Industry Top Trends 2018

North America Merchant Power

Authors

Aneesh Prabhu
New York
+1 212 438 1285
aneesh.prabhu@spglobal.com

Simon White
New York
+1 212 438 7551
simon.white@spglobal.com

Mike Ferguson
New York
+1 212 438 7670
mike.ferguson@spglobal.com

Kim Yarborough
New York
+1 212 438 1089
kim.yarborough@spglobal.com

Yousaf Siddique
Toronto
+1 416 507 2559
yousaf.siddique@spglobal.com

Research
Ian Wang
New York
+1 212 438 0513
ian.wang@spglobal.com

Overview

- **Ratings Outlook:** Although 55% of our independent power producers (IPPs, or merchant generators) have stable outlooks, there is a negative bias to our non-stable outlooks. Our outlook bias primarily reflects demand slowdown because of energy efficiency and distributed generation. Simultaneously, energy margins are under pressure as wind and solar generation--which has been increasingly deployed over the past three years--has shaved off peak price formation.
- **Forecasts**: We expect modest growth and flat margins in 2018: We think power prices could strengthen in the Pennsylvania-Jersey-Maryland (PJM) Interconnection as energy price reforms appear likely. Electric Reliability Council of Texas (ERCOT) will likely see some upside as retirements accelerate.
- **Assumptions:** While regional differences persist, on average, we expect IPPs to have weather-adjusted demand growth of only about 0.25%. The one exception is the ERCOT market, which we expect to see grow at 0.5%. We see flat capacity prices in New England, downward pressure in capacity prices in New York but pockets of potential capacity price upsides in PJM.
- **Risks and Opportunities:** Regulatory risks appear lower after PJM's recommendation to the Federal Energy Regulatory Commission (FERC) to implement energy price reforms. The FERC, in turn, has remanded the Department of Energy's (DoE) notice of proposed rulemaking (NOPR) back to the Regional transmission organizations (RTO) and asked them to propose reforms in their respective markets. If PJM's market reforms are implemented as proposed, we expect round-the-clock energy prices to recover about $3.00-$3.50 per megawatt hour (MWh); this would be a favorable development for PJM base-load (predominantly nuclear) generators.
- **Industry Trends:** We see IPPs that are making a strategic shift toward retail power businesses and/or contracting a meaningful proportion of their generation as the ones likely to successfully respond to the evolving commodity environment. On the other hand, IPPs with modest retail business, exposure to coal-fired generation, and limited regional (or fuel) diversity are vulnerable to further credit deterioration. Predominant market trends relate to the combined onslaught on power prices of still-depressed natural gas prices, proliferating renewables, and increasing distributed generation. Disruptive forces like energy efficiency and advancing battery storage add to these risks.

S&P Global Ratings

Ratings trends and outlook

Utilities - North America Unregulated (Merchant Power)

Chart 1 – Ratings distribution

