2017 Forecast
10 trends shaping the electric utility industry

By Gavin Bade
The dawn of the Trump era holds uncertainty for the power sector, but the trends pointing toward a cleaner grid are still very much in play.

If there’s one hallmark of the power sector at the beginning of 2017, it’s uncertainty.

At the time of our last trend forecast list in September 2015, the utility industry was already being disrupted: Customer demand for distributed resources and the push for cleaner electricity were reshaping centralized fossil fuel-based grids across the country to accommodate variable renewables and customer-sited resources.

Those trends toward a two-way, decarbonized grid are still very much in play at the beginning of 2017. Lower prices for wind and solar energy have seen those resources reach grid parity across much of the nation, and utilities continue to add flexible natural gas generation along with new technologies like energy storage to integrate the intermittent resources coming online.
But the election of Donald Trump as U.S. president threatens the political will behind the clean energy revolution. Whereas federal regulations and incentives pushed the power sector toward an increasingly decarbonized grid throughout the last eight years, the new president has openly disavowed the idea of climate change and plans to scrap the Clean Power Plan, Obama’s signature energy regulation and the centerpiece of his climate legacy.

While Donald Trump’s election threatens federal environmental regulations and pro-clean energy policies, the U.S. power sector is already in the middle of wholesale transformation.

Just how that will manifest into actual policy is still unclear. While Trump’s appointments to the Environmental Protection Agency and Department of Energy broadly committed to regulate carbon and protect clean energy programs in their Senate confirmation hearings, both did so without any specific promises or concrete policy positions.

But regardless of the policies of the incoming administration, they will be greeted by a power sector already in the midst of wholesale transformation. To help guide the industry through these uncertain times, Utility Dive has outlined the top ten trends that will shape the U.S. power industry in 2017. This list, like the last one, isn't meant
to be exhaustive or rank one trend over another, but to simply give readers an idea of where the industry is headed at the dawn of the Trump era.

**Trend #10**

**Coal power could get a second lease on life**

There’s one resource that embodies the uncertainty present in the power sector today, it’s coal.

Coal power has had a tough go of it over the last decade. Low natural gas prices and increased environmental regulation — particularly the Mercury and Air Toxics Standards — have meant many coal plants were not competitive in regional markets or required costly upgrades to operate, leading to widespread retirements.

Since 2000, utilities have announced more than 100 GW of coal generation retirements; in 2015 alone, nearly 14 GW came offline, accounting for 80% of the plant retirements that year.

Those trends were set to continue under the EPA’s proposed Clean Power Plan, the nation’s first set of carbon regulations for existing plants. Under that Obama program, the Energy Information Administration estimated coal retirements would accelerate, with about 90 GW expected to come offline by 2040.
But the Clean Power Plan was put on hold by the Supreme Court last year pending legal challenges. Now, the Trump administration has promised to cancel it outright with no concrete plans for a replacement. If that happens, and a new regulatory regime is not put in place quickly, it could give remaining coal plants a new lease on life.

While utilities are not expected to add new coal capacity in the absence of carbon rules, EIA estimates the ones already on the system could generate more, and for longer. In its latest Annual Energy Outlook, the agency forecasts that coal generation would continue to decline with the Clean Power Plan, but could stay steady for the next decade if the rules are repealed.

Without the Clean Power Plan, coal generation could stay steady throughout the coming decades. Credit: EIA AEO
Carbon regulations get all the headlines, but whether coal power enjoys the resurgence predicted in EIA forecasts will depend as much on natural gas as the repeal of the Clean Power Plan.

The reason is that natural gas sets the standard for power generation in the U.S. today. Due to their low cost and flexible generation capabilities, combined cycle gas plants typically set the prices in wholesale power market auctions, helping determine the dispatch order for other resources.

Since 2010, historically low prices for natural gas have encouraged utilities to run their gas plants more, and often at the expense of coal. Coal-to-gas switching helped natural gas surpass coal as the top U.S. generating resource last year.

A pro-gas agenda from the Trump administration would likely keep gas prices low for U.S. plants — and greatly increase the resource’s share of power generation.
If those low prices continue, it could see natural gas generation increase its dominance in the U.S. power sector at the expense of other resources. In its AEO report, the EIA forecasts that an increase in domestic oil and gas production (the “high oil and gas” scenario) would allow gas generation to widen its gap over coal and stunt growth in renewable resources.

