ELECTRIC INDUSTRY GENERATION, CAPACITY, AND MARKET OUTLOOK

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Updated July 2019

NRECA

America's Electric Cooperatives

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Introduction

The electricity industry in the United States continues to change from a centralized power plant model to an increasingly decentralized model with the inclusion of distributed energy resources. Trends of historically low natural gas prices and the increasing market share of intermittent renewable resources are projected to continue. After surpassing coal for the first time in 2016, natural gas is projected to remain the largest source of generation over the long term. These trends are putting increased pressure on coal and nuclear resources that have traditionally provided baseload power, and on existing infrastructure to provide additional flexibility in dealing with this altered landscape. This report presents high-level analyses and projections of electricity generation, capacity, 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. 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:

- *In 2018, 13 GW of coal-fired capacity were retired, for a total of 42 GW retired since 2015. Generators announced plans to retire an additional 16.8 GW of coal fired electricity resources through 2025.*
    - *Over the 2014 to 2018 period, electric cooperatives retired or converted 1.5 GW of coal capacity, with another 2.1 GW of retirements announced through 2028.*
- *Due to continuing low fuel prices, natural gas generation exceeded coal generation for the third year in a row in 2018, accounting for 35% of national generation output. Natural gas is projected to remain the largest source of generation, growing to represent more than 37% of the generation mix in 2040.*
    - *While still more coal heavy than the national average, co-ops have followed the same trends away from coal and towards natural gas in their overall retail power supply (including owned generation and purchases).*
- *Low settlement prices in wholesale energy and capacity markets continue to put economic pressure on nuclear units, with more than 6 GW of nuclear capacity scheduled to retire by 2025, and another 4 GW facing great uncertainty.*
- *Though still expected to rise over time, the Energy Information Administration (EIA) projects average annual gas prices at Henry Hub will remain between $3 and $4/MMBtu through 2035 and might remain closer to $3/MMBtu if higher natural gas production drives down prices.*
- *EIA also projects that load growth will remain low, averaging about 1% annually through 2050; slow growth is driven in part by increasing energy efficiency and growth in distributed generation, though there are opportunities for greater electrification at homes and businesses and in transportation.*
- *Out of the total 90 GW of new capacity planned for the 2019-2027 period, 46% is from natural gas units, primarily at natural gas combined cycle (NGCC) plants. Together, wind and solar make up an additional 48%.*
    - *Several Generation & Transmission (G&T) cooperatives have recently added or are planning new NGCC plants, either on their own or through joint ownership. Electric cooperatives also continue to add significant wind and solar resources to their generating portfolios, primarily through power purchase agreements.*
- *Since 2009, utility-scale solar costs for crystalline panels have decreased by 88% and utility-scale wind costs have decreased by 69%, according to Lazard in its most recent levelized cost of energy (LCOE) analysis.*
- *Federal tax incentives and declining costs have made renewable technologies increasingly cost-competitive. In these market conditions, utility-scale renewables accounted for 37% of capacity additions in 2018.*
- *Generation from renewables is projected to steadily increase, reaching 26% in 2040 and surpassing coal by 2031.*
- *As the share of intermittent renewable resources on the grid increases and more coal and nuclear units retire, the industry is more likely to face challenges in terms of resource adequacy and reliability.*
- *Energy storage paired with intermittent resources offers the prospect of helping to address these challenges.*

What's Changed

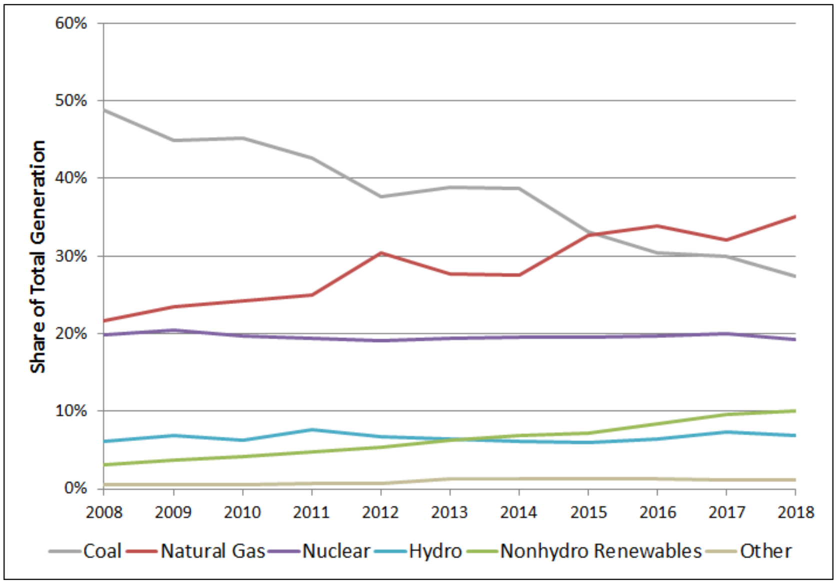
Economic, regulatory, and technology changes continue to shape the electric utility sector. Low natural gas prices are resulting in increased gas-fired generation, largely at the expense of coal generation. This increased reliance on natural gas is evident in the changing generation mix. Natural gas generation has become the largest generation resource in the United States and is projected to remain so for the foreseeable future due to abundant natural gas supply. In 2018, natural gas generation made up a record 35.1% of the U.S. generation mix, up from 32.1% in 2017.

Declining technology costs, tax incentives, and Renewable Portfolio Standards (RPS) have encouraged steady increases in non-hydro renewable generation. Renewables continued to grow rapidly in 2018 and for the first time made up 10% of total generation in the United States. As the Production Tax Credit (PTC) for large-scale wind phases out by 2024, and the Investor Tax Credit (ITC) is lowered to 10% for utility-scale solar resources by 2022, this pace of growth may slow down. Hydroelectric generation has maintained its share of around 7% of generation with fluctuations driven primarily by annual precipitation levels.

Historically, coal was the predominant energy source of the U.S. generation mix, accounting for 50% of the market share as recently as the late 2000s, but that paradigm has changed due primarily to competition from gas-fired and renewable generation. In 2018, coal fell to 27.4% of U.S. generation, its lowest share to-date.[1]

Nuclear generation has maintained its share of around 20% of generation. In 2016, the first new nuclear reactor since the 1980s became operational with Tennessee Valley Authority's Watts Bar Plant in Tennessee. Two new reactors are planned online in 2022-2023 at Plant Vogtle in Georgia, but nuclear units are also facing market pressures and future prospects are limited barring commercialization of small modular reactor (SMR) technologies.

Figure 1: Share of Total Generation, 2008-2018[2]



[1] U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO 2019), available at: http://www.eia.gov/outlooks/steo/.

[2] STEO 2019.

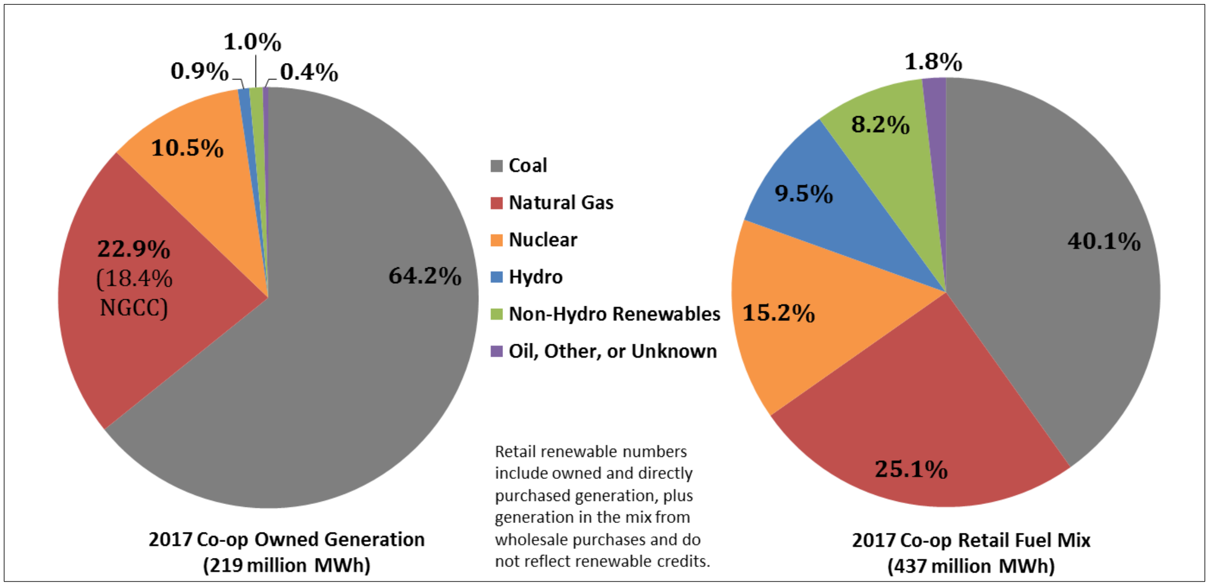
Cooperative Focus

Co-op owned electric plants generated about 219 million MWh of output in 2017,[3] roughly 5% of U.S. electric generation. Coal continues to be the largest source of co-op self-generation, but its share has trended downward in recent years as low natural gas prices have led to a significant increase in co-op natural gas generation, with most of the growth coming from increased output from new and existing NGCC plants. The dispatch of co-op units varies year to year, so while the trend has been a shift from coal to gas generation, there was actually a slight increase (~3%) in co-op coal generation and a corresponding decline in natural gas generation from 2016 to 2017.

At the retail level, distribution cooperatives sold about 437 million MWh in 2017, slightly down from 440 million MWh in 2016. G&T cooperatives sell some of their power (approximately 10% to 15%) to non-members, so co-op owned generation actually provides somewhat less than half of the power that distribution cooperatives sell at retail. There were only very minor changes in the co-op retail mix from 2016 to 2017, with natural gas again providing a quarter of power supply.

Figure 2 compares the fuel mix of co-op owned generation with the blended retail mix (including generation and purchases) for 2017. This highlights the importance of power purchases for renewable resources, primarily preference hydropower from federal dams and bilateral power purchase agreements for other resources. National trends away from coal and towards natural gas and renewables are reflected in both the co-op generation and retail mixes.

Figure 2: Co-op Owned Generation and Retail Fuel Mix, 2017[4]



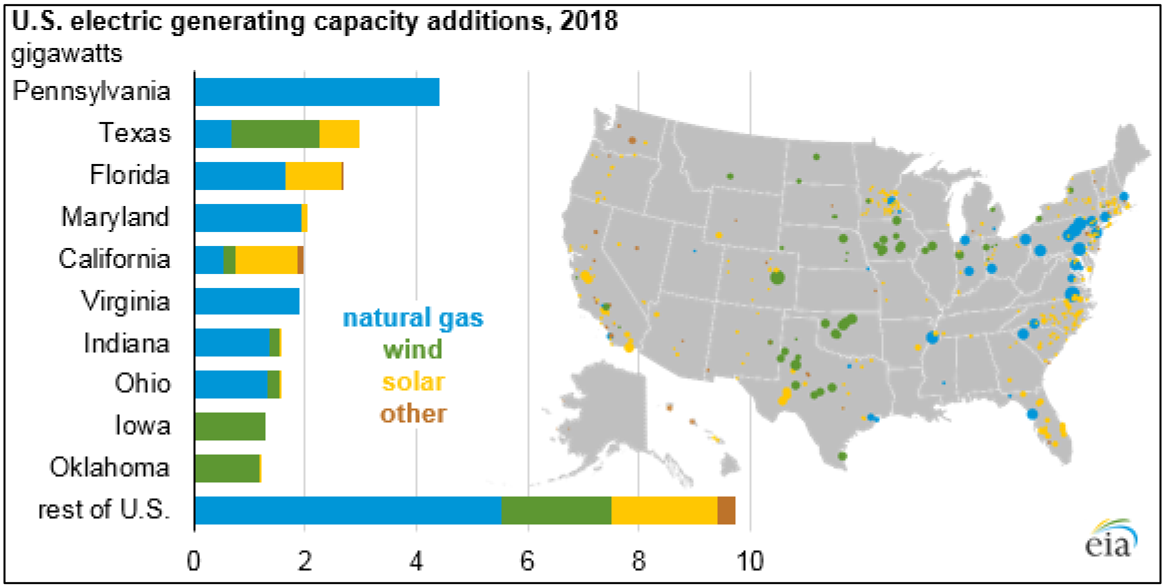
As shown in Figure 3, total capacity additions exceeded 33 GW in 2018, with new renewables accounting for approximately 37% of this total.[5] The overwhelming majority of these additions came from utility-scale solar and

[3] 2017 was the latest available year for unit-level data from the U.S. Energy Information Administration (EIA).
[4] NRECA Research .

wind, which are expected to contribute an additional 72 GW of capacity by 2021 with average annual growth rates of 8% and 4%, respectively.[6]

Natural gas-fired generation units made up 62% of new capacity additions, with most of this capacity (almost 90%) at new NGCC plants.[7] Many of those combined cycle plants were built in the PJM Interconnection's geographical footprint, with about a quarter located in the state of Pennsylvania alone.[8] This increased reliance on natural gas as a primary fuel source has many in the industry concerned about the lack of fuel diversity and the availability of natural gas if a pipeline is interrupted or if more pipelines cannot be built.

