

ELECTRIC INDUSTRY GENERATION, CAPACITY, AND MARKET OUTLOOK

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Introduction

The electric industry in the United States has changed dramatically in just the last few years. Historically low gas prices and increasing market share of intermittent resources have led to significant baseload retirements and have put increased pressure on existing infrastructure to be more flexible in dealing with this altered landscape. Although the new administration in Washington may provide relief from pending environmental regulations, the industry is still faced with future uncertainty as electricity market fundamentals are driving substantial changes in the energy outlook. This report presents high-level analyses and projections of electricity capacity and generation, transmission, and markets to provide a summary of the current state of the industry and where it may be headed, from both a national view and from the perspective of electric cooperatives.¹ With more information, cooperatives can be better positioned to confront the challenges posed by shifting market fundamentals and future uncertainty.

Key points from this report include:

- Due to widespread changes throughout the industry, nearly 22 GW of capacity from coal-fired units shut down in 2015 and 2016, with an additional 28 GW scheduled to retire before 2040.
 - Over the 2014 to 2016 period, electric cooperatives retired or converted about 700 MW of coal capacity, with another 1,355 MW announced by 2028, a combined 8% reduction in cooperative-owned coal capacity.
- Due to low natural gas prices, 2016 was the first year that natural gas generation exceeded coal on an annual basis.
 - There has also been a significant increase in natural gas generation and a corresponding decrease in coal generation across the electric cooperative generating fleet.
- Low natural gas prices, and in turn low settlement prices in wholesale energy and capacity markets, continue to put pressure on nuclear units, with nearly 7.2 GW of nuclear capacity scheduled to retire by 2025.
- Out of the total 114 GW of new capacity planned for the 2017-2027 period, nearly 59% is from natural gas combined-cycle units, with wind and solar making up another 34%.
 - Electric cooperatives have two major NGCC projects underway and several are considering whether to build new NGCC plants or buy on the market. Electric cooperatives also continue to add significant wind and solar resources to their generating portfolios, primarily through power purchase agreements.
- Federal tax incentives have made renewable technologies more cost-competitive which led to utility-scale renewables dominating the new additions in 2016, accounting for 63% of capacity additions in that year.
 - Electric cooperatives added 1.19 GW of new renewable capacity in 2016, more than in any previous year; most of this capacity was added through long-term Power Purchase Agreements
- According to the most recent levelized cost analysis, utility-scale solar costs for crystalline panels dropped 85% and utility-scale wind costs dropped 66% in the last seven years.
- As intermittent resources are making up a larger share of capacity being added to the system to replace baseload coal and nuclear retirements, the industry is more likely to face challenges with regard to resource adequacy and reliability.
- With the increase of intermittent resources on the bulk power system, transmission investments are projected to top 22.5 billion dollars in 2017.
- Though still expected to rise over time, gas prices at Henry Hub are forecasted by EIA in AEO2017 to be 25-30% lower over the 2017-2040 period than was estimated a year and a half earlier in AEO2015. EIA projects that the price at Henry Hub will not reach \$5 per MMBtu until after 2030.
- Generation from renewable resources is projected by EIA to increase by almost 70% from 2017 to 2040, at an average annual growth rate of 2.3%.

¹ This report will be updated periodically as new information and projections become available.

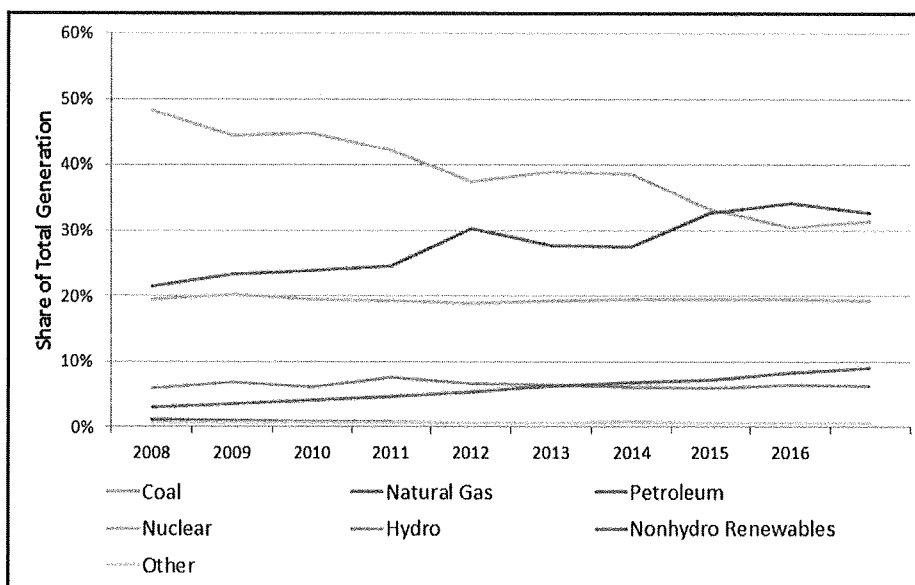
What's Changed

Economic, regulatory, and technology changes continue to shape the electric utility sector. Declining prices, tax incentives, and Renewable Portfolio Standards (RPS) have led to an increase in renewable resources. Low natural gas prices are resulting in increased gas-fired generation, largely at the expense of coal generation. This increased reliance on natural gas is evident in the changing generation mix. As shown in Figure 1, 2016 was the first year that the share of natural gas generation was higher than coal on an annual basis.

Historically, coal was the predominant energy source of the U.S. generation mix, accounting for as high as 50% of the market share in the late 2000s, but that paradigm is changing due mostly to low natural gas prices and increased renewable generation. In 2016, coal fell to its lowest share of total generation to-date at 30.4%.² With natural gas prices expected to remain low, 2017 will see this trend continue with coal generation projected to be a little over a third of the generation mix.

Figure 1 shows nuclear generation remaining constant at 19% of total generation. In 2016, the first new nuclear reactor since the 1980s became operational with Tennessee Valley Authority's Watts Bar Unit 2 near Spring City, Tennessee. In addition, there is ongoing construction on four new reactors, Vogtle Units 3 and 4 in Georgia, and V.C. Summer Units 2 and 3 in South Carolina. While the new construction of these units has gone forward, in general the future outlook for nuclear generation is mixed, with several units announced to retire in the next decade.

Figure 1: Share of Total Generation, 2008-2016³



Low natural gas prices, along with low marginal energy cost intermittent resources, have caused wholesale power prices to fall, and nuclear plants that participate in organized markets are finding it particularly difficult to recoup their costs through the energy and capacity markets operated by the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), leading to early retirement. Capacity market prices are set through

² U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO 2016), available at: <http://www.eia.gov/outlooks/steo/>, last accessed December 21, 2016.

³ *Ibid.*

centralized auctions run by the ISOs/RTOs, often applying some form of downward sloping demand curve with values based on the costs of new entry, which can make it difficult for baseload plants to recover their costs.

Renewables were the other major story in 2016. With the extension of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) in December 2015, non-hydro renewables were able to expand their share of total generation to 8.3%; up from 3.1% of total generation in 2008. Figure 2 shows the phase-out timeline of the ITC and PTC credits. Although the wind credit expires in 2020, the IRS rule gives wind developers until 2024 to finish their projects.⁴ These federal tax incentives have made renewable technologies more cost-competitive with conventional generation, and have driven rapid growth in renewables development.

Figure 2: ITC/PTC Timeline⁵

Technology	12/31/16	12/31/17	12/31/18	12/31/19	12/31/20	12/31/21	12/31/22	Future Years
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%
Hybrid Solar Lighting, Fuel Cells, Small Wind	30%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Heat Pumps, Microturbines, Combine Heat and Power Systems	10%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Electric	10%	10%	10%	10%	10%	10%	10%	10%
Large Wind	30%	24%	18%	12%	N/A	N/A	N/A	N/A

The renewable growth trend is further emphasized in a recent article from the Energy Information Administration (EIA).⁶ Utility-scale solar and wind have dominated the new additions of electric generating capacity for the last six years and, according to EIA, new renewables accounted for 63% of the 2016 capacity additions, with wind and solar making up the lion's share.⁷

Figure 3 illustrates this trend, and it also shows the sensitivity of the renewable sector to federal tax incentives. The significant drop off in renewable additions between 2012 and 2013 can be attributed to the anticipated expiration of the PTC at the end of 2012. The PTC was ultimately extended in January 2013 with the passages of The American Taxpayer Relief Act of 2012,⁸ but due to uncertainty the growth in renewable capacity was significantly lower in 2013. Figure 3 also provides a quarterly breakout of the 2016 renewable capacity additions and highlights that most renewable projects are completed in the fourth quarter of the year, due in part to the timing of qualifications for federal, state, or local tax incentives.⁹

⁴ U.S. Internal Revenue Service, <https://www.irs.gov/pub/irs-drop/n-16-31.pdf>, last accessed January 10, 2017.

⁵ U.S. Department of Energy, "Business Energy Investment Tax Credit (ITC)", available at: <http://energy.gov/savings/business-energy-investment-tax-credit-etc>, last accessed November 7, 2016.

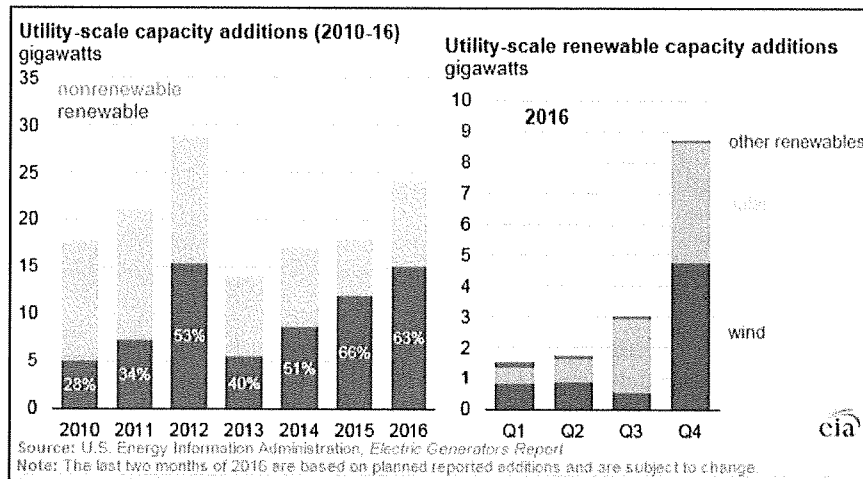
⁶ EIA's Renewable Generation Capacity Expected to Account for Most 2016 Capacity Additions (EIA TIE 2017), January 2017, available at: <http://www.eia.gov/todayinenergy/detail.php?id=29492&src=email>, last accessed January 10, 2017.

