability of the company to resolve these issues, we find it proper to impose a management efficiency adjustment. … until management practices and efficiencies, particularly in the areas of customer service and with respect to the Company's system maintenance practices have improved and have provided real benefits to ratepayers." Further, the examiners said the company's call center performance "has substantially departed from regular and accepted practices and has resulted in inadequate service when considering the number of customers affected by the departure from accepted and reasonably achievable service standards." The examiners also said the company failed to regularly inspect roadsides and right-of-way transmission and distribution lines.

El Paso Electric New Mexico

In El Paso Electric's case in New Mexico, the commission authorized a 9.48% ROE based on its preferred constant-growth discounted cash flow analysis. This differed from the company's proposed 9.95% ROE. The commission eliminated three companies from El Paso's proposed proxy group because the companies were in merger proceedings; this accounted for the difference.

The commission disallowed from inclusion in rate base El Paso's proposed pension-liability-related accumulated deferred income taxes ($12.6 million), saying "Because EPE is not out of pocket any money with respect to its post-employment benefits liabilities, allowing EPE to include its ADIT in rate base would give EPE an undeserved windfall at the expense of ratepayers." The commission also disallowed $0.4 million of the company's proposed revenue requirement attributable to short-term incentive plan expenses. The commission adopted a three-year average of the expenses rather than the full amount as proposed by the company. The commission disallowed $0.1 million in revenue requirement associated with the company's long-term incentive plan and restricted stock and another $0.1 million associated with incentive payments related to a nuclear plant, saying the company did not provide sufficient evidence that these programs benefitted ratepayers. The commission also disallowed the company's benefit plan for "highly paid" employees, among other miscellaneous items.

The commission allocated the rate increase entirely to the residential customer class in an effort to move "the rates of each customer class closer to a relative return of 1.00." The commission rejected the company's request to increase the residential customer charge, saying such a rate design change "hurts low income and average volume users [and] … discourages conservation, which can ultimately, and unnecessarily, lead to the need for additional generation and higher rates."

Georgia Power

Georgia Power's case resulted in a settlement stipulating that none of the $3.3 billion in costs incurred through the end of 2015 for construction of nuclear facilities are to be disallowed for imprudence. The settlement revised the in-service capital cost forecast up from $4.418 billion to $5.68 billion. The settlement also stipulated that the costs between $3.3 billion and $5.68 billion are prudent, with the burden of proving imprudence falling on parties challenging such costs. The burden of proving prudency falls on the company for any costs above $5.68 billion. The company can earn a cash return on construction work-in-progress costs up to $4.418 billion and can accrue an allowance for funds used in construction of costs above that amount. The settlement decreased the return on equity for the project from 10.95%, the amount the commission approved in Georgia Power's most recent rate case, to 10%. If the project is not operational by the end of 2020, the ROE falls to 7%, until the project is operational. This rate settlement follows a settlement with the project contractor, Westinghouse, which in turn follows a $900 million federal lawsuit addressing cost overruns at the project. The settlement with Westinghouse limits the contractor's ability to seek further increases in the contract price.

Avista Washington

The Washington state commission rejected Avista's proposed rate increase, with one commissioner, Philip Jones, dissenting. The commission said the company did not meet the burden of proof that current rates are insufficient to meet its needs and that it should moderate capital expenditures and expenses. The commission directed staff to initiate a collaborative process with stakeholders "to more clearly define the scope and expected outcomes of, as well as a reasonable procedural schedule for, generic cost of service proceedings that will provide an opportunity to establish greater clarity and some degree of uniformity in cost of service studies going forward." The company responded that the outcome of the case will prevent it from recovering costs necessary for safe and reliable service and prevent it from earning its allowed return. Further, the company noted that the decision will "likely raise serious concerns from financial stakeholders and the rating agencies regarding the level of support from the Washington jurisdiction." The company intends to file a petition for reconsideration, and if that petition is rejected, may file an appeal with the Thurston County Superior Court.

Indianapolis Power & Light

In the course of Indianapolis Power & Light's rate case, the company experienced underground explosions that resulted in power outages. In deciding the case in Q1, the commission said it could support a 10% ROE, but lowered it to 9.85% to relate the commission's concern about the explosions and outages. The commission also instituted a collaborative process to address the company's asset management program, certain operating performance measures, and the company's commitment to infrastructure improvements. The commission also suggested that "additional written processes may be appropriate."

The commission determined that the company's prepaid pension asset "represents a component of working capital" and consequently should be in rate base. However, the commission said that laws mandating a minimum funding of the pension asset prevent those funds from being available for other uses by shareholders. Consequently, the commission would not award the company a return on the minimum pension funding. However, the commission found the additional discretionary prepaid pension asset was prudently incurred and therefore is eligible for inclusion in rate base.

New York State Electric & Gas and Rochester Gas & Electric

The New York commission approved joint proposals (JPs) for both New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RG&E). Both JPs incorporate a rate adjustment mechanism that will collect from or return to customers the costs associated with New York's Reforming the Energy Vision (REV) initiative that are not recovered elsewhere, along with a number of other miscellaneous costs. The REV is a state program that seeks to allow electric competition at the distribution level of the business (competition was already a part of the electric utilities' generation business) largely to take advantage of customer-owned generation. The JPs limit recovery through the rate adjustment mechanism to $19.3 million per year for NYSEG and $11.4 million per year for RG&E. The JPs also allow the companies to recover $262 million of deferred costs associated with Hurricane Irene, Superstorm Sandy and Tropical Storm Lee.

Florida Power & Light

Florida Power & Light's case in Q4 resulted in a settlement stipulating a three-step rate increase and allows the company to rate base up to 300 MW of solar generation each year from 2017-2020, with the possibility of retaining rights for any unused capacity under the program. The company must demonstrate solar facilities are cost effective, and the facilities are capped at $1,750/kW. The company can recover storm restoration costs on an interim basis 60 days from the filing of a cost recovery request, but can increase charges no more than $4 per 1000 kilowatt-hours of residential usage in the first year. The company can recover additional costs in future years. However, if storm restoration costs exceed $800 million in a year, the company can request an increase to the $4 cap.

Jersey Central Power & Light

Jersey Central Power & Light's case resulted in a settlement that is silent on many rate case parameters but allows the company to accelerate amortization and recovery of major storm expenses incurred in 2012 "to improve JCP&L's Funds from Operations to Debt credit metric." Further, the company must submit a report to the commission by June 30, 2017 containing a plan to improve its standalone credit rating by strengthening the company's Funds from Operations to Debt credit metric so that it qualifies for a Standard & Poor's BBB credit rating. The company cannot issue a dividend to its parent until it achieves a 45% equity capital structure, which the company must do by 2020.

Business Strategies

Business Segmentation

Revenue declined in 2016 for four of the industry's five primary business segments, rising only for Natural Gas Distribution. The industry's total 2016 revenue was $350.6 billion, down $2.9 billion, or 0.8%, from 2015's $353.5 billion. Regulated Electric revenue, at $253.2 billion, edged down only slightly, falling $209 million or 0.1%. Nationwide electric output increased for a fourth straight year, yet only by a minimal 0.2%. The year's main theme in terms of segmentation of the industry's business mix was a continued expansion into Natural Gas Distribution and Natural Gas Pipeline businesses, as several natural gas-related acquisitions closed during the year. The industry's regulated asset base expanded 8.3%, extending a multi-year trend and driving most of the year's $107.4 billion, or 7.6%, increase in total industry assets, although the industry's four largest business segments all grew assets in 2016. Regulated assets rose to a 79.3% share of total assets at yearend, up from 78.5% at the start of the year; the gas acquisitions, a record-high $112.5 billion of capital expenditures, and a generally constructive regulatory environment all supported the percentage increase. The Competitive Energy segment showed a decline in revenue (-11.4%) and an increase in assets (+3.8%).

2016 Revenue by Segment

Regulated Electric revenue was essentially flat in 2016, declining by $209 million, or 0.1%, to $253.2 billion from $253.5 billion in 2015. Despite the incremental decline, the segment's share of total industry revenue grew slightly, to 70.1% from 69.5% in 2015, remaining well above the 52.1% level of 2005.

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2016	2015r	Difference	% Change
Regulated Electric	253,248	253,458	(209)	(0.1%)
Competitive Energy	53,373	60,239	(6,866)	(11.4%)
Natural Gas Distribution	36,302	33,346	2,957	8.9%
Natural Gas Pipeline	3,945	4,488	(543)	(12.1%)
Natural Gas and Oil Exploration & Production	34	222	(187)	(84.6%)
Other	14,141	13,144	997	7.6%
Discontinued Operations	(2)	—		
Eliminations/Reconciling Items	(10,412)	(11,380)	969	(8.5%)
Total Revenues	**350,630**	**353,514**	**(2,884)**	**(0.8%)**

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)	12/31/2016	12/31/2015r	Difference	% Change
Regulated Electric	1,085,881	1,031,154	54,727	5.3%
Competitive Energy	196,143	188,959	7,184	3.8%
Natural Gas Distribution	171,552	130,085	41,468	31.9%
Natural Gas Pipeline	28,581	23,107	5,475	23.7%
Natural Gas and Oil Exploration & Production	1,022	1,527	(505)	(33.1%)
Other	101,390	104,308	(2,917)	(2.8%)
Discontinued Operations	211	191		
Eliminations/Reconciling Items	(62,418)	(64,365)	1,947	(3.0%)
Total Assets	**1,522,363**	**1,414,966**	**107,397**	**7.6%**

r = revised

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

Natural Gas Distribution revenue rose by $3.0 billion, or 8.9%, to $36.3 billion from $33.3 billion in 2015. This followed a 19.2% drop in 2015 and double-digit percentage increases during the three previous years (up 10.8% in 2014, 12.2% in 2013, and 15.6% in 2012). The growth in 2016 was due to the completion of four acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — increased by $2.7 billion, or 1.0%, to $289.6 billion. The year-to-year change for this metric has fluctuated up and down in recent years within a range of about 7%. Despite these year-to-year variations, revenue from regulated operations has steadily grown as a percentage of total industry revenue. Regulated revenue accounted for 80.2% of total industry revenue in 2016, 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 are added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2016 and 2015*.

2016 Assets by Segment

Regulated Electric assets decreased from 69.7% of total industry assets at December 31, 2015 to 68.5% at December 31, 2016, despite rising by $54.7 billion, or 5.3%, over the yearend 2015 level. Competitive Energy assets increased by $7.2 billion, or 3.8%, from the prior year. Natural Gas Distribution assets showed the highest percent growth, jumping $41.5 billion, or 31.9%. Natural Gas Pipeline assets also experienced significant growth of $5.5 billion, or 23.7%, although from a relatively small base of $23.1 billion. The asset total in the very small Natural Gas and Oil Exploration & Production category fell 33.1%, to $1.0 billion.

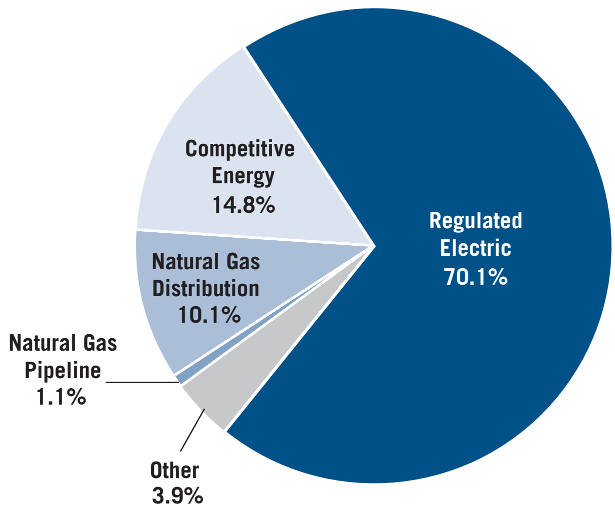
Total regulated assets (Regulated Electric plus Natural Gas Distribution) accounted for 79.3% of total industry assets at yearend 2016, up from 78.5% on December 31, 2015. This aggregate measure has grown steadily from 61.6% at yearend 2002, underscoring the industry's significant regulated rate base growth in recent years and the fact that several companies sold off non-core businesses during the period. During 2016, 60% 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, transmission and distribution of electricity

Revenue Breakdown 2016

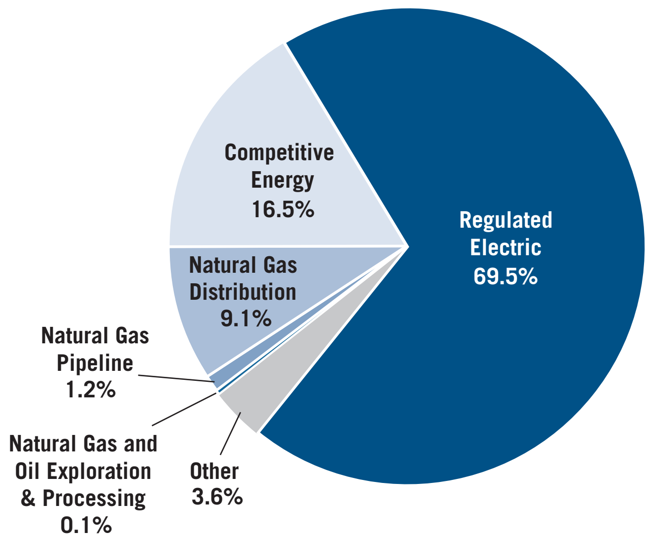
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2015r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

under state regulation for residential, commercial and industrial customers. A majority of companies experienced an increase in Regulated Electric revenue in 2016 despite the industry's overall $209 million, or 0.1%, decrease. Twenty-eight of 50 companies (56%) had higher revenues for this segment. Four companies (8%) reported a double-digit percentage increase.

2016 was the second straight year in which Regulated Electric revenue decreased slightly. It fell 2.6% in 2015 after showing solid gains of 4.9% in 2014 and 4.7% in 2013, although it also declined in the two preceding years, falling 2.8% in 2012 and 0.6% in 2011. U.S. electric output increased by 0.2% in 2016, the fourth consecutive year with only a marginal increase (output grew 0.1% in 2015, 0.5% in 2014 and 0.1% in 2013). Output has been largely flat over the past decade, although with some year-to-year variation; it declined 1.8% in 2012 and 0.6% in 2011, grew 3.7% in 2010, and decreased 3.7% in 2009 and 0.9% in 2008. Until recent years, year-to-year output declines were rare events in an industry that typically experienced low-single-digit percent gains. 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 decreased by 11.4% in 2016, falling $6.9 billion to $53.4 billion from $60.2 billion in 2015. This marked the second straight double-digit percent decline as revenue fell by $7.4 billion (-10.3%) in 2015 after rising $1.6 billion (+2.3%) and $984 million (+1.5%) in 2014 and 2013, respectively. The segment's 2016 revenue was its lowest annual total to date, based on data going back to 2000. The segment's peak annual revenue over the last 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 regional power pools, large industrial customers, and electric utilities seeking to supplement generation capacity. 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 2016. Only 28% had revenue gains.

Natural Gas Distribution

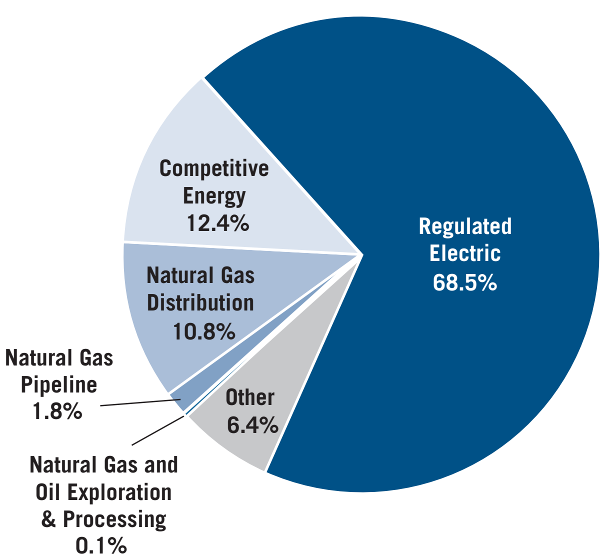
Natural Gas Distribution was the only primary business segment in which revenue grew in 2016, rising $3.0 billion, or 8.9%, to $36.3 billion from $33.3 billion. This followed a decline of $7.8 billion (-19.2%) in 2015 and increases of $4.0 billion (+10.8%) in 2014 and $3.9 billion (+12.2%) in 2013, which reversed the declining trend of the previous four years. Large gas acquisitions drove the 2016 increase. Southern Company's purchase on July 1 of AGL Resources had the biggest impact; AGL is an Atlanta-based gas company with operations in natural gas distribution, retail operations, wholesale services and midstream operations. The Southern deal alone produced $1.7 billion in additional revenue from natural gas assets valued at $21.9 billion at year end 2016. Other notable deals that closed in 2016 include Black Hills' acquisition of SourceGas Holdings (completed February 12), Dominion Resources' purchase of Questar (completed September 16) and Duke Energy's acquisition of Piedmont Natural Gas (completed October 3). These transactions more than offset the revenue impacts of a 6.5% decrease in heating degree days and continued low natural gas prices. Spot natural gas averaged about $2.50/MMBtu at the national benchmark Henry Hub; this was the lowest annual average price since 1999. Overall, 17 of the 28 companies (61%) that report gas distribution revenue showed a year-to-year decrease in 2016, following a decrease for 90% of companies in 2015 and increases for 91% of companies in 2014 and 88% in 2013, respectively. The majority of companies also showed year-to-year revenue declines from 2009 through 2012, while 89% experienced gains in 2008.

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, Natural Gas Pipeline and Exploration & Production (E&P) activities produced $40.3 billion of the industry's revenue in 2016, up from $38.0 billion in 2015. In percentage terms, the revenue contribution from natural gas activities increased to 12.7% in 2016 from 10.5% in 2015.

Natural Gas Pipeline assets rose by $5.5 billion, or 23.7%, while the segment's revenue fell by $543 million, or 12.1%. The largest dollar increase in assets was realized by Dominion Resources, which grew gas pipeline assets by $2.5 billion, or 27.3%, with its acquisition of Questar. DTE Energy's purchase of several Appalachian-region midstream natural gas assets also played a significant part in the industry's increase as DTE's gas

Asset Breakdown
As of December 31, 2016

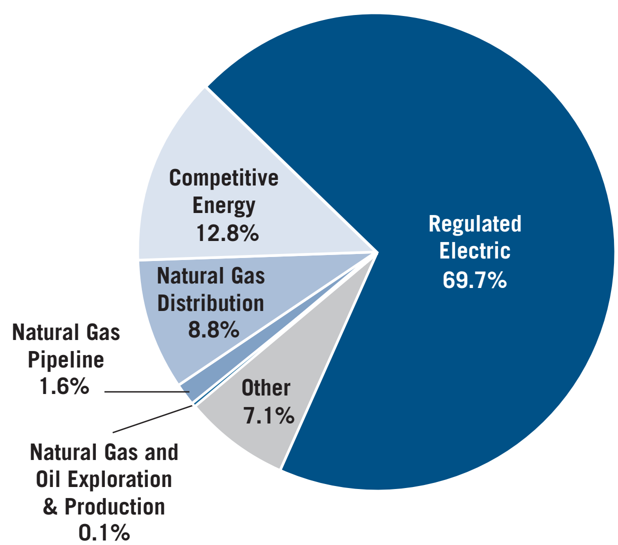
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2015r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

pipeline assets grew by $1.4 billion, or 131%, in 2016.