Figure 3: Utility-Scale Capacity Additions[9]

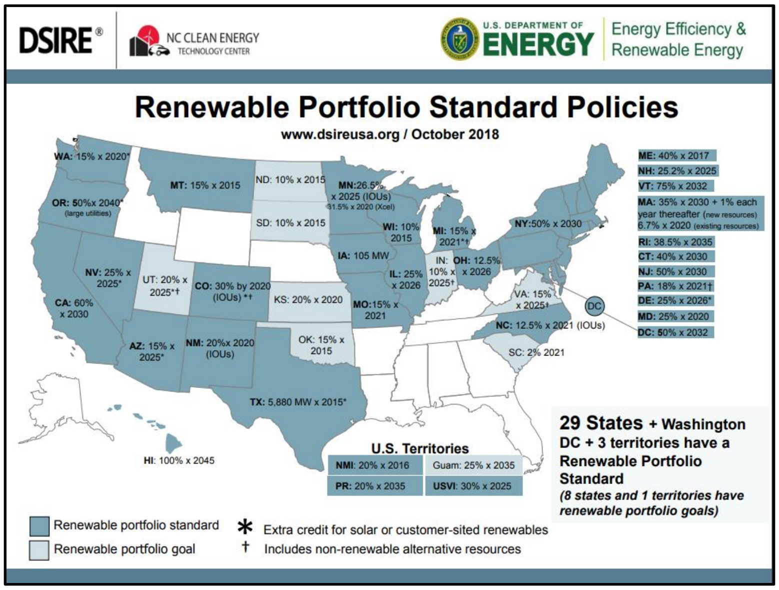


In addition to Federal tax incentives, state policies have a significant impact on renewable energy deployment, with renewable mandates in particular acting as important drivers for renewable growth. RPS policies have been adopted by 29 states and the District of Columbia, with several others adopting voluntary standards. Many of these states direct not only investor-owned utilities (IOUs) to meet these thresholds, but also public power and cooperative utilities, though their requirements are sometimes lower. Since 2016, eleven states (CA, CT, IL, MA, MD, ME, MI, NJ, NY, RI, and OR) and the District of Columbia have extended or expanded their RPS standards,[10] and many other states have ongoing conversations about altering their renewable standards. According to analysis by Lawrence Berkeley National Laboratory, renewable mandates have been the driving force behind roughly half of all renewable energy growth since 2000 and were a key factor in 34% of capacity additions in 2017.[11] As penetration levels of

[5] Dubin, Kenneth. "More than 60% of electric generating capacity installed in 2018 was fueled by natural gas," *EIA Today in Energy*, March 11, 2019, available at: https://www.eia.gov/todayinenergy/detail.php?id=38632.
[6] AEO 2019. *See Note 3.*
[7] EIA Form EIA-860: Monthly Update to the Annual Electric Generator Report. f
[8] EIA TIE 2019.
[9] *Ibid.*
[10] Advanced Energy Legislation Tracker, available at: http://www.aeltracker.org.
[11] Lawrence Berkeley National Laboratory. "US Renewable Portfolio Standards 2018 Annual Status Report." Available at: http://eta-publications.lbl.gov/sites/default/files/2018_annual_rps_summary_report.pdf.

intermittent resources increases on the bulk electric system, voltage and frequency regulation will become more critical.

Figure 4: Renewable Portfolio Standards[12]

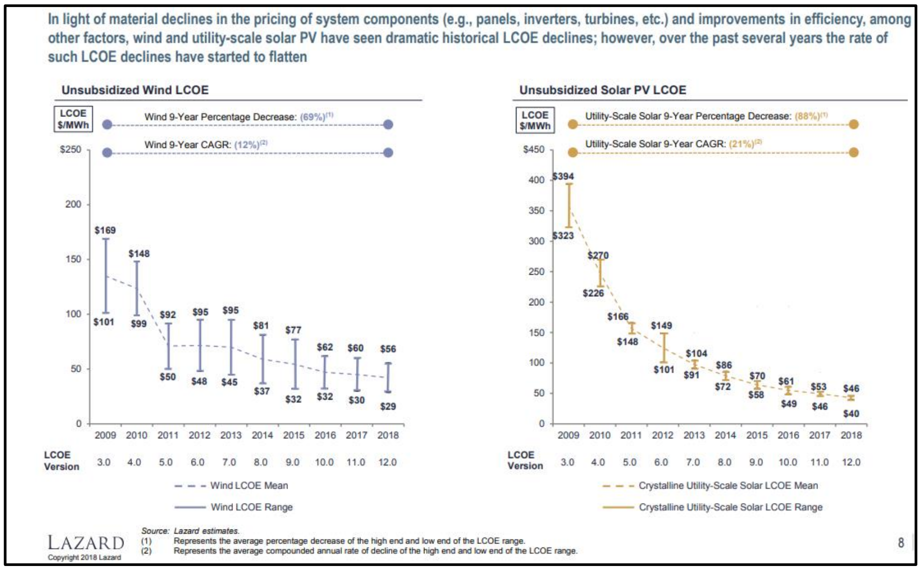


Many states have been able to meet or surpass their RPS targets, in large part due to the declining costs of wind and solar photovoltaic (PV) resources. Figure 5 below shows the levelized cost of energy for wind and solar PV without federal tax incentives. According to Lazard's *2018 Levelized Cost of Energy Analysis*, utility-scale solar costs for crystalline panels dropped 88%, and utility-scale wind costs dropped 69% in the last decade.[13]

[12] Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standards (DESIRE), available at: http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2018/10/Renewable-Portfolio-Standards-2018.pdf.

[13] Lazard's Levelized Cost of Energy Analysis, December 2018 (Lazard 2018), available at: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf. 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.

Figure 5: Historical Unsubsidized Levelized Cost of Energy – Wind and Solar PV[14]



Developers have leveraged these declining costs, federal tax incentives, and RPS policies to increase renewable deployment across the country. This proliferation of renewable resources can best be seen in the impact it has on regional wholesale markets. Earlier this year, the Southwest Power Pool (SPP) recorded a 66.5% wind penetration in the early hours of April 21, 2019; the highest wind penetration that had ever been recorded for an organized market.[15] SPP has nearly 21 GW of wind on its system, and in 2018 wind resources accounted for 23.5% of total energy production, second only to coal (42.4%) and just edging out natural gas (23.4%) in the market.[16] As the penetration of renewables continues to grow, the challenges of balancing those intermittent resources will increase for system operators and regional markets.

In January of 2018, the Trump Administration decided to impose tariffs on imported solar cells and modules. Starting at a 30% rate in 2018, these tariffs were set to decline by 5% each year before expiring in 2022. Meanwhile, the Administration levied a 10% tariff on solar inverters, which was originally slated to increase to 25% in January of 2019. However, due to ongoing talks with China, the 25% rate did not take effect until May of 2019.[17] GTM Research projected that both tariffs, aimed primarily at China, will reduce total solar installations by 7.6 GW through 2022, an 11% reduction from their projections, with nearly two-thirds of the impact on utility-scale projects.[18] In spite of this, total U.S. solar installations exceeded 10.6 GW in 2018, for an annual total that is 2% below 2017.[19]

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[14] *Ibid.*

[15] AWEA, "Wind breaks a new record in Southwest Power Pool." April 26, 2019. Available at: https://www.aweablog.org/wind-breaks-new-record-southwest-power-pool/.

[16] "SPP101: An Introduction to Southwest Power Pool," *SPP*, May 2019, available at: https://www.spp.org/documents/31587/intro%20to%20spp.pdf.

[17] Arthur Villasanta. "US-China Trade Talks Tensions Escalate as Trump Threatens 25% Tariffs on $200B Goods." *International Business Times.* May 5, 2019. Available at: https://www.ibtimes.com/us-china-trade-talks-tensions-escalate-trump-threatens-25-tariffs-200b-goods-2790049

[18] Pyper, Julia. "New Tariffs to Curb US Solar Installations by 11% through 2022,"*Green Tech Media*, January 23, 2018, available at: https://www.greentechmedia.com/articles/read/tariffs-to-curb-solar-installations-by-11-through-2022#gs.1Vv3zvw.

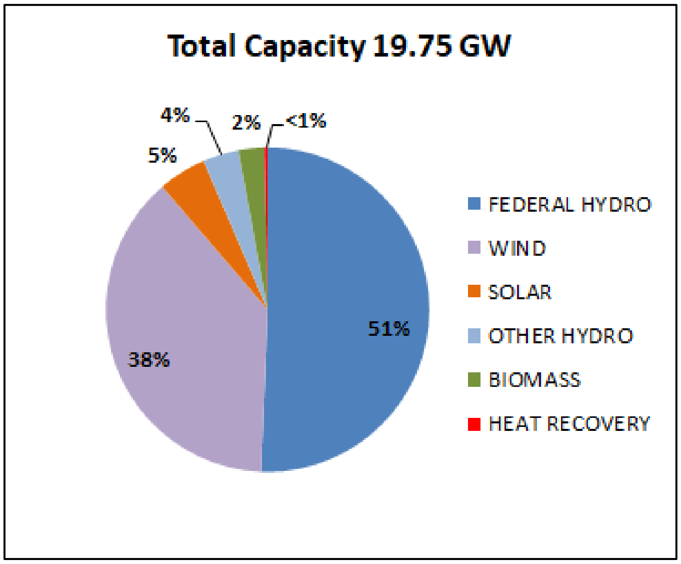
[19] Solar Energy Industries Association. "Solar Market Insight Report 2018 Year in Review." March 13, 2019. Available at: https://www.seia.org/research-resources/solar-market-insight-report-2018-year-review.

Cooperative Focus

Electric cooperatives have seen rapid growth in renewable resources in recent years. 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. This allows cooperatives to indirectly take advantage of federal tax incentives for wind and solar projects through their negotiations with developers over contract terms. In all, electric cooperatives have more than 9.7 GW of renewable capacity deployed, with more than 3 GW of additional capacity planned and new announcements made frequently. As seen in figure 6, this is in addition to 10 GW of federal hydropower purchased by cooperatives annually, for a total of nearly 20 GW of renewable resources.

As shown in Figure 6, wind dominates the current non-hydro renewable portfolio deployed by cooperatives in terms of capacity, with more than 7.5 GW owned or under contract. Wind is set to remain the largest non-hydro renewable resource deployed by cooperatives, with more than 1.2 GW of new wind PPAs planned over the next two years.

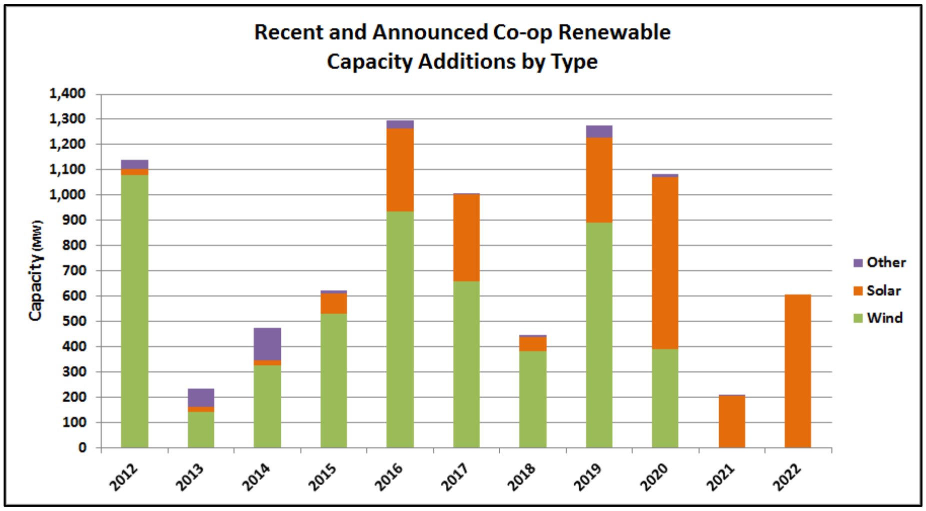
Figure 6: Current Cooperative Renewable Capacity by Type



In recent years, there has been significant growth in co-op solar resources, with deployed capacity more than quadrupling since the beginning of 2016. As of the end of 2018, cooperative solar capacity stood at more than 900 MW, with more than 1,800 MW of additional capacity planned. In terms of capacity, these additions have made solar the second largest non-hydro renewable resource for cooperatives after wind. More than 100 MW of current solar capacity is offered to consumer-members through community solar programs, with nearly a quarter of distribution cooperatives offering these programs to their members either directly or in partnership with their G&T.

While most of the solar projects deployed by co-ops have been relatively small, there is a trend towards larger arrays, including several planned PPAs for projects of 100 MW or larger. These large projects are driving co-op solar capacity growth, and for the first time co-ops have more planned solar capacity than wind capacity.

Figure 7: Recent and Planned Cooperative Renewable Additions, 2012-2022[20]



According to the Department of Energy, more than 70% of U.S. transmission infrastructure (e.g. transmission lines and large power transformers) is older than its recommended 25-year service life, with some of the oldest lines dating back to the 1960s.[21,22] While regular maintenance can extend this service life significantly, many of the oldest assets in the system are at high risk for failure and are in dire need of replacement.