⁷ *Id.*

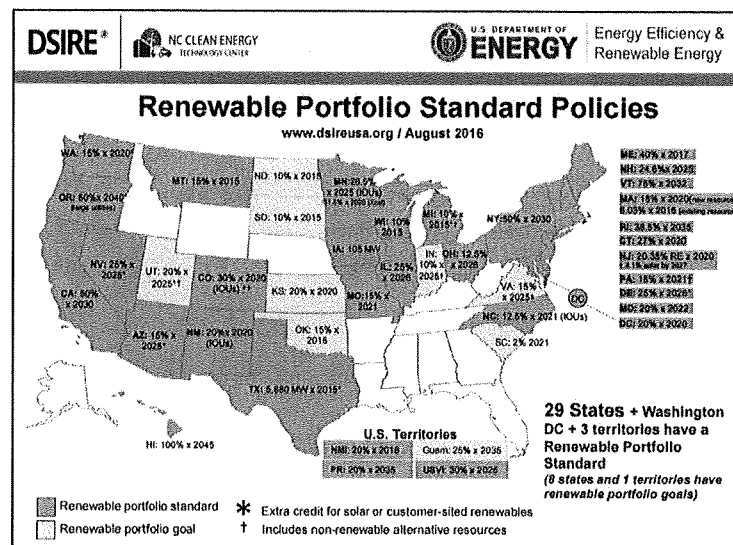
⁸ Sherlock, Molly. "The Renewable Electricity Production Tax Credit: In Brief", Congressional Research Service, July 2015, available at: <http://nationalaglawcenter.org/wp-content/uploads/assets/crs/R43453.pdf>, last accessed January 12, 2017.

⁹ EIA TIE 2017.

Figure 3: Utility-Scale Capacity Additions



Although the federal tax incentives are a primary factor for renewable projects, Renewable Portfolio Standards (RPS) are another important driver. RPS standards have been adopted by 29 states and Washington D.C., with several others adopting voluntary standards. Many of these states direct not only investor-owned utilities (IOUs) to meet these thresholds, but also public and cooperative utilities, though their requirements are sometimes lower. Recently, some states have extended their standards or increased their goals. In 2016 alone, D.C., Oregon, and New York extended and expanded their RPS standards¹⁰ with many other states in ongoing conversations about altering their renewable standards.¹¹

Figure 4: Renewable Portfolio Standards¹²

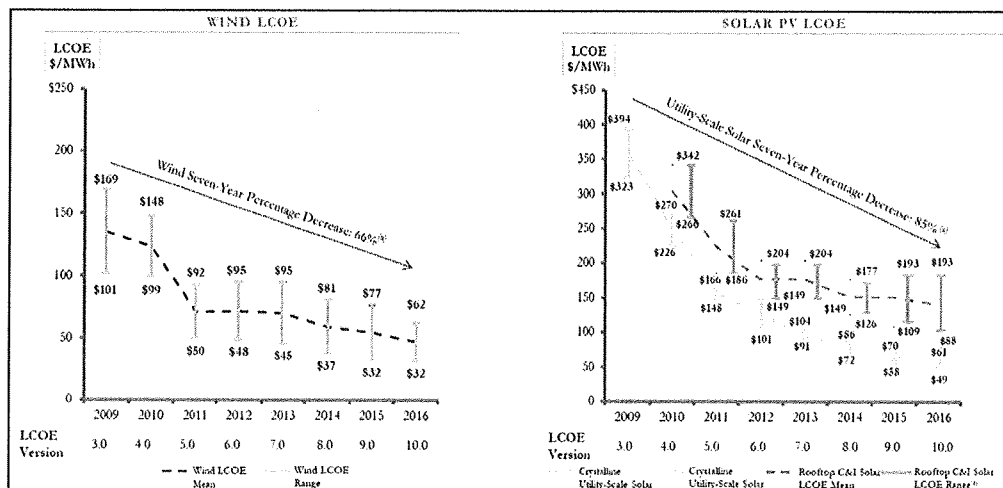
¹⁰ Advanced Energy Legislation Tracker, available at: <http://www.aeltracker.org>, last accessed on January 10, 2017.

¹¹ For example, in Ohio, the governor vetoed a bill that would have kept a freeze in place on the RPS standards for Ohio.

¹² <http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2014/11/Renewable-Portfolio-Standards.pdf>. Accessed November 7, 2016.

States have been able to meet or surpass these standards, in part, because of the declining costs of solar and wind. Figure 5 below shows the levelized cost of energy for wind and solar technologies without federal tax incentives. According to Lazard's 2016 Levelized Cost of Energy Analysis, utility-scale solar costs for crystalline panels dropped 85% and utility-scale wind costs dropped 66% in the last seven years.¹³

Figure 5: Historical Unsubsidized Levelized Cost of Energy-Wind/Solar PV¹⁴



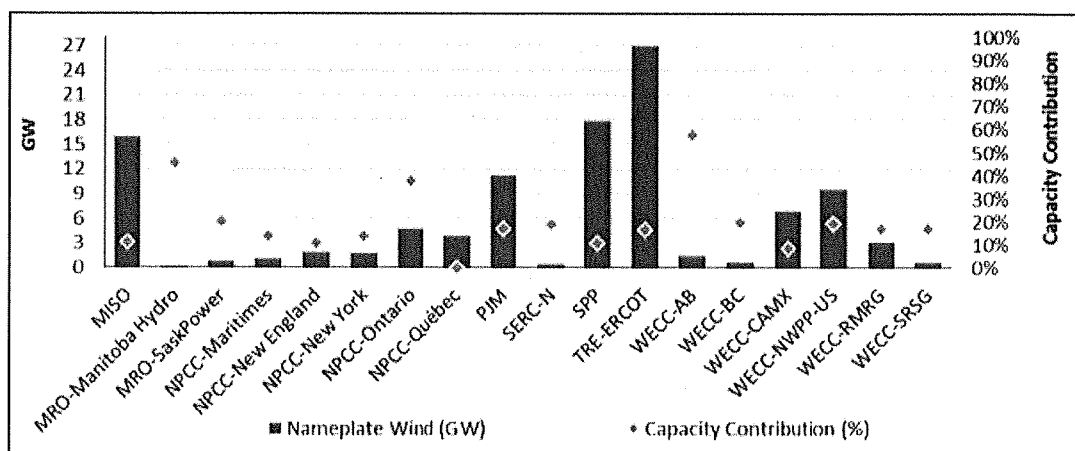
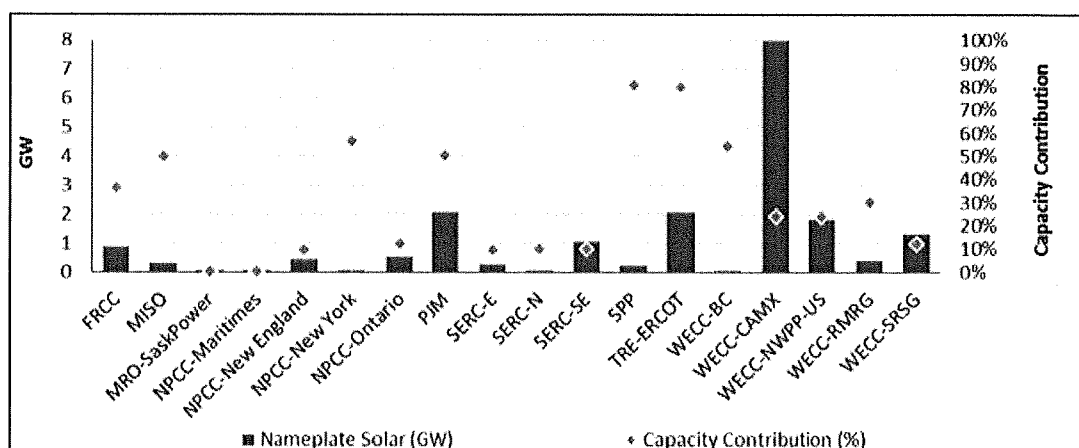
Developers have leveraged these declining costs, federal tax incentives, and RPS standards to further renewable development throughout the country. This progression can be seen by the contribution that solar and wind make to peak load. In Figures 6 and 7, the North American Electric Reliability Corporation (NERC), in their 2016 Long Term Reliability Assessment, looked at the projected contribution of renewable technologies to on-peak capacity in 2026 and noted that with a higher amount of intermittent resources during peak hours, ensuring reliability could be challenging.

For example, by 2026 wind and solar could make up around 20% and 50% of PJM's on-peak capacity, respectively. With a large portion of peak demand met by intermittent resources, resource adequacy and frequency challenges will be at the forefront. NERC is increasingly concerned about how these resources will integrate into the grid and made this recommendation in its analysis of the Clean Power Plan (CPP), "NERC should continue the development of sufficiency guidelines for industry on essential reliability services to ensure that the grid maintains adequate levels of voltage control, load ramping, and frequency response as the bulk power system becomes more dependent on intermittent resources."¹⁵ With many baseload units retiring, meeting the need for essential reliability services¹⁶ will be an ongoing discussion.

¹³ Lazard's Levelized Cost of Energy Analysis, December 2016 (Lazard 2016), available at: <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>, last accessed December 20, 2016. It is important to note that solar and wind are intermittent resources and should not be directly compared to their baseload counterparts on a \$/MWh basis due to their non-dispatchable characteristics.

¹⁴ *Id.*

¹⁵ North American Electric Reliability Corporation, Potential Reliability Implications of EPA's Clean Power Plan – Phase II, May 2016, (NERC-CPP), available at: <http://www.nerc.com/news/Headlines%20DL/CPP%20Phase%20II%2019MAY16.pdf>, last accessed on January 13, 2017.

Figure 6: Wind's On-Peak Capacity Contribution (2026)¹⁷Figure 7: Solar's On-Peak Capacity Contribution (2026)¹⁸

The increase in variable generation to the wholesale market has led to increasing concerns about transmission congestion. Congestion concerns have led to an increase in transmission investments to help ensure the continued reliability of the bulk power system. According to a report by the Edison Electric Institute (EEI), "Transmission investments provide an array of benefits that include: providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio and

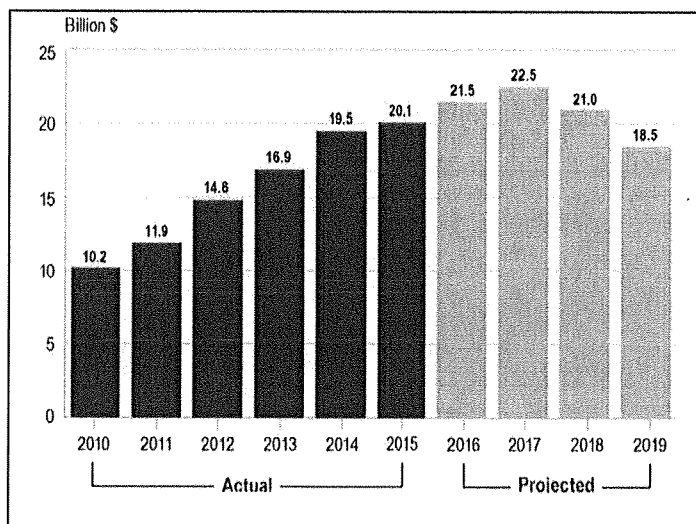
¹⁶ "Essential reliability services are comprised of primary frequency response (PFR), voltage support, and ramping capability, all needed for the continued reliable operation of the bulk power system. Significant ramping capabilities are needed to address the challenges presented from variable energy resource operational impacts.", LTRA 2016.

¹⁷ North American Electric Reliability Corporation, 2016 Long Term Reliability Assessment, December 2016 (LTRA 2016), available at: <http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf>, last accessed December 16, 2016.

¹⁸ *Id.*

mitigating damage and limiting customer outages during adverse conditions.”¹⁹ According to a recent survey by EEI, the projected amount of money spent by IOUs on transmission projects will surpass \$22 billion in 2017. As transmission projects become more difficult to site due to environmental concerns, land availability, local opposition, and other constraints planners will need to find innovative ways to meet these challenges.