Prior to the significant growth in Pipeline assets in 2016, the Pipeline and E&P segments had jointly accounted for a declining share of total industry assets. This was due to growth in the other business segments and divestitures within these two. Natural Gas Pipeline and Natural Gas E&P fell from 3.7% and 2.1% shares of total assets on December 31, 2004 to 1.8% and 0.1% on December 31, 2016. Their combined total assets fell by $25.1 billion, or 46%, over this 12-year time frame.

2016 Year-End List of Companies by Category

Early each calendar year EEI updates our list of shareholder-owned electric utility holding companies organized by business category; the list is based on previous year-end business segmentation data presented in 10Ks and supplemented by discussions with parent companies. Our categories have been defined as follows: Regulated (80% or more of holding company assets are regulated); Mostly Regulated (50% -79% of holding company assets are regulated); Diversified (less than 50% of holding company assets are regulated). Starting January 1, 2017, the Diversified Category will no longer exist due to its dwindling number of companies. The business segmentation breakdown will consist of two categories: Regulated (80% or more of total assets are regulated) and Mostly Regulated (less than 80% of total assets are regulated).

We use assets rather than revenue for determining categories because we think assets provide a clearer picture of strategic trends. Fluctuating natural gas and power prices can impact revenue so greatly that the analysis of companies' strategic approach to business segmentation is distorted by a 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.

The Regulated category decreased by two companies during 2016, to 36, due to the net effect of the loss of Pepco Holdings and TECO Energy by acquisition, the addition of Energy Future Holdings and FirstEnergy, and the migration of DPL and DTE Energy to the Mostly Regulated category. Energy Future Holdings Corp. (EFH) was moved to the Regulated Category because we only capture their ownership in Oncor Electric Delivery in our data set; Oncor is a Texas electricity distribution utility.

The Mostly Regulated category had a net increase of three companies, rising from 11 to 14. Exelon and Hawaiian Electric moved to the Mostly Regulated category from the Diversified category, which will no longer exist.

The total number of companies in the EEI universe fell from 52 at yearend 2015 to 50 at yearend 2016 as a result of two completed mergers. Pepco was acquired by Exelon in March and TECO Energy was purchased by Emera in July. Beginning in 2017, there are 36 Regulated and 14 Mostly Regulated companies (*see List of Companies by Category at December 31, 2016*).

List of Companies by Category at December 31, 2016

Regulated (36)

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

Mostly Regulated (14)

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

Note:* Non-publicly traded companies.

Mergers and Acquisitions

Not much has changed from 2015. That was one analyst's verdict on the M&A landscape early in 2016 and events of the year largely bore it out — both in terms of deal motivations and deal activity, which again was pretty fast paced. There were six announced whole company deals: i) Dominion's purchase of gas distributor Questar, ii) Canadian utility Algonquin's acquisition of Empire District Electric, iii) Canadian utility Fortis' successful bid for transmission utility ITC Holdings, iv) Great Plains move to acquire neighboring utility Westar, v) NextEra Energy's offer to buy Texas' Oncor, and vi) DTE's acquisition of several Appalachian mid-stream natural gas assets. Nine deals closed, including three listed above (Dominion/Questar, Fortis/ITC, and DTE/Appalachian-region midstream natural gas assets) that were announced and completed in 2016. In addition: i) Black Hills acquired SourceGas, ii) Exelon successfully completed its two-year effort to acquire Pepco, iii) Macquarie found success after a year-and-a-half long navigation in Louisiana and purchased Cleco, iv) Emera acquired TECO Energy, v) Southern Company successfully closed its purchase of gas distributor AGL, and vi) Duke Energy acquired Piedmont Natural Gas. One previously announced deal was withdrawn as NextEra abandoned its 18-month effort to buy Hawaiian Electric.

A range of inter-related themes that shaped M&A in 2015 persisted in 2016; these include:

- the trend of slowing power demand growth throughout the industry;
- the ongoing desire across the industry to grow regulated assets, earnings and cash flows and de-emphasize competitive generation businesses;
- use of synergies from buyouts of similar and neighboring utilities to gain incremental earnings growth;
- the appeal of acquiring regulated natural gas pipelines and distribution assets that benefit from rising gas demand as the nation's migration from coal to natural gas and renewable generation continues;
- the desire of small- to mid-size utilities to reward shareholders with buyout premiums while joining up with larger companies to lower capital costs and position themselves to better contend with the changes sweeping the industry;
- the growth potential offered by the nation's need for transmission infrastructure investment; and
- very low global interest rates and wide-open capital markets offering low cost financing.

The low cost of natural gas and wind generation along with state renewable power mandates are shaping coal's future far more than the uncertain outlook for national-level carbon standards.

Another familiar theme that continued in 2016 was Canadian utilities' interest in U.S. utilities; analysts noted that Canadian utilities see the U.S. as a market with considerable capital investment opportunities and appealing geographical diversification given Canada's oil and natural-gas dependent economy. Canadian shareholders also have a reputation as more patient and tolerant than U.S. investors of long-term shareholder value creation strategies, giving Canadian buyers the time to let their acquisition visions bear fruit.

The year also provided more evidence of the challenges consummating M&A, which requires the blessings of state regulatory commissions and broad support from a wide range of local stakeholders. This was evident in Exelon's two-year struggle to close the proposed acquisition of Pepco, the success of which surprised skeptics who thought the deal was dead. It was also evident in NextEra's termination of its effort to acquire Hawaiian Electric, which was finally canned by local power politics, and in the resistance Macquarie faced in its move to acquire Louisiana's Cleco, which like the Exelon/Pepco deal was completed in defiance of what seemed to be daunting odds against it. Viewed from an opposite perspective, both the successful Exelon/Pepco and Macquarie/Cleco deals received some analytic commentary that said states and regulators were reluctant to kill deals that demonstrated a range of benefits as long as the acquired utility's local presence was supported and respected, less the state gain a reputation as a hard place to do good business. Job losses and erosion of local political power are each radioactive and the sluggish U.S. economy may offer not only a motivation for M&A but a constraint on too much emotional stakeholder resistance to deals that otherwise seem to offer benefits to ratepayers, shareholders and local economies.

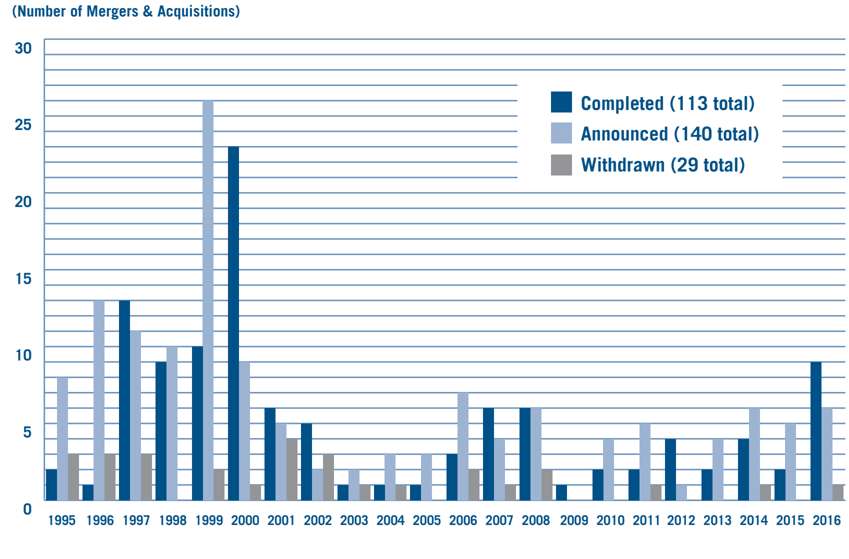
Announced Deals in 2016

Dominion Buys Questar

On February 1, Dominion Resources announced its intent to buy integrated natural gas energy company Questar in a cash offer of $25 per share (a 30% premium to the pre-announcement price, or about $4.4 billion) and also assume $1.5 billion in Questar debt. Questar distributes natural gas to retail customers in Utah, Wyoming and Idaho; operates interstate natural gas pipelines and storage facilities in the western U.S.; and develops and produces natural gas in Wyoming, Colorado and Utah. On the announcement date, Questar had about $4.2 billion in assets, including gas distribution pipelines, gas transmission pipelines and working gas storage facilities. Dominion said the acquisition supports its strategic focus on core regulated energy operations, improves its balance between electric and gas operations, and provides it with enhanced scale and diversification into Questar's regulatory jurisdictions, which Dominion noted have strong pro-business credentials and constructive regulatory environments. Dominion operates in the mid-Atlantic region while Questar is a principal source of gas supply to Western states. Dominion said it expects the value of Questar's pipeline system will rise as Utah and other Western states migrate from coal to

Status of Mergers & Acquisitions 1995–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

low-carbon, natural gas-fired generation to comply with federal clean air requirements and state renewable standards. Questar's gas distribution operations will also benefit from being located in one of the country's fastest growing regions.

Dominion said it the transaction would be accretive and that it would finance the transaction in a manner that supports the company's existing credit ratings targets. Dominion also expects the acquisition will support 2017 earnings growth and allow it to reach the top of or exceed its 2018 growth targets. Dominion made special note that Dominion Midstream Partners, LP — of which Dominion is general partner and the majority holder of limited partner units — will benefit from the acquisition; Questar will contribute more than $425 million of EBITDA to Dominion's inventory of MLP-eligible assets, supporting Dominion Midstream's targeted annual cash distribution growth rate of 22 percent.

The transaction received approval from the FTC and Wyoming and Utah regulators and closed on September 16, 2016.

Algonquin Acquires Empire District Electric

In the first of two acquisitions U.S. utilities by Canadian utilities announced on February 9, Ontario-based Algonquin Power and Utilities Corp. (APUC) said it intended to buy 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 approximately $0.8 billion of EDE debt. The offer represented a 21% premium to Empire District's closing price on February 8, 2016 and a 50% premium to its price in December, before news emerged that the utility was interested in being acquired. 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 mid-west United States, boost its total asset base 87% to $8.9 billion (Canadian), and increase EBITDA from regulated utility operations increasing from 51% to 72% of the total on a pro forma basis. APUC expected the deal at closing to be immediately accretive to earnings per share and funds from operations per share and generate average annual accretion of approximately 7% to 9% and 12% to 14%, respectively, for the three year period following completion. 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. The deal closed in January 2017 when EDE became a member of Liberty Utilities. Algonquin Power & Utilities Corp. is a North American diversified generation, transmission and distribution utility with $10 billion in total assets at yearend 2016. Liberty Utilities provides rate regulated natural gas, water and electricity generation, transmission and distribution utility services to over 782,000 customers in the United States.

Fortis Acquires ITC Holdings

Also on February 9, Canadian utility Fortis said it had reached an agreement to acquire independent electric transmission company ITC Holdings in a transaction valued at approximately $11.3 billion, including $6.9 billion in stock and cash along with assumption of $4.4 billion of ITC debt. In the transaction, which closed successfully in October 2016, ITC shareholders received $22.57 in cash and 0.752 Fortis shares for each ITC share, representing a 33% premium over ITC's pre-announcement price. Fortis called the acquisition of transmission utility ITC a continuation of Fortis' growth-by-acquisition strategy that strengthens and diversifies its business and accelerates its growth. Fortis cited in particular the long-term growth opportunities associated with the need for new transmission to improve grid reliability, support grid access for new renewable generation and reduce the cost of delivered energy. Fortis also noted that the predictable returns of the transmission business, which avoids commodity or fuel exposure, are very at-

Status of Announced Mergers & Acquisitions
1995–2016

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
Totals	**113**	**140**	**29**

Source: EEI Finance Department.

tractive. Among other motivations for the acquisitions, Fortis cited the diversification of its regulatory jurisdictions, business risk profile and regional economic mix by adding eight additional U.S. states to its territories; the appeal of FERC's supportive transmission regulation with reasonable returns and equity ratios; and ITC management's strong operational and earnings growth track record. Fortis said it expects approximately 5% earnings per share accretion in the first full year after closing, excluding one-time acquisition costs

ITC owns and operates high-voltage transmission lines in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 megawatts. It has grown average rate base at a compounded rate of 16% annually over the last three years and reported assets of $7.4 billion as of September 30, 2016. Based on ITC's planned capital expenditure program, the company said it expects average rate base and construction work in progress to grow at a compound average annual rate of 7.5% through 2018. ITC said the Fortis offer provided an attractive premium for its shareholders, who will benefit from future value creation as part of a larger company with greater diversification and scale and a growing dividend program. According to news reports, the agreement with Fortis occurred two months after ITC disclosed it retained advisers to help arrange a sale of the company. Fortis continues to target 6% average annual dividend growth through 2020. Including ITC, Fortis has assets of approximately $48 billion and 2016 revenue of $6.8 billion serving utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Great Plains Seeks to Acquire Westar

On May 31, Kansas-based Great Plains Energy announced it had reached an agreement to purchase neighboring utility 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 the assumption of approximately $3.6 billion in Westar's debt. If the transaction is approved by regulators, Westar shareholders will receive $51.00 in cash and $9.00 in Great Plains Energy common stock for each Westar share. Upon closing, Westar will become a wholly owned subsidiary of Great Plains Energy. Previous to the May 31 announcement, Westar shares had already climbed to $53 from $43 in early March, when news reports said Westar was exploring strategic options that included sale of the company. The two companies also noted their similar cultures and the maintenance of local ownership inherent in the merger, calling each other trusted neighbors that have worked together for generations in Kansas. The two utilities jointly own and operate the Wolf Creek Nuclear Generating Station as well as the La Cygne and Jeffrey power plants.

As motivations for the deal, Great Plains noted that the utility industry is facing rising customer expectations, increasing environmental standards, emerging cyber security threats and slower demand growth, all of which are driving costs and rates higher. The company said the acquisition of Westar will create operational efficiencies and cost savings that will help reduce future rate increase requests. The companies noted that with the addition of Westar's generation fleet Great Plains will have a more diverse and sustainable generation portfolio and one of the largest portfolios of wind generation in the country among U.S. investor-owned utilities. The combined utility would have more than 1.5 million customers in Kansas and Missouri, nearly 13,000 megawatts of generation capacity, almost 10,000 miles of transmission lines and over 51,000 miles of distribution lines. In addition, more than 45 percent of the combined utility's retail customer demand can be met with emission-free energy.

In 2008, Great Plains bought neighboring Missouri utility Aquila in a deal reviewed and approved by the Missouri and Kansas commissions and which Great Plains said has generated greater-than-expected savings for customers. The proposed Westar acquisition requires approval from Kansas regulators as well as FERC and the Nuclear Regulatory Commission.

Great Plains said it plans to issue a long-term financing package consisting of a combination of equity, equity-linked securities and debt prior to closing of the transaction, and said it intends to maintain its investment grade credit rating. Great Plains expects the acquisition to be neutral to earnings-per-share in the first full calendar year of operations and significantly accretive thereafter. It said the long-term earnings growth target for the combined company is expected to grow to six to eight percent—better than either company on a standalone basis.

NextEra Energy Bids for Texas' Oncor

The year's largest proposed deal came on July 29 when Florida's NextEra Energy said it reached agreement to acquire 100 percent of the equity of Energy Future Holdings Corp. (EFH) and EFH's approximately 80 percent indirect interest in Texas electricity distribution utility Oncor Electric Delivery for a total enterprise value of $18.4 billion. The move followed a May 2016 decision by Texas' Hunt family to terminate its plan to buy Oncor and turn it into a Real Estate Investment Trust (REIT) after the Texas Public Utility Commission imposed conditions on the purchase that the Hunts said were too onerous. The agreement with NextEra is part of reorganization plan designed to allow EFH to emerge from Chapter 11 bankruptcy. NextEra has for years been a suitor, along with the Hunt family, seeking to acquire and bring EFH and Oncor out of bankruptcy. NextEra noted in the deal announcement that it has had a significant presence in Texas since 1999 through its Lone Star Transmission subsidiary and over $8 billion in overall transmission, power generation, gas pipelines and other operational assets in Texas. If the transaction is completed, Oncor will become a principal business of NextEra Energy together with Florida Power & Light Company (FPL) and NextEra Energy Resources.

NextEra enumerated a wide range of benefits to Oncor and its customers if the deal closes, including: the transaction will extinguish all EFH-related debt that currently exists above Oncor; NextEra's strong balance sheet and credit rating will support Oncor's five-year capital investment plan and improve its credit rating post-closing, generating savings for customers in terms of lower borrowing costs; the transaction is a straightforward, traditional acquisition by a utility holding company and will employ a traditional utility company structure; and Oncor can benefit from Next Era's expertise and best practices that have resulted in comparatively low rates, demonstrated operational efficiency, strong customer satisfaction and high reliability ratings.

NextEra also said it expects the transaction to be meaningfully accretive to earnings, helping it achieve the top end of its targeted 6% to 8% adjusted earnings per share growth rate through 2018 off a 2014 rate base. It noted the transaction is consistent with its focus on regulated and long-term contracted assets and that it remains committed to maintaining its strong balance sheet. It expects that its credit ratings and its subsidiaries' credit ratings will be maintained post-closing. NextEra said it would maintain Oncor's local management, Dallas headquarters and Oncor name with no involuntary workforce reductions for at least two years after closing. Finally, NextEra pitched the deal to creditors, saying the transaction payment would be composed primarily of cash and NextEra common stock, delivering a high degree of certainty of value to the EFH bankruptcy estate.

The transaction is subject to bankruptcy court confirmation of EFH's plan of reorganization, approval by the Public Utility Commission of Texas, the expiration or termination of the waiting period under the Hart-Scott-Rodino Act, and the Federal Energy Regulatory Commission. NextEra said it hopes the transaction can be completed in early 2017.

DTE Acquires Appalachian Mid-Stream Natural Gas Assets

On September 26, DTE Energy announced its intent to purchase several Appalachian-region mid-stream natural gas assets including Appalachia Gathering System (AGS), located in Pennsylvania and West Virginia, and a 55% interest in Stonewall Gas Gathering (SGG) in West Virginia. The combined purchase price for the assets $1.3 billion. When the deal closed less than a month later, on October 20, the assets became part of DTE's non-utility gas storage and pipeline business, which owns and manages a network of natural gas gathering, transmission and storage facilities serving the Midwest, Ontario and Northeast markets. The acquired assets gather natural gas produced in the Appalachia region and provide access to multiple markets, including the Great Lakes region. DTE noted that demand for natural gas in the Great Lakes region is expected to increase significantly, driven both by coal-to-gas conversions for electricity generation and by economic growth. The low-cost natural gas supply from the Marcellus/Utica region is expected to serve this growth and displace higher cost alternatives.

DTE said the transactions will significantly increase its midstream presence in the Appalachian basin and said the deal would complement its existing gas midstream business, provide a foundation for new value creation with significant growth potential, expand the company's footprint in the most prolific natural gas production region in the country spanning the heart of the SW Marcellus and Dry Utica shale plays, and provide solid economics underpinned by long-term contracts and high quality reserves.

DTE Energy is a Detroit-based diversified energy company that develops and manages energy-related businesses and services nationwide. It operates an electric utility serving 2.2 million customers in Southeastern Michigan and a natural gas utility serving 1.2 million customers in Michigan. DTE's portfolio includes non-utility energy businesses focused on power and industrial projects, natural gas pipelines, gathering and storage, and energy marketing and trading.

Merger Impacts 1995–2016

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%)

Number of Companies Declined by 55% since Dec.'95

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

Source: EEI Finance Department.