At the same time, renewable energy growth has increased the need for transmission infrastructure to connect remote generation sources to load centers. For example, PJM has reported that $13.7 billion in transmission investment will be necessary to achieve member states' goals of 30% renewable energy across its footprint by 2030.[23] According to the Brattle Group, this continued growth in renewable energy will be one of the primary drivers for future transmission development, with interregional buildout, reliability upgrades, and load growth due to electrification playing a more significant role over time.[24,25]

While building transmission lines can be very expensive, the greater challenge for many transmission developers is a complex regulatory environment. This is especially challenging for projects that cross state lines, with siting and permitting processes taking up to a decade as multiple state and federal authorities are required to coordinate.

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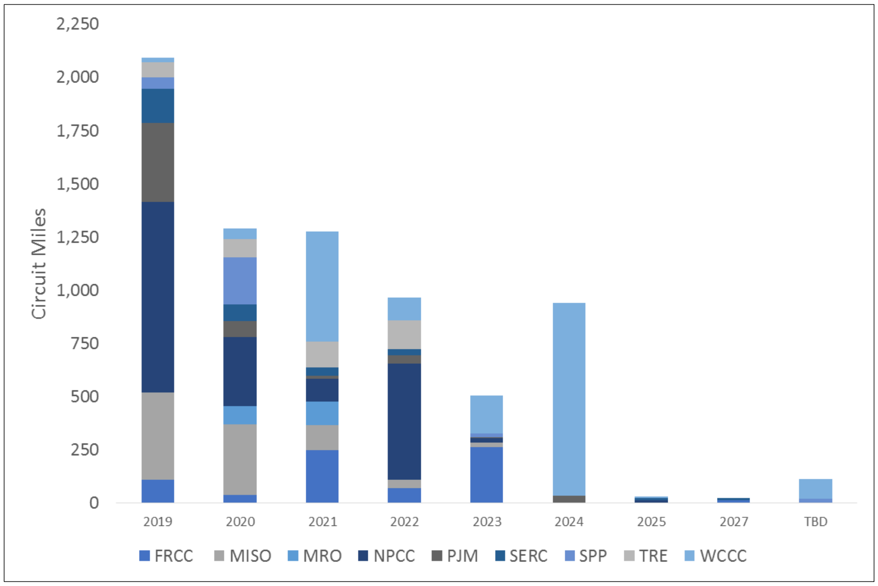
[20] NRECA Research.
[21] Sarah Gerrity. "Understanding the Grid (Nov. 2014)." *U.S. Department of Energy.* Available at: https://www.energy.gov/articles/infographic-understanding-grid.
[22] U.S. Department of Energy Office of Electricity Delivery and Energy Reliability. "Infrastructure Security and Energy Restoration (June 2012)." Available at: https://www.energy.gov/sites/prod/files/Large%20Power%20Transformer%20Study%20-%20June%202012_0.pdf.
[23] GE Energy Consulting. "PJM Renewable Integration Study (March 2014)." Available at: https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx?la=en.
[24] Johannes Pfeifenberger, Judy Chang, and John Tsoukalis. "Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure (July 2015)." *The Brattle Group.* Available at: http://files.brattle.com/system/publications/pdfs/000/005/190/original/investment_trends_and_fundamentals_in_us_transmission_and_electricity_infrastructure.pdf?1437147799.
[25] Jurgen Weiss, J. Michael Hagerty, and Maria Castaner. "The Coming Electrification of the North American Economy (Mar. 2019)." *The Brattle Group.* Available at: https://wiresgroup.com/new/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf.

Moreover, developers must contend with increasingly common opposition from residents and activists who are concerned about disruptions to culturally or environmentally sensitive land.

Despite these challenges, Figure 8 shows that an estimated 2,100 circuit miles of transmission line are expected to be completed in 2019, with an additional 5,000 circuit miles expected to be in service by 2024. These planned additions include approximately 1,800 circuit miles of high voltage (400 – 599 kV) line, primarily in the Western Interconnection.

Figure 8: Planned Transmission Additions 2019-2027[26]

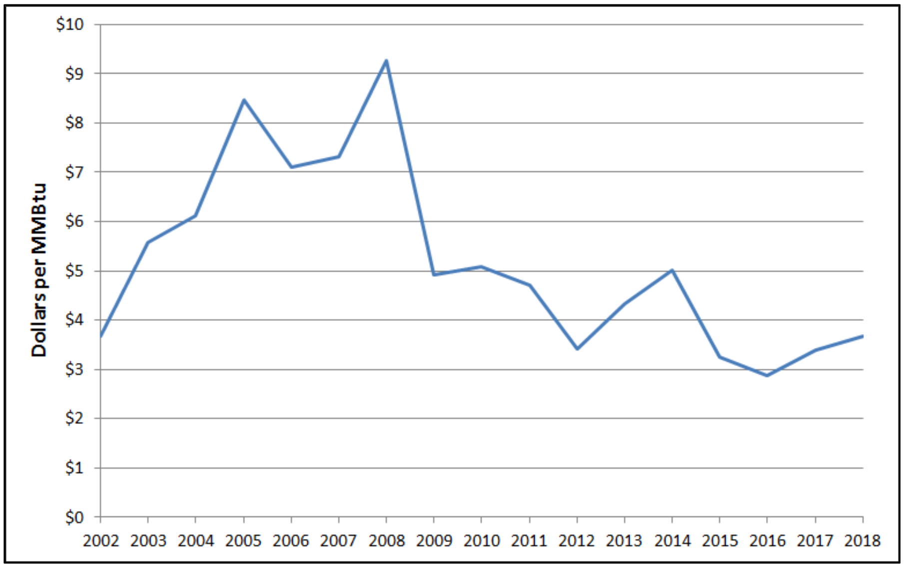


Current Capacity and Generation Mix

Many of the changes experienced throughout the industry relate to the greatly increased supply of natural gas from unconventional sources, resulting in historically low gas prices. Figure 9 presents natural gas prices at Henry Hub over the 2001 to 2018 period. After a steep decline in 2009, prices have remained below $5 per MMBtu and declined even further than expected, remaining below $4 per MMBtu since 2016. In 2018, prices continued to be below $4 per MMBtu.[27] As discussed later in this report, EIA's Annual Energy Outlook for 2019 (AEO2019) 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 2050.[28]

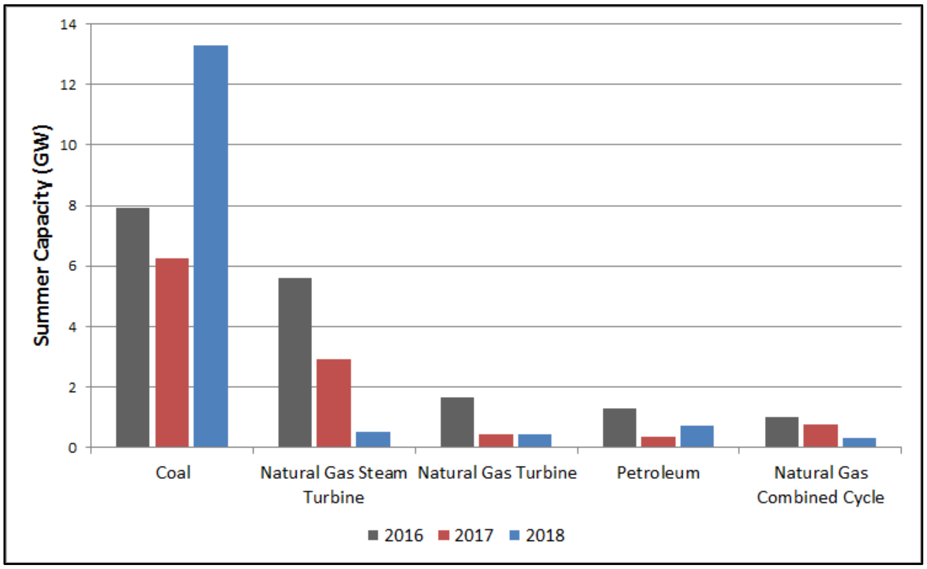
[26] NERC. "Electricity Supply and Demand (2018)." Available at: https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx
[27] STEO 2019. *See Note 1.*
[28] AEO 2019. *See Note 3.*

Figure 9: Henry Hub Natural Gas Spot Price, 2002-2018[29]



The growth in gas supply and the lower than expected natural gas prices have put downward pressure on aging fossil fuel infrastructure, especially coal and natural gas steam units. Due to these widespread changes throughout the industry, more than 71 GW of capacity shut down between 2015 and 2018, with fossil fuel resources making up nearly 96% of the total. Just over 42 GW of this capacity is from coal-fired units that retired in large part due to changing economics, but also environmental regulations such as the Mercury Air and Toxics Standards (MATS), which took effect in April 2016. Figure 10 shows the breakdown of the conventional capacity that was retired in 2016, 2017, and 2018. In 2018, coal capacity retirements rose to 13 GW, largely driven by economics despite a more favorable regulatory environment.

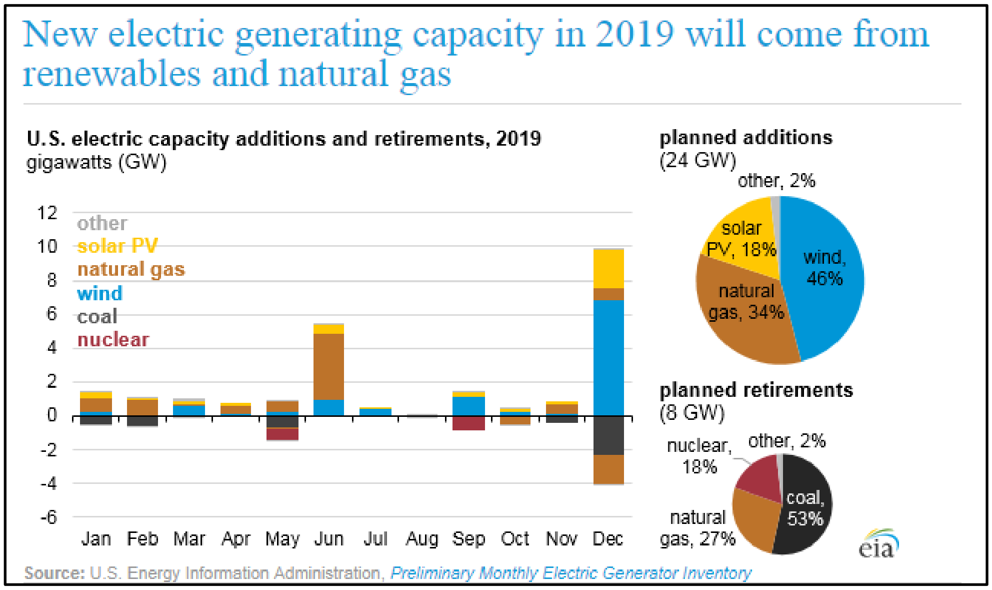
Figure 10: Fossil Fuel Retirements in 2016-2018[30]



[29] U.S. Energy Information Administration, *Natural Gas Futures Prices (NYMEX)*, available at: http://www.eia.gov/dnav/ng/hist/rngwhhda.htm.

According to the EIA, 18.7 GW of capacity retired in 2018, and an additional 9 GW of capacity is expected to retire in 2019, with most of these retirements being scheduled towards the end of the year. Out of the anticipated 4.3 GW of coal-fired retirements, half of the retired capacity is expected to come from the Navajo Generating Facility in Arizona, which first came online in the 1970s." These retirements are expected to be replaced by 24 GW of new wind, solar PV, and natural gas capacity. As shown in Figure 11, nearly two-thirds of the planned additions are utility-scale renewables, mostly scheduled to come online in December.[31]

Figure 11: Plant Additions and Retirements in 2019[32]



Looking forward, a substantial amount of additional capacity is scheduled to be retired over the next decade, primarily from coal and nuclear units most impacted by market pressures. Figure 12 shows anticipated future retirements through 2030 by fuel type.[33] Over 18 GW of coal retirements have already been announced through 2030, along with 14 GW of natural gas retirements.

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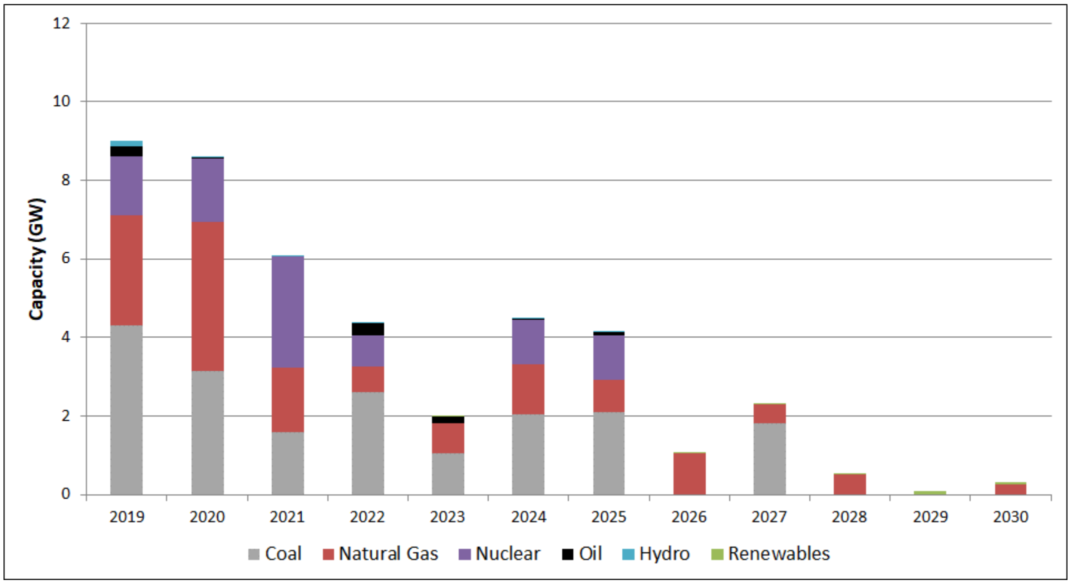
[30] EIA-860M.