Figure 8: Historical and Projected Transmission Investment (Nominal Dollars)²⁰



Current Capacity and Generation Mix

Many of the changes experienced throughout the industry relate to the greatly increased supply of natural gas from unconventional sources, resulting in historically low prices for natural gas in recent years. Figure 9 presents natural gas prices at Henry Hub over the 2000 to 2016 period. After a steep decline in 2009, prices have remained below \$5 per MMBtu, and declined even further than had been expected, to historically low levels below \$3 per MMBtu in 2015 and 2016. As discussed further in this report, EIA’s Annual Energy Outlook for 2017 (AEO2017) predicts low gas prices to continue, increasing more slowly than was previously estimated, with the price at Henry Hub not reaching \$5 per MMBtu again until after 2030.²¹

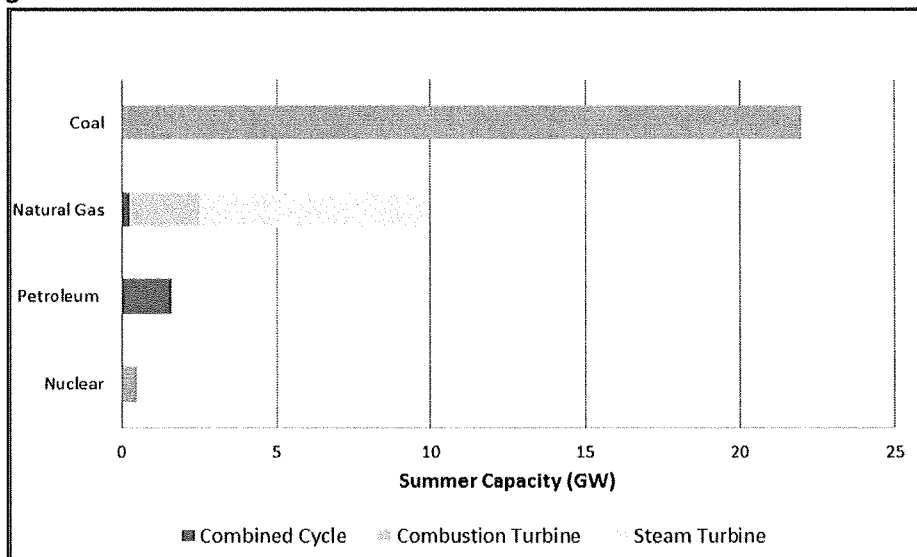
¹⁹ Edison Electric Institute’s Transmission Projects: At A Glance, December 2016, (EEI 2016), available at: http://www.eei.org/issuesandpolicy/transmission/documents/trans_project_lowres_bookmarked.pdf, last accessed January 13, 2017.

²⁰ *Id.*

²¹ U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, (AEO2017), available at: <https://www.eia.gov/outlooks/aeo/>.

Figure 9: Henry Hub Natural Gas Spot Price, 2000-2016²²

Due to widespread changes throughout the industry, more than 30 GW of capacity shut down in 2015 and 2016, with conventional sources making up nearly 97% of the total. Approximately 21.7 GW of this capacity is from coal-fired units that retired in large part due to changing economics, and environmental regulations such as the Mercury Air and Toxics Standards (MATS), which took effect in April 2016. Figure 10 shows the full breakdown of the conventional capacity that went offline in 2015 and 2016.

Figure 10: Electric Power Sector Conventional Source Retirements in 2015 & 2016²³

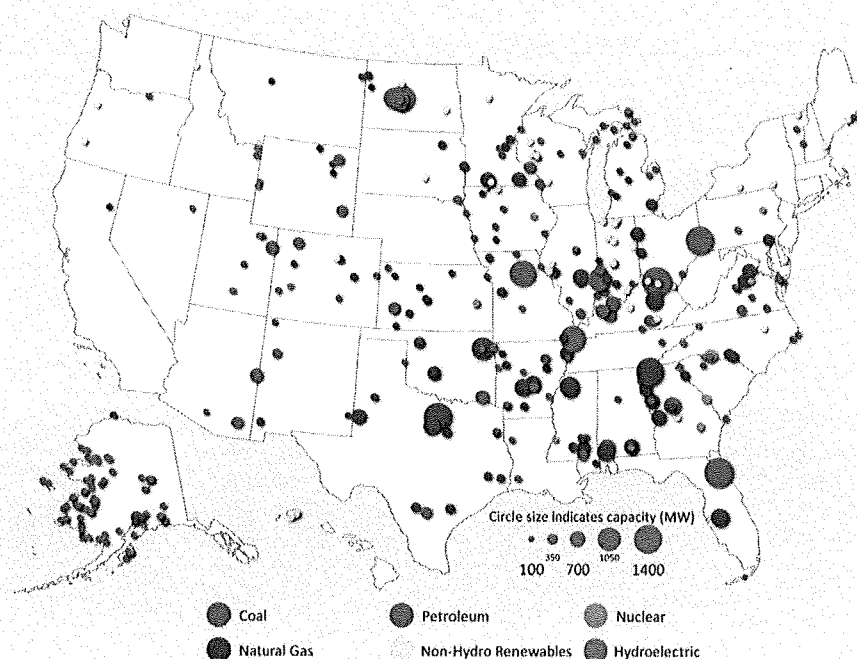
²² U.S. Energy Information Administration, *Natural Gas Futures Prices (NYMEX)*, available at: <http://www.eia.gov/dnav/ng/hist/rngwhhda.htm>, last accessed December 22, 2016.

²³ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory April 2017*, (EIA-860M), available at: <https://www.eia.gov/electricity/data/eia860m/>, last accessed May 24, 2017.

Cooperative Focus

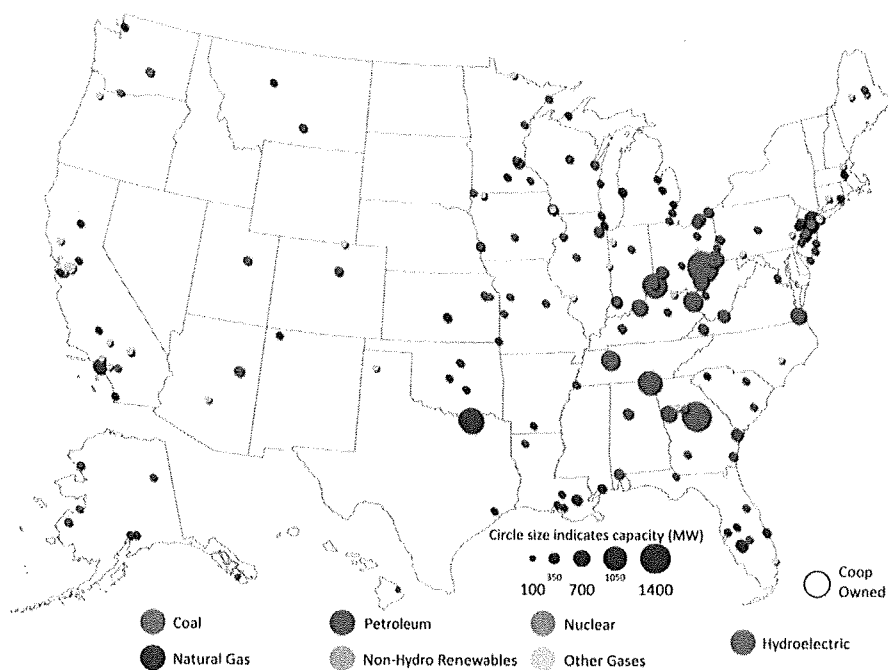
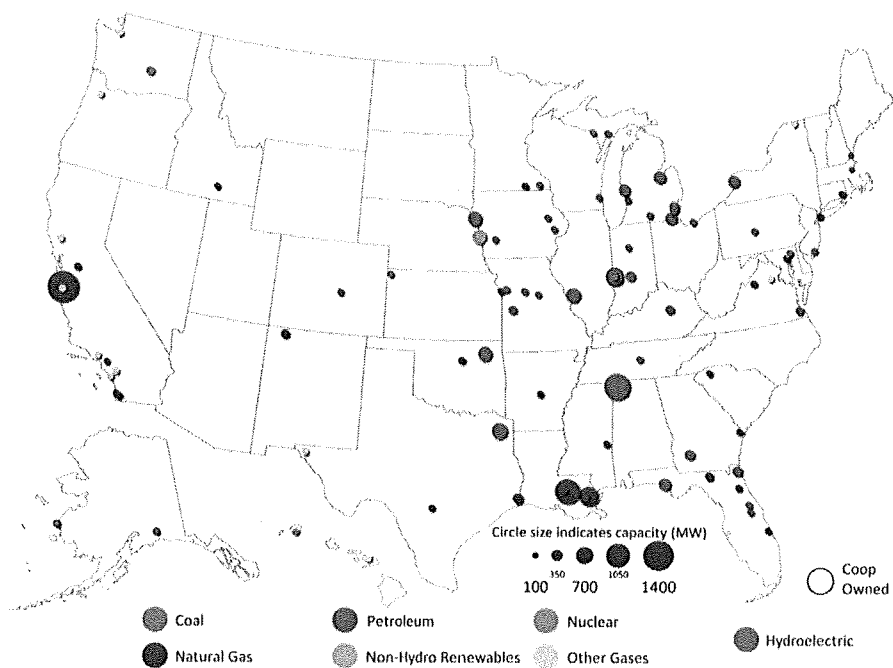
As shown in Figure 11, electric cooperatives own around 64 GW of generating capacity nationwide, primarily through Generation and Transmission Cooperatives (G&Ts), but with some capacity owned directly by distribution cooperatives. In total, cooperatives accounts for about 5% of total U.S. generation. On net, cooperatives self-generate about half of the power they sell at retail, though some of this power is sold off-system to non-cooperatives. The balance of electricity sold by electric cooperatives is purchased through bilateral contracts, organized markets, or from federal and state utilities (including preference hydropower).

Figure 11: Map of Cooperative Owned Generation²⁴



Figures 12 and 13 map the location of all units in the U.S. that retired in 2015 and 2016, along with the relative size of each unit. As shown in the maps, the Eastern U.S. was hit hardest, with almost 40% of all retirements occurring in Appalachian states.

²⁴ Figure derived from data from U.S. Energy Information Administration, *2015 Electric Power Annual* (EIA EPA 2015), available at: <http://www.eia.gov/electricity/annual/>, last accessed on November 7, 2016.

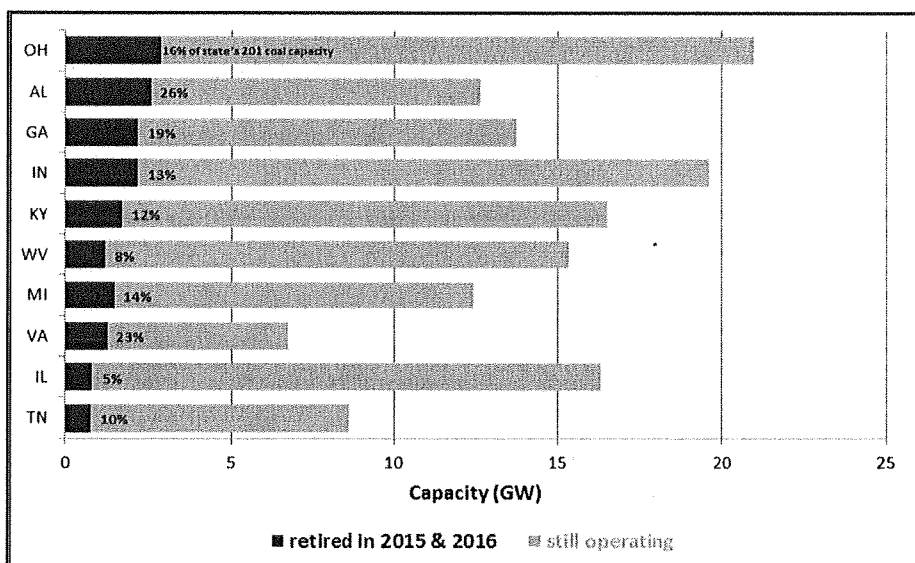
Figure 12: Plant Retirements in 2015²⁵Figure 13: Plant Retirements in 2016²⁶

²⁵ EIA-860M.