Completed Transactions

Black Hills Acquires SourceGas

On February 12, 2016 Black Hills completed its move to buy SourceGas Holdings. The deal, announced in July 2015, was the first of 2015's flurry of five deals driven by utilities' desire to buy natural gas distribution assets. SourceGas operates four regulated natural gas utilities serving approximately 425,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado. Black Hills said the combination delivers on its commitment to grow earnings and create long-term shareholder value, citing the two utilities complementary geographic footprints, capital investment opportunities in growing service territories, and the ability to share best practices in support of organic growth initiatives. Black Hills' also said the acquisition would increase its regulatory and geographic diversity, strengthen its "excellent" business risk profile and support its investment-grade credit ratings. Over the last decade, the company has acquired 19 electric and natural gas systems in support of its growth strategy.

Exelon Closes Pepco Acquisition

Opposition from Washington, D.C. stakeholders threatened to scuttle the Exelon/Pepco deal, announced on April 30, 2014. The transaction was approved by the FERC and Virginia regulators in late 2014 and by New Jersey regulators in February 2015. In March 2015, the companies increased proposed benefits in Maryland – a state where regulatory opposition scuttled several large merger proposals during the previ-

Mergers & Acquisitions Announcements Updated through December 31, 2016

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)
9/28/16	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	C		10/20/2016	1	EG	Undisclosed	1,300.0
7/29/16	NextEra Energy	Oncor Electric Delivery Company	PN					$9.5B debt + additional cash and common stock	18,400.0
5/31/16	Great Plains Energy	Westar Resources	PN					$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/16	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
2/9/16	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
2/1/16	Dominion Resources	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	169,500.0
5/29/2013	MidAmerican Energy Holdings Co.	NV Energy	C		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 Resources	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

ous decade. Maryland regulators approved the merger in May 2015 after the companies expanded the scope of benefits to ratepayers. Delaware likewise approved the merger in May 2015. The companies had hoped to close the transaction in mid-2015 but protracted negations with and among Washington D.C. regulators, business leaders and local politicians created uncertainty over the deal's ultimate fate; D.C. regulators blocked the merger twice, most recently in February 2016, casting considerable pessimism on prospects for the deal's success. However, the merger was in fact completed on March 23, 2016 after D.C. regulators finally gave it their approval. The $7 billion merger brings together Exelon's three electric and gas utilities — BGE, ComEd and PECO — and Pepco Holdings' three electric and gas utilities — Atlantic City Electric, Delmarva Power and Pepco — to create a leading mid-Atlantic electric and gas utility company. The combined Exelon utility businesses serve approximately 10 million customers with a rate base of approximately $30 billion.

Macquarie Completes Purchase of Cleco

Local opposition almost nixed the proposed acquisition of Louisiana regulated utility Cleco by Macquarie and a group of infrastructure investors, announced in October 2014. Macquarie manages more than $100 billion in infrastructure assets worldwide; its North American infrastructure businesses include utilities Puget Energy, Aquarion Water and Duquesne Light. Macquarie said Cleco is a well-run utility with growth opportunities that can be supported by Macquarie's expertise and experience with other portfolio utility companies, and that Cleco would complement Macquarie's existing infrastructure portfolio assets. The companies originally had hoped to close the deal in the second half of 2015, but revised the proposed transaction in October 2015 to address concerns by Louisiana regulators. On February 24, 2016, Louisiana regulators rejected the merger, citing concerns about leverage used to finance the deal, questions about tax consequences for customers, and concerns about foreign ownership (Macquarie is based in Australia and a second prominent investment partner is Canadian). However, the Louisiana commission approved the deal in March 2016 after the companies agreed to freeze rates until June 2019 and committed to $136 million in rate credits. The transaction was completed on April 13, 2016. The buyer's commitment to maintain Cleco's local presence was instrumental in gaining approval. Cleco retained its Pineville, Louisiana headquarters; the new owners will continue the company's local charitable giving, investments in economic development and staffing levels; and salaries and benefits will be maintained for 10 years.

Emera Acquires TECO

On July 1, 2016, Canadian utility Emera successfully closed its acquisition of Tampa, Florida-based TECO Energy. The deal, announced in September 2015, was motivated by Emera's desire for regulated earnings, increased scale and geographical diversification. The companies noted the combination would make a top-20 North American regulated utility with approximately $20 billion of assets and more than 2.4 million electric and gas customers. Emera called TECO an ideal strategic fit due to its regulated business and generation mix, U.S. presence, constructive regulatory jurisdictions and growth markets offering opportunities to supply customers with cleaner generation. TECO cited the appeal of increased scale that results from being part of a larger, more diverse organization. Emera noted the deal would include a regulated natural gas local distribution business, which shares many of the key competencies of its regulated electric utilities. It also said it expected pro-forma regulated earnings would be more than 80% of total earnings and that it planned to maintain a strong investment-grade credit profile. The companies said they expect the deal to be accretive to Emera's earnings per share in the first full year of operations (2017), growing to more than 10 percent by the third full year (2019), and that the deal would support Emera's 8% dividend growth target through 2019. Emera said it would preserve and further invest in TECO's employee base and local presence as it has in other Emera acquisitions.

Southern Closes AGL Acquisition

Also on July 1, 2016, Southern Company closed its acquisition of AGL Resources; the proposed acquisition was announced in August 2015 and was the largest of 2015's five natural gas deals. Atlanta-based AGL is an energy services holding company with operations in natural gas distribution, retail operations, wholesale services and midstream operations, and serves approximately 4.5 million utility customers through its regulated distribution subsidiaries in seven states. Southern said the acquisition would support its long-term desire to participate in natural gas infrastructure development, citing AGL's experienced team, premier natural gas utilities and investments in several major infrastructure projects. Southern also said the acquisition is expected to be accretive to earnings per share in the first full year after, accelerate its expected long-term EPS growth to 4-5%, preserve its strong financial profile, further support investment in its diversified energy platform, and enhance its ability to increase the growth rate of its dividend.

Duke Energy Acquires Piedmont Natural Gas

On October 3, 2016, Duke Energy successfully completed its acquisition of Piedmont Natural Gas Company, a Charlotte, N.C. based energy services company primarily engaged in the distribution of natural gas to residential, commercial, industrial and power-generation utility customers. Duke Energy paid $60 per share in cash to acquire each outstanding share of Piedmont, and also assumed approximately $2 billion of Piedmont's net debt. The acquisition will add Piedmont's one million natural gas customers to Duke Energy's existing customer base of 525,000 natural gas customers and 7.4 million electric customers. Piedmont Natural Gas will retain its operating name and operate as a business unit of Duke Energy.

Withdrawn Deals

NextEra Abandons Effort to Buy Hawaiian Electric

On July 18, NextEra Energy cancelled its proposed merger with Hawaiian Electric (HEI). The deal was announced on December 3, 2014 and encountered considerable local opposition due to varying views among stakeholders as to how Hawaii should meet its aggressive renewable energy goals. The companies had viewed NextEra's expertise in renewables and financial strength as supportive of HEI's need to implement a clean-energy transformation plan that involves modernizing its grid, reducing Hawaii's dependence on imported oil, and integrating more rooftop solar energy. In June 2015, after the deal was proposed, Hawaii accelerated its planned renewables timeline, becoming the first state to pass a 100% renewable energy goal. The new goal set targets of 30% by 2020, 40% by 2030, and 70% by 2040 with a final target of 100% by 2045. The companies originally hoped to close the deal within a year, but in December 2015 extended the target date by six months to June 2016. The companies cancelled the deal after the Hawaiian Public Utilities Commission voted on July 15, 2016 against the transaction, arguing it did not offer adequate benefits to ratepayers, it lacked sufficient ring-fencing measures, it lacked assurances that Hawaiian Electric would remain locally governed and controlled, and that NextEra lacked specific experience with renewable energy issues facing Hawaii (integration of rooftop solar distributed generation in particular).

Construction

Generation

New Capacity

The electric utility industry brought 33,177 MW of new capacity online in 2016, almost 60% more than in 2015. Solar (including private solar) was the dominant contributor with 12,843 MW of new capacity (39% of the total). Wind followed with 9,182 MW (28%) and natural gas with 9,093 MW (27%). NextEra Energy (4,181 MW), Southern Co. (1,665 MW), Dominion Resources (1,476 MW) and Berkshire Hathaway (1,226 MW) were the investor-owned electric utilities that brought the most new capacity online.

Solar, for the first time, was the year's leading source of new generation capacity, and 2016 was yet another record year for solar with capacity additions more than double 2015's total. The continued decline in photovoltaic (PV) system costs and the continued availability of federal and state incentives — such as the federal investment tax credit (ITC), state renewable portfolio standards (RPS) and net metering — are enabling solar's rapid growth. Solar capacity additions also benefitted from a large pipeline of universal solar projects that began construction in 2015 in anticipation of a year-end 2016 expiration and non-extension of the 30% ITC. At the end of 2015, however, the solar ITC was extended until 2021, with declining rates after 2019.

All new solar capacity added in 2016 used PV technology given its cost advantage over solar thermal. NextEra and Southern Co were

New Capacity Online (MW) 2012–2016

	Entire Industry
2016	
New Plant	25,127
Plant Expansions	8,050
Total	**33,177**
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**
2012	
New Plant	17,962
Plant Expansions	13,540
Total	**31,503**

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.

the investor-owned utilities that brought online the most universal solar, at 1,089 MW and 878 MW, respectively.

Among the largest solar projects brought online by investor-owned utilities in 2016 were:

- Southern Co's. RE Roserock Solar project in Texas, Desert Stateline Solar project in California, and Taylor County Solar and Buttler Solar projects in Georgia (these four installations range from 103 MW to 158 MW);
- NextEra's 101 MW White Pine Solar project in Georgia;
- Sempra's 100 MW Mesquite Solar project in Arizona and 93.5 MW Copper Mountain Solar project in Nevada.

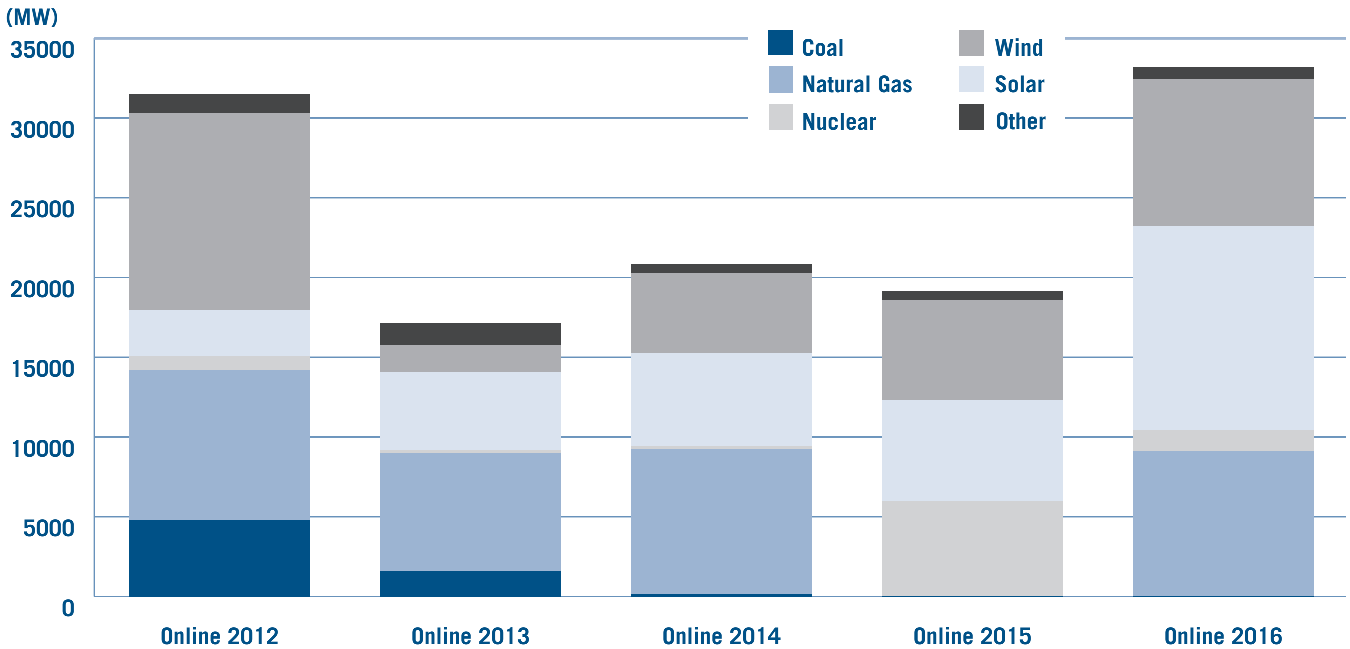
In total in 2016 there were 54 solar projects over 50 MW, 112 between 10 MW and 49.9 MW, and almost 300 between 1MW and 9.9 MW. In addition to these large projects, many more small private solar projects were added to the grid during the year. Private solar generation continues to grow rapidly as homeowners and businesses install PV panels on rooftops and utilities explore ways to use distributed solar to relieve congestion during peak hours and provide customers with additional energy solutions.

Wind continued to rebound after a few lackluster years and was the second-largest source of new capacity. While below 2012's record 12,327 MW, new wind capacity added in 2016 rose 12% from 2015's level and, as in 2015, exceeded 2013's and 2014's capacity additions combined. NextEra Energy (1,353 MW) and Berkshire Hathaway (1,226 MW) were the investor-owned electric utilities that brought the most new wind capacity online. Duke, Xcel Energy and Exelon also brought online significant amounts of wind capacity. NextEra Energy completed a total of seven wind farms in North Dakota, Oklahoma, Texas, Kansas and Missouri. Berkshire Hathaway completed three projects in Iowa totaling 751 MW, one 400 MW project in Nebraska, and a 75 MW project in Kansas.

New natural gas capacity added to the grid grew by 50% in 2016 after falling significantly in 2015; the 9,093 MW added in 2016 brought natural gas capacity additions back to levels consistent with previous years (the 2012-2014 average was 8,600 MW). Combined-cycle projects accounted for 5,767 MW while simple-cycle turbines contributed 3,326 MW.

Dominion Resources and NextEra were among the investor-owned electric utilities that added new combined-cycle capacity. Dominion built a new 1,358 MW NGCC plant in

New Capacity Online by Fuel Type 2012–2016



Fuel Type	2012	2013	2014	2015	2016
Coal	4,823	1,618	136	3	45
Natural Gas	9,395	7,370	9,081	5,971	9,093
Nuclear	875	172	227	0	1,270
Solar	2,882	4,936	5,808	6,316	12,843
Wind	12,327	1,646	5,041	8,179	9,182
Other	1,200	1,421	557	556	744
Total	**31,503**	**17,163**	**20,849**	**21,025**	**33,177**

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.

Virginia and NextEra added 1,277 MW through an expansion at its Port Everglades power plant in Florida.

Although not counted towards net capacity additions, fuel conversions amounted to 4,312 MW; these included conversions from coal to natural gas at AEP's Clinch River in Virginia (475 MW), AES's Harding Street in Indiana (463 MW) and Ameren's Meramec plant in Missouri (275 MW).

The only new coal capacity added to the grid in 2016 was a 45 MW rerate at the Columbia coal power plant in Wisconsin.

Cancelations

Capacity canceled or postponed totaled 49,044 MW, 81% more than in 2015. However, 2015's total was unusually small and the 2016 amount is in line with prior years; the year-to-year jump was mostly due to an increase in cancelations of renewable projects. Compared to 2015, renewable project cancellations grew 70% as wind's doubled and solar's share grew by 36%. As a result, wind accounted for most project cancellations, with 41% of the total, followed by natural gas (17%) and solar (16%).

New Capacity Online by Region 2016

Region	Online	Canceled
ASCC	70	2,388
FRCC	1,409	599
HCC	21	258
MRO	593	5,671
NPCC	734	1,792
RFC	2,307	7,286
SERC	3,632	6,874
SPP	1,181	785
TRE	1,541	4,256
WECC	2,795	19,135
NA	6,898	
Total	**21,180**	**49,044**

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

NA: Not available. Includes private, residential solar.

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

Announcements

The electric utility industry in 2016 announced plans for 46,693 MW in new capacity, 17% more than in 2015 and largely in line with the five-year average. New wind capacity led announcements (16,650 MW), followed by natural gas (15,817 MW) and solar (12,986 MW). Natural gas and renewables (wind and solar in particular) continue to be the favored choices for new generation.

The planned new capacity is fairly evenly distributed around the country, although there are regional differences regarding generation type.

Almost half of the announced capacity is located in the Southeast Reliability Council-SERC and Reliability First-RF regions (25% and 20% respectively), followed by Northeast Power Coordinating Council-NPCC (15%), Western Electricity Coordinating Council-WECC (14%), Midwest Reliability Organization-MRO (10%), Electric Reliability Council of Texas-ERCOT (6%), Southwest Power Pool-SPP (5%), and Florida Reliability Coordinating Council-FRCC (2%).

Solar accounts for 77% of the planned capacity in WECC and represents 35% of planned capacity additions in SERC. Solar is rapidly expanding beyond the desert southwest with plans announced for new capacity in virtually all states.

Natural gas is the primary resource planned in SERC (50%) and RF (73%), whereas wind dominates in SPP (99.6%), MRO (90%) and NPCC (58%).

New vs. Canceled Capacity by Fuel Type (MW)

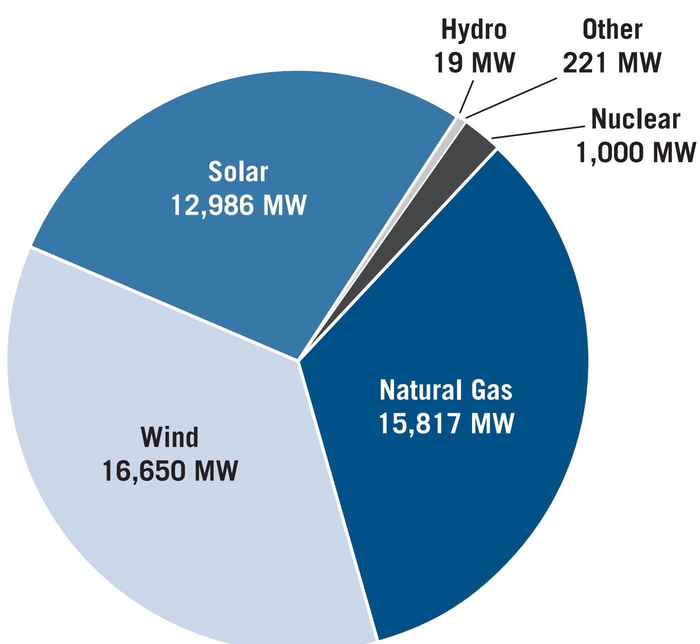
Fuel Type	Online 2012	Canceled 2012	Online 2013	Canceled 2013	Online 2014	Canceled 2014	Online 2015	Canceled 2015	Online 2016	Canceled 2016
Coal	4,823	5,362	1,618	4,645	136	279	3	100	45	3,866
Natural Gas	9,395	12,064	7,370	4,278	9,081	3,549	5,971	9,090	9,093	8,337
Nuclear	875	3,036	172	10,813	227	3,583	0	0	1,270	1,600
Solar	2,882	19,604	4,936	6,651	5,808	11,741	6,316	5,800	12,843	7,895
Wind	12,327	22,195	1,646	16,497	5,041	21,414	8,179	10,212	9,182	20,301
Other	1,200	17,244	1,421	9,974	557	4,850	556	1,946	744	7,045
Total	**31,503**	**79,503**	**17,163**	**52,858**	**20,849**	**45,415**	**21,025**	**27,148**	**33,177**	**49,044**

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.