The EIA numbers are only forecasts, and the actual generation numbers will almost certainly differ. But most analysts expect pro-gas policies from the Trump administration, from the cancellation of the EPA’s methane rules to easier siting for pipelines and other gas infrastructure. If that’s the case, it would likely keep gas prices low for U.S. plants, producing generation trendlines similar to the “high oil and gas” scenarios in EIA forecasts.
Wind and solar are the lowest cost generation resource across large swaths of the country — even without subsidies.

Trend #8

Renewables are at grid parity and will continue to grow

While the trend for gas generation depends on the price of its fuel, the outlook for renewable energy is simpler — it will continue to grow because prices continue to fall. The only question is how quickly.

The wind and solar industries have done well in the past few years. The resources accounted for over half of the more than 14 GW of generation capacity added in 2015, and renewables’ share of new generation is only expected to increase after the extension of key federal tax incentives at the end of that year.

Before the extension of the investment tax credit for solar and production tax credit for wind, renewables and natural gas were expected to split U.S. capacity additions over the next few years, with wind and solar adding less than 5 GW annually until the 2020s. But after the tax extenders, the Rhodium Group forecasted that renewables would “run the table” for capacity additions, “with annual capacity additions topping out at an unprecedented 30 GWs in 2021.”
Those forecasts took the Clean Power Plan into account, but wind and solar are expected to keep growing regardless of the carbon rules or even changes to tax policy. The reason is that renewables now find themselves increasingly at grid parity with natural gas, and are cheaper than coal, across large swaths of the country.

Recent numbers from the investment firm Lazard show the average levelized cost of energy (LCOE) for unsubsidized wind generation fell between $32/MWh and $62/MWh, lower than the average LCOE for natural gas, which came in between $48/MWh and $78/MWh. Utility-scale solar was not far behind, ranging between $48/MWh and $56/MWh for thin film systems. Both renewable resources were shown to be cheaper than coal.

**Gas combined cycle plants still set the prices in organized markets, but renewables are increasingly competitive.**

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**Levelized Cost ($/MWh)**

<table>
<thead>
<tr>
<th>Alternative Energy</th>
<th>Conventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar PV–Rooftop Residential</td>
<td>$32</td>
</tr>
<tr>
<td>Solar PV–Rooftop C&amp;I</td>
<td>$88</td>
</tr>
<tr>
<td>Solar PV –Community</td>
<td>$135</td>
</tr>
<tr>
<td>Solar PV–Crystalline Utility Scale</td>
<td>$49</td>
</tr>
<tr>
<td>Solar PV–Thin Film Utility Scale</td>
<td>$46</td>
</tr>
<tr>
<td>Solar Thermal Tower with Storage</td>
<td>$119</td>
</tr>
<tr>
<td>Fuel Storage</td>
<td>$106</td>
</tr>
<tr>
<td>Microturbine</td>
<td>$76</td>
</tr>
<tr>
<td>Geothermal</td>
<td>$79</td>
</tr>
<tr>
<td>Biomass Direct</td>
<td>$77</td>
</tr>
<tr>
<td>Wind</td>
<td>$32</td>
</tr>
<tr>
<td>Diesel Reciprocating Engine</td>
<td>$62</td>
</tr>
<tr>
<td>Gas Combined Cycle</td>
<td>$212</td>
</tr>
<tr>
<td>Gas Combined Cycle</td>
<td>$212</td>
</tr>
<tr>
<td>IGCC</td>
<td>$165</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$165</td>
</tr>
<tr>
<td>Coal</td>
<td>$143</td>
</tr>
<tr>
<td>Natural Gas Reciprocating Engine</td>
<td>$101</td>
</tr>
<tr>
<td>Gas Peaking</td>
<td>$165</td>
</tr>
</tbody>
</table>

Credit: Lazard
While those numbers are U.S. averages, localized LCOE research reveals that wind and solar are the lowest cost generation resource across large swaths of the country. County-level cost analyses conducted by the University of Texas-Austin reveal that wind is the cheapest capacity across much of the heartland, while solar PV is most competitive in the Southwest, and natural gas dominates much of the South and Northeast.
With gas and renewables suppressing power prices in organized markets, policymakers are looking for ways to save zero-carbon nuclear resources.

Trend #7
Organized markets are in flux — and nuclear plants are at risk

If the trends for renewables and natural gas continue, it will likely mean more upheaval in the nation’s organized power markets.

In recent years, low-priced natural gas, stagnant load growth and growing penetrations of renewable energy have acted together to suppress power prices in the wholesale electricity markets that serve two-thirds of the U.S. population.