²⁶ *Id.*

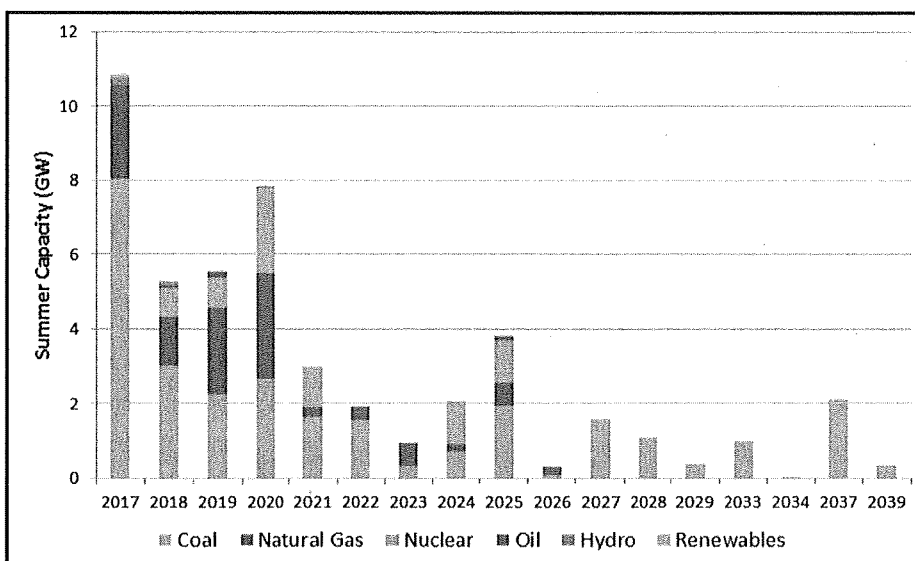
Figure 14 shows the 10 states that retired the most coal capacity in 2015 and 2016, as well as the percentage of each state's coal capacity represented by these shut-downs.²⁷ As a percentage of its total coal capacity, Alabama retired the largest concentration of coal, followed by Virginia and Georgia.

Figure 14: Coal Plants Operating Status in Selected States²⁸



Moving forward, a substantial amount of additional capacity is scheduled to be retired over the next 20 years, most notably from coal and nuclear units. Figure 15 shows future retirements announced to occur by 2040, by unit type.

Figure 15: Announced Retirements²⁹



²⁷ Percentage of state's coal capacity is based on February 2017 data from the U.S. Energy Information Administration, *April 2017 Electric Power Monthly*.

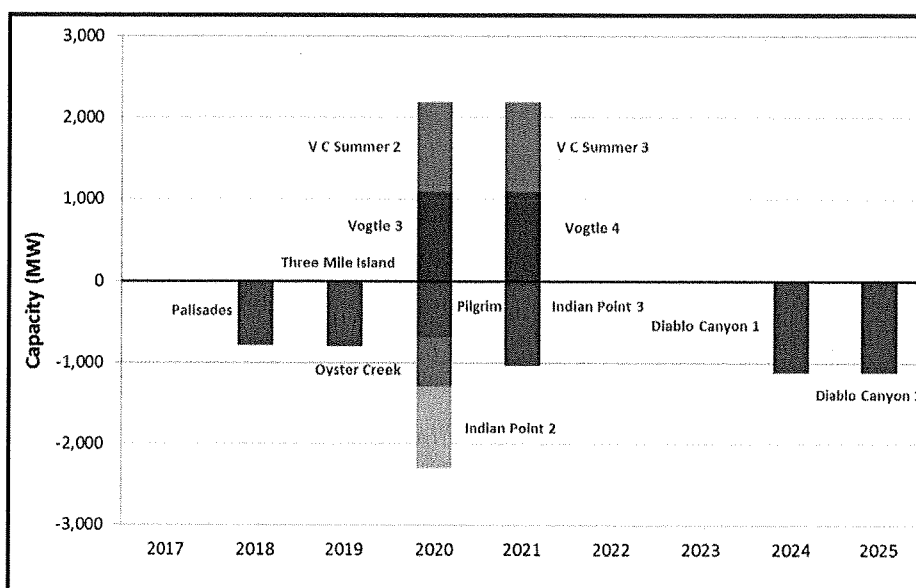
²⁸ EIA-860M.

²⁹ *Id.*

A total of 46.9 GW of capacity are scheduled to retire before 2040, with coal units accounting for 61.1%, gas units for 22.3%, and nuclear comprising 15.3%. Many of these shutdowns were announced in the second half of 2016, representing the relative frequency at which new retirement decisions are currently being made.

With low natural gas prices, and in turn low settlement prices in wholesale and capacity markets, nuclear plants have struggled to recover their costs, and several units are scheduled to shut down over the next decade, as shown in Figure 16.³⁰ Although a total of 4.4 GW of new capacity will be coming online, there are nearly 7.2 GW retiring, with a net loss of almost 2.8 GW of nuclear from the system.

Figure 16: Nuclear Retirements and Additions 2017-2025³¹



Cooperative Focus

Figure 17 shows announced retirements and planned construction of cooperative-owned baseload generation. The electric cooperative coal fleet tends to be newer than the national fleet, and cooperative plants faced fewer closures due to federal environmental regulations than the rest of the industry. Approximately 700 MW of cooperative-owned coal capacity was retired or converted to natural gas over the 2014-2016 period, accounting for about 3% of total cooperative coal capacity (as of the start of the period). Another 1,355 MW of coal retirements or conversions have been announced through 2028, another 5% of the cooperative coal fleet circa 2014. One new small 50 MW coal unit was brought online in 2016 in Alaska, but no additional coal units have been announced. New construction of baseload natural gas combined cycle (NGCC) and nuclear units will offset the closures and planned closures across the fleet, with 2,079 MW of new capacity announced by 2024.

Like other generators, cooperatives are facing pressures from continued low gas prices and the expansion of renewable generation, particularly in organized markets. In their resource planning processes, many G&Ts are making decisions whether to build or buy new capacity. This is an especially challenging decision for smaller G&Ts

³⁰ It should be noted that some states are considering innovative subsidy programs to address this issue, and both Illinois and New York have introduced specific measures to allow the continued operation of nuclear plants.

³¹ EIA-860M.

where a small number of coal units provide the primary source of generation. There has been a long-term trend of G&Ts self-generating a larger share of their power. It remains to be seen whether this trend will continue, or if G&Ts will move towards greater reliance on markets and bilateral contracts to supply power to their members.

Figure 17: Cooperative Baseload Retirements and Additions through 2016 and Planned³²

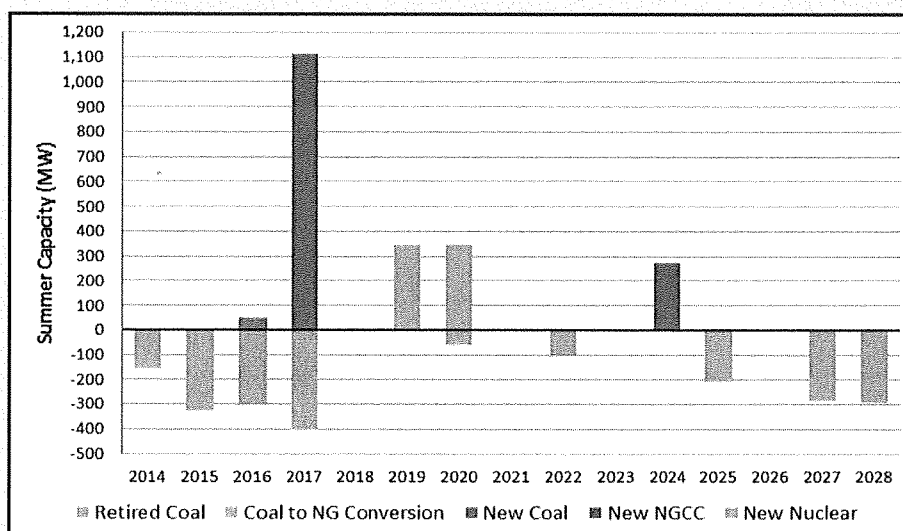
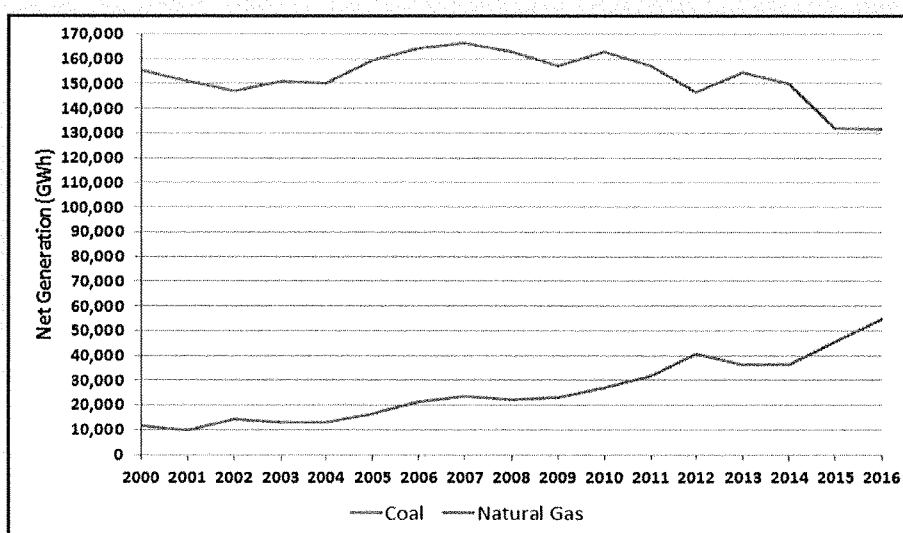


Figure 18 shows that while coal still dominates cooperative-owned fossil generation, natural gas generation has increased significantly. There is a strong correlation between natural gas generation and coal generation, when one increases the other declines. In 2016 cooperative natural gas generation reached historic highs while coal generation was at historic lows. This figure does not include purchases through bilateral agreements or from organized markets.

Figure 18: Generation from Cooperative Owned Coal and Natural Gas Plants³³



³² EIA EPA 2015, except for the 2024 new NGCC capacity recently announced by Dairyland Power Cooperative, available at: <http://www.dairylandpower.com/dcontent/article/DPCNaturalGasAnnouncement2017AnnualMtg.pdf>. Accessed June 15, 2017

³³ Ventyx Velocity Suite. "IQ Dataset: Monthly Plant Production Costs - Ownership View." Last accessed July 14, 2017.