2016 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.

While not all announced projects will be built, more than 34,000 MW of announced new capacity is already under construction and expected to come online in 2017 or 2018. This includes several large natural gas combined cycle plants and a large number of wind and solar facilities ranging from 1 MW to 300 MW.

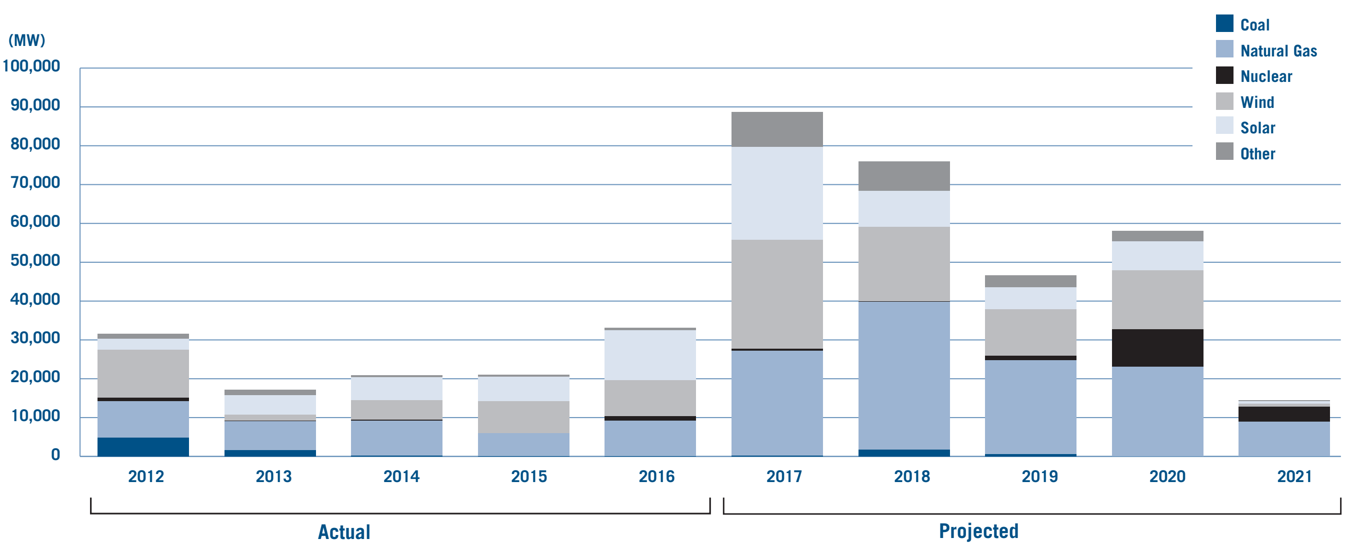
There are a few previously announced coal plants that remain officially on the books and it is unclear whether they will be built. These were proposed as long as 13 years ago and none have progressed beyond the permit stage. There are no new coal plants under construction in the U.S. and any coal capacity added in coming years will likely be small expansions at existing facilities.

Retirements

Almost 16,000 MW of capacity was retired in 2016; just over 9,500 MW (60%) was coal. A record 15,380 MW of coal was retired in 2015, therefore about 10% of the existing coal fleet was retired in the last two years alone. In fact, since 2010, the industry has retired 50,667 MW of coal capacity (about 15% of the 2010 coal fleet).

More coal plant retirements are expected in coming years due to economic and regulatory pressures. The low price of natural gas continues to make the competitive environment difficult for coal generation. In addition, EPA's Mercury and Air Toxics Standard (MATS) went into effect in 2015 and EPA's Clean Power Plan requirements go into effect in 2022, provided the rule is upheld in the courts. The electric power industry has already announced plans to retire another 20,760 MW of coal generation between 2017 and 2021.

Actual and Projected Capacity Additions 2012–2021



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	4,823	1,618	136	3	45	245	1,687	590	0	0
Natural Gas	9,395	7,370	9,081	5,971	9,093	26,929	38,181	24,196	23,060	8,969
Nuclear	875	172	227	0	1,270	505	99	1,100	9,697	3,838
Wind	12,327	1,646	5,041	8,179	9,182	28,050	19,106	12,037	15,180	691
Solar	2,882	4,936	5,808	6,316	12,843	24,019	9,312	5,558	7,452	735
Other	1,200	1,421	557	556	744	9,003	7,601	3,213	2,615	146
Total	**31,503**	**17,163**	**20,849**	**21,025**	**33,177**	**88,751**	**75,986**	**46,693**	**58,003**	**14,379**

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates. Data does not include projects with an expected online date beyond 2021.
Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.
2012-2016 is actual plants brought online. 2017-2021 is projected based on projects announced as of March 2017.
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	–	17	200	2,260	–	45	–	2,522
Natural Gas	36,463	2,201	28,950	21,263	1,438	27,625	1,285	119,225
Nuclear	1,699	2,185	4,619	2,200	–	4,434	–	15,137
Wind	40,544	3,870	10,657	11,879	536	6,521	379	74,387
Solar	30,775	306	8,604	3,721	28	2,775	213	46,421
Other	5,302	10,083	4,883	1,645	8	646	4	22,569
Total	**114,782**	**18,661**	**57,912**	**42,968**	**2,011**	**42,046**	**1,881**	**280,260**

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 2021.

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

Proposed New Nuclear Plants

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

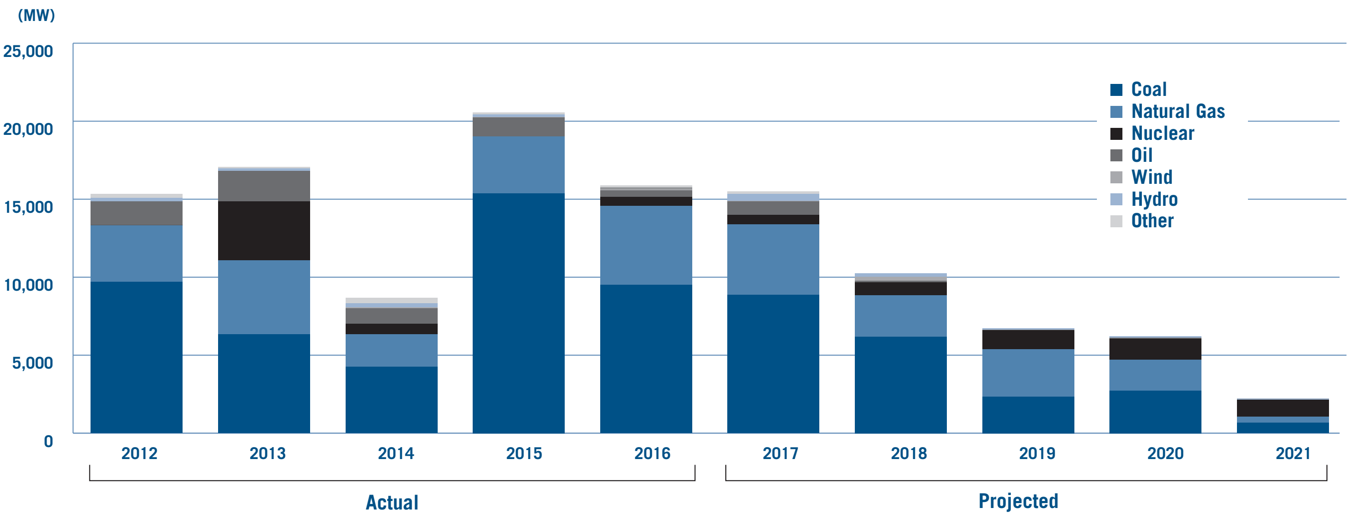
Company	Site (State)	Early Site Permit	Design (# of units)	Construction & Operating License	# Units	Status
Tennessee Valley Authority	Watts Bar (TN)	–	Gen II PWR	Operating License Issued Oct. 2015	1	Operational in October 2016
SCANA Corp.	V.C. Summer (SC)	–	AP1000	Approved March 2012	2	Under Construction
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 Resources Inc.	North Anna (VA)	Approved November 2007	ESBWR	Submitted November 2007	1	Under Active NRC Review
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 2007	TBD	TBD		Early Site Permit

Legend:
TBD: To Be Determined
ABWR: Advanced Boiling Water Reactor
AP1000: Reactor designed by Westinghouse
APWR: Advanced Pressurized Water Reactor
EPR: Pressurized Water Reactor designed by Framatome
ESBWR: Economic Simplified Boiling Water Reactor
Gen II PWR: Generation II Presurized Water Reactor

Source: Nuclear Energy Institute, EEI Finance Department. Last updated March 2017.

For updates, please visit: http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/New-Nuclear-Plant-Status.

Actual and Projected Retirements 2012–2021



	Actual					Projected				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	9,700	6,333	4,259	15,380	9,503	8,849	6,185	2,344	2,729	653
Gas	3,636	4,747	2,071	3,647	5,055	4,544	2,659	3,038	1,957	405
Nuclear	0	3,781	676	0	577	605	823	1,215	1,371	1,074
Oil	1,512	1,954	997	1,215	447	846	108	11	50	0
Solar	0	0	5	0	30	0	0	0	0	0
Wind	14	0	64	37	49	54	256	0	0	0
Hydro	227	165	270	138	126	425	213	95	95	95
Other	236	79	330	160	128	169	10	1	1	2
Total	**15,326**	**17,058**	**8,672**	**20,576**	**15,915**	**15,492**	**10,254**	**6,704**	**6,203**	**2,229**

Notes: Data includes new plants and expansions of existing plants. Data does not include projects with an expected online date beyond 2021.
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.
2012-2016 is actual plants retired. 2017-2021 is projected based on announced retirements.
Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department.

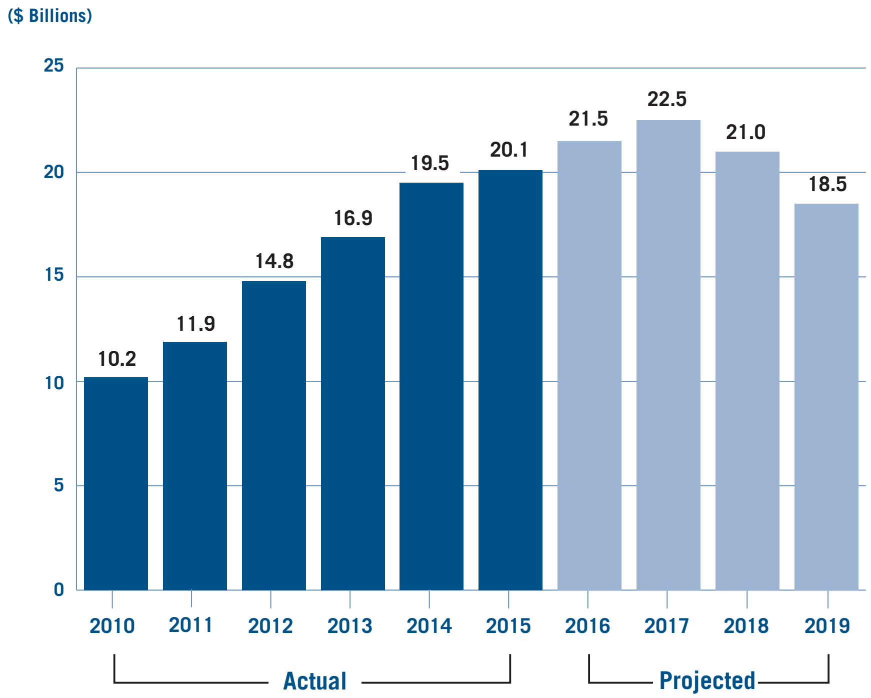
Natural gas retirements totaled 5,055 MW, or nearly one-third of the total. Retirements of all the other technologies amounted to 1,357 MW, accounting for about 9% of total retirements.

Transmission

According to EEI's latest *Annual Property & Plant Capital Investment Survey*, investor-owned electric utilities and stand-alone transmission companies invested a record $20.1 billion in transmission infrastructure in 2015. This represents a 3% increase over the $19.5 billion that the industry invested in 2014. Electric utilities attribute the increased transmission investment to several key factors, including transmission reliability improvements; transmission infrastructure to accommodate increased shale oil and gas development; new infrastructure to ease congestion; replacement of outdated transmission lines; transmission system expansion projects; storm hardening activities; interconnection of new sources of generation (including renewables); and accommodating retirements of inefficient or uneconomic generation. Given the large amount of coal capacity that will be retired over the next few years, transmission system upgrades can help preserve reliability in areas where plants are shutting down.

EEI members are projected to spend a total of $84 billion (nominal dollars) over the 2016-2019 fore-

Actual and Planned Transmission Investment* 2010–2019



*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, Business Information Group.

Updated November 2016.

cast period. Investment spending is projected to peak in 2017, then moderate due to the cyclical nature of transmission planning and development, expanded demand-side resources (including demand response, energy efficiency and distributed generation) and the uncertainty of project selection under FERC Order 1000 planning processes.

The growing use of distributed generation makes transmission investment critical to system-wide reliability by enabling access to reliable power sources when intermittent distributed generation is unavailable. Large concentrations of distributed generation also increase the need for the transmission system to detect and quickly react to supply/demand imbalances when distributed sources go offline or cannot meet 100% of customer demand.

Distribution

EEI's latest *Annual Property & Plant Capital Investment Survey* showed that investment in electric distribution infrastructure in 2015 totaled $25.8 billion, a 14.7% increase over the $22.5 billion invested in 2014. The increased spending was primarily attributed to infrastructure improvements that enhanced general system reliability; improvements that enhanced storm hardening and the resiliency of the distribution network; additional investment required to accommodate customer projects; additions of new distribution infrastructure, including substations and replacement of aging distribution lines; and an increase in smart grid investments.

In general, investments in the distribution sector are primarily driven by the ongoing need to replace assets that have lived out their useful lives, serve new load, preserve reliability, improve system resiliency and restoration capabilities, and increasingly, accommodate distributed resources. Investment in utility infrastructure tends to be cyclical; large investments are made to support major development projects, investment levels off as focus shifts to maintenance and incremental upgrades, and investment then rises again to support load growth and/or adoption of new technologies.

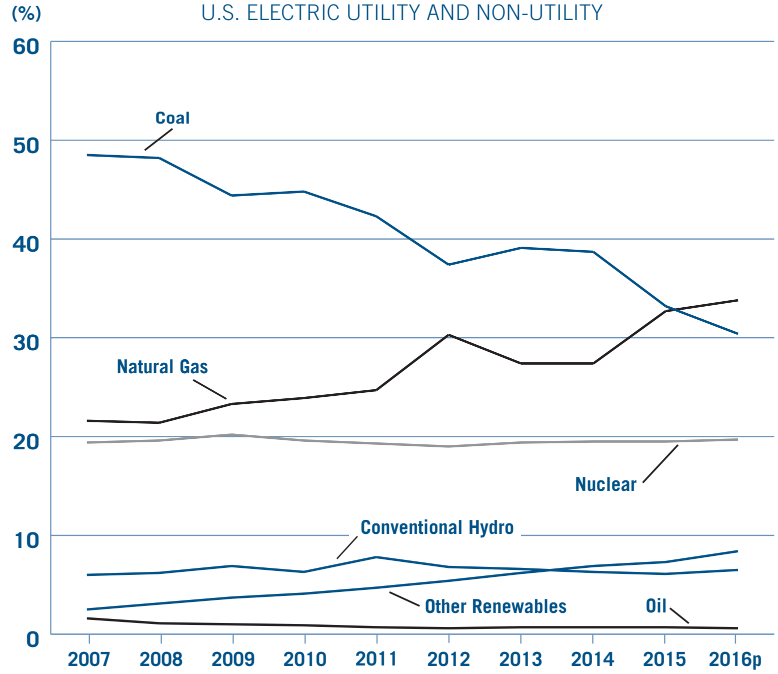
The electric power industry is facing significant distribution-related capital spending needs to address the normal replacement cycle for aging infrastructure, to harden the grid and improve storm restoration response, and to expand the grid's ability to support growing use of distributed resources. These investments will improve reliability and enable customers to adopt new technologies such as rooftop solar and electric vehicles. They will also allow utilities to operate the grid more efficiently by providing more detailed information about grid conditions so that resources can be used more effectively.

Fuel Sources

The primary trends that have impacted fuel use for power generation over the past few years continued in 2016; these are flat power demand, low natural gas prices and the continued growth of renewable energy production. Electric generation declined by 0.2% in 2016 and has fallen in six of the last ten years, resulting in a 10-year average demand growth rate of only 0.1%. In fact, electricity generation in 2016 was only about equal to the level a decade earlier, in 2006. Sluggish demand growth has resulted from declining consumption by the industrial sector and reduced demand growth from the residential and commercial sectors. Newer and more energy efficient equipment, energy efficiency standards, slower population growth and a shift towards a less energy intensive economy have also contributed to the trend.

Fuel Sources for Electric Generation 2007–2016

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

	2016p	2015
Coal	30.4%	33.2%
Gas	33.8%	32.7%
Nuclear	19.7%	19.5%
Oil	0.6%	0.7%
Hydro	6.5%	6.1%
Renewables	8.4%	7.3%
Biomass	1.5%	1.6%
Geothermal	0.4%	0.4%
Solar	0.9%	0.6%
Wind	5.6%	4.7%
Other fuels	0.5%	0.5%
Total	100%	100%

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

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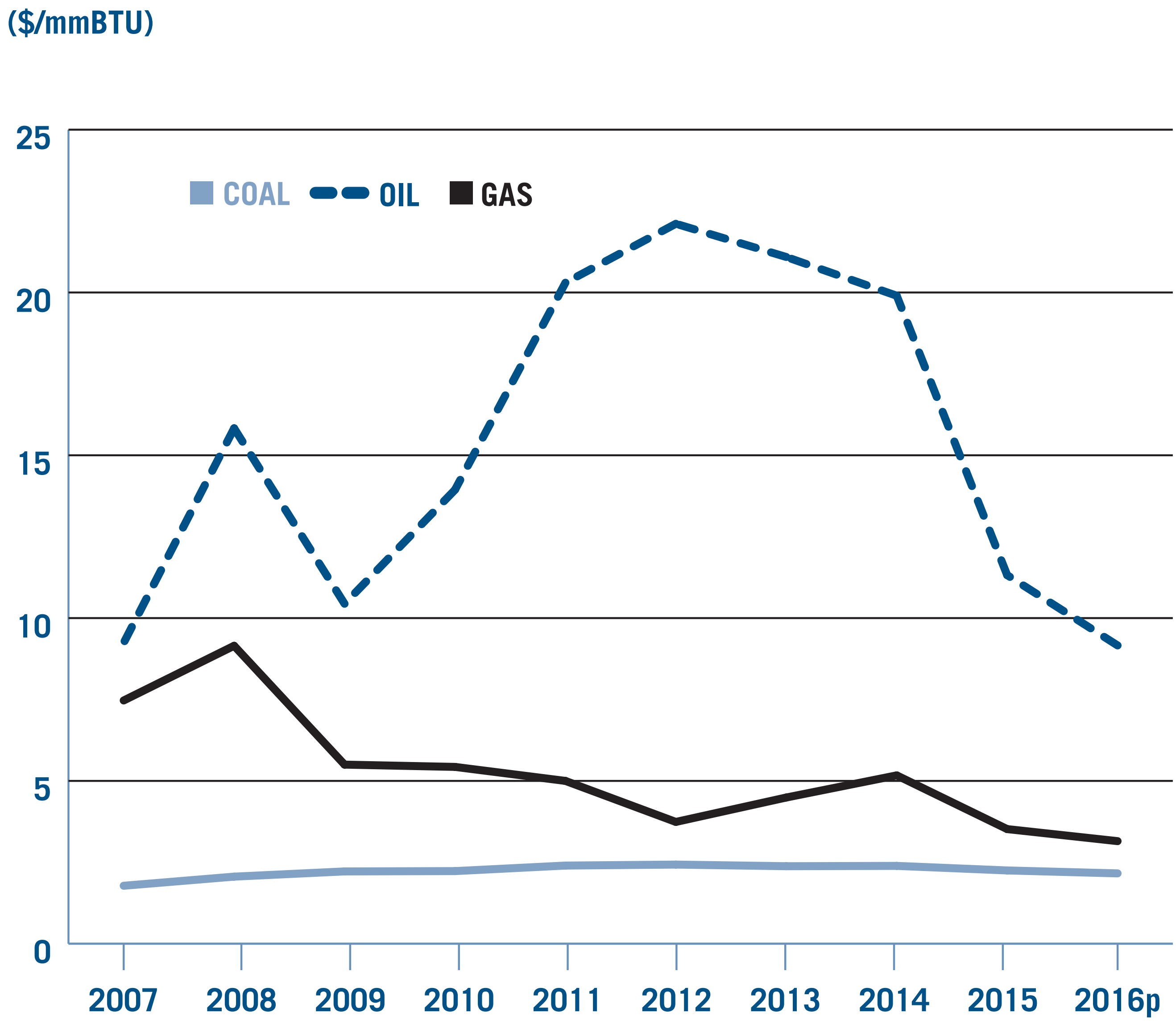
Source: U.S. Department of Energy, Energy Information Administration (EIA).