While that has helped keep electricity prices in check for consumers, it’s also made life difficult for aging baseload power plants, which have been unable to recover their fixed costs and are increasingly going offline as a result. Last summer, SNL identified 21 GW of coal, gas and nuclear generation as being “at risk” of retirement due to market conditions and aging by 2020, and nuclear lobbyists say as many as 20 nuclear plants could be threatened in the nation’s organized markets.
To preserve these plants, a number of states have devised “around market mechanisms” to compensate plants at risk of retirement. Last year, for instance, AEP and FirstEnergy won income supports for aging coal and nuclear plants in Ohio, only to see FERC block the subsidies and force the utilities to change course. Nuclear plants in Illinois and New York won income supports from policymakers based on their zero-carbon generation.

Grid operators, meanwhile, must continue to protect price formation and attempt to run efficient markets in the face of a litany of state interventions. How they and Donald Trump’s FERC respond to the plight of nuclear generation will have a significant impact on U.S. carbon emissions, as the zero-carbon resource accounts for nearly 20% of the nation’s generation. On top of compensation issues, nuclear operators say extending existing licenses will be key to keeping the resources on the grid.
Trend #6

Energy storage is maturing into a viable grid-scale resource

Just as a number of aging baseload plants are exiting the power system, a new grid resource is emerging on the horizon — energy storage.

Long thought of as a niche resource, energy storage showed in 2016 that it can be a viable replacement for fossil fuel peaker plants, potentially setting it up for massive growth in the coming years as other resources go offline.

In late 2015, when the Aliso Canyon methane leak shut down natural gas supplies to generators in the Los Angeles basin, California regulators enacted a number of emergency mitigation measures, including an expedited energy storage solicitation.
Local utilities responded by contracting for large battery systems on an accelerated deployment schedule. Southern California Edison chose Tesla for 20 MW (80 MWh) of storage, and San Diego Gas & Electric tapped AES for two projects totalling 37.5 MW (150 MWh). Both projects were scheduled for deployment and operation within 6 months from signing, significantly faster than the timeframe for deploying gas peaker plants.

While battery storage remains more expensive than combined cycle gas plants on average, it may be able to challenge peaker plants on price. A proposal from the Arizona consumer advocate would mandate that some renewable resources must supply power during peak demand periods, which would necessitate the use of energy storage. With a recent solar-plus-storage PPA in Hawaii coming in at $0.11/kWh, the proposal posits that solar-plus-storage could compete with those peaker plants today, supplanting carbon-emitting generation and saving consumers money.

That “Clean Peak Standard” is still only a proposal, but it and the Aliso Canyon projects show that energy storage can be a viable alternative to natural gas peakers today. As battery prices continue to fall, utilities and policymakers could turn to storage as alternatives for traditional peaking generation in the future.

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**Cost Reductions Since 2008**

Modeled battery costs have declined 78% since 2008, according to DOE, mirroring the trends with other alternative energy technologies. Credit: DOE ‘Revolution Now’
Change in the electric utility industry is by no means confined to the bulk power system. From rooftop solar to electric vehicles and smart thermostats, the American energy consumer is becoming more energy-savvy and increasingly demanding new generation and control technologies to give them a greater say in their energy consumption.

These evolving consumer preferences are forcing utilities and policymakers to adapt. Utilities facing DER proliferation must modernize their grids, installing smart meters, sensors and communication technologies that allow greater visibility into the system and two-way power flows. That requires new expenditures and justification to state regulators on grid modernization.

Often, the growth of DERs has given way to policy fights, particularly on rooftop solar. Utilities in high-distributed solar regions claim that...
customers with rooftop systems do not pay their fair share of grid upkeep costs, while solar advocates say utilities and regulators fail to account for the benefits they provide the grid.

a set of behaviors that inform people-based marketing.”

The disputes have given way to contentious regulatory proceedings — the compensation scheme that pays solar owners the retail rate of electricity for exported power — in many states. In Nevada, for instance, regulators ended retail rate net metering for both existing and new solar owners at the end of 2015, sparking a year of controversy as solar companies protested and sued the commission.

Eventually, the governor convened an energy task force and installed a new regulator on the PUC, settling the initial contention. But net metering fights persist in states like Arizona and are expected to continue and pop up in new states as more customers go solar.