[31] Marcy, Cara. "New electric generating capacity in 2019 will come from renewables and natural gas," *EIA Today in Energy*, January 10, 2019, available at: https://www.eia.gov/todayinenergy/detail.php?id=37952.

[32] EIA TIE Additions.

[33] *Id*. The EIA-860 Annual Generator Report is self-reported data, so retirement dates can change year from year depending on the respondent provided information. Years with no announced retirements are not shown in the figure.

Figure 12: Announced Plant Retirements, 2019-2030



A total of 42.8 GW of capacity is scheduled to retire before 2030 with coal, gas, and nuclear units accounting for approximately 43%, 33%, and 21%, respectively. In the near term, 16.8 GW of coal is announced to retire by 2025. Additionally, due to low settlement prices in wholesale and capacity markets driven by cheap gas and renewables, nuclear plants have struggled to recover their costs, and several units are scheduled to shut down over the next decade, as shown in Figure 13. Although a total of 2.2 GW of new capacity is scheduled to come online, there is nearly 8.9 GW retiring, with a net loss of almost 6.7 GW of nuclear capacity from the system. Despite recent retirements, a combination of uprates, reduction of outages, and thermal efficiency improvements led the U.S. nuclear fleet to set a new generation record of 807.1 million MWh and record capacity factor of 92.6% in 2018.[34]

While the construction of the two new units at Plant Vogtle has gone forward, the outlook for nuclear generation is mixed, with several units announced to retire in the next decade. With the cancellation of two new units at V.C. Summer Station in 2017,[35] the Vogtle units are expected to be the last large-scale reactor additions through 2050,[36] though there is some opportunity for nuclear expansion if SMRs achieve commercial scale within that period. Meanwhile, existing plants are projected to undertake 2 GW of uprates beginning in 2030.[37] Taken together, EIA projects that nuclear will decline to 14.2% of the generation mix by 2050.

To prevent the premature retirement of nuclear plants, several states moved to compensate nuclear facilities for their environmental benefits through Zero Emissions Credits (ZECs). These bills were initially challenged in court as

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[34] Scott, Michael and Owen Comstock. "Despite closures, U.S. nuclear electricity generation in 2018 surpassed its previous peak," *EIA Today in Energy*, March 21, 2019, available at: https://www.eia.gov/todayinenergy/detail.php?id=38792.

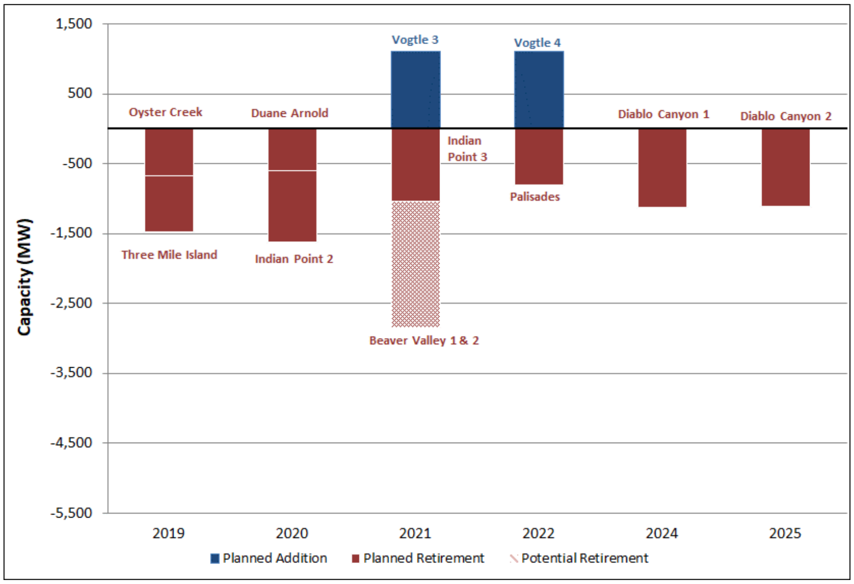
[35] Steve Cunningham and Jim Polson. "Two Half-Finished Nuclear Reactors Scrapped as Costs Balloon." *Bloomberg.* July 31, 2017. Available at: https://www.bloomberg.com/news/articles/2017-07-31/scana-to-cease-construction-of-two-reactors-in-south-carolina.

[36] U.S. Energy Information Administration, *Annual Energy Outlook 2019* (AEO 2019), available at: https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

[37] *Ibid.*

overreach into FERC regulated markets, but the 2nd and 7th Courts of Appeals held in *Coalition for Competitive Electricity, et al. v. Zibelman, et al.* and *Village of Old Mill v. Anthony Star and Exelon Generation Co. LLC* respectively that these were an acceptable form of state climate action. A similar bill in Ohio passed the legislature in late July 2019, even with consumer advocates and stakeholders from a variety of industries coming out in opposition.[38] The Pennsylvania legislative session came to an end in May 2019 without passage of a nuclear subsidy bill, so the future of the Three Mile Island and Beaver Valley plants remains uncertain.[39]

Figure 13: Announced Nuclear Plant Retirements and Additions 2019-2025[40]



To replace retiring capacity, new generating units must be added. Figure 14 depicts the historical and projected additions according to EIA. In its most recent Annual Energy Outlook, EIA projects that natural gas will make up most of the new additions through 2050. Due to the phase out of the wind tax credits in 2024, projected wind capacity additions drop off significantly after 2022 and natural gas and solar additions make up the difference. According to EIA projections, "solar generation growth continues because the costs for solar continue to fall faster than other sources."[41] Excluding the new planned units at Vogtle, the AEO does not project any new coal or nuclear-powered generation to be operational between now and 2050.

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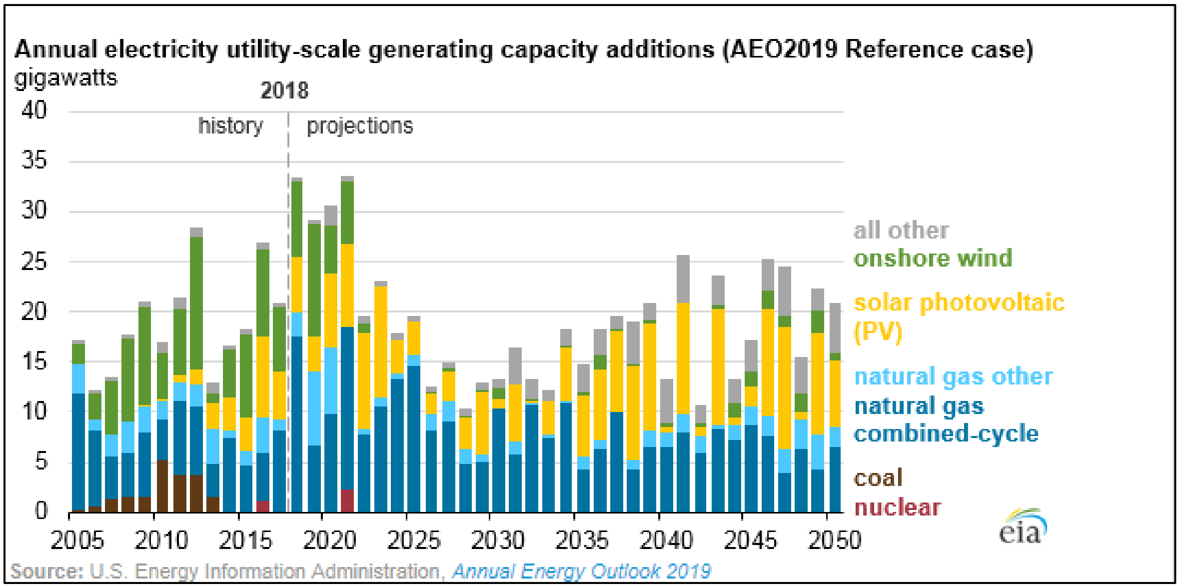
[38] Dan Gearino. "Ohio Governor Signs Nuclear and Coal Bailout at Expense of Renewable Energy." *Inside Climate News.* July 23, 2019. Available at: https://insideclimatenews.org/news/23072019/ohio-coal-nuclear-bailout-law-signed-cuts-renewable-energy-efficiency-programs-governor-dewine.

[39] Pennsylvania SB 510. Available at: https://www.legis.state.pa.us/cfdocs/billInfo/billInfo.cfm?sYear=2019&sInd=0&body=S&type=B&bn=510

[40] EIA-860M.

[41] AEO 2019.

Figure 14: Historical and Future Capacity Additions[42]



As intermittent resources make up a larger share of capacity on the bulk electric system and replace retired coal and nuclear units, the industry is more likely to face challenges in terms of resource adequacy and reliability. This can be seen with the most recent appeal by FirstEnergy; in March of 2018, the company asked the U.S. Department of Energy to declare an emergency under the Federal Power Act. This would allow "PJM to promptly compensate at-risk merchant nuclear and coal-fired power plants for the full benefits they provide to energy markets and the public at large, including fuel security and diversity, as detailed herein."[43] In June 2019, the U.S. Secretary of Energy Rick Perry stated that coal and nuclear should be part of an "all of the above" energy strategy, but that the department does not have the necessary "regulatory or statutory ability" to establish incentives for these resources.[44]

Figure 15 shows all announced future utility-scale-additions to the electric system by fuel type.[45] Out of the total 90 GW of new capacity planned for the 2019-2025 period, 46% is from natural gas units and 48% is from wind and solar. As will be discussed further in this report, growth in renewable generation, particularly solar PV, is projected to continue over the next several years. This is likely to underrepresent solar and wind projects, which tend to have a shorter lead times compared to traditional generation projects.

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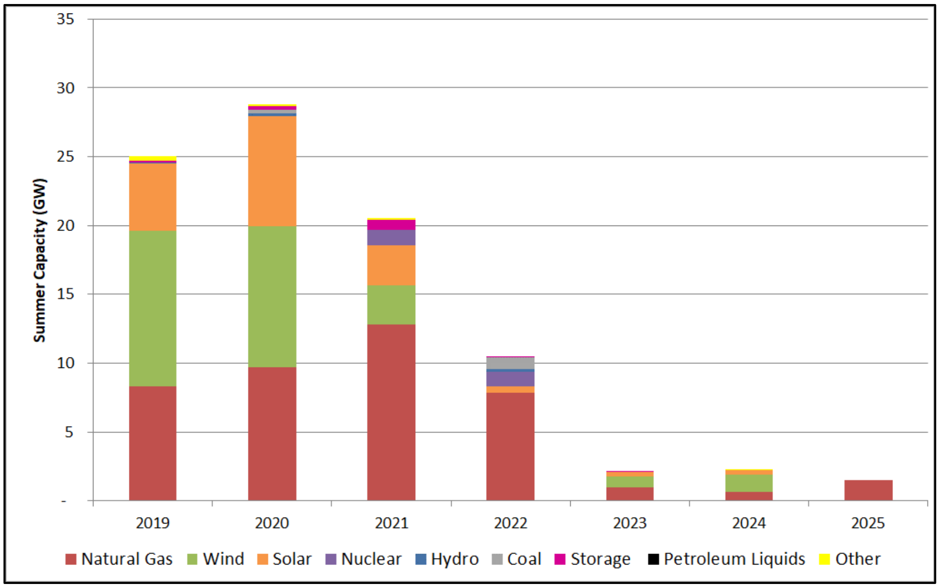
[42] Sukunta, Manussawee. "New U.S. power plants expected to be mostly natural gas combined-cycle and solar PV," *EIA Today in Energy*, March 8, 2019. Available at: https://www.eia.gov/todayinenergy/detail.php?id=38612.

[43] First Energy Solutions Corporation, "Request for Emergency Order Pursuant to Federal Power Act Section 202(c)", available at: https://statepowerproject.files.wordpress.com/2018/03/fes-202c-application.pdf.

[44] Power Magazine, "DOE's Perry: Coal, Nuclear Must Be Saved." June 12, 2019. Available at: https://www.powermag.com/does-perry-coal-nuclear-must-be-saved/.

[45] EIA-860M. 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.