Average Cost of Fossil Fuels 2007–2016

U.S. ELECTRIC UTILITIES



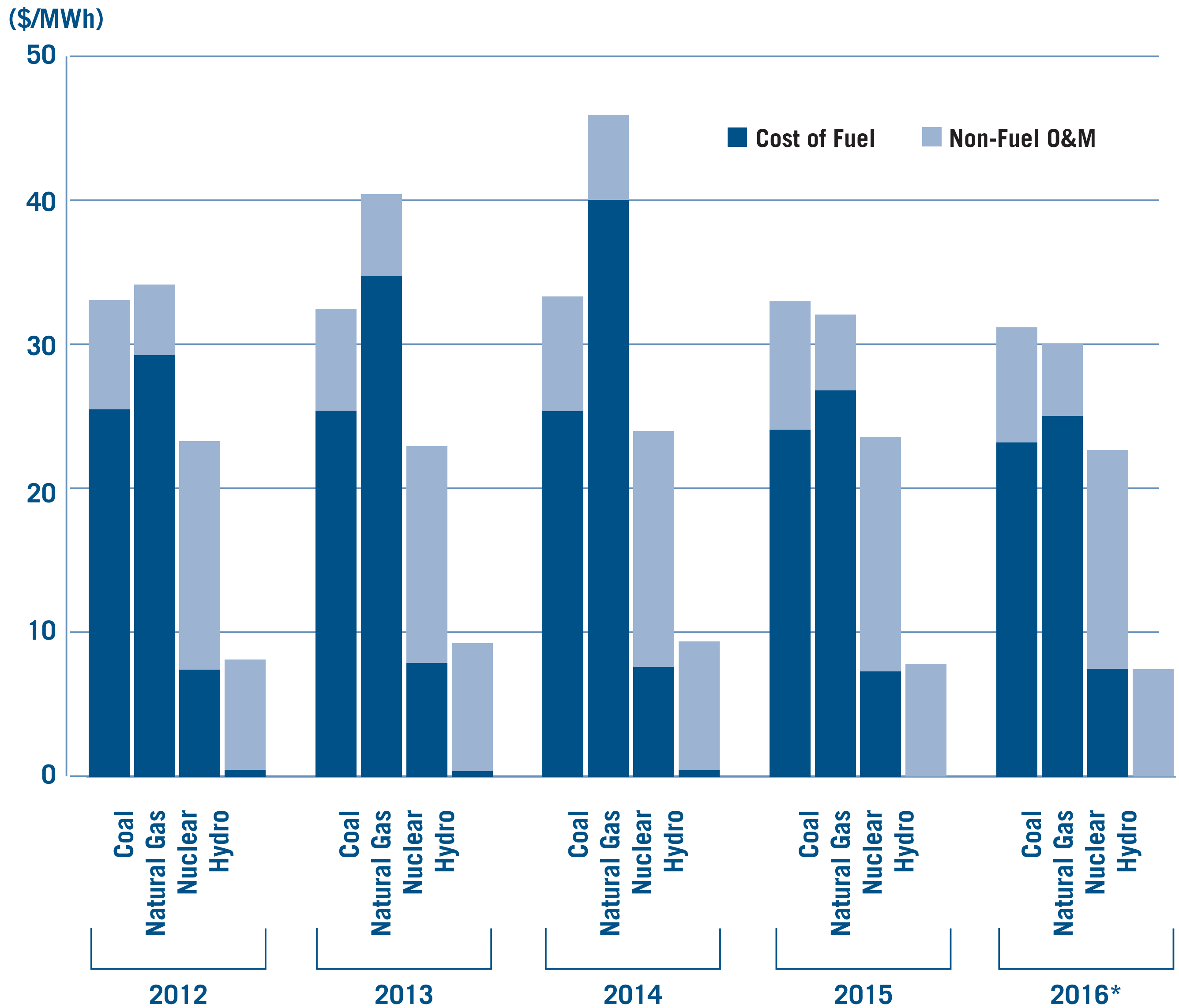
p = preliminary

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.

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

Average Cost to Produce Electricity 2012–2016

U.S. ELECTRIC UTILITY AND NON-UTILITY



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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.

* 2016 results are preliminary and based on modeled data from ABB's Velocity Suite.

Source: Velocity Suite, ABB Enterprise Software.

Fuel price dynamics caused natural gas in 2016 to overtake coal as the primary source of power generation for the first time in U.S. history. And at 8.4% of the energy mix, generation from non-hydro renewable resources achieved yet another record. It is worth noting that over one-third (34.7%) of U.S. electric generation in 2016 came from zero-carbon-emission sources (nuclear, hydropower and other renewables). Another one-third (33.8%) came from low-emissions natural gas, while oil and coal accounted for only 31% of total generation, down from 52.1% a decade earlier.

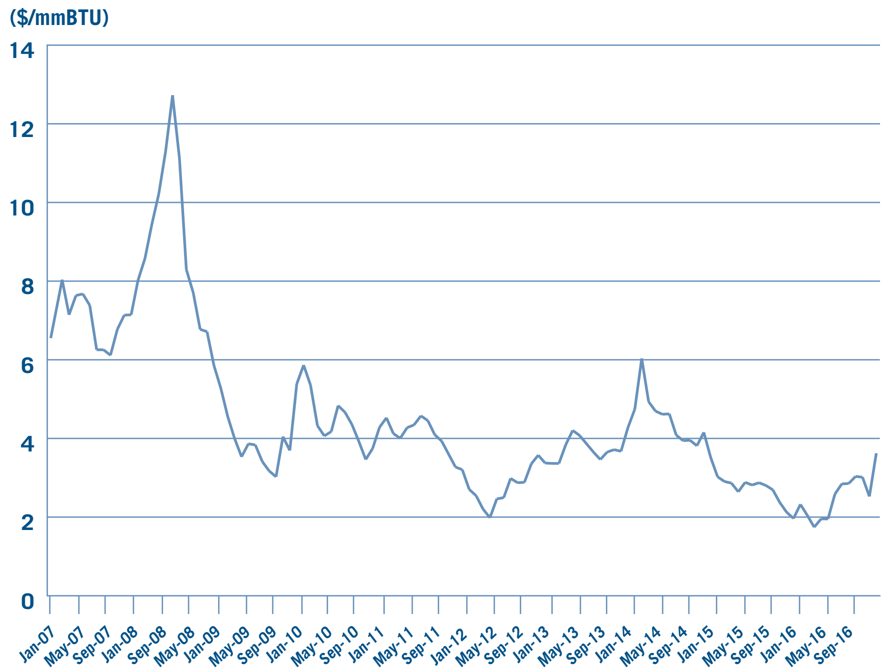
Coal

In 2016, coal lost its long-standing role as the primary fuel used to produce electricity in the U.S. Coal generation declined by 8.5% year-year and its share of the generation mix declined from 33.2% in 2015 to 30.4%. At 33.8% of the mix, natural gas became the leading resource for power generation.

The long-term decline in coal-fired generation has been evident for a number of years. One factor driving the trend in recent years is the shrinking fuel price differential between coal and natural gas. Up until 2008, coal enjoyed a significant cost advantage over natural gas and other fuels used for power generation. The "shale revolution" that started in 2008-09, however, caused a rapid rise in production of unconventional natural gas, which dramatically reduced prices and narrowed the cost gap between natural gas and coal generation. In addition, the impact of environmental regulations has forced the coal fleet to shrink in favor of natural gas and renewable plants. Although the new Trump administration's policy direction may try to preserve fossil fuel generation, zero-marginal-cost renewable power and low-cost, flexible and cleaner natural gas generation will likely continue to erode coal's market share for economic reasons.

In 2016, reduced demand for coal brought coal prices and production down from 2015 levels and some coal producing regions experienced the lowest prices of the decade. The average spot price for Central Appalachian coal in 2016 was $46.04 per ton compared to $53.37 per ton in 2015 (a reduction of 13.7%). Northern Appalachian coal prices fell from $58.15 in 2015 to $48.94 in 2016, a decline of 15.8%. Prices in the Powder River Basin declined 15.8%, from $10.09 per ton to $8.49 per ton. Over the 2015-2016 period, coal spot price declines ranged from -20% in PRB to -31% in the Northern Appalachian region. As a result, the total cost to produce electricity from coal fell about 6% year-to-year, from $33.20 per MWh in 2015 to $31.20 per MWh in 2016.

NYMEX-Henry Hub Natural Gas Close Prices
2007–2016



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

Natural Gas

The share of total electricity generation fueled by natural gas rose to 33.8% in 2016, making natural gas for the first time the primary fuel for power generation. Production and consumption of natural gas increased continually from 2010 to 2015, and, while consumption broke yet another record in 2016 (27,497 Bcf) production declined by 2.0% to 28,296 Bcf.

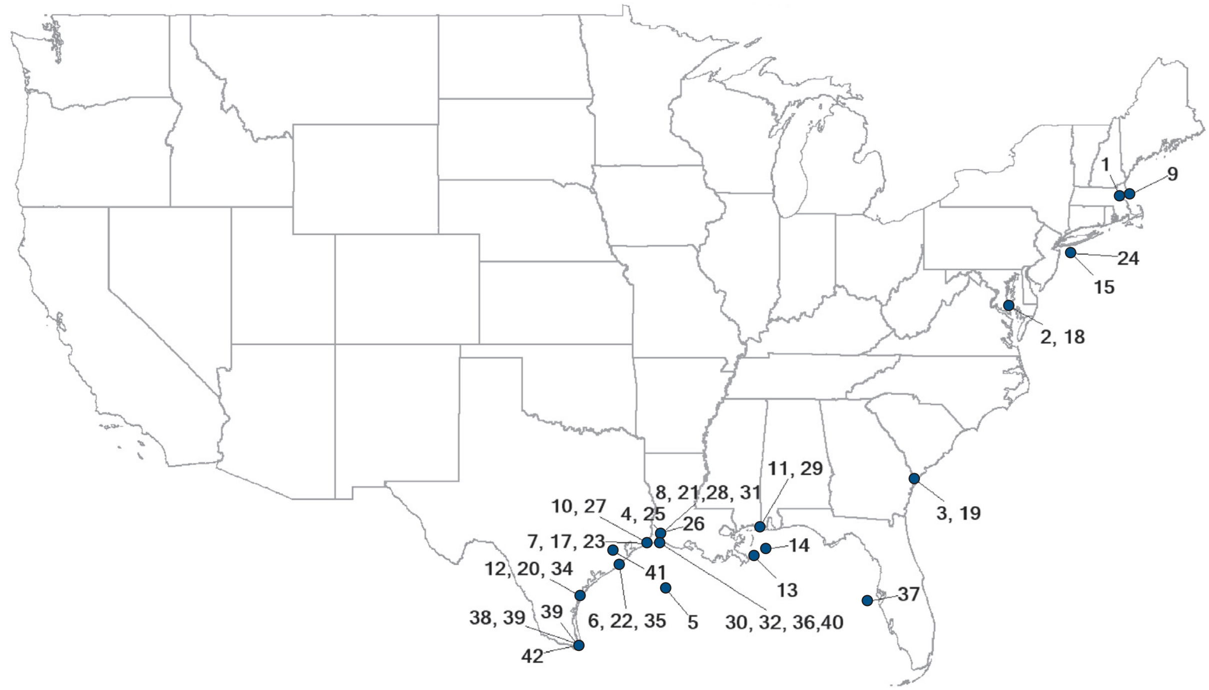
The increase in natural gas demand was small (0.7%) and driven almost exclusively by a rise in demand from power generation and industrial users. Natural gas use for power generation grew 3.2% in 2016 and now accounts for over 36% of total U.S. natural gas consumption. Demand from the industrial sector also increased (+2.5%) although a mild winter caused residential and commercial sector demand to fall by 4.7% and 2.3%, respectively.

The average Henry Hub spot price in 2016 was $2.51 per million BTU, down from $2.63 in 2015; this was the lowest average price since the 1990s when the annual average ranged between $1.50 and $3.00 per million BTU. The decline in spot prices also contributed to a decrease in the cost to produce electricity from natural gas, which declined from $31.97 per MWh in 2015 to $30.09 per MWh in 2015, less than the cost of producing electricity from coal ($31.20 per MWh).

The natural gas domestic energy balance influences natural gas imports and exports. After a sharp and steady decline in imports from 2008 to 2014, the import market seemed to rebound. In 2016, overall imports grew 10%, driven by a strong increase in imports from Canada. Canada continued to account for nearly all imported natural gas (at 97% of the total). Liquefied natural gas (LNG) imports declined by 3% in 2016. Exports of natural gas continued to increase rapidly, growing by 31% in 2016 due mostly to an increase in exports to Canada (+12.4%) and Mexico (+28.7%). These two countries account for 92% of U.S. exports of natural gas. In 2015, exports to Mexico exceeded those to Canada for the first time and now account for almost 60% of all U.S. exports. LNG exports grew in percentage terms by 558%, but overall volume remained relatively modest and accounted for only 8% of total exports, up from 2% in 2015.

LNG export growth in recent years has resulted from the growth of natural gas reserves and high levels of domestic production, which have caused LNG developers to cancel some import projects and consider options for re-exporting and/or expanding terminals to add liquefaction, storage and export facilities. FERC has authorized facilities in Texas, Louisiana and Maryland to re-export LNG. DOE has approved multiple applications for terminals to liquefy and export domestically produced gas to countries with which the U.S has signed a free trade agreement.

Existing and Proposed U.S. LNG Terminals
As of December 31, 2016



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 by MARAD/Coast Guard

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

Proposed to FERC/MARAD

15. Offshore, NY: 0.4 Bcfd (Liberty Natural – Port Ambrose)

(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.

Export terminals

Constructed

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

Under Construction

18. Cove Point, MD: 1.0 Bcfd FTA & 0.77 Bcfd non-FTA (Dominion -Cove Point LNG) (b) (c)
19. Elba Island, GA: 0.35 Bcfd (Southern LNG) (b) (d)
20. Corpus Christi, TX: 2.1 Bcfd (Cheniere - Corpus Christi LNG) (b) (c)
21. Hackberry, LA: 2.1 Bcfd (Cameron LNG -Sempra Energy) (b) (c)
22. Freeport, TX: 2.14 Bcfd FTA & 0.4 Bcfd non-FTA (Freeport LNG Dev./FLNG Liquefaction) (b) (c)
23. Sabine Pass, LA: 1.4 Bcfd (Cheniere/Sabine Pass Liquefaction) (b) (c)
24. Sabine Pass, LA: 1.4 Bcfd (Sabine Pass Liquefaction) (b) (c)

Approved by FERC

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

Proposed to FERC/MARAD

29. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (b) (d)
30. Plaquemines Parish, LA: 0.30 Bcfd (Louisiana LNG)
31. Cameron Parish, LA: 1.84 Bcfd (G2 LNG)
32. Calcasieu Parish, LA: 4.0 Bcfd (Driftwood LNG)
33. Nikiski, AK: 2.55 Bcfd (ExxonMobil, ConocoPhillips, BP, TransCanada and Alaska Gasline)
34. Corpus Christi, TX: 1.4 Bcfd (Cheniere – Corpus Christi LNG)
35. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev)
36. Cameron Parish, LA: 1.84 Bcfd (Venture Global) (b) (d)
37. Jacksonville, FL: 0.075 Bcfd (Eagle LNG Partners) (d)
38. Brownsville, TX: 0.55 Bcfd (Texas LNG Brownsville) (b) (d)
39. Brownsville, TX: 0.9 Bcfd (Annova LNG Brownsville) (b)
40. Gulf of Mexico, Cameron Parish, LA: 1.8 Bcfd (Delfin LNG) (b) (d)
41. Port Arthur, TX: 1.86 Bcfd (Port Arthur LNG) (b) (d)
42. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade)

Nuclear

The U.S. continues to produce more electricity using nuclear power than any other nation. With 99 electricity-generating nuclear reactors, the U.S accounts for more than 30% of worldwide nuclear generation output. Total nuclear generation grew slightly (+1%) in 2016 versus 2015 and its share of the total U.S. electric generation mix grew accordingly, from 19.5% to 19.7%.

Given the cost structure of nuclear power, changes in total nuclear output are mostly driven by the number of plants operating rather than fuel price differentials relative to other resources. In early 2012, the Nuclear Regulatory Commission (NRC) approved Southern Company's two new nuclear reactors at its Vogtle plant in Georgia and SCANA's Virgil C. Summer Nuclear Station's two reactors in South Carolina. These were the first nuclear reactors approved in decades. In May 2016, after 44 years of construction, TVA's Watts Bar 2 came online; this is the first new reactor in the U.S. in 20 years, although many nuclear reactors have been granted 20-year license extensions during the last few years.

Despite these indications of growth potential, nuclear output has not been immune to the broader developments impacting U.S. energy markets. Since 2013, six reactors with more than 5,000 MW of combined total capacity have been decommissioned and electric companies have announced plans to retire another eight (7,500 MW) between 2017 and 2025.

In 2013, for the first time since 1998, four nuclear reactors were retired and another (Vermont Yankee) was decommissioned in 2014. Weak pricing conditions in wholesale power markets and declining profitability caused Dominion Power to close the Kewaunee plant in Wisconsin. Concerns about maintenance and high repair costs drove Duke Energy to retire the Crystal River plant in Florida, which had been out of service for repairs since 2009, and caused Edison International to permanently close the San Onofre Nuclear Generating Station (SONGS), which had been shut down since January 2012. Low profitability was also the reason cited for the announced retirement of Entergy's Vermont Yankee at the end of 2014. In the fall of 2015, Entergy announced the planned closure of two more nuclear plants, Pilgrim in Massachusetts and James A. Fitzpatrick in New York. In June 2016, Exelon Corp. announced that it would close its Clinton and quad Cities nuclear plants in 2017 and 2018, respectively, after the Illinois legislature failed to pass legislation supporting zero-emissions power.