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**Issues of DER compensation and rate design span the entire nation.** Credit: CETC Q3 2016 update

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**Action on net metering, rate design and solar incentive strategies (Q3 2016)**

- [Map showing states with recent action and no recent action]
Utilities continue to push rate design reform

One of the main ways utilities have sought to respond to the proliferation of DERs and stagnant load growth is through rate design reform.

As customers consume less power or generate their own, utilities have sought to shore up their bottom lines by decreasing the volumetric portion of utility bills and increase the fixed portion that customers pay.

Most commonly, utilities have requested increases to fixed charges or fees, either for DER customers or the entire rate base. But consumer and DER advocates decry the changes as limiting customer control over their energy bills, and regulators have seldom awarded utilities the full fixed charge increase amounts that they request.

Utilities continue to push fixed charge increases across the nation, with 44 utilities in 25 states either involved in or proposing a fee hike of at least 10% in the third quarter of 2016 alone.

While utilities push fixed charge increases in response to DERs and stagnant load growth, new rate design solutions — such as time-of-use rates and demand charges — are emerging.
But as opposition to them has mounted, some companies have opted for more sophisticated rate design solutions, such as time-of-use (TOU) rates or demand charges. TOU rates charge higher rates during periods of high power demand on the grid, incentivizing customers to shift their usage to lower-demand periods. Demand charges, common for commercial and industrial customers, charge a higher rate for each individual customer’s peak demand period each month.

Utility proposals to apply demand charges to residential customers are a relatively new development, and one that’s been met with fierce opposition from consumer advocates and solar companies. More consensus is emerging around TOU rates, however, which have been shown to help reduce customer usage and bring down system costs. California utilities will move to default TOU rates in 2019 and the state is experimenting with special rates for EV charging.

As DERs proliferate and utilities feel the continued squeeze of stagnant demand, more rate design reform debates are expected in 2017 and beyond.

### Summary of Policy Actions (Q3 2016)

<table>
<thead>
<tr>
<th>Policy Type</th>
<th># of Actions</th>
<th>% by Type</th>
<th># of States</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential fixed charge increase</td>
<td>44</td>
<td>38%</td>
<td>25 + DC</td>
</tr>
<tr>
<td>Net metering</td>
<td>31</td>
<td>26%</td>
<td>22</td>
</tr>
<tr>
<td>Solar valuation or net metering study</td>
<td>17</td>
<td>15%</td>
<td>15 + DC</td>
</tr>
<tr>
<td>Community solar</td>
<td>10</td>
<td>9%</td>
<td>9</td>
</tr>
<tr>
<td>Residential solar charge</td>
<td>9</td>
<td>8%</td>
<td>7</td>
</tr>
<tr>
<td>Third-party ownership of solar</td>
<td>3</td>
<td>3%</td>
<td>3</td>
</tr>
<tr>
<td>Utility-led rooftop PV programs</td>
<td>3</td>
<td>3%</td>
<td>3</td>
</tr>
<tr>
<td>Total</td>
<td>117</td>
<td>100%</td>
<td>42 States + DC</td>
</tr>
</tbody>
</table>

The North Carolina Clean Energy Technology Center chronicled more than 40 fixed charge increase actions in Q3 2016 alone. Credit: CETC Q3 2016 update
Trend #3

Federal policy uncertainty is likely to persist

While rate design and DER compensation discussions play out at the state level, the picture for federal energy and environmental policy is unlikely to get much clearer in the coming year.

Coming out of the Obama administration, the general trajectory of power sector regulation was relatively straightforward. Utilities would use gas and renewables to comply with the Clean Power Plan as the federal government supported advanced research into technologies to support deeper decarbonization. States and grid operators would work together to support the reliability of the transitioning power sector, and the whole nation would gradually move toward a less carbon-intensive energy system.

Now, with the election of Donald Trump, that narrative is thrown into question. While renewables and gas are expected to continue their growth, both federal environmental regulation and clean energy supports remain in question.

For a sector that thrives on predictability at the policy level, Trump’s election has thrown federal environmental regulations and clean energy supports into question.
Last week, Trump’s pick to lead the EPA, Oklahoma Attorney General Scott Pruitt, told senators in his confirmation hearing that he would follow the 2009 endangerment finding on carbon and saw “no reason” to review it. That finding labeled CO2 and other greenhouse gases as pollutants under the Clean Air Act, meaning the EPA would have to regulate them even if it rescinded the Clean Power Plan.

But Pruitt and his surrogates at the hearing offered no details on what a new carbon regulatory scheme would look like. Since the CPP is still tied up in a court challenge and any new federal regulation could take years to write and finalize, utilities will likely have to live with uncertainty on environmental regulation for some time.