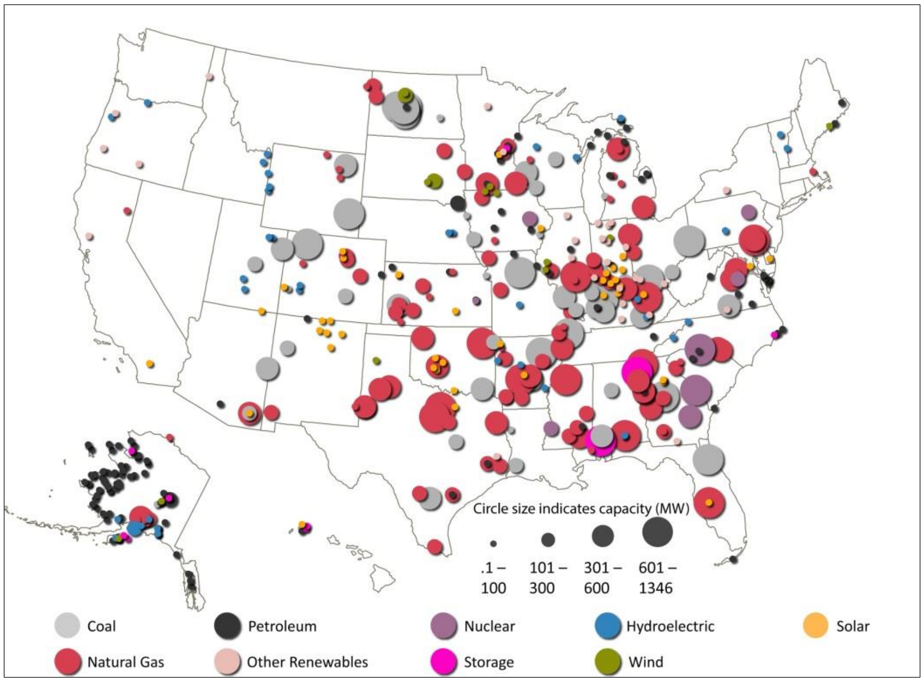
Figure 15: Announced Additions, 2019-2025[46]



Cooperative Focus

As shown in Figure 16, electric cooperatives own more than 62 GW (Summer Capacity) of generating capacity nationwide, primarily through G&Ts.

Figure 16: Map of Cooperative Owned Generation[47]

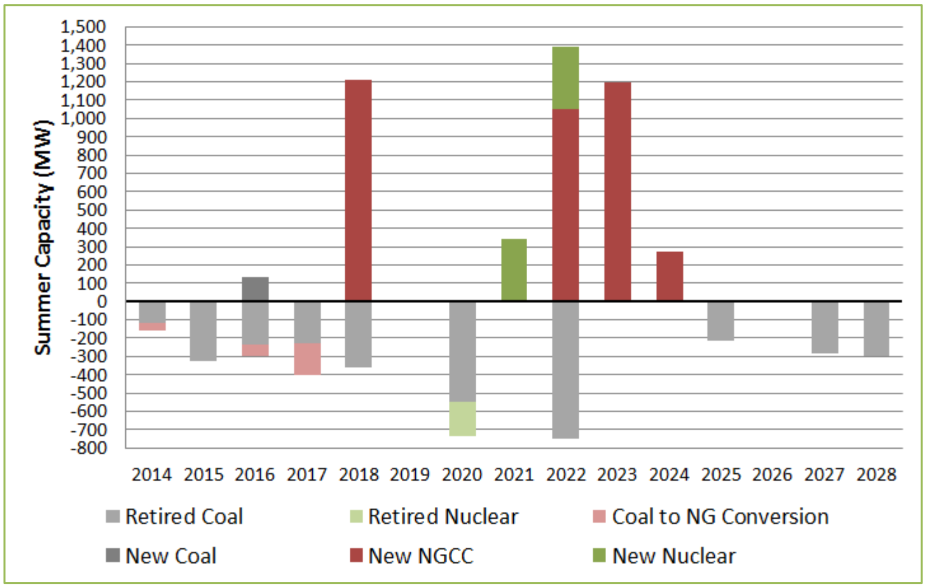


[46] EIA-860M.

[47] Figure derived from data from U.S. Energy Information Administration, *2016 Electric Power Annual* (EIA EPA 2016), available at: http://www.eia.gov/electricity/annual/.

Figure 17 shows announced retirements and planned construction of cooperative-owned baseload generation capacity.[48] The electric cooperative coal fleet tends to be newer than the national fleet and cooperative plants have faced fewer closures due to federal environmental regulations than the rest of the industry, though this is narrowing as older non-co-op coal units are retired. Nevertheless, more than 1.5 GW of cooperative-owned coal capacity was retired or converted to natural gas over the 2014-2018 period, accounting for about 6% of total cooperative coal capacity (as of the start of 2014). Another 2.1 GW of co-op coal retirements have been announced through 2028. New construction of NGCC and nuclear units more than offsets recent closures and planned closures across the period, with nearly 3.9 GW of new capacity online or announced through 2024.

Figure 17: Cooperative Baseload Retirements and Additions[49]



Like other generators, cooperatives are facing pressures from continued low natural gas prices and the expansion of renewable generation, particularly in organized markets. In their resource planning processes, many G&Ts are making decisions about whether to build or buy new capacity. This is an especially challenging decision for smaller G&Ts where a small number of coal units are the primary source of generation. There has been a long-term trend of G&Ts self-generating a larger share of their power, but it remains to be seen whether this will continue, or if G&Ts will move towards greater reliance on wholesale markets and bilateral contracts to supply power to their members.

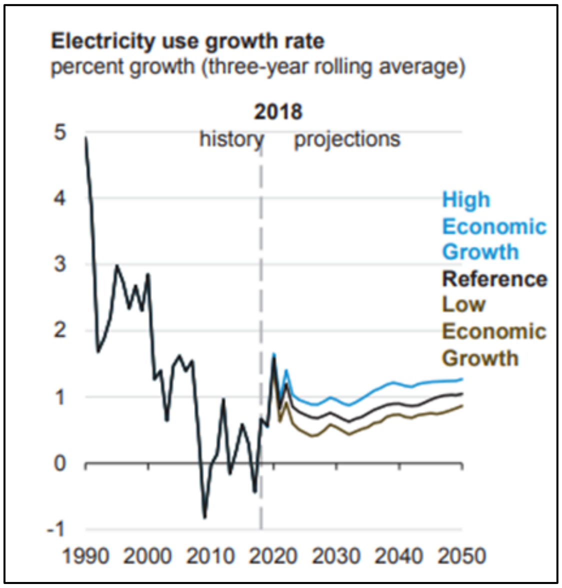
[48] For purposes of this section, these include coal and nuclear fueled steam generation plants designed to be run as baseload generators, as well as new efficient natural gas combined cycle plants capable of operating at very high capacity factors.
[49] EIA-860 Monthly Electric Generator Data (EIA-860M) supplemented by NRECA research.

Annual Energy Outlook 2019 and Forecasts

EIA's 2019 Annual Energy Outlook provides long-term projections for the future of the US energy economy, including the electricity industry, based on modeled projections and detailed analysis of a wide range of energy topics.[50] 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.

According to EIA, load growth began to flatten and even decline in some markets after the 2009 recession and the trend continued through the economic recovery. The sluggish load growth reflects increases in energy efficiency, conservation, and slower population growth. As shown in Figure 18, EIA expects moderate load growth of around 1% annually through 2050, trending upward somewhat over time due to increased demand for electric services, offset by increases in efficiency, distributed generation (mainly solar PV), and other distributed energy resources (DER). While there is some prospect for increased electric demand from greater end-use electrification and the growing market for electric vehicles, electric growth remains modest even in EIA's High Economic Growth projections.

Figure 18: Historical and Projected Load Growth[51]

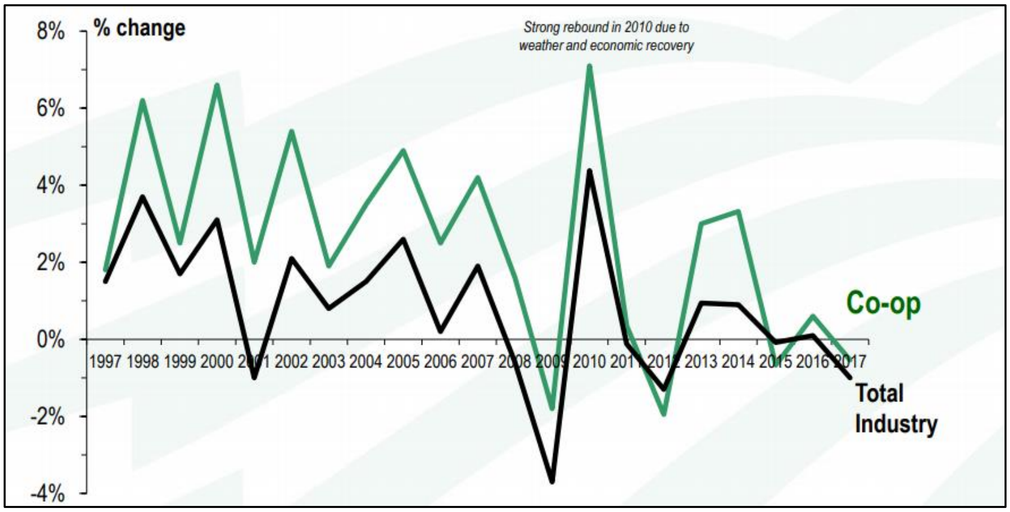


[50] AEO2019 provides several cases with different assumptions, including a Reference Case, a High Economic Growth Case, and a Low Economic Growth Case.
[51] AEO2019

Cooperative Focus

As shown in Figure 19, in most years electric cooperative retail sales have grown significantly faster than the industry as a whole, driven by faster consumer growth in suburban and exurban areas, though they dipped below national averages in 2012 and 2015, before bouncing back in 2016. While co-ops seem likely to continue outpacing the rest of the industry, cooperatives are impacted by the same national trends of slower sales growth that have been seen since the Great Recession. Furthermore, national averages do not show the significant regional variation both nationally and among co-ops. Slower growth poses challenges at a time when investments in new generation and growing investments in transmission are anticipated.

Figure 19: Retail Sales Growth of Electric Cooperatives vs. Total Industry[52]



Projected natural gas prices at Henry Hub for the period 2019 to 2040 are presented in Figure 20 with both the AEO2019 Reference Case and the High Oil and Gas Resource and Technology side case. According to EIA, "The High Oil and Gas Resource and Technology case represents a potential upper bound for crude oil and NGPL production, as additional resources and higher levels of technological advancement result in continued growth in crude oil and NGPL production."[53] In this side case, annual average gas prices at the Henry Hub are expected to remain around $3/MMBtu through 2040, while in the Reference Case they remain below $4/MMBtu until around 2035. This is consistent with prevailing opinions throughout the industry that natural gas will continue to be cost-competitive for the foreseeable future.

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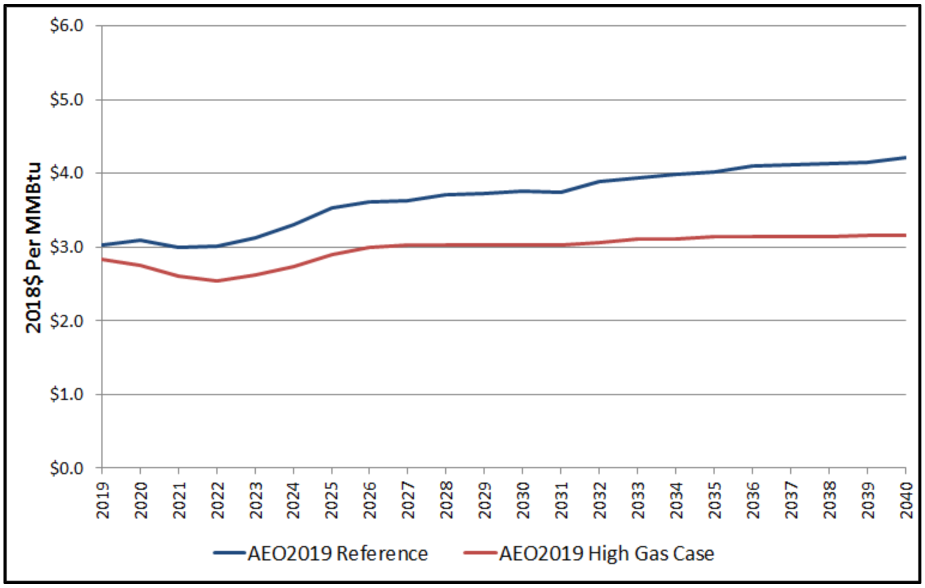
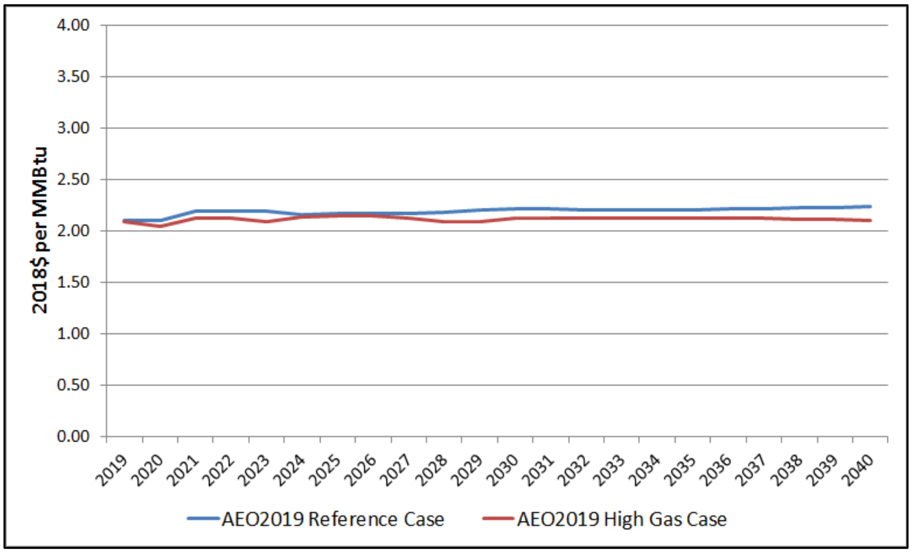
[52] Vital Signs Report, NRECA Research, available at: https://www.cooperative.com/programs-services/bts/Pages/Data/Vital-Signs.aspx.
[53] AEO 2019.