To replace the retiring capacity, new generating units must be added. Figure 19 maps the location and relative size of each capacity addition in 2016.³⁴ Several of the largest additions are natural gas resources, due to current economic conditions with low gas prices, and the improved efficiency of combined-cycle technology. Non-hydro renewables account for the largest number of new plants at 61%, and this trend is expected to continue going forward, with the extension of tax incentives for wind and solar, and costs for solar PV declining.³⁵ However, as intermittent resources are making up a larger share of capacity being added to the system to replace baseload coal and nuclear retirements, the industry is more likely to face challenges with regard to resource adequacy and reliability,

Figure 19: Plant Additions in 2016³⁶

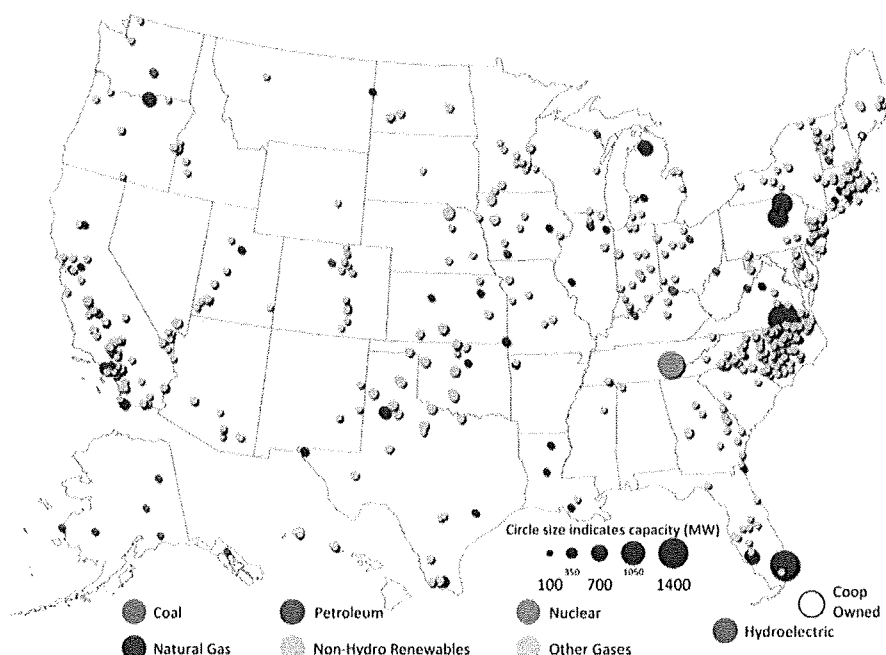


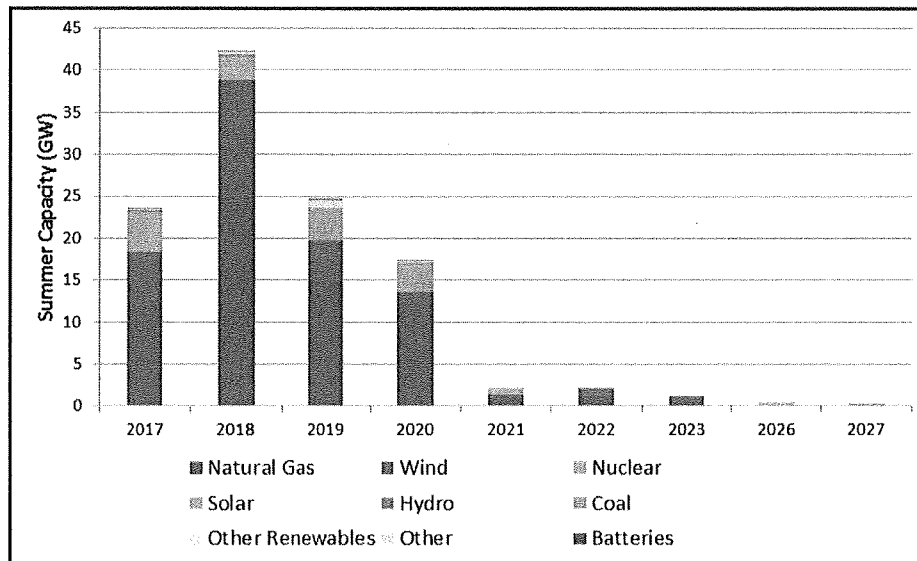
Figure 20 shows all announced future utility-scale additions to the electric system, by unit type.³⁷ Out of the total 114 GW of new capacity planned for the 2017-2027 period, more than 58.6% is from natural gas combined-cycle units, with wind and solar making up 33.9%. As will be discussed further in this report, growth in renewable generation, particularly solar PV, is projected to continue over the next several years. It is important to note that new solar and wind plants can be planned, constructed, and completed in as little as one year, so there tends to be less long-term announcements about new plants.

³⁴ Restricted to units with capacities of 25 MW or greater.

³⁵ Levelized costs for solar PV and other technologies are shown in Figure 39, in the Appendix.

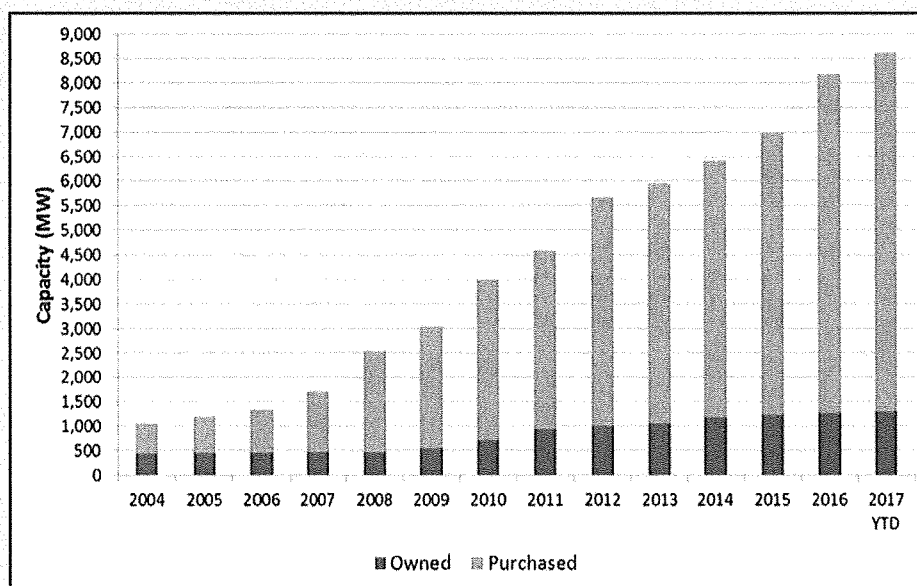
³⁶ EIA-860M.

³⁷ *Id.* All additions listed in EIA-860 must have full financing and a power purchase agreement in place before being included in the database. Years that the units come online are subject to change, due to potential lags in construction progress.

Figure 20: Announced Additions, 2017-2027³⁸

Cooperative Focus

As shown in Figure 21, electric cooperatives have seen steady growth in renewable resources in recent years, and 2016 saw more renewable capacity added (1.19 GW) than in any previous year. This growth has been driven by the improving economics of renewable resources, the extension of federal tax incentives, and the adoption or expansion of renewable portfolio standards in several states.

Figure 21: Cooperative Renewable Capacity Growth, 2004-2017³⁹

³⁸ EIA-860M.

³⁹ NRECA Research

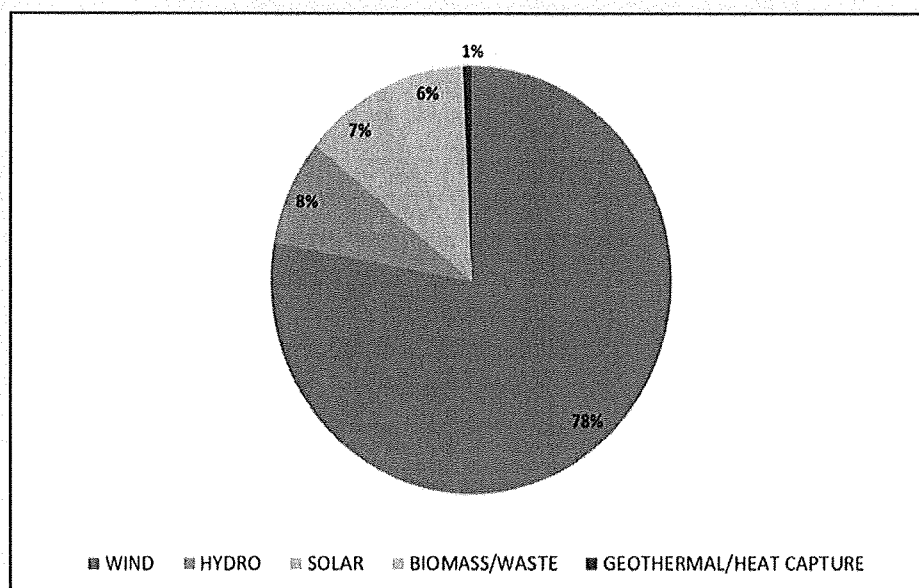
Most of this expansion has been through long-term power purchase agreements (PPAs) for the total or partial output from a project owned by a third-party developer, primarily wind. This allows cooperatives to indirectly take advantage of federal tax incentives for wind and solar generation as these savings are passed along by developers in their contract terms. In all, electric cooperatives have more than 8.6 GW of renewable capacity deployed, with more than 1.5 GW of additional capacity planned and new announcements made frequently. This is in addition to 10 GW of federal hydropower purchased by cooperatives annually. The extension of federal tax incentives for wind and solar will provide additional impetus for cooperative renewable growth over the next five years.

As seen in Figure 22, wind dominates the current non-hydro renewable portfolio deployed by cooperatives in terms of capacity, with over 6.7 GW owned or under contract. Wind is set to remain the largest non-hydro renewable resources deployed by cooperatives, with more than 850 MW of new wind PPAs planned over the next two years, accounting for nearly two-thirds of planned additions.

In recent years, there has been significant growth in solar resources, with deployed capacity nearly tripling in 2016. Today, cooperative solar capacity stands at more than 580 MW, with at least 520 MW of additional capacity on the drawing board. In terms of capacity, these additions have made solar the second largest non-hydro renewable resource for cooperatives after wind. While most of the solar projects deployed by cooperatives have been relatively small and located at the distribution level, there is a trend towards larger arrays, including several active or pending PPAs for projects of 50 MW or larger.

While their capacity share and planned growth are smaller, other renewable technologies play an important role in the cooperative renewable portfolio. These technologies, including biomass, heat capture and small hydro often provide a higher capacity factor, dispatchability, and local investment in plant and fuel stock that can make them attractive options for electric cooperatives.

Figure 22: Current Cooperative Renewable Capacity by Type⁴⁰



⁴⁰ NRECA Research; this figure does not include roughly 10 GW of federal hydropower purchased by cooperatives.

In addition to utility-scale solar, growth in generation from distributed solar PV has been steadily increasing in recent years, as shown in Figure 23. From January 2014 through November 2016, distributed solar generation has more than doubled, increasing at an average rate of 2.1% each month.