The situation is similar with Department of Energy programs. At his hearing, former Texas Gov. Rick Perry, Trump’s pick for Energy Secretary, pledged to uphold climate science and clean energy research at DOE, though he would not commit to protecting particular programs by name. The comments came just hours after a leaked budget proposal showed the Trump team may be preparing to gut DOE programs, and Perry’s apparent lack of knowledge of the proposal before it surfaced in media reports did little to inspire confidence for those reliant on DOE programs.

Whether Pruitt and Perry intend to follow through on their commitments to regulate carbon and support the DOE remains to be seen, the DOE picture will likely become clearer as the federal budget is finalized. But for an industry that thrives on predictability, federal policy in 2017 is looking like it will be anything but predictable.

Credit: State of the Electric Utility 2016

How should the EPA proceed with the Clean Power Plan, which sets a goal to reduce carbon emissions from the power sector 32% nationwide by 2030?

41% EPA should hold to its current emissions standards and timetable

29% EPA should make the emissions reduction targets more aggressive leading up to 2030

17% EPA should lessen emissions reduction targets and timetables

13% EPA should scrap the plan altogether
As the federal government takes a back seat on clean energy policies, proactive states are poised to take up the mantle.

Already, states like California, Vermont, New York, Oregon and others are pushing ambitious clean energy standards, with Hawaii in particular targeting 100% renewables by 2045. And some are protecting existing clean generation, with deals in New York and Illinois to save ailing nuclear plants and give them extra compensation for their carbon-free attributes.

While federal energy policy may revert under President Trump, proactive states plan to push forward on clean energy regardless.

Meanwhile, the nation’s grid operators are figuring out ways to integrate ever-increasing amounts of intermittent renewables and devising strategies (such as in CAISO and ISO-New England) to integrate carbon pricing into their market structures.
That progress comes on the back of a productive decade for many states in decreasing emissions. Using a combo platter of natural gas, nuclear and renewables, a number of states have grown their economies over the last decade while decreasing carbon emissions — though the pace is still not yet fast enough to meet U.S. goals under the Paris Accord.

The U.S. an its states need to make greater progress in decarbonizing their economies (Average annual decrease in carbon intensity of the economy, 2000 - 2014)

With the federal initiative on decarbonization diminishing, the role of states in the clean energy transition will become even more important. The lessons that places like California and Hawaii learn as they integrate more renewables could show the nation the best path to the deep decarbonization needed to stem the most disastrous consequences of climate change.
On top of energy mandates and carbon goals, the single most important development coming out of state energy policymaking in 2017 may be the continued evolution of the utility business model.

As the sector moves away from the traditional model of centralized generation, many are rethinking the utility’s role to help it encourage the adoption of customer-sited resources and optimize them for the grid.

Instead of the traditional cost-of-service revenue model, in which utilities petition regulators to build infrastructure for a set rate of return, many commissions are encouraging new revenue models and incentives. The New York REV docket, for instance, is testing performance-based incentives to push utilities to serve grid needs with DERs rather than building new bulk power infrastructure.

In a *shift away from the traditional cost-of-service revenue model*, many state regulatory commissions are encouraging new utility revenue models and incentives.
The REV docket, the most well-known of the “utility of the future” proceedings, is working alongside a number of other similar reform initiatives in states like California, Minnesota, and Massachusetts. And regulators in Illinois, Ohio and elsewhere have stated their intention to open proceedings soon.

In some states, like California and New York, this year could see some of the regulatory initiatives solidify into concrete utility plans for grid modernization and DER optimization. Other states will watch closely for lessons learned. But if one thing’s certain, it’s that the industry itself wants the regulatory model to change — and that could be the most significant trend of all.

What is the greatest obstacle to the evolution of your utility’s business model?

- Existing regulatory model: 35%
- Integration of emerging technologies: 21%
- Internal resistance to change: 20%
- Cost of stranded assets: 11%
- Stakeholder consensus: 10%
- Nothing - my utility’s business does not need to evolve: 3%

State of the Electric Utility survey respondents named the existing regulatory model as the top obstacle to business model transformation. Credit: State of the Electric Utility 2016
Utility Dive covers the ongoing transformation of the electricity business.

Key coverage areas include the disruption of traditional utility business models, the changing habits of the American energy consumer, the emergence of rooftop solar and other new technologies, and more.

Learn more at www.UtilityDive.com