Figure 20: Projected Natural Gas Spot Price at Henry Hub, 2019-2040[54]



Projected delivered coal prices from AEO2019 are similarly shown in Figure 21. Over the 2019-2040 period, coal price projections are nearly flat, expected to grow at an average annual rate of just 0.5%, with only limited impacts from natural gas supply assumptions.

Figure 21: Average Coal Price Projections, 2019-2040[55]



The AEO2019 projected electricity generation mix from EIA's Reference Case is shown in Figure 22, with significant shifts expected from 2019 to 2040. Because of low natural gas prices and the fact that no new coal units are being built, the gap between generation from coal and natural gas is projected to increase, with coal's share of generation falling from 28% to 21% while natural gas rises from 32% to over 37%. Renewable generation (including hydro) is

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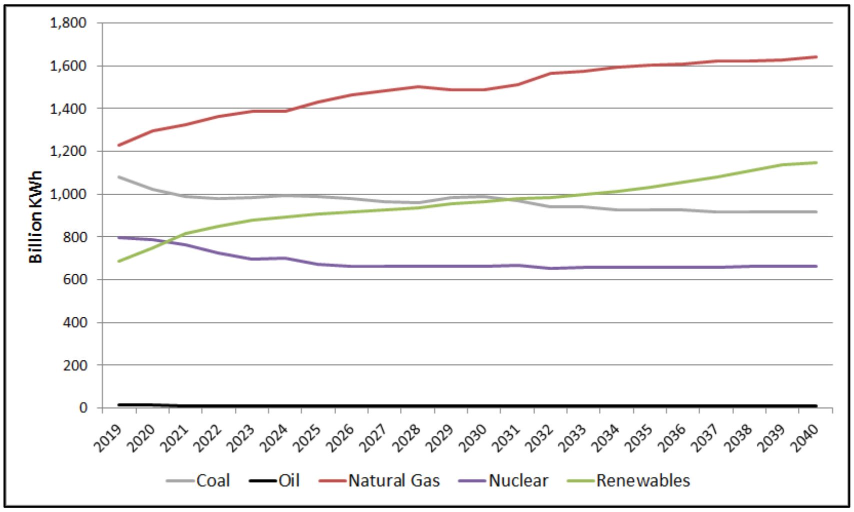
54 *Ibid.*
55 AEO 2019.

also projected to grow steadily, from 18% to over 37%, surpassing coal generation in 2031 to become the second largest source of generation. Nuclear generation erodes over time as capacity is retired, falling from 21% to 15% over the period.[56]

Figure 22: Projected Generation Mix, 2019-2040[57]



Solar PV generation in particular is expected to continue to increase due to declining costs.[58] This is true for both utility projects and distributed solar PV deployed by end-use residential, commercial, and industrial customers. While the output from these distributed installations is primarily used on-site, excess output is sold onto the grid. Figure 23 shows the projected growth in installed PV capacity in the U.S. in the AEO 2019 Reference Case. Of note, unlike the AEO 2018, this most recent projection has the electric power sector continuing to deploy the majority of capacity, underlining the trend towards larger utility projects highlighted earlier.

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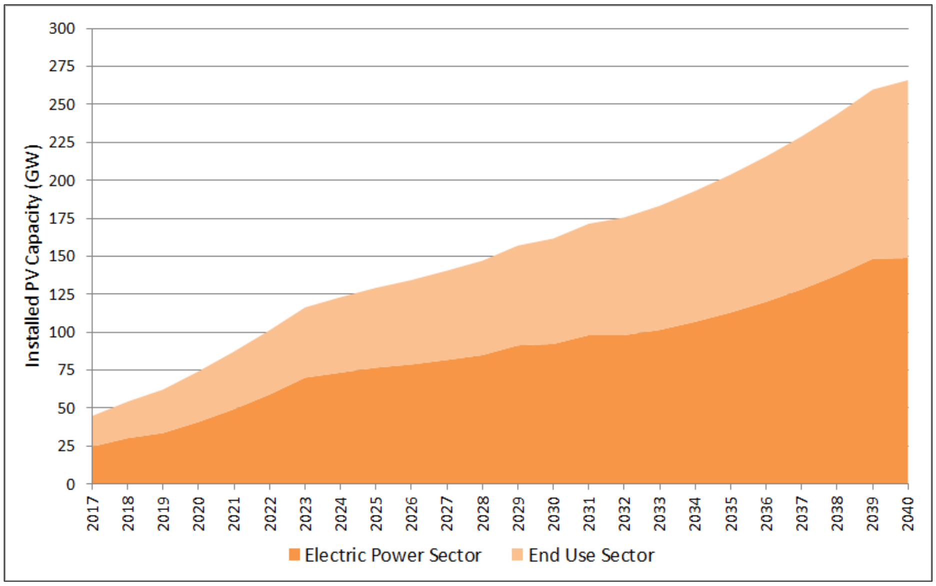
[56] *Ibid.*

[57] *Ibid*. EIA's Short-Term Energy Outlook now forecasts that natural gas will remain the predominant energy source in the United State over the long term. This report is available at: https://www.eia.gov/outlooks/steo/.

[58] See Lazard 2018.

Figure 23: Projected Cumulative U.S. Installed Solar PV Capacity by Sector[59]



Energy storage for utilities can take many forms other than batteries, with pumped hydroelectric comprising 96.5% of the existing storage capacity today.[60] In recent years, smaller scale mechanical technologies such as flywheels, compressed air, and localized gravity-based systems have seen a dramatic surge in research, development, and deployment. Battery energy storage systems (BESS) have enjoyed particular growth in recent years, especially lithium-ion technologies that are common across a wide range of products and can be scaled. Policy support, increased demand from utilities and consumers, and the growth of electric vehicles (EVs) all contribute to falling lithium-ion battery costs and growth in overall BESS capacity.

Since 2003, the United States has added almost 1 GW of battery storage to the electrical grid.[61] GTM research projects that the deployment of energy storage will accelerate dramatically in the next few years. Figure 24 projects that by 2023 energy storage installations will reach 3.9 GW.[62]

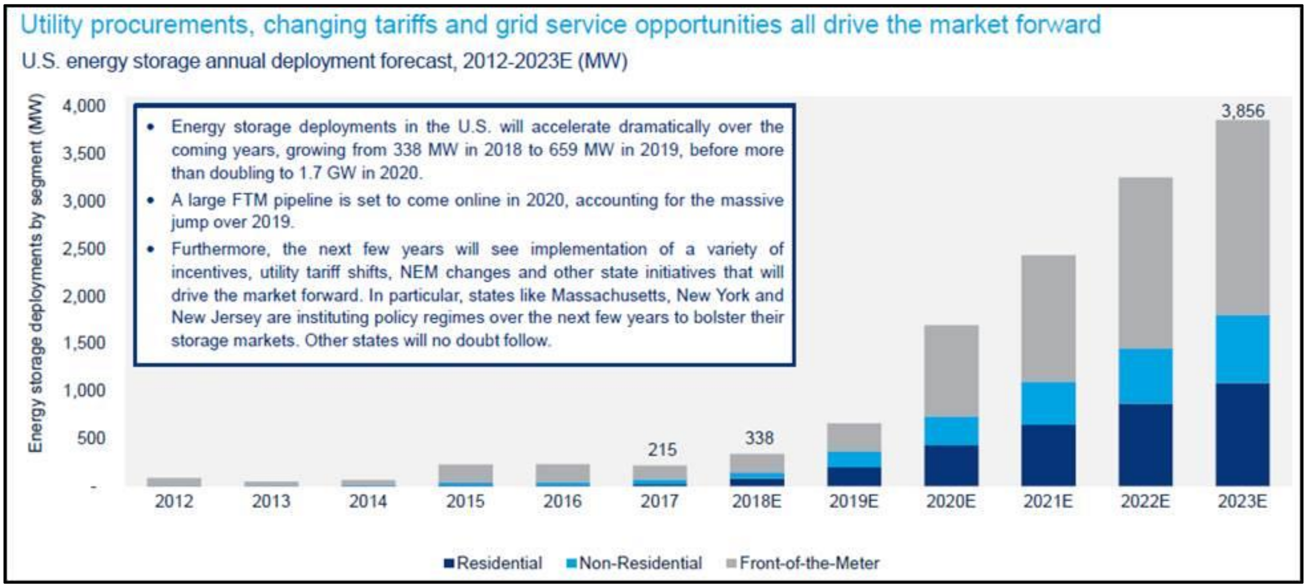
[59] AEO2019

[60] DOE Global Energy Storage Database, available at: https://www.energystorageexchange.org/projects/data_visualization.

[61] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory,* February 2019 (EIA-860M), available at: https://www.eia.gov/electricity/data/eia860m/.

[62] For more information about Battery Energy Storage, please see NRECA's Battery Energy Storage Overview, available at: https://www.cooperative.com/topics/distributed-energy-resources/Pages/Battery-Energy-Storage-Overview-Report.aspx.

Figure 24: U.S. Energy Storage Annual Deployments



Increasing battery deployment and experience among installers has been another critical factor driving increasing adoption of battery storage. As seen in Figure 25, the associated costs of BESS systems have fallen even faster than the costs of the batteries themselves.

Figure 25: Breakdown of Costs of Battery Elements

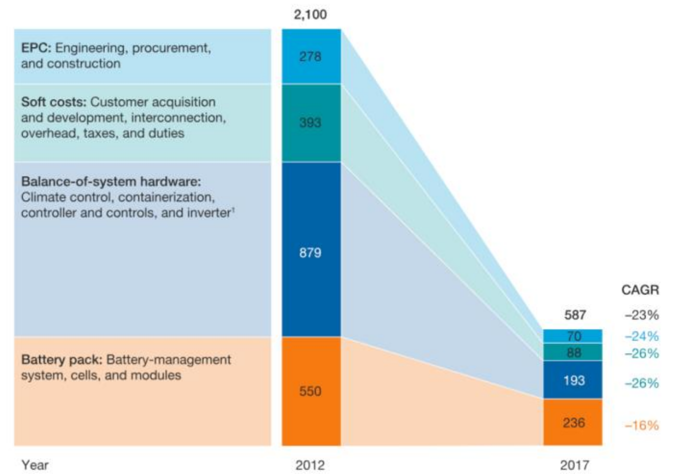


FIGURE 3.5 – Cost Breakdown of a 1 MWh BESS (2017 $/kWh)
Source: McKinsey & Company, GTM Research

At the utility level, battery energy storage can be an ideal complementary resource in locations where there are high penetrations of renewable power generation.[63] Energy storage can allow for more efficient use of renewables, because of its ability to smooth out intermittent generation that is often characterized by large fluctuations. Large

[63] NRECA, "When It Comes to Battery Storage, Co-ops Should Focus on a Primary Application," (NRECA Battery) available at: https://www.cooperative.com/programs-services/bts/Pages/TechSurveillance/battery-storage-systems-primary-application.aspx.

long-duration batteries can actually shift and optimize production from intermittent renewable resources, storing renewable energy when demand is low and discharging the energy when production ramps down and demand ramps up. For example, in many places the power supply profile of solar generation is in opposition to the load profile, with production at its highest during off-peak daytime hours and production at its lowest during on-peak hours in the late afternoon. Similarly, wind resources tend to have the highest output overnight, but could be shifted through batteries to meet morning peaks in winter. This does create additional operations and maintenance challenges since lithium-ion batteries have shorter lives than the accompanying renewable resources, requiring replacement of battery packs multiple times over the life of a hybrid project.[64]

Cooperative Focus

Cooperatives in sixteen states have implemented energy storage solutions either in combination with a solar plant, with other resources in a microgrid installation, or as residential rooftop.[65] These hybrid deployments of intermittent renewables plus storage offer great potential. For example, combining solar generation during the day with wind generation at night and balancing it with 3 to 4 hours of battery storage can create a dispatchable or near-dispatchable resource.[66] Large renewable developers are planning large hybrid projects to pilot this concept on a large scale, and it seems likely that cooperatives might ultimately be power purchasers from these types of projects. For example, NextEra Energy Resources (the largest PPA counterparty for co-ops)[67] is developing a project in Oregon in partnership with Portland General Electric that combines 300 MW of wind, 50 MW of solar PV, and 30 MW of four-hour battery storage. The batteries will be charged by the solar array which will discharge excess energy during evenings or other peak times.[68]

Wholesale Markets

Common Challenges facing RTOs/ISOs

Across the country, wholesale markets and utilities are grappling with preserving bulk electric system reliability in a time of rapid transition of the generation mix. Historically low natural gas prices and reduced costs for wind and solar resources continue to put pressure on coal and nuclear generators. While the specific circumstances differ across the various markets, each is experiencing the retirement of long-standing coal, nuclear, and gas resources and their replacement in the dispatch stack with more-efficient NGCC units, both existing and new, and intermittent renewable generation. New resources often are not located in the same areas as retiring resources, creating additional challenges for transmission planning and costs. The organized markets are also assessing the impact of expanded state renewable and clean energy mandates, including several states adopting targets of 50% to 100% over the coming decades. Incorporating state policies into organized markets without substantially altering market design continues to be a challenge.