While declining prices in wholesale power markets and declining profitability for competitive generation are casting doubt on the long-term viability of nuclear power in organized markets, these are not the only reasons nuclear power is being decommissioned. In 2016, under pressure to build a more flexible power grid, PG&E announced it would not seek to relicense the two units in Diablo Canyon and that it would phase out the plant by 2025. Diablo Canyon supplies around 6% of the state's electricity; PG&E plans to replace it with energy efficiency, renewables and energy storage.

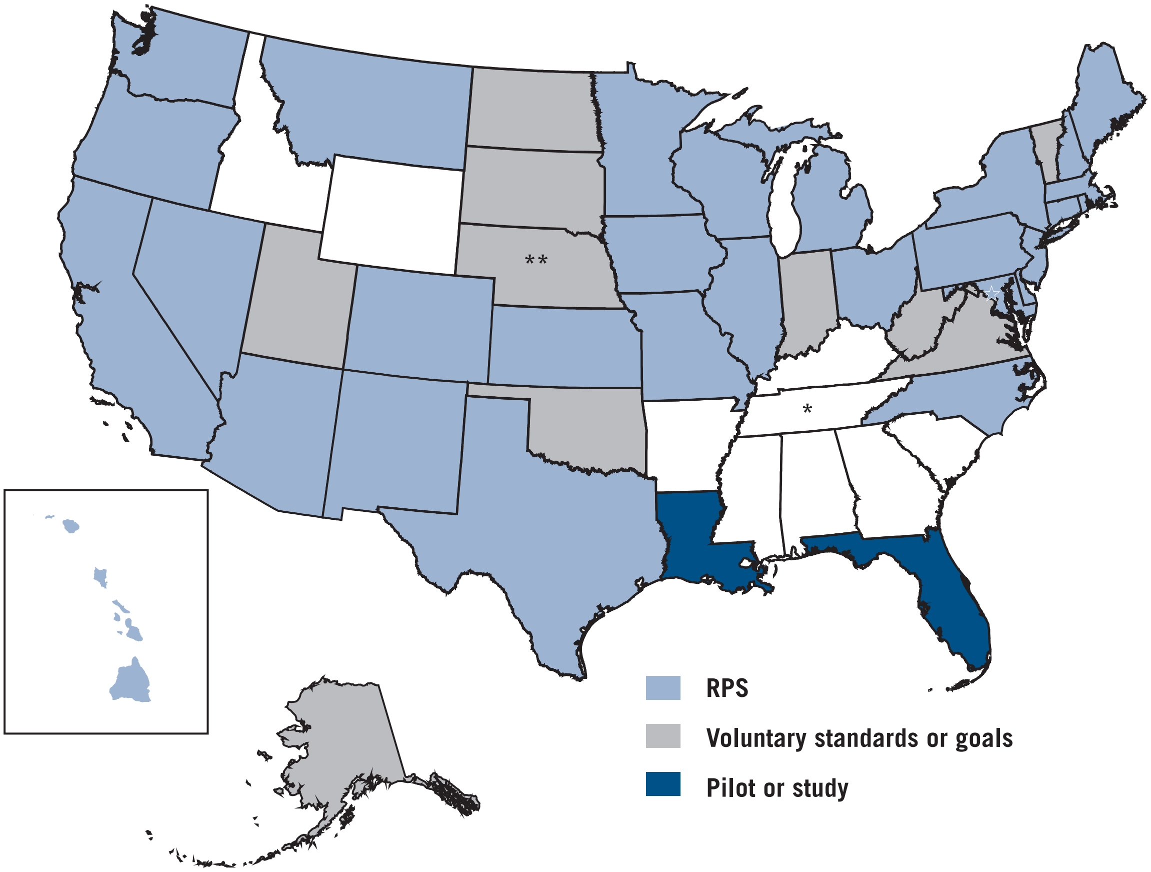
Renewable Energy

Renewable fuel sources, including hydro, achieved yet another record at 14.9% of total U.S. electric generation in 2016. Non-hydro generation likewise hit a new record, at 8.4% of the generation mix (up from 7.3% in 2015). This growth was primarily due to an 18.6% increase in wind output. Wind generation is the largest source of non-hydro renewable power in the country and accounted for 66% of all non-hydro renewable electricity production in 2016.

Solar generation is the fastest growing source of electricity in percentage terms; however its share of total nationwide output remains modest. Solar output grew 39% in 2016, although this was less than its growth rate in both 2015 and 2014. Solar generation represented 10.7% of non-hydro renewable generation (up from 8.2% in 2015) and only 0.9% of total electric output. Biomass and geothermal continued to make a small but steady contribution to the nation's energy mix; in 2016, biomass accounted for 1.5% of total output and geothermal 0.4%. Their shares of the total have remained steady over the years, accomplished through steady increases in production roughly equivalent to the growth of the whole renewable sector.

Renewable energy generation is growing not only at the bulk power level but also (and perhaps more visibly) at the distribution system

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



AZ: 15% by 2025; 4.5% DG
CA: 33% by 2020
CO: 30% by 2020 (10% co-ops, munis), 3% DG and 1.5% customer sited.
CT: 27% by 2020
DC: 20% by 2020, 2.5% solar by 2023
DE: 25% by 2026, 3.5% PV. Triple credit for PV
HI: 40% by 2030
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2026; wind 75%, 1.5% PV and 0.25% DG
IN: 15% by 2025 (goal)
KS: 20% by 2020
MA: 22.1% by 2020, then 1% annually; 2 GW wind and 400 MW PV by 2020
MD: 20% by 2022, 2% solar by 2020
ME: 10% new by 2017; 8 GW wind goal by 2030
MI: 10% by 2015. 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: 29% by 2015, 0.58% customer sited by 2015
OH: 12.5% by 2026, 0.5% solar electric
OK: 15% by 2015 (goal)
OR: 25% by 2025 (5-10% - smaller utilities). 20 MW PV by 2020. Double credit for PV
PA: 18% by 2021, 0.5% PV by 2021
RI: 16% by end 2020
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: 20% by 2017; 1% DG by 2017 + 3/5 of 1% per year until 10% by 2032
WA: 15% by 2020, double credit for DG
WI: 10% by 2015
WV: 25% by 2025, various multipliers (goal)

Updated March 2016

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 level through residential rooftop solar installations. Lower costs, net metering and other state policies are supporting deployment of distributed energy technologies, solar rooftop photovoltaics in particular. Yet these policies were not designed to promote deployment of a maturing technology and are being revised to reduce unnecessary costs to consumers and unfair cost-shifts between customer types. Many state public utility commissions are working with stakeholders to revise rate designs and other rules so that solar power can continue to thrive while unfair cost-shifts among customers are reduced or eliminated.

Oil

Oil fueled only 0.6% of U.S. electric output in 2016, down from 0.7% the previous year. Hawaii has the largest share of oil-powered generation (at 70-80%) of all states, followed by Alaska (at 10-15%). These two states account for about 30% of all oil used for power generation nationwide. The remainder is used by Louisiana, Florida and several other states (mostly in the Northeast) that are heavily dependent on natural gas plants, some of which have dual-fuel units.

Oil has played a diminishing role in the U.S. electric fuel portfolio since 2006, when it accounted for about 3% of generation. High oil prices contributed to the decline in oil use. While crude oil prices averaged $15 to $25/barrel in the mid-1990s, the price of oil began an upward climb at the beginning of the 2000s. West Texas Intermediate crude spot prices peaked at over $145/barrel in July 2008, before the onset of the 2008/2009 financial crisis and recession. Prices fluctuated in a range of $85-105/barrel from early 2011 through the summer of 2014. Crude oil prices then began a precipitous decline after Saudi Arabia's decision not to reduce production in the hope of driving higher-cost producers (shale oil producers in particular) out of the market. Crude oil prices fell from $105.79/barrel in July 2014 to $47.82/barrel in March 2015 and closed the year at $37.19/barrel. By February 2016, the price of crude oil had fallen to just over $30/barrel. Starting in March 2016, however, crude oil prices began rising and ended 2016 at $53.75/barrel.

While dramatic, these price moves should not have a meaningful impact on the power sector's consumption of oil for generation. The state most dependent on oil, Hawaii, has aggressive plans to move away from this resource, including increased use of LNG and a significant build-out of renewable energy facilities. In May 2015, Hawaii's legislature passed a mandate to generate 100% of the state's electricity from renewables by 2045, the first state to embrace a 100% renewable power policy.

As has historically been the case, crude oil prices in the U.S. will remain subject to the dynamics of the international oil market, itself driven by changes in global demand, supply constraints in oil producing regions, the levels of stocks and spare capacity in industrialized countries, geopolitical risks, and the relative strength of the U.S. dollar versus other currencies. However, these dynamics may evolve as the U.S. role in international oil markets changes. In 2013, for the first time since the 1990s, the U.S. produced more oil than it imported. In 2015, the U.S. became the world's leading producer of oil and natural gas, surpassing energy giants Russia and Saudi Arabia. At the end of the year, a decades-old export ban on crude oil was lifted, showing the profound historical change in sentiment surrounding the energy situation in the U.S.

Capital Markets

Stock Performance

The EEI Index returned a strong 17.4% in 2016, just ahead of the Dow Jones Industrial Average's 16.5% return and well ahead of both the S&P 500's 12.0% return and the Nasdaq Composite's 7.5% gain. But the full-year was very much a tale of two halves. Rarely, in fact, does a full-year pattern of stock market return bisect itself precisely at the mid-year point, but that was the case for electric utilities as a group in 2016. Moreover, the year offered a showcase in the way fast-changing global macroeconomic trends, rather than the industry's very slow-changing fundamentals, tend to drive the industry's stock performance over shorter-term time frames.

A Tale of Two Halves

The first half of the year was the strongest for utility stocks in a quarter century, both in absolute terms and relative to the broad market averages. The EEI Index jumped 23.5% through June 30, while the Dow Jones Industrials Average and S&P 500 each returned about 4% and the Nasdaq declined 3.3%. Utility shares peaked for the year in early July, then declined about 5% in Q3 and were flat in Q4, while the Dow and S&P 500 gained 8% to 10%, respectively, in the year's second half. Trends in interest rates and global economic data largely produced these moves.

2016 Index Comparison

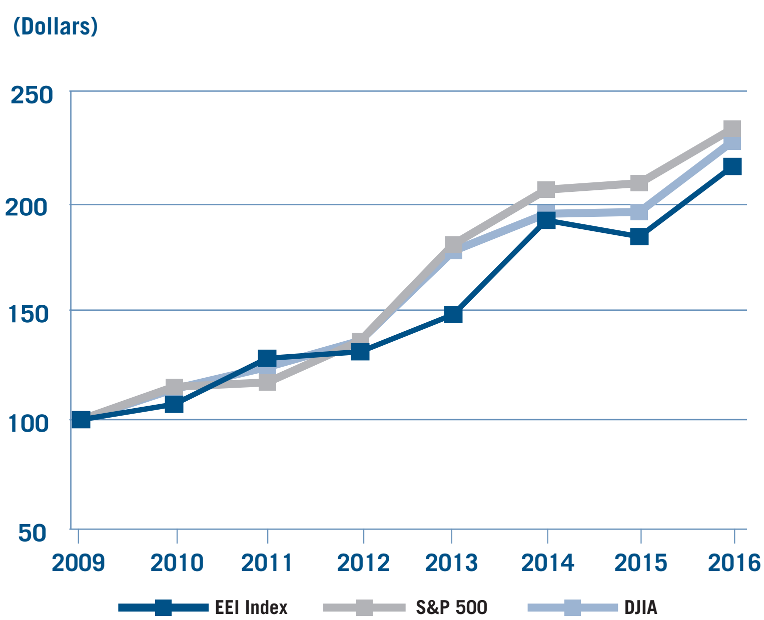
EEI Index	**17.44**
Dow Jones Industrials	16.50
S&P 500	11.96
Nasdaq Composite Index*	7.50

* 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 1/1/10–12/31/16

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2009.

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

2016 Returns By Quarter

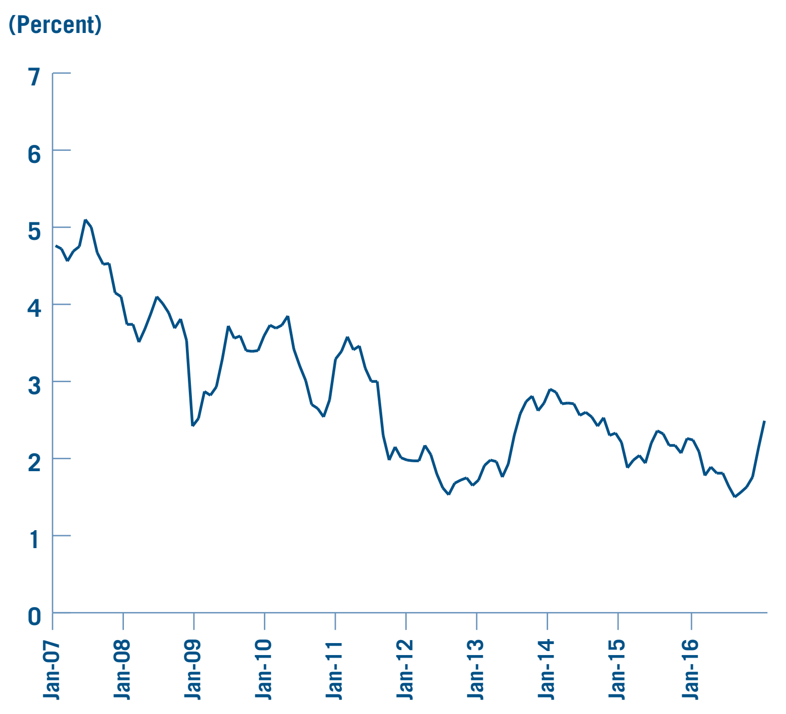
Index	Q1	Q2	Q3	Q4
EEI Index	15.6	6.9	(5.4)	0.5
Dow Jones Industrial Average	2.2	2.1	2.8	8.7
S&P 500	1.4	2.5	3.9	3.8
Nasdaq Composite*	(2.8)	(0.6)	9.7	1.3

Category	Q1	Q2	Q3	Q4
All Companies	15.5	7.7	(4.3)	2.7
Regulated	15.9	7.2	(4.3)	1.9
Mostly Regulated	13.2	10.1	(3.7)	3.8
Diversified	21.6	2.2	(7.8)	9.5

* 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
1/1/07 through 12/31/16



Source: U.S. Federal Reserve.

First Half: Weak GDP and Falling Yields

The broad market began 2016 with one of its worst starts in history, falling about 10% through mid-February as concern over weakening Chinese economic data and sharply falling oil prices were compounded by worries about already sluggish global economic growth. The U.S. 10-year Treasury yield slid from 2.3% to 1.7% by late February, then drifted sideways with a downward bias through Q2, falling to 1.4% by early July. U.S. real gross domestic product (GDP) data gave substance to slowdown fears; real GDP grew only 0.8% quarter-to-quarter in Q1 after rising only 0.9% in Q4 2015, while Q2 GDP grew only 1.4%. Slow growth was a global phenomenon as well. European continent-wide real GDP growth was mired at a 0.4% quarter-to-quarter pace in the first half, while Japan was also under stuck 1% annualized. Global interest rates declined as well. By late June, an astonishing range of European government debt yields were in negative territory. Swiss government yields were negative out to the 20-year maturity, German bunds out to the nine-year point, Austrian sovereign debt to the eight-year point and France to seven years. Japan's sovereign yields were negative out to 15 years. Fully twelve European nations, as well as Japan, had negative yields on two-year sovereign debt. Low to negative global interest rates forced yield hungry overseas investors into positive yielding U.S. bonds and into dividend paying U.S. equities. This flood of global capital contributed to utilities' first half strength.

Second Half: Stronger GDP and Rising Yields

The 10-year U.S. Treasury yield bottomed for the year on July 8 at 1.37% and it was up from there; utility stocks peaked for the year on July 6 and then declined. The 10-year yield climbed to 1.6% by September 30 and — sparked by the prospect of aggressive fiscal stimulus and tax cuts created by Donald Trump's unexpected presidential election victory — to 2.5% at yearend. Stronger U.S. economic data was a key reason for the rate rise. Strength in consumer spending helped the U.S. economy grow 3.5% in Q3, its fastest quarterly growth rate in two years. The outlook for corporate profits also strengthened. After a four quarter stretch of year-to-year declines in S&P 500 aggregate earnings (due in part to weak energy sector results from the two year fall in oil prices) corporate earnings growth turned positive in Q3. Analysts expect S&P 500 earnings to rise 11% to 12% in both 2017 and 2018, according to consensus estimates at yearend. Corporate earnings in Europe were forecast to be up 15% in 2017 and 10% in 2018.

The jump in interest rates and stronger profit outlook caused utilities to lag more cyclical and economically sensitive market sectors. In Q4, for example, the EEI Index gained 0.5% while the oil & gas, industrials and basic materials sectors showed 6% to 7% gains while financials jumped over 13% on hopes for a profit recovery from better net interest margins and potential for easier regulation in a Trump administration.

Industry Fundamentals Remain Stable

There was little meaningful change in the industry's fundamental picture during 2016. Electricity demand remained virtually flat; total electric output rose only 0.2% over the level in 2015 in the lower 48 states. Nationwide power demand has, in fact, been about flat for a decade; EIA net generation data shows 2007 generation at 4,064,702 thousand megawatthours and 2015 generation at 4,077,601 thousand megawatthours. Output notched up in 2007 to 4,156,745 thousand megawatthours but fell during the subsequent recession and has yet to reach the 2007 level. Yet the pattern is not a new trend or a surprise; the impact of energy efficiency programs and the changing economic landscape (away from energy-intensive industry and manufacturing and toward services) has been well recognized in the industry for several years. In response, a number of state utility commissions have adopted rate designs that help utilities cope with flat demand while still enabling investment required to comply with environmental regulations, grid modernization and upgrades to vital infrastructure. Nevertheless, the outlook for flat demand is a "new normal" that represents a departure from the consistent demand growth that characterized the industry's experience for more than a century.