Figure 23: EIA Distributed Solar Estimates⁴¹

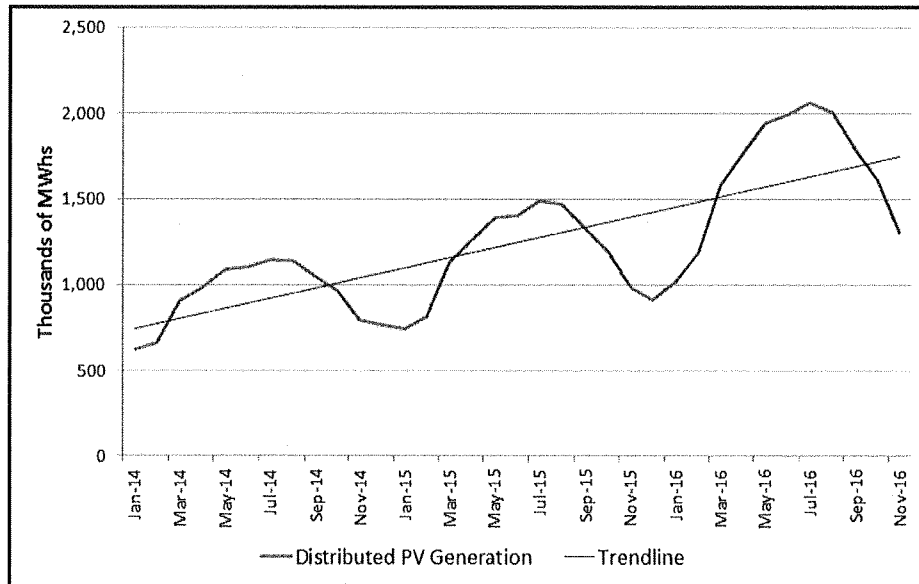
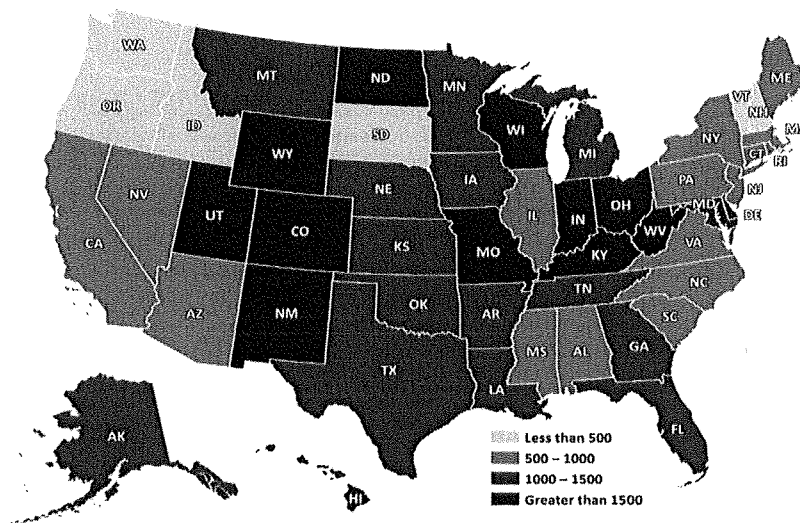


Figure 24 maps the lbs per MWh CO₂ emissions rate for each state, as of 2015. As expected, states that are more reliant on coal generation have the highest carbon intensity.

Figure 24: 2015 Carbon Intensity (lbs/MWh)⁴²

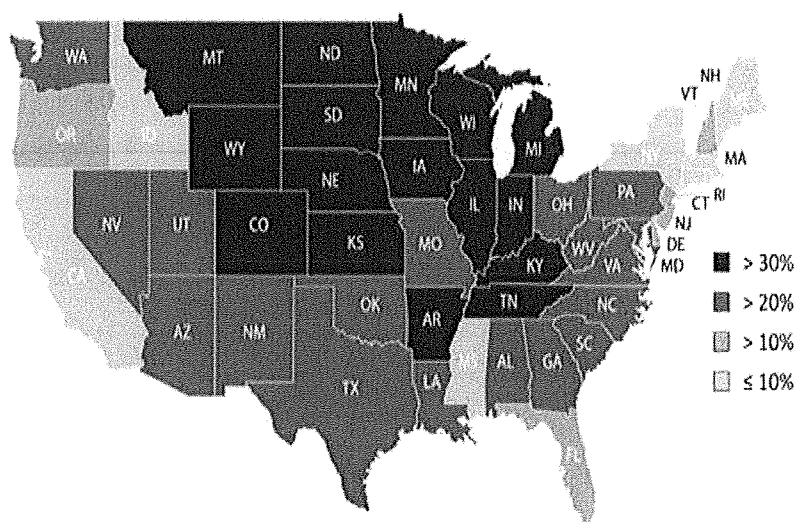


⁴¹ U.S. Energy Information Administration, *Electric Power Monthly*, December 2016, (EPM 2016), available at: <http://www.eia.gov/electricity/monthly/>, last accessed on January 30, 2017.

⁴² EIA EPA 2015.

Figure 25 maps the percent of CO₂ reductions⁴³ required by each state under the EPA's Clean Power Plan (CPP).⁴⁴ As shown in the figure, several states with higher carbon intensities (from Figure 24) would face the largest reductions, and would in turn face higher compliance costs. If a carbon price were implemented as an alternative means of CO₂ reduction, these states would also likely be the most vulnerable to changes in CO₂ pricing.

Figure 25: State CO₂ Emission Reduction Requirements Based on CPP⁴⁵



Annual Energy Outlook 2017 and Forecasts

EIA's 2017 Annual Energy Outlook provides long-term projections for the future of the electricity industry, based on modeled estimates and detailed analysis of energy topics.⁴⁶ Although energy market predictions cannot be calculated with absolute certainty, the AEO presents a well-respected and generally robust set of forecasts to help inform future decision making.

Projected natural gas prices at Henry Hub for the period 2017 to 2040 are presented in Figure 26. In the AEO2017 No CPP Case, real Henry Hub prices are projected to grow at an annual rate of 2.3%. To illustrate how these estimates have changed, projections from EIA's 2016 Annual Energy Outlook (AEO2016) and 2015 Annual Energy Outlook (AEO2015) are included as well. As displayed in the figure, AEO2017 shows a significant decrease from the AEO2015 forecast and is slightly lower than AEO2016 estimates. Though still expected to rise over time, gas prices at Henry Hub are projected by EIA to be 25-30% lower over the 2017-2040 period than was previously estimated in

⁴³ Reductions shown are based on mass-based targets.

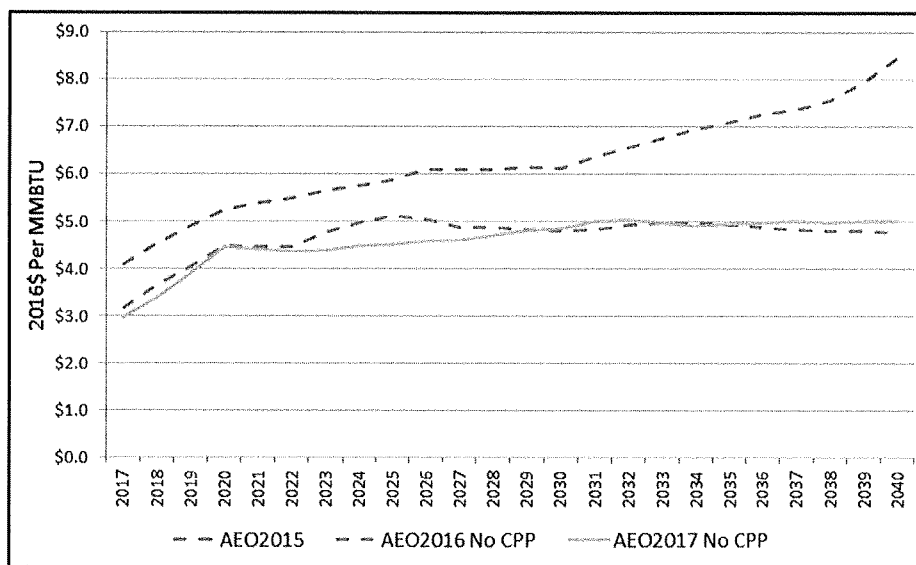
⁴⁴ The U.S. Environmental Protection Agency released its Final Clean Power Plan in August 2015, which called for reductions in electric sector CO₂ emissions, beginning in 2022. In February 2016, the U.S. Supreme Court issued a stay on the CPP, putting these regulations on hold until a final determination is made on the legality of the rule. With a new Presidential Administration now in place, the future of the CPP remains uncertain.

⁴⁵ NERC-CPP.

⁴⁶ AEO2017 provides several cases with different assumptions, including both a Reference Case with the EPA's CPP in place, as well as a "No CPP Case" to reflect "business-as-usual" conditions without the rule. Given the uncertainty of the CPP's future, all AEO2017 estimates discussed in the body of this report are based on EIA's No CPP Case.

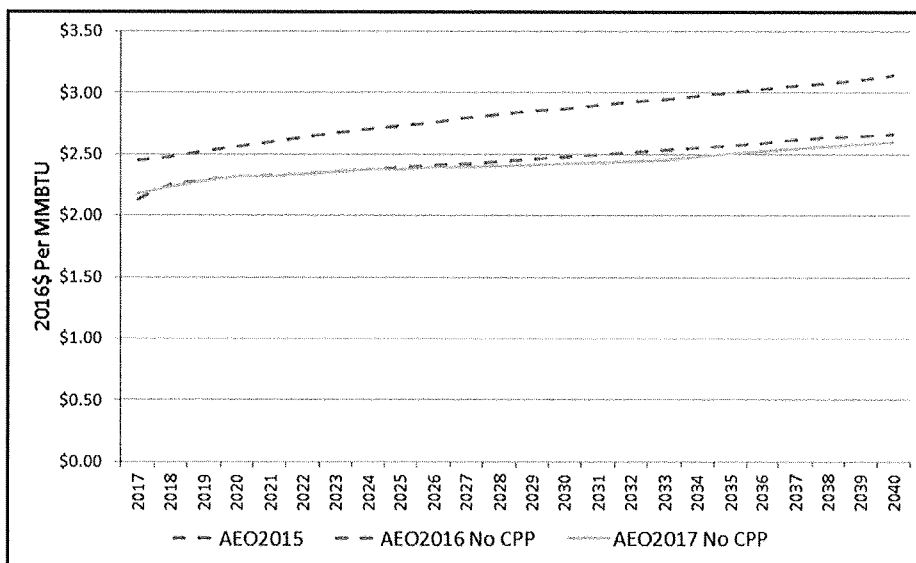
AEO2015, which was released just a year and a half before AEO2017. This is consistent with prevailing opinions throughout the industry that natural gas will continue to be competitive, even in absence of the CPP.

Figure 26: Projected Natural Gas Spot Price at Henry Hub, 2017-2040⁴⁷



Projected delivered coal prices from AEO2017 are similarly shown in Figure 27. Over the 2017-2040 period, coal prices are expected to grow at an annual rate of approximately 0.8%. As with EIA's gas price projections, coal prices in AEO2017 are lower than forecasts from AEO2015 and AEO2016.

Figure 27: Average Coal Price Projections, 2017-2040⁴⁸



⁴⁷ AEO2017.

⁴⁸ *Id.*

The electricity generation mix, both historical and as projected in AEO2017, is shown in Figure 28. As a result of low natural gas prices, the gap between generation from coal and generation from gas has closed in recent years, and that trend is expected to continue going forward, with natural gas generation approaching coal generation by 2040, absent CO₂ regulation. Generation from renewables is also projected to grow, particularly in the short-term, growing at an annual rate of 6.6% over the 2017-2023 period.