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[64] Bedeschi, Beatrice. "Giant Oregon wind-solar plant to use 4-hour battery for peak shifting," NewEnergyUpdate: PV, March 20, 2019, available at: http://newenergyupdate.com/pv-insider/giant-oregon-wind-solar-plant-use-4-hour-battery-peak-shifting
[65] NRECA Battery.
[66] Trabish, Herman K. "Utilities take note: Hybrid renewables projects are coming," *Utility Dive*, April 3, 2018, available at: https://www.utilitydive.com/news/utilities-take-note-hybrid-renewables-projects-are-coming/520319/.
[67] Co-ops have nearly 2.5 GW of active or pending power purchase agreements for wind facilities owned by NextEra.
[68] Bedeschi, Beatrice. "Giant Oregon wind-solar plant to use 4-hour battery for peak shifting."

With the increase in distributed energy resources, system operators are trying to understand the impact that these smaller resources will have and how to include and value them in wholesale markets. Specifically, regulators are looking at the possibility of utilities or other third-party providers aggregating these resources to participate in wholesale markets. FERC has issued a notice of proposed rulemaking to investigate this type of DER aggregation. One of the concerns raised by NRECA and others is that FERC's proposal does not allow state or local regulators to determine whether to allow third-party DER aggregation in markets. As NRECA's CEO Jim Matheson noted:

> Bypassing this important element of local control could have serious and harmful consequences for co-ops and their members, including:
>
> - system disruptions, including overloading distribution lines that were not designed with DER aggregation in mind;
> - fluctuations in voltage and reduced service quality to consumers;
> - increased costs for co-ops and their members if distribution systems require adaptations to accommodate DER aggregation; and
> - implementing a mandatory two-way communications backbone needed to maximize DER, which not all utilities or co-ops may have.[69]

Another major issue facing organized markets is growing deployment of battery energy storage and how to value and include storage in markets. Battery deployment has been primarily concentrated in the West, with California accounting for 30% of national deployment due in part by strong state policies.

FERC notes that its recent Order 841 could further accelerate battery deployment.[70] This Order asks FERC regulated RTOs/ISOs to remove barriers to entry for all storage resources to participate in wholesale markets. FERC provides specific guidelines to allow RTOs/ISOs to revise their tariffs to establish market participation rules that recognize the physical and operational characteristics of storage resources. These guidelines include (1) allowing storage resources to be eligible to participate in energy, capacity, and ancillary services markets if technically capable; (2) allowing storage resources to be eligible to set wholesale market prices as a buyer or a seller; (3) accounting for the physical and operational characteristics of storage resources; and (4) establishing a minimum size requirement for participation that does not exceed 100 kW.[71]

NRECA and several other parties requested a rehearing of Order 841 on the grounds that it appears to require utilities to permit storage resources located on the distribution system or behind the retail meter access to the wholesale markets.[72] The parties asked FERC to narrow the Order's reach and to include language that would allow the "relevant electric retail regulatory authority" to decide whether to allow such electric storage resources to participate directly in wholesale markets. FERC has denied a rehearing of this order.

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[69] Utility Dive, "Will FERC trample state and local authorities in DER rulemaking?" April 2019. Available at: https://www.utilitydive.com/news/will-ferc-trample-state-and-local-authorities-in-der-rulemaking/552069/.

[70] FERC Summer 2019 Reliability and Energy Market Assessment (FERC) https://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2019/05-16-19.pdf

[71] Federal Energy Regulatory Commission, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC. Available at: https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

[72] *Ibid*

The retirement of fossil-fueled generators is an additional concern in several markets. In 2018, the North American Electric Reliability Corporation (NERC) released a report, *Special Reliability Assessment: Generation Retirement Scenario*, exploring the potential implications of the changing generation mix and the increased reliance on one fuel, natural gas.[73] NERC noted that:

> The key conclusion is that generator retirements are occurring, disproportionately affecting large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur. Therefore, resource planners at the state and provincial level, as well as wholesale electricity market operators, should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service. Again, ensuring reliability throughout a significant retirement transition will likely include construction of new transmission and fuel infrastructure.[74]

As the U.S. generation mix continues to evolve, it will be critical to ensure that transmission and other infrastructure is in place to allow for the continued decentralization of the power grid. Additionally, correct pricing of market resources will be paramount to ensuring successful markets. The remainder of this section focuses on emerging issues in specific wholesale markets.

Issues in the PJM Interconnection

Despite extreme temperatures and a return of Polar Vortex conditions in the northeast, PJM maintained reliability during the winter of 2018/2019, even with the retirement of about 3.3 GW of coal units between January 2018 and February 2019. The fuel mix in 2019 was similar to that in 2018, with slightly more gas (due to lower fuel prices) and slightly less coal (due to retirements). While forced outages increased during the cold snap at the end of January, the number of outages related to fuel supply issues was less than half of those experienced during a similar event in 2018, which PJM attributes to pipeline expansions, better gas-electric coordination, natural gas generators "firming up" their fuel supply contracts, and the relatively shorter duration of extreme cold weather. According to PJM, "[o]verall, generator performance was good and continued to show market improvement over the 2013-2014 polar vortex." During the system peak on January 31, prices on PJM's Synchronized Reserve Market were at or near zero, though PJM stated that "the price of procuring reserves does not always reflect their value," and identified this as an ongoing problem in the PJM market that PJM would seek to address with FERC.[75]

Although summer temperatures are forecasted to be higher than average in the east in 2019,[76] NERC has no major resource adequacy concerns for summer 2019 in PJM, with its reserve margin of 29% well exceeding the NERC

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[73] NERC, *Special Reliability Assessment: Generation Retirement Scenario*, December 2018. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf.
[74] *Ibid.*
[75] Randolph, Kevin. "Natural gas, wind made increased contributions to PJM fuel mix this winter," *Daily Energy Insider*, March 20, 2019, available at: https://dailyenergyinsider.com/news/18283-natural-gas-wind-made-increased-contributions-to-pjm-fuel-mix-this-winter/.
[76] Chris Dolce. "Summer 2019 Temperatures Expected to be Hot in the East and Mild in the Plains and Midwest." May 16, 2019. *The Weather Channel.* Available at: https://weather.com/forecast/national/news/2019-05-15-summer-temperature-outlook-may-2019-update.

requirement of 15.9%.[77] Though the winter 2019/2020 assessment has not been released, reserve margins are on track to again be well in excess of NERC requirements.

An additional 800 MW of coal capacity and 1,500 MW of nuclear capacity are scheduled to retire in PJM during the summer of 2019. In comments to the ACES Members Meeting in May 2019, Steve Herling, PJM's Vice President of Planning, noted that power plant retirements and construction are "shifting the center of gravity" in the market, with new builds occurring slightly to the east of retiring coal and nuclear plants. As noted earlier, retirements in PJM have tended to be concentrated in western Pennsylvania near Lake Erie, while new builds (primarily NGCC plants) have been in eastern Pennsylvania and Maryland. PJM has a fairly short 90 day retirement process, which can make it challenging to identify and implement transmission upgrades to adjust to the changing resource geography, or to identify projects that might offer additional benefits or optimization.

In 2018, PJM put forth two competing proposals to address out-of-market payments in its forward capacity markets. The first, Capacity Repricing, was developed and submitted by PJM staff and would result in a two-stage auction. The first stage of the auction would determine the unit commitments consistent with current auction procedures. In the second stage of the auction, PJM would administratively adjust the market offers of resources with "actionable subsidies."[78] The second proposal, the Extended Minimum Offer Price Rule (MOPR-Ex) comes from the PJM Market Monitor. The MOPR-Ex would extend the MOPR to include existing resources and a wider range of new subsidized resources. Independent stakeholders roundly panned both PJM proposals, with slight preferences for the MOPR-Ex.[79]

In June 2018, FERC rejected the initial proposals, but acknowledged that out-of-market payments have put downward pressure on capacity prices. PJM submitted a new proposal that adjusts the Resource Carve-Out (RCO) component of the auction. The new proposal would remove subsidized resource bids from the pricing auction and recalculate the clearing price based on the demand that the resources would be able to serve (as opposed to an administrative adjustment).[80]

In March 2019, PJM also filed a complaint with FERC to "[e]ffectuate and enhance price formation in PJM's reserve markets."[81] The intent is to price reserve components of locational marginal prices (LMP) to account for the value of flexibility and reliability in the face of increasing intermittent resources. PJM's modeling indicates that the change would result in average increases in combined energy and reserve prices of about 2%.[82] PJM has asked to implement the new rules in June of 2020 and requests a response from FERC in December 2019.

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[77] NERC. "Summer Reliability Assessment," (NERC) June 2019, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2019.pdf.

[78] PJM Interconnection, PJM's Capacity Market Repricing Proposal, 2018, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/2018/20180116-capacity-market-repricing-proposal-updated.ashx.

[79] Bade, Gavin. "PJM stakeholders pan capacity market reforms in FERC comments," *Utility Dive*, May 8, 2018, available at: https://www.utilitydive.com/news/pjm-stakeholders-pan-capacity-market-reforms-in-ferc-comments/523036/.

[80] Vallanueva, Sidney and Miles Kiger. "PJM Asks FERC to Act Urgently on Proposed Capacity Market Reforms," *Washington Energy Report*, March 21, 2019, available at: https://www.troutmansandersenergyreport.com/2019/03/pjm-asks-ferc-to-act-urgently-on-proposed-capacity-market-reforms/.

[81] PJM. "Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.," March 2019, available at: https://pjm.com/directory/etariff/FercDockets/4036/20190329-el19-58-000.pdf.

[82] *Ibid.*

As of June 2019, FERC has yet to rule on the new proposals despite PJM urging action to avoid "uncertainty" and "confusion." PJM initially directed market participants to prepare for the August auction under both the current and new rules,[83] before deciding in April to proceed under the current rules pending any direction by FERC.[84]

Issues in the Midcontinent ISO (MISO)

MISO also experienced extreme low temperatures during the winter of 2018/2019, especially in its North and Central regions where temperatures dipped below -30°F in some areas during the January 30-31 cold snap. This led to an earlier than expected drop in production from wind units that could not operate in the extremely low temperatures, leading MISO to declare a Maximum Generation Event early in the morning of January 30. Cold temperatures also led to additional unplanned outages of conventional generation, with nearly a quarter of all capacity unavailable in the affected regions during the peak event, a higher outage rate than in the Polar Vortex of 2014 or the Arctic Cold Snap of 2018.[85] Of note, natural gas generation in MISO during the event was more than double the amount of gas generation during the 2014 event, highlighting the significant shift from coal to gas in the region's conventional generation fleet.[86]

MISO maintained reliability with the use of deployed and self-scheduled load modifying resources, as well as unplanned load reductions from businesses and schools that shut down due to the extreme low temperatures. MISO was also able to import power into the region, both from MISO's South Region and from other markets. While reliability was maintained, MISO notes that the experience points towards the need for improvements in load and wind forecasting, as well as the impact of voluntary load curtailments.[87]

Looking towards the summer of 2019, MISO's reserve margins are expected to be 19%, slightly above the NERC reference margin of 17%. This is sufficient to cover normal peak scenarios, but in the case of extreme summer heat the system might need to employ additional measures.[88] In February 2019, FERC approved MISO's proposal requiring greater documentation and firmer commitments of availability from owners of load-modifying resources before they can participate in MISO's capacity market,[89] which NERC expects to enhance the market's ability to access these resources when needed.[90]

MISO is also experiencing geographic challenges from its changing resource mix, primarily the retirement of coal resources in the east and the huge growth of wind resources that tend to be in the west, far from load centers.

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[83] Bade, Gavin. "PJM pushes FERC to act on capacity market rules, citing 'uncertainty' and 'confusion,' *Utility Dive*, March 12, 2019, available at: https://www.utilitydive.com/news/pjm-pushes-ferc-to-act-on-capacity-market-rules-citing-uncertainty-and/550297/.

[84] Bade, Gavin. "PJM won't delay capacity market order despite ERC impasse over rule changes," *Utility Dive*, April 11, 2019, available at: https://www.utilitydive.com/news/pjm-wont-delay-capacity-market-order-despite-ferc-impasse-over-rule-change/552530/

[85] "MISO January 30-31 Maximum Generation Event Overview," *MISO*, February 27, 2019, available at: https://cdn.misoenergy.org/20190227%20RSC%20Item%2004%20Jan%2030%2031%20Max%20Gen%20Event322139.pdf.

[86] Tomich, Jeffrey and Hannah Northey. "Polar vortex reveals growing role for gas in Midwest," E&E News, February 5, 2019, available at: https://www.eenews.net/stories/1060119619.

[87] "MISO January 30-31 Maximum Generation Event Overview."

[88] NERC.