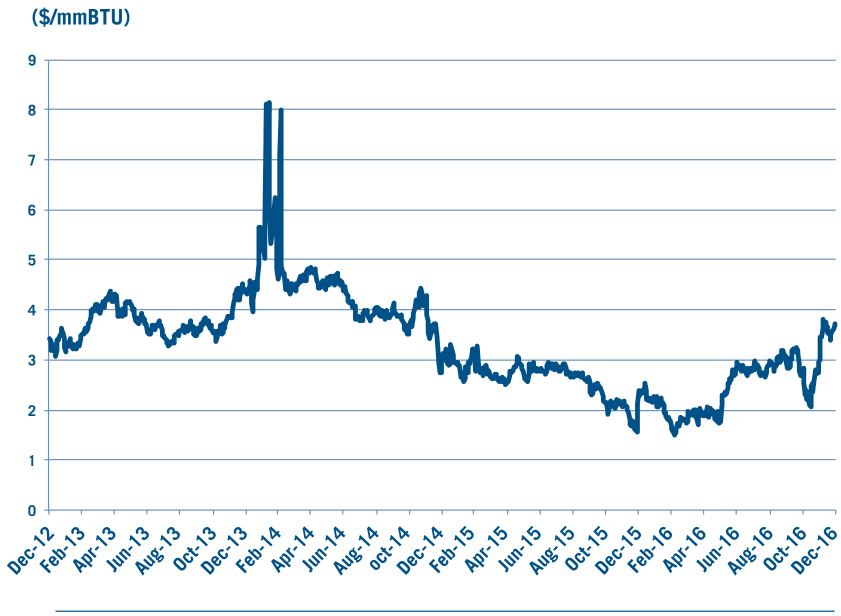
While the industry has reduced its exposure to the merchant generation business, several large utilities maintain competitive subsidiaries and influence EEI Index performance. Natural gas generation sets power prices in many competitive market areas. Natural gas spot prices in 2016 averaged about \$2.50/MMBtu at the national benchmark Henry Hub, the lowest annual average price since 1999. The monthly average price fell below \$2.00/MMBtu from February through May, but later increased, holding through most of December above \$3.50/MMBtu. Analyst outlooks at yearend generally did not foresee anything that would produce

Sector Comparison 2016 Total Shareholder Return

Sector	Total Return %
Oil & Gas	26.3%
Telecommunications	24.0%
Basic Materials	20.3%
Industrials	19.5%
EEI Index	**17.4%**
Financials	17.3%
Utilities	17.1%
Technology	14.2%
Consumer Services	6.0%
Consumer Goods	5.3%
Healthcare	-2.4%

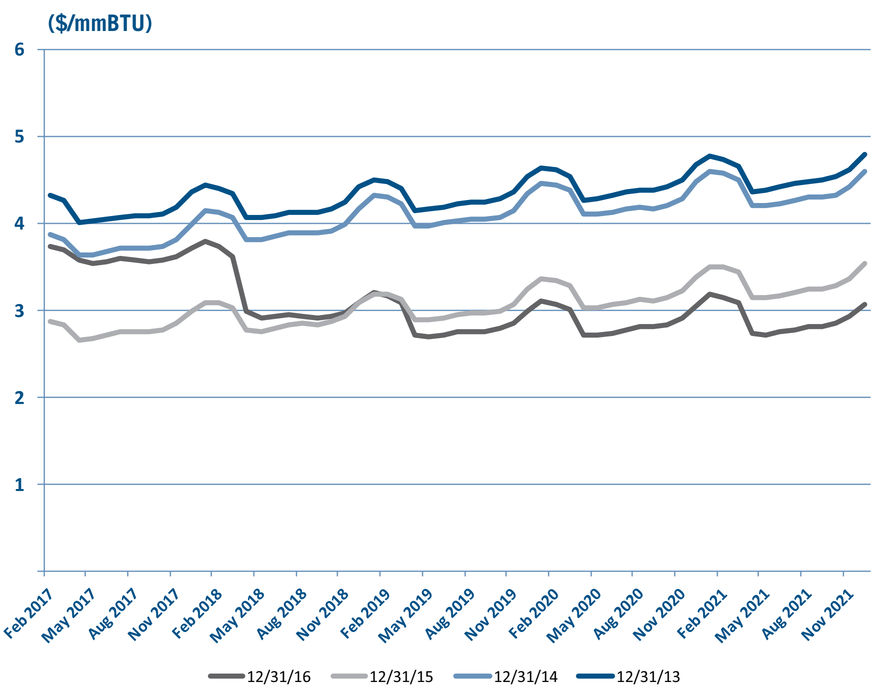
Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

Natural Gas Spot Prices - Henry Hub
12/31/12 through 12/31/16



Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2017 through December 2021



Source: S&P Global Market Intelligence.

a sustained up move in natural gas; the potential reserve supply from the shale gas revolution is simply too great and many expect spot gas to remain below $3.50/MMBtu over the next year or two. The magnitude of the multi-year decline in natural gas prices has both crushed competitive power prices and also supported the industry's ongoing migration away from coal generation to much cleaner natural gas generation. As recently as 2010, gas futures showed market expectations for $6.00/MMBtu gas.

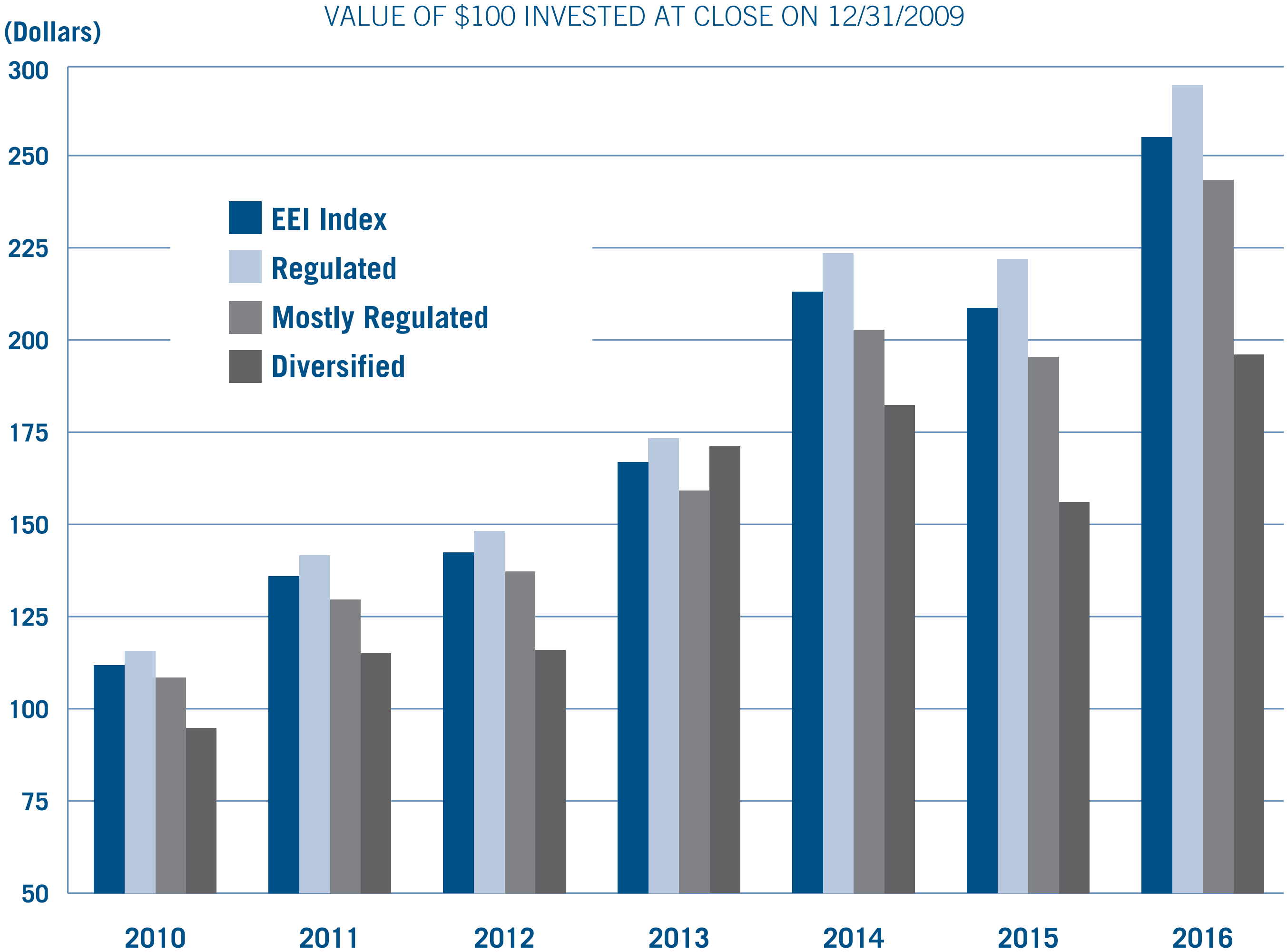
While utility regulation largely occurs at the state level and must be analyzed state by state, industry analysts at yearend generally viewed regulation as largely fair and balanced overall for the industry taken as a whole. While allowed return on equity has come down in recent years so have interest rates. Moody's in early 2017 called the industry's credit outlook "stable" based on expectation that utilities will continue to recover costs in a timely manner and maintain stable cash flows.

Slow Growth and Dividends

Flat demand "growth" is posing a challenge to utilities seeking to maintain mid-single-digit earnings growth with stable or slowly growing dividends. Several companies have acquired gas distribution utilities and invested in natural gas infrastructure in search of growth. Other smaller utilities have agreed to be acquired in order to give shareholders a boost and enhance financial and operation strength as part of a larger company. The industry's earnings growth outlook has also been challenged somewhat by a flattening in industry capex spending, since ca-

Comparative Category Total Annual Returns 2010–2016

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2009



	2010	2011	2012	2013	2014	2015	2016
EEI Index Annual Return (%)	11.87	21.39	4.82	17.27	27.63	(2.05)	22.21
EEI Index Cumulative Return ($)	111.87	135.79	142.34	166.92	213.04	208.66	255.01
Regulated EEI Index Annual Return	15.75	22.30	4.72	16.97	28.92	(0.67)	21.16
Regulated EEI Index Cumulative Return	115.75	141.56	148.24	173.40	223.55	222.04	269.02
Mostly Regulated EEI Index Annual Return	8.51	19.52	5.81	15.97	27.46	(3.67)	24.57
Mostly Regulated EEI Index Cumulative Return	108.51	129.68	137.21	159.13	202.82	195.37	243.37
Diversified EEI Index Annual Return	(5.16)	21.36	0.78	47.54	6.61	(14.43)	25.59
Diversified EEI Index Cumulative Return	94.84	115.09	115.98	171.12	182.43	156.11	196.06

- 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, 2009.

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

2016 Category Comparison

Category	Return (%)
EEI Index	**22.21**
Regulated	21.16
Mostly Regulated	24.57
Diversified	25.59

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2016 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 12/31/2016

Company	Total Return %	Category
MDU Resources Group, Inc.	62.0	MR
Otter Tail Corporation	58.9	R
MGE Energy, Inc.	43.7	MR
CenterPoint Energy, Inc.	40.3	MR
Westar Energy, Inc.	36.6	R
Black Hills Corporation	35.8	R
Exelon Corporation	32.5	D
OGE Energy Corp.	32.0	R
Unitil Corporation	30.7	R
ALLETE, Inc.	30.7	MR

Note: Return figures include capital gains and dividends.

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

Market Capitalization at December 31, 2016 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Symbol	Market Cap.	% of Total	Company Name	Symbol	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	55,346	8.39%	Pinnacle West Capital Corporation	PNW	8,694	1.32%
Duke Energy Corporation	DUK	53,480	8.10%	Alliant Energy Corporation	LNT	8,609	1.30%
Dominion Resources, Inc.	D	47,938	7.26%	Westar Energy, Inc.	WR	8,007	1.21%
Southern Company	SO	47,616	7.22%	NiSource Inc.	NI	7,136	1.08%
Exelon Corporation	EXC	32,828	4.98%	OGE Energy Corp.	OGE	6,680	1.01%
American Electric Power Company, Inc.	AEP	30,957	4.69%	MDU Resources Group, Inc.	MDU	5,619	0.85%
PG&E Corporation	PCG	30,446	4.61%	Vectren Corporation	VVC	4,318	0.65%
Sempra Energy	SRE	25,199	3.82%	Great Plains Energy Inc.	GXP	4,228	0.64%
Edison International	EIX	23,469	3.56%	IDACORP, Inc.	IDA	4,051	0.61%
PPL Corporation	PPL	23,090	3.50%	Portland General Electric Company	POR	3,853	0.58%
Consolidated Edison, Inc.	ED	22,436	3.40%	Hawaiian Electric Industries, Inc.	HE	3,580	0.54%
Public Service Enterprise Group Incorporated	PEG	22,159	3.36%	Black Hills Corporation	BKH	3,201	0.49%
Xcel Energy Inc.	XEL	20,714	3.14%	ALLETE, Inc.	ALE	3,171	0.48%
WEC Energy Group, Inc.	WEC	18,510	2.81%	NorthWestern Corporation	NWE	2,748	0.42%
DTE Energy Company	DTE	17,633	2.67%	PNM Resources, Inc.	PNM	2,735	0.41%
Eversource Energy	ES	17,552	2.66%	Avista Corporation	AVA	2,554	0.39%
FirstEnergy Corp.	FE	13,162	1.99%	MGE Energy, Inc.	MGEE	2,264	0.34%
Entergy Corporation	ETR	13,153	1.99%	El Paso Electric Company	EE	1,877	0.28%
Ameren Corporation	AEE	12,727	1.93%	Otter Tail Corporation	OTTR	1,584	0.24%
AVANGRID, Inc.	AGR	11,724	1.78%	Empire District Electric Company	EDE	1,502	0.23%
CMS Energy Corporation	CMS	11,579	1.75%	Unitil Corporation	UTL	634	0.10%
CenterPoint Energy, Inc.	CNP	10,612	1.61%				
SCANA Corporation	SCG	10,472	1.59%		**Total Industry**	**659,845**	**100.00%**

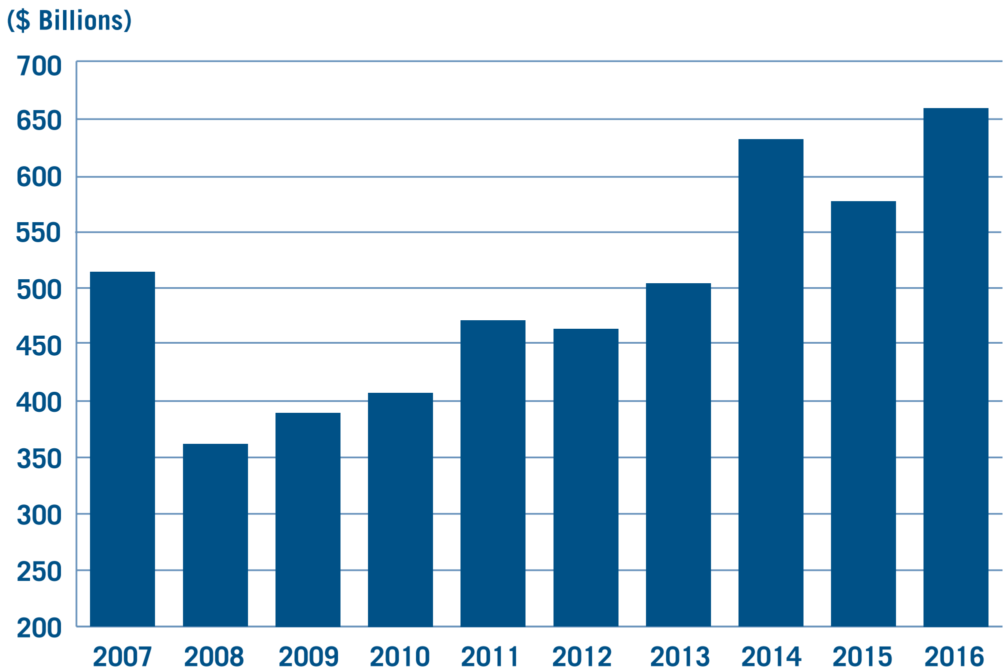
Source: EEI Finance Department and S&P Global Market Intelligence.

pex translates into rate base growth and non-rate base investments that can produce earnings growth. But companies have also responded to growth challenges with increasingly stringent operations and maintenance (O&M) cost containment.

Nevertheless, capex-related growth opportunities continue to result from the nation's ongoing move to cleaner generation, from building transmission necessary to move power from plants to load centers, updating and modernizing the grid, enhancing grid reliability and from distribution system upgrades and maintenance. The industry's total capital expenditures have doubled in the last decade and nearly tripled since 2004. EEI estimates 2017 capex at about $120 billion, up from $113 billion in 2016 and $104 billion in 2015. These estimates are based on publicly available disclosure in 10-K's and company reports and have tended to be conservative in relation to subsequent actual spending.

The industry is now focused largely on regulated businesses with a strong 3.4% dividend yield (at December 31, 2016), healthy balance sheets and the chance to drive the nation's ongoing transition to cleaner energy and a modernized grid. The classic 20th century utility formula — slow earnings and dividend growth — should continue to attract investors. Provided inflation doesn't surge and produce sharply higher interest rates, utility shares should continue to do well on a relative (and possibly absolute) basis when bearish sentiment dominates the broader stock market.

EEI Index Market Capitalization 2007–2016

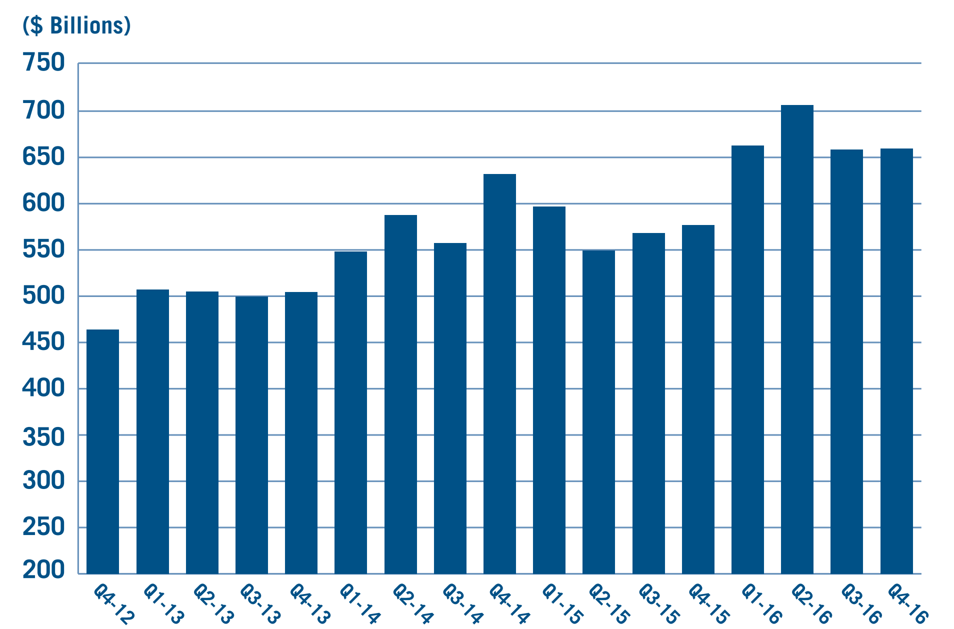


Note: Results are as of December 31 of each year.