Figure 28: Projected Generation Mix, 2017-2040⁴⁹

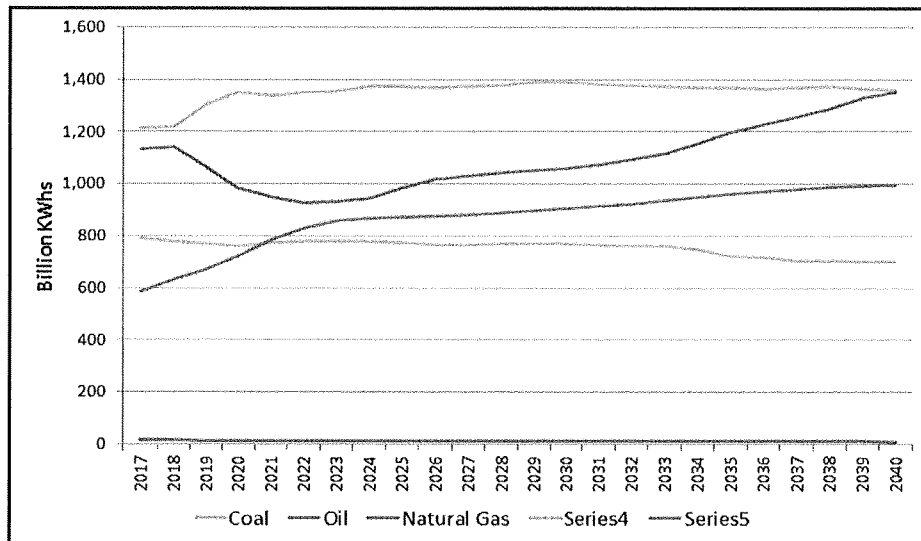
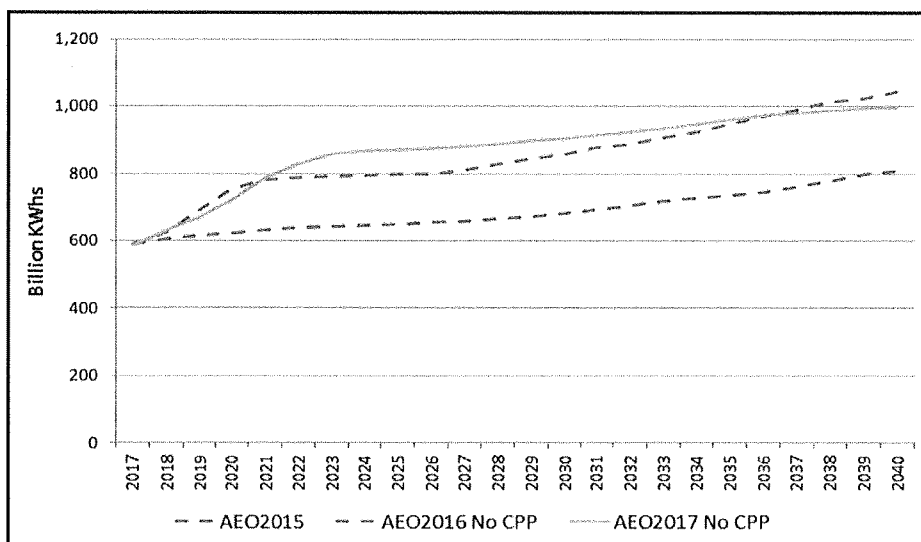


Figure 29 isolates forecasted renewable generation from AEO2017, showing growth at an annual rate of 2.3% from 2017 to 2040. Projections from AEO2016 and AEO2015 are also included for comparison.

Figure 29: Renewable Generation Projections, 2017-2040⁵⁰



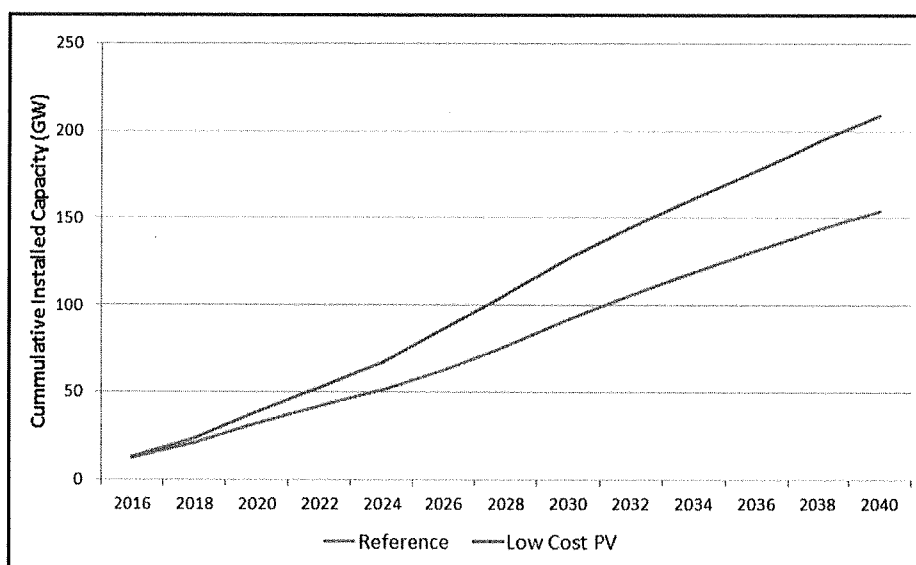
⁴⁹ *Id.*

⁵⁰ *Id.*

It should be noted that in December 2015, the Investment Tax Credit (ITC) and Production Tax Credit (PTC) for solar and wind were extended, resulting in an expected increase in renewable capacity and generation. Estimated total generation from renewables over the 2017-2040 period in AEO2017 is thus 26.8% higher than in AEO2015, which did not account for the ITC and PTC extensions. Similarly, renewable generation in AEO2016 was 23.5% higher than in AEO2015. This difference represents the increase largely attributable to these tax incentives.

Solar PV generation in particular is expected to increase due to rapidly declining costs.⁵¹ This is true not only for utility-scale solar, but also for distributed solar PV. Figure 30 shows the projected growth in installed distributed PV capacity in the U.S., based on state-level forecasts from NREL's dSolar model forecast. By 2040, distributed solar capacity is estimated to be more than 150 GW, with an annual growth rate of 10.7% over the 2017-2040 period. To demonstrate the price elasticity of installed distributed PV capacity, NREL also modeled cumulative capacity assuming PV costs at 25% lower than their modeled reference scenario from 2020 onward. A 25% reduction in costs would result in 35.5% more cumulative capacity by 2040.

Figure 30: Cumulative U.S. Installed Capacity of Distributed PV⁵²



Wholesale Markets

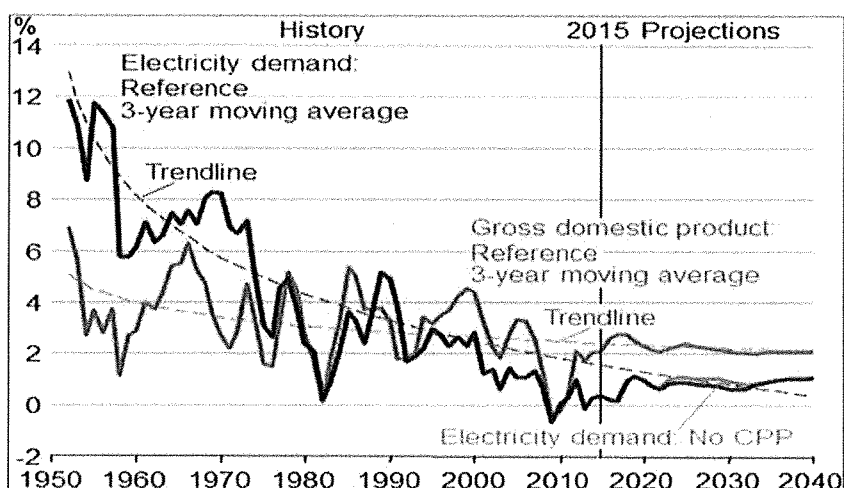
According to EIA, load growth began to flatten and even decline in some markets after the 2009 recession and the trend continued after the economic rebound. The sluggish growth reflects increases in energy efficiency, conservation, and slower population growth. EIA expects moderate growth in electricity through 2040 due to increased demand for electric services, offset by increases in efficiency and demand side management programs.

⁵¹ See Lazard 2016.

⁵² National Renewable Energy Laboratory, Distributed PV Adoption – Sensitivity to Market Factors, February 2016, <http://www.nrel.gov/docs/fy16osti/65984.pdf>, last accessed on December 27, 2016. Capacities shown are in DC, rather than AC.

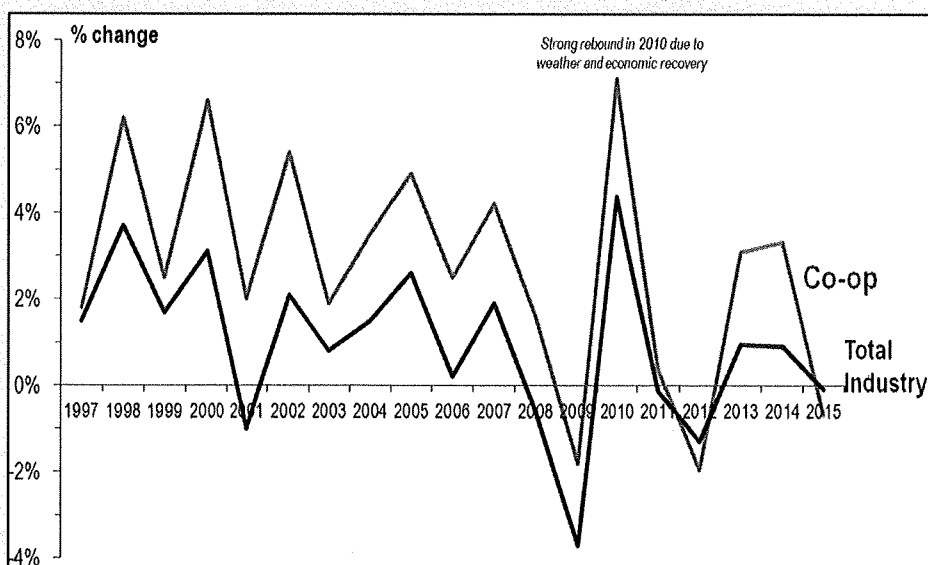
Figure 31: Historical and Projected Load Growth⁵³

Growth in electricity use slows, but electricity use still increases by 20% (0.7%/year) from 2015 to 2040



Cooperative Focus

As shown in Figure 32, in most years electric cooperative retail sales have grown significantly faster than the industry as a whole, though they dipped below national averages in 2012 and 2015. While trends suggest that cooperative sales growth will continue to outpace the industry in most years, in accordance with the national trend cooperative sales growth is expected to remain historically low in the coming years. Slower growth poses challenges at a time when investments in new generation and growing investments in transmission are anticipated.