[89] Durish-Cook, Amanda. "MISO LMR Capacity Rules Get FERC Approval," *RTO Insider*, February 22, 2019, available at: https://rtoinsider.com/miso-lmr-rules-ferc-111771/.

[90] NERC.

MISO has attempted to use multi-value transmission projects to address these changes, especially from wind intermittency, and hopes that the growth of solar might help balance out wind output during daylight hours.

Issues in the Southwest Power Pool (SPP)

According to the NERC Summer Reliability Assessment, reserve margins in SPP are expected to be almost 32% in 2019 and there are no reliability issues anticipated for the coming summer.[91] Increased penetration of zero marginal cost resources and low natural gas prices have kept power prices low in the region. However, the report also notes that SPP has "experienced a mid-range forecast error" for wind generation which could create scarcity conditions if the error continues throughout the day. SPP is working to ensure ramping resources are available on a daily basis.

In June 2019, SPP announced its intent to establish a Western Energy Imbalance Service (WEIS) to offer reliability services to entities in the west. According to an SPP source, the WEIS "will allow resources across the market footprint to be dispatched in real-time to meet market-wide demand based on the most cost-effective set of resources available at that time while respecting transmission constraints." Similar to the Energy Imbalance Market operated by CAISO, utilities do not need to join SPP to contract for services in the WEIS.

Last year, the Mountain West Transmission Group, a group of ten utilities operating in the Western Interconnect, including two large G&T cooperatives, declared its intent to join SPP but later announced it would "defer further Mountain West activity while continuing to evaluate opportunities to optimize the use of generation and transmission resources."[92] The establishment of the WEIS would give these and other entities in and around SPP the ability to optimize renewable resources and export excess capacity while maintaining a level of self-governance. The table below shows the timeline for implementation.

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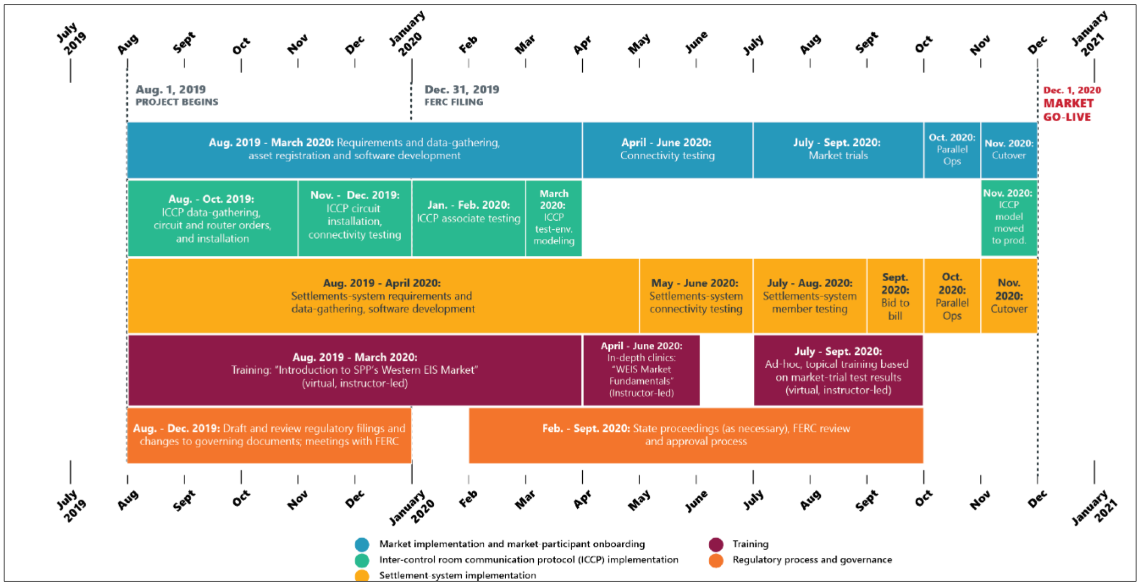
[91] *Ibid.*

[92] "Mountain West Transmission Group Initiative," Western Area Power Administration, October 30, 2018, available at: https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

Figure 26: WEIS Implementation Timeline[93]



Issues in the Electric Reliability Council of Texas (ERCOT)

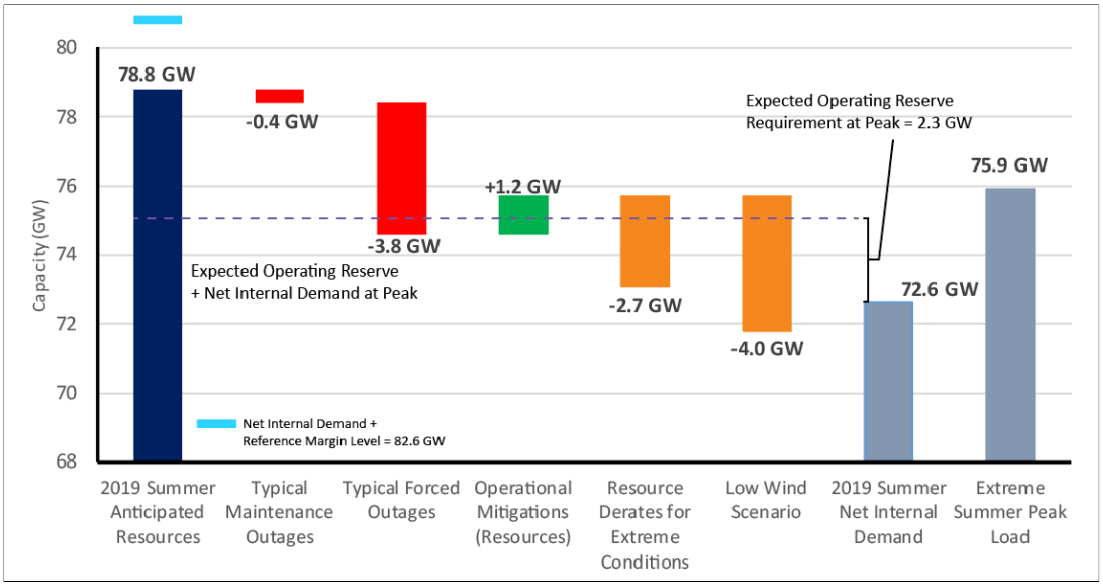
Heading in to the summer of 2018, ERCOT had a projected reserve margin of 10.9%, below the NERC reference margin of 13.75%.[94] As expected, the summer was very hot, and ERCOT's peak hourly load surpassed the 2016 record during 14 one-hour periods from July 18-24, exceeding the projected peak during four of these periods and setting a new record of more than 73.2 GW from 4-5pm on July 19. The market was able to meet these peaks without any widespread outages on the system. ERCOT does not have a capacity market, but instead allows very high scarcity pricing when demand spikes, up to a cap of $9,000/MWh. In July, real-time prices spiked on five days, ranging from about $800/MWh to a high of $2,160/MWh.[95] Wind power had been projected to contribute a daily average output of 4.1 GW, but actually averaged 6.6 GW in July, helping to ease the burden on fossil generation.[96]

With summer 2019 looming and even hotter summer temperatures expected in the region, ERCOT is again the only NERC region that will not meet its reserve target, and ERCOT's reserve levels are expected to be even lower than they were in the previous year. NERC attributes ERCOT's continued difficulty in meeting reserve targets to faster than average load growth in the region – 2.5-3% growth is expected annually through at least 2022 — and delays in new plant construction.[97] Uncertainty about specific resources has also led to fluctuations in anticipated reserves. In January, the projected margin fell from 8.1% to 7.4% with the announced indefinite mothballing of a 470 MW coal-

[93] SPP. "A proposal for the Southwest Power Pool Western Energy Imbalance Service Market (WEIS)," June 2019. Available at: https://spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf
[94] Kleckner, Tom, "ERCOT Gains Additional Capacity to Meet Summer Demand," RTO Insider, May 1, 2018, available at: https://www.rtoinsider.com/ercot-summer-peak-planning-reserve-margin-91676/.
[95] Bowers, Richard. "Electric Reliability Council of Texas surpassed all-time peak hourly load in July," *EIA Today in Energy*, July 31, 2018, available at: https://www.eia.gov/todayinenergy/detail.php?id=36775&src=email.
[96] Kleckner, Tom, "Plentiful Generation Helps ERCOT Meet Extreme Demand," RTO Insider, August 7, 2018, available at: https://www.rtoinsider.com/ercot-demand-dan-woodfin-97727/.
[97] NERC.

fired plant,[98] but rose back to about 8% with the announcement in May that a previously mothballed 385 MW natural gas-fired plant in Corpus Christi would be brought back online. NERC does not foresee specific transmission concerns in ERCOT but notes that "delays or cancellations of planned transmission expansion projects, if they occur, may contribute to potential localized reliability concerns." Demand response capability is also expected to be lower than in 2018.[99]

Figure 27: Contributing Factors to ERCOT's Reserve Margin Changes Since May 2017 and Operational Risk Assessment for Summer 2019[100]



Resource planners will be watching ERCOT again this summer to see if hot weather and a historically low reserve margin put substantial stress on bulk electric system reliability. NERC notes that based on ERCOT's Seasonal Assessment of Resource Adequacy report[101] released May 8:

> ERCOT expects that a number of operational tools may be needed this summer to help maintain sufficient operating reserves given the range of resource adequacy scenarios they evaluated. For example, ERCOT system operators can release ancillary services (including load resources that can provide various types of operating reserves based on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids.[102]

[98] U.S. Energy Information Administration. "Today in Energy." June 18, 2019. Available at: https://www.eia.gov/todayinenergy/detail.php?id=39892&src=email.

[99] NERC.

[100] *Ibid.*

[101] ERCOT. "Summer Performance Update," May 8, 2019, can be found at: http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx.

[102] NERC.

Issues in the California ISO (CAISO)

In CAISO, conditions for summer reliability have improved slightly due to a higher level of snow pack leading to more generation from hydro resources. However, the infamous 'duck curve' problem still exists, with the system needing support from fast ramping resources to meet load when generation from non-coincident peak solar resources quickly declines in the late afternoon and early evenings. The oversupply of solar, and increased ramping needs, create concerns about resource adequacy. NERC, in its Summer Reliability Assessment, states that "increasing penetrations of solar resources and the retirements of dispatchable generation units has contributed to a shortage of ramping resources.[103] If there is a shortfall in resources from ramping, CAISO has indicated that it would need to import from neighboring systems.

The risk of fire in California is still paramount. Based on last year's deadly fire season, Pacific Gas & Electric has put a fire plan in place that may require some residents to be without power during periods of time with increased fire risk as well as significant investments in vegetation management. CAISO has required all utilities in its footprint to submit fire plans to the commission for approval ahead of the wildfire season.

Issues in the New York ISO (NYISO)

In the last year, the state of New York has moved to increase its renewable goals, currently 50% by 2030. The state has drafted a study to examine the effects that expanded policies would have on the New York grid. As reported by RTO Insider, "[t]he draft 'Reliability and Market Considerations for a Grid in Transition' study comes after New York Gov. Andrew Cuomo in January nearly quadrupled the state's offshore wind energy goal to 9 GW by 2035, while his proposed Green New Deal would mandate 100% clean power by 2040, increase renewable energy requirements from 50% to 70% by 2030, and require other clean energy benchmarks."[104] As the generation mix continues to evolve in this market, pairing these intermittent resources will become critical, especially with significant natural gas pipeline constraints. Recently, both Consolidated Edison and National Grid have announced that there will be no new natural gas customers added until their resource constraint concerns are addressed.[105]

Issues in ISO-New England (ISO-NE)

As in other regions, New England is seeing a shift in its resource mix. State-level renewable and energy efficiency targets, and increased distributed generation are altering usage patterns and the retirement of fossil-fuel generation is providing additional pressure on the system. While overall demand is down in the region, extreme weather events can still drive price spikes, particularly in the winter when gas pipelines can become constrained, and new natural gas pipelines are difficult to build. The ISO in April of this year put out a white paper to discuss fuel security in the region. They conclude in the report,

> ISO New England (ISO) is concerned, given the power system's evolving resource mix and the region's constrained fuel delivery infrastructure, that there may be insufficient energy available to the New England power system to satisfy electricity demand during cold winter conditions. While there has been no loss of

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[103] *Ibid.*

[104] RTO Insider, "Stakeholders Discuss NYISO Grid Study, LBMPc Change." June 2019. Available at: https://rtoinsider.com/nyiso-grid-study-carbon-price-137785/.

[105] Utility Dive, "National Grid says no new NYC gas customers until state approves pipeline." May 2019.Available at: https://www.utilitydive.com/news/national-grid-says-no-new-nyc-gas-customers-until-state-approves-pipeline/555283/.

> load attributable to insufficient energy supplies to date, we expect that industry trends will increase this risk over time unless proactive solutions are developed.[106]

The issue of fuel security is not a new one. Many system operators note that with increased retirements of baseload plants, increased penetration of renewables, the reliance on natural gas, and the lack of new infrastructure there could be significant resource adequacy problems in the future. The ISO also notes in their report that there are "misaligned incentives" at play, whereas the value the consumer places on having electricity is not always in agreement with the value generators put on having an on-site fuel supply.[107] As the generation mix continues to evolve, having adequate resources in place to meet load may become even more challenging.

[106] ISO New England, *Energy Security Improvements,* April 2019. Available at: https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf.
[107] *Ibid.*