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

EEI Index Market Capitalization

December 31, 2012–December 31, 2016



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

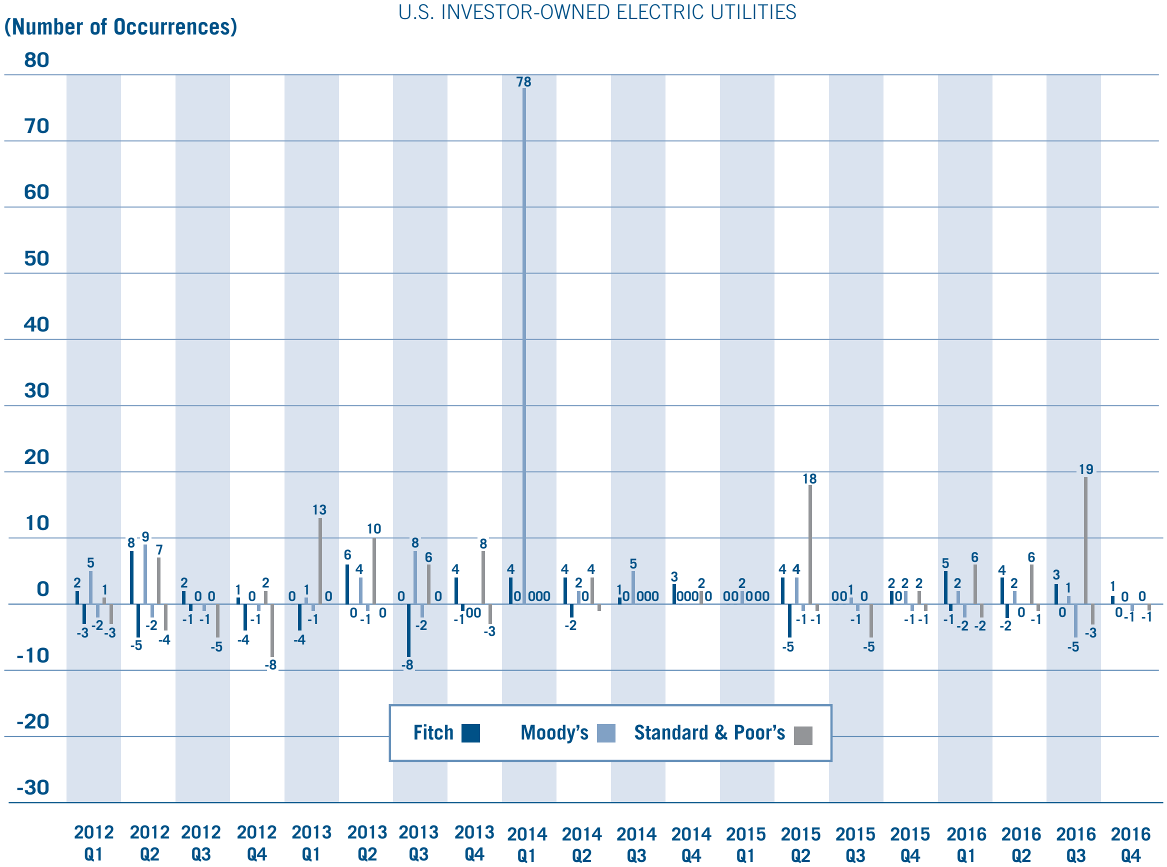
Credit Ratings

The industry's average credit rating was BBB+ in 2016, remaining for a third straight year above the BBB average that has held since 2004. Ratings activity, at 67 changes, was in line with the industry's annual average of 70 changes per year since 2008. Upgrades were 73.1% of total actions, the third-highest annual figure for upgrades in our dataset. In fact, the last four years have produced the four highest annual 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 rating was unchanged at BBB+, the underlying data show a modest strengthening. Six companies received upgrades at the parent level while only two were downgraded. Our universe of U.S. "parent" company electric utilities includes a few that are either a subsidiary of an independent power producer, a subsidiary of a foreign-owned company, or that have been acquired by an investment firm; three of the year's upgrades focused on a relationship with that ultimate parent company. Two other upgrades cited a reduced focus on merchant generation and an improved business risk profile. At January 1, 2017, 74.0% of ratings outlooks were "stable", 18.0% were "negative" or "watch-negative", 6.0% were "positive" or "watch-positive", and 2.0% were "developing".

Credit Rating Agency Upgrades and Downgrades 2012 Q1–2016 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 2012 Q1–2016 Q4

	2012		2013		2014		2015		2016	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	2	(3)	0	(4)	4	0	0	0	5	(1)
Q2	8	(5)	6	0	4	(2)	4	(5)	4	(2)
Q3	2	(1)	0	(8)	1	0	0	0	3	0
Q4	1	(4)	4	(1)	3	0	2	0	1	0
Total	**13**	**(13)**	**10**	**(13)**	**12**	**(2)**	**6**	**(5)**	**13**	**(3)**
Moody's										
Q1	5	(2)	1	(1)	78	0	2	0	2	(2)
Q2	9	(2)	4	(1)	2	0	4	(1)	2	0
Q3	0	(1)	8	(2)	5	0	1	(1)	1	(5)
Q4	0	(1)	0	0	0	0	2	(1)	0	(1)
Total	**14**	**(6)**	**13**	**(4)**	**85**	**0**	**9**	**(3)**	**5**	**(8)**
S&P										
Q1	1	(3)	13	0	0	0	0	0	6	(2)
Q2	7	(4)	10	0	4	(1)	18	(1)	6	(1)
Q3	0	(5)	6	0	0	0	0	(5)	19	(3)
Q4	2	(8)	8	(3)	2	0	2	(1)	0	(1)
Total	**10**	**(20)**	**37**	**(3)**	**6**	**(1)**	**20**	**(7)**	**31**	**(7)**

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 Changes at Ultimate Parent and Overall Regulated Focus

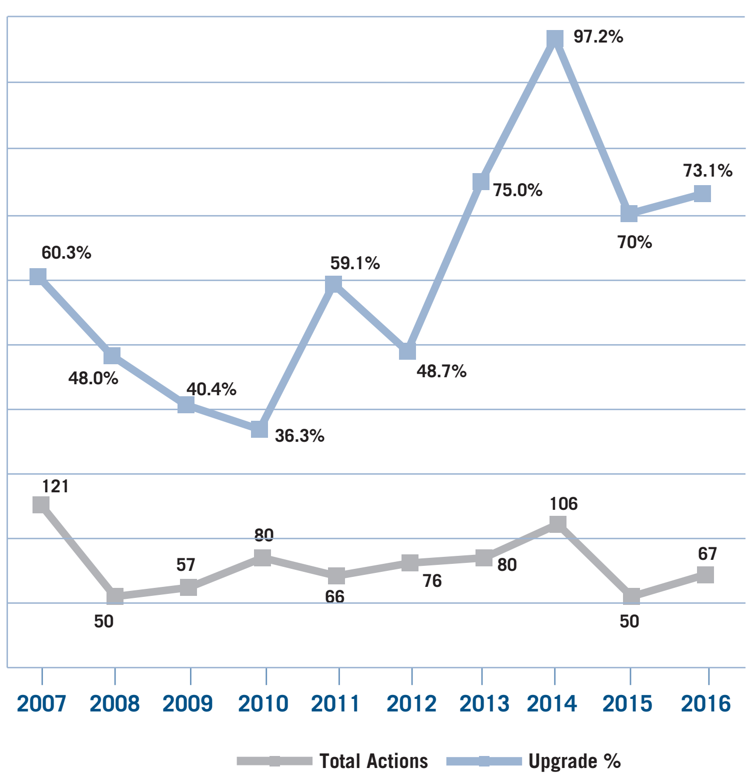
Ratings actions in 2016 included six parent company-level upgrades and only two downgrades.

Dominion Resources

On February 1, S&P lowered its issuer credit rating for Dominion Resources and subsidiaries Virginia Electric & Power and Dominion Gas Holdings LLC to BBB+ from A- following Dominion's announcement of its intent to acquire Questar Corp., a natural gas distribution, pipeline, storage and cost-of-service gas supply company headquartered in Salt Lake City, Utah. The downgrade was based on S&P's expectations that Dominion will continue to pursue growth through acquisition at a faster pace than peers. The Questar acquisition was completed in September *(please see Mergers & Acquisitions section for more details).*

Direction of Rating Actions

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

Berkshire Hathaway Energy

On February 19, S&P raised its issuer credit rating for Berkshire Hathaway Energy Co. to A from BBB+. The two-notch increase was based on S&P's reassessment of Berkshire Hathaway Energy's (BHE) relationship with ultimate parent Berkshire Hathaway, which revealed a higher contribution from BHE to the parent's consolidated earnings and a stronger strategic role within Berkshire Hathaway's overall business portfolio. S&P said BHE is important to Berkshire Hathaway's long-term strategy and is unlikely to be sold.

Cleco

On April 8, S&P lowered its issuer credit rating for Cleco Corp. to BBB- from BBB+, a two-notch downgrade. The move followed completion of Cleco's acquisition by a consortium of investors led by Macquarie Group LTD. The deal, valued at approximately $4.7 billion, includes approximately $1.3 billion of assumed debt; S&P cited materially weaker financial measures, including funds from operations, resulting from the acquisition and related debt.

IPALCO Enterprises

On April 14, S&P upgraded the issuer credit rating for IPALCO Enterprises and subsidiary Indianapolis Power & Light to BBB- from BB+, reflecting its upgrade the previous day of parent AES Corporation from BB- to BB. S&P said it rates IPALCO two notches higher than AES because of IPALCO's higher stand-alone credit profile and structural protections that include dividend limitations, a significant minority shareholder with an economic interest and certain veto rights, and a non-consolidation opinion.

AVANGRID

On April 22, S&P raised its issuer credit rating for AVANGRID and its subsidiaries to BBB+ from BBB. The higher rating resulted from S&P's upgrade of AVANGRID's ultimate parent, Spanish power company Iberdrola S.A. S&P assessed AVANGRID as a core member of Iberdrola, whose stand-alone credit profile is BBB+. In the absence of insulation, AVANGRID's issuer credit rating is determined by Iberdrola's rating. AVANGRID was formed by the merger between Iberdrola USA and UIL Holdings Corporation in December 2015.

Entergy

On August 4, S&P raised its issuer credit rating for Entergy Corp. and its subsidiaries to BBB+ from BBB. The upgrade reflected the company's improved business risk profile, which S&P placed at the higher end of the "strong" business risk profile category range. The improvement resulted from Entergy's execution of its long-term strategy of strengthening its management of regulatory risk while shrinking the size of its merchant generation business. Work with regulators to incorporate formula rate plans in Arkansas and Mississippi has allowed Entergy's subsidiaries to more consistently earn close to their authorized returns on equity; S&P said it expects this improvement to be sustained. The company's improving management of regulatory risk and above-average industrial demand growth within its service territory have also helped its financial measures remain steady despite its high capital spending and weak electricity prices.

PG&E Corp.

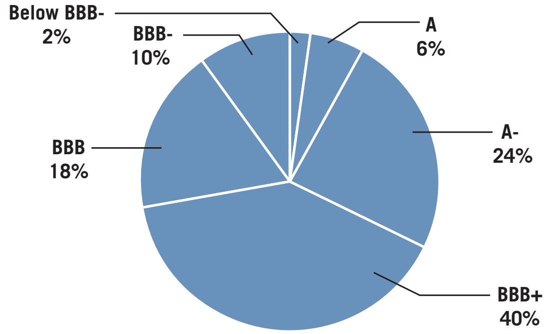
On August 15, S&P raised the issuer credit rating for PG&E Corp. to BBB+ from BBB. The upgrade reflects PG&E's continued steps since the 2010 San Bruno gas transmission explosion to improve its business risk profile. Following a guilty verdict related to pipeline safety violations, a federal jury set the company's maximum fine at $3 million, significantly below initial estimates. S&P placed PG&E at the higher-end of the "strong" business risk profile category.

American Electric Power

On September 19, S&P upgraded the issuer credit ratings for American Electric Power Co. and its subsidiaries to BBB+ from BBB following the company's announcement that it agreed to sell four Midwest generating plants for about $2.2 billion. S&P said the rating action reflects the reduced contribution of merchant generation to AEP's overall growth strategy, which emphasizes lower-risk regulated utility operations. The sale was completed in January 2017 to Lightstone Generation LLC, a joint venture of Blackstone Group LP and an affiliate of Arclight Capital Partners LLC. The sale included 5,200 MW of generation assets located in the

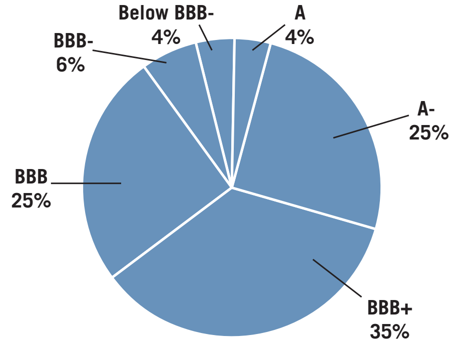
Bond Ratings December 31, 2016
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



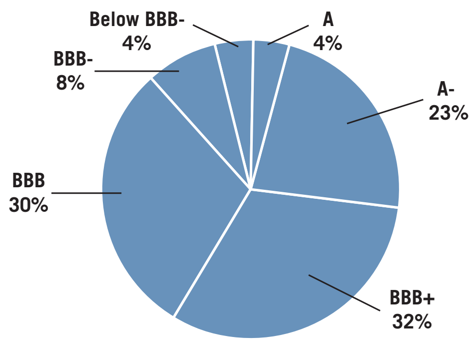
Bond Ratings December 31, 2015
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



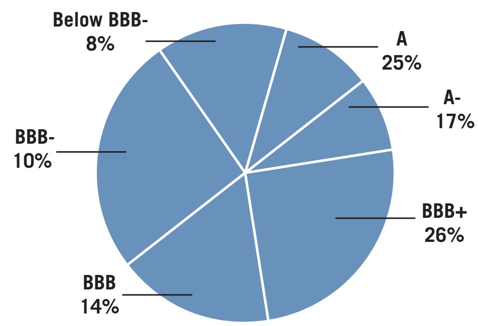
Bond Ratings December 31, 2014
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Rating applies to utility holding company entity.

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

region served by PJM Interconnection, with a mix of about 51% coal and 49% natural gas.

Light Activity by Moody's and Fitch

Moody's and Fitch each issued a modest number of ratings actions, affecting both parent companies and subsidiaries, relative to their annual totals since 2001. Moody's issued five upgrades and eight downgrades. Moody's noted stronger financial metrics and a constructive regulatory environment in upgrades of Entergy Arkansas to Baa1 from Baa2 and Eversource Energy subsidiary Western Massachusetts Electric Company to A2 from A3. Moody's upgraded Pepco Holdings to Baa2 from Baa3 based on the completion of Pepco's merger with parent company Exelon; Moody's said Exelon's larger size and scale provide resources and capital for Pepco's investment plans. Reasons for downgrades varied among the eight companies and included weaker credit metrics and a challenging regulatory environment. Two downgrades were tied to recent/pending M&A deals and related high debt levels at the parent company; the downgrade was assigned to the parent company in one case and a subsidiary in the other.

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Fitch	41	17	14	24	25	26	23	14	11	16
Moody's	32	6	23	20	11	20	17	85	12	13
Standard & Poor's	48	27	20	36	30	30	40	7	27	38
Total	**121**	**50**	**57**	**80**	**66**	**76**	**80**	**106**	**50**	**67**

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

Fitch's 16 actions showed a strengthening of the industry's credit profile in 2016, with 13 upgrades and only three downgrades. Fitch's upgrades were based on its perception of stronger financial metrics, constructive regulatory environments and strong/improving business risk profiles. Fitch cited improved financial metrics and a constructive regulatory environment in upgrades of American Electric Power subsidiary Appalachian Power to BBB from BBB-; DTE Energy to BBB+ from BBB and subsidiary Detroit Edison to A- from BBB+; CMS Energy to BBB from BBB- and subsidiary Consumers Energy to A- from BBB; and Exelon subsidiary Commonwealth Edison to BBB+ from BBB. A low-risk business profile was central to Fitch's upgrades of NiSource to BBB from BBB- and Eversource Energy subsidiaries Connecticut Light & Power, Public Service Company of New Hampshire and Western Massachusetts Electric, all to A- from BBB+. Fitch cited FirstEnergy's plan to exit its merchant generation business in upgrading the company from BB+ to BBB-. In upgrading AVANGRID to BBB+ from BBB Fitch noted its strong financial profile and the completed UIL Holdings acquisition; Fitch also upgraded AVANGRID subsidiary Rochester Gas & Electric to BBB+ from BBB. Two downgrades resulted from other M&A transactions and increased leverage at the acquiring companies. Another downgrade was due to execution risk and regulatory uncertainty about cost recovery relating to construction of a generation plant.

Ratings by Company Category

The table *S&P Utility Credit Rating Distribution by Company Category* presents the distribution of credit ratings over time for the investor-owned electric utilities organized into Regulated, Mostly Regulated and Diversified categories. 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, 2016, the categories had the following average ratings: Regulated = BBB+, Mostly Regulated = BBB+, and Diversified = BBB.

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2012		2013		2014		2015		2016	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	2	6%	1	3%	1	3%	1	3%	2	6%
A-	6	17%	7	20%	8	21%	8	22%	10	28%
BBB+	5	14%	6	17%	12	32%	12	33%	13	36%
BBB	13	36%	17	49%	14	37%	12	33%	8	22%
BBB-	6	17%	2	6%	1	3%	1	3%	3	8%
Below BBB-	4	11%	2	6%	2	5%	2	6%	0	0%
Total	36	100%	35	100%	38	100%	36	100%	36	100%
Mostly Regulated										
A or higher	1	6%	1	6%	1	8%	1	8%	1	8%
A-	2	12%	5	29%	4	31%	5	38%	2	17%
BBB+	7	41%	5	29%	4	31%	5	38%	7	58%
BBB	3	18%	3	18%	2	15%	1	8%	0	0%
BBB-	4	24%	3	18%	2	15%	1	8%	1	8%
Below BBB-	0	0%	0	0%	0	0%	0	0%	1	8%
Total	17	100%	17	100%	13	100%	13	100%	12	100%
Diversified										
A or higher	0	0%	0	0%	0	0%	0	0%	0	0%
A-	0	0%	0	0%	0	0%	0	0%	0	0%
BBB+	1	33%	1	50%	1	50%	1	50%	0	0%
BBB	0	0%	0	0%	0	0%	0	0%	1	50%
BBB-	1	33%	0	0%	1	50%	1	50%	1	50%
Below BBB-	1	33%	1	50%	0	0%	0	0%	0	0%
Total	3	100%	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).

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

- 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.

FERC MILESTONES:

- 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, RM17-3-000

- 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:

- 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 a policy overview section giving an update on major FERC initiatives. In addition, the report provides an annual update on construction and fuel use by electric utilities.

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

Annual 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. Starting in 2017, this Committee will meet 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, and the Accounting Standards 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 2017, we expect to offer a webcast in lieu of a live training session. Look for a live session in 2018. 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 Revenue Recognition, Leases, and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

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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, Charnita Garvin at (202) 508-5057, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

June 14-15, 2017

Annual Finance Committee Meeting
(Closed meeting, admittance by invitation only)
Boston Marriott Copley Plaza
Boston, Massachusetts

June 25-28, 2017

Accounting Leadership Conference
(open meeting)
Chief Audit Executives Conference
(closed meeting, admittance by invitation only)
The Nines Hotel
Portland, Oregon

November 5-8, 2017

52nd EEI Financial Conference
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Walt Disney World Swan & Dolphin Resort
Lake Buena Vista, Florida

December 7, 2017

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

December 8, 2017

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)	2016	2015r
Earnings Excluding Non-Recurring and Extraordinary Items	**46,716**	**39,949**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	767	789
Other Non-Recurring Revenues	888	(4)
Asset Write-downs	(17,480)	(5,189)
Other Non-Recurring Expenses	(3,110)	(1,764)
Total Non-Recurring Items	**(18,935)**	**(6,168)**
Extraordinary Items (net of taxes)		
Discontinued Operations	(668)	(1,148)
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**(668)**	**(1,148)**
Net Income	**27,112**	**32,633**
Total Non-Recurring and Extraordinary Items	**(19,604)**	**(7,316)**

r = revised Note: Totals may reflect rounding.

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

U.S. Investor-Owned Electric Utilities

(At 12/31/2016)

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 Resources, Inc.
DPL Inc. *
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Energy Future Holdings Corp. *
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.
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 44 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**.

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