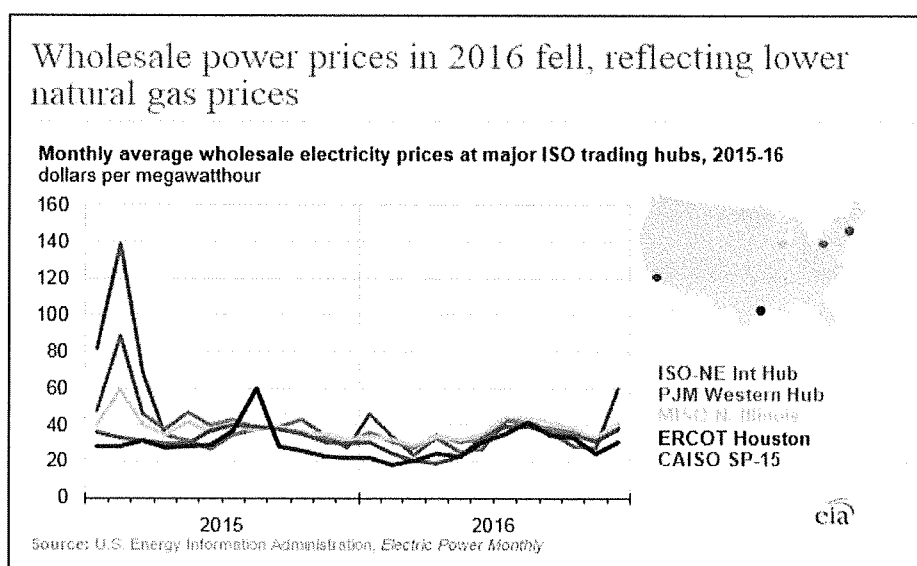
Figure 32: Retail Sales Growth of Electric Cooperatives vs. Total Industry

⁵³ AEO2016.

According to EIA, wholesale electricity locational marginal prices (LMPs) at major hubs across the U.S. declined in the first quarter of 2016 compared to the same period in 2015. EIA cited lower natural gas prices and milder weather for the drop in prices. In California, prices dropped 24%, while in New England prices dropped as much as 64%. EIA reported that monthly wholesale electricity prices dropped to between \$20 and \$45 per MWh through the first 10 months of 2016, also reflecting lower gas prices.

"The primary driver of the low wholesale electricity prices was the sustained low cost of natural gas prices, which is the fuel that often determines the marginal generation cost in most power markets," EIA said. The cost of natural gas delivered to power generators averaged \$2.78 per MMBtu during the first 10 months of 2016, the latest reporting period, a 17% decline from the same period in 2015.

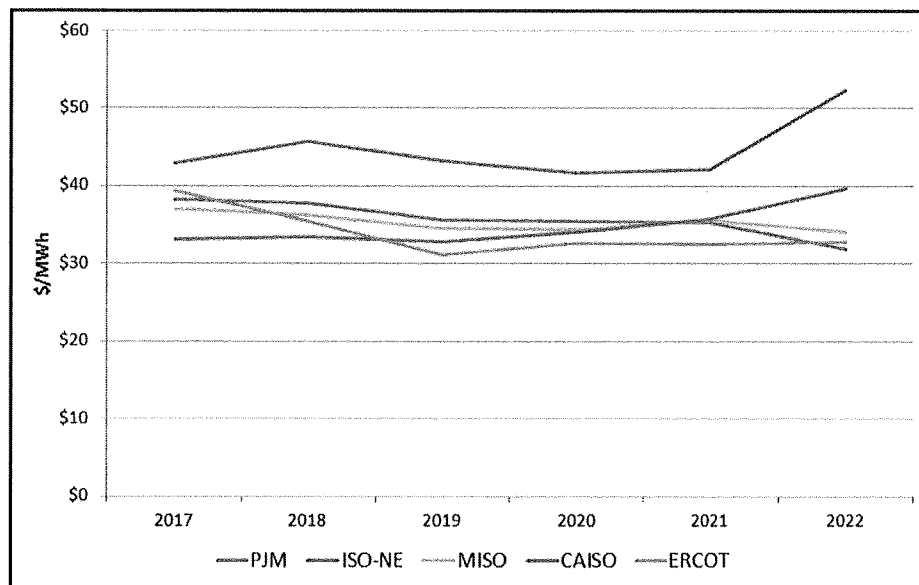
Figure 33: Wholesale Power Prices⁵⁴



Electricity futures prices at the most liquid hubs are generally down through 2022. Futures in the PJM Western Hub, the most liquid hub, dropped in price from \$38.20 to \$31.90 for the 2017 to 2022 period. This is consistent with declining gas futures prices in the near-term. Futures prices in ISO-NE for 2022 spiked almost \$10 to \$52.35, reflecting colder weather in the northeast and less certainty for future years.⁵⁵ In the 2016 AEO, EIA report predicts natural gas to gradually increase starting in 2018, and the northeast tends to have greater delivery constraints in the winter. Futures prices in CAISO and ERCOT are less predictable as those products are less frequently traded.

⁵⁴ EPM 2016.

⁵⁵ Figure derived from data from the Chicago Mercantile Exchange future prices, available at: <http://www.cmegroup.com/trading/energy/#electricity>.

Figure 34: Regional On-Peak Electricity Futures⁵⁶

PJM, New England ISO (ISO-NE) and New York ISO (NYISO) have well-formed mandatory capacity markets, but their characteristics vary significantly from each other. Both PJM and ISO-NE are forward markets with auctions three years out. NYISO operates shorter term auctions for spot, monthly, and winter and summer seasonal auctions. MISO has a voluntary capacity market which acts like a spot market for capacity shortfalls. Currently, the other markets (CAISO, ERCOT, and SPP) are energy-only and do not have capacity markets.

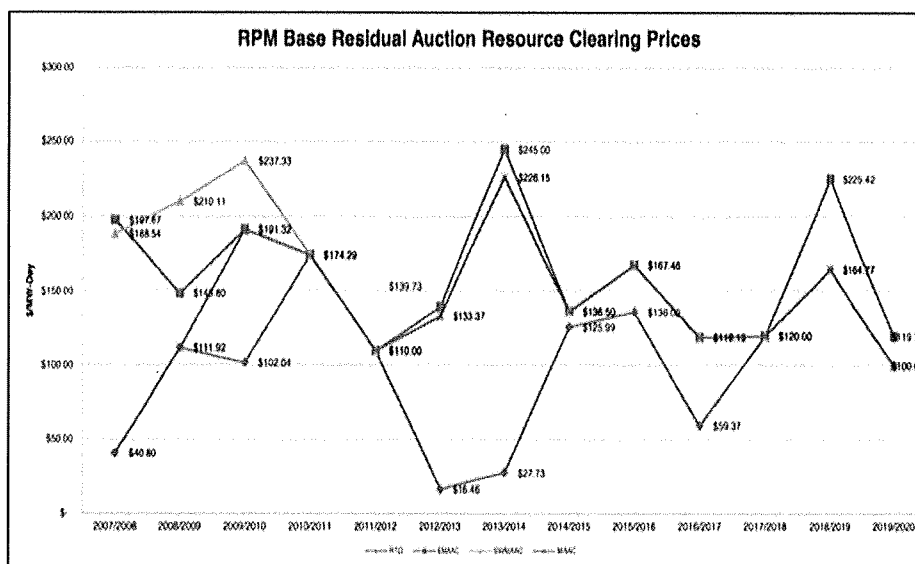
As illustrated in Figure 35, capacity market prices in PJM (other eastern markets show a similar trend) can fluctuate wildly, creating price uncertainty for generation and load. The capacity markets in the east have been in flux in recent years due to continued litigation and extreme weather that caused power shortfalls and extreme price spikes. PJM introduced a new product, called Capacity Performance, a “requirement that generators must meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies.”⁵⁷ In return for firm commitments, generators may receive higher capacity payments and are expected to invest in the grid infrastructure to ensure reliability. The product will be phased in over a two-year period from 2018 to 2020.

There have been growing concerns about how the organized markets value nuclear power, as a non-emitting baseload resource. In a few of the RTOs/ISOs, recent capacity payments were substantially lower than in historical auctions, leading to concerns that nuclear power plants would not be able to recoup their costs and be forced to retire early, endangering reliability and greenhouse gas reduction goals. New York and Illinois passed legislation in late 2016 to address these concerns. These state policies have led to a larger conversation about the role of state policy in the organized markets which resulted in the Federal Energy Regulatory Commission (FERC) holding a technical conference in May 2017.

⁵⁶ *Id.*

⁵⁷ “Capacity Markets at a Glance”, available at: <http://pjm.com/~media/library/reports-notice/capacity-performance/20150720-capacity-performance-at-a-glance.ashx>, last Accessed on January 4, 2017.

Figure 35: Reliability Pricing Model Base Residual Auction Resource Clearing Prices

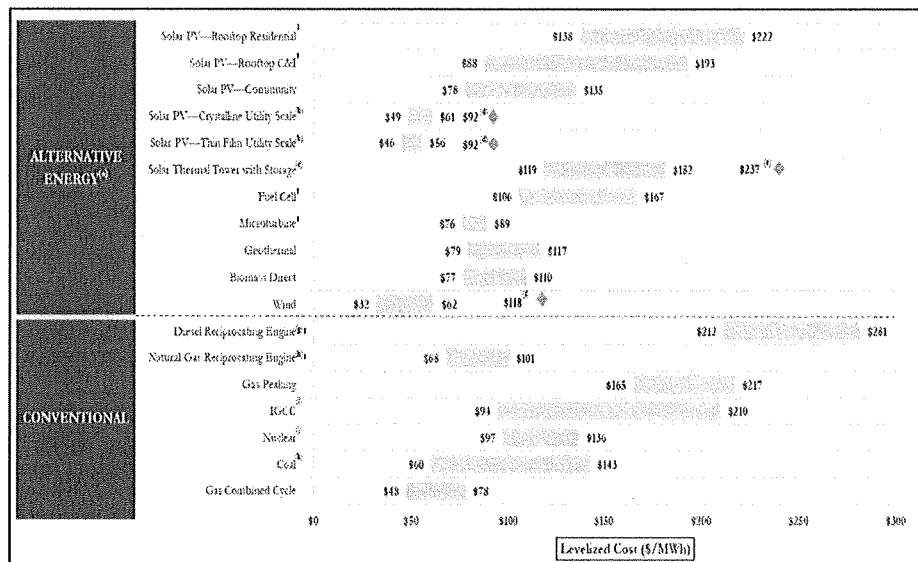


The Commission initiated this proceeding because of disputes in three RTOs over state legislative and state commission efforts to procure or prevent the retirement of traditional baseload generation. Depressed energy market prices resulting from low variable cost intermittent resources can make it difficult for traditional generation to compete in organized energy markets, particularly where tax incentives allow for even lower, or sometimes negative, bids. Although renewable resources are at times more economic than traditional baseload resources, they do not necessarily offer the same reliability benefits. Regulators have therefore explored the capacity markets and other state actions as a solution. However, incumbent generators who participate in mandatory capacity markets allege that state actions distort these markets by depressing capacity auction prices as well. A related issue is how state policies that favor environmental attributes can work alongside FERC-regulated wholesale capacity markets that currently only value generator capacity and cost. When the commission returns to quorum these issues and others will be front and center.

Cooperative Focus

Many G&T cooperatives are now part of organized markets which can control their transmission and dispatch their generation resources. As mentioned above, this has had an impact in some areas where coal resources that previously provided baseload generation are dispatched far less often due to low cost natural gas and wind resources that are able to bid at low or negative levels due to the PTC. This has led to increased gas generation for G&Ts that own efficient NGCC units. Some G&Ts have expressed concerns about the allocation of transmission expenses within organized markets.

Appendix

Figure 37: Unsubsidized Levelized Cost of Energy⁵⁸⁵⁸ Lazard 2016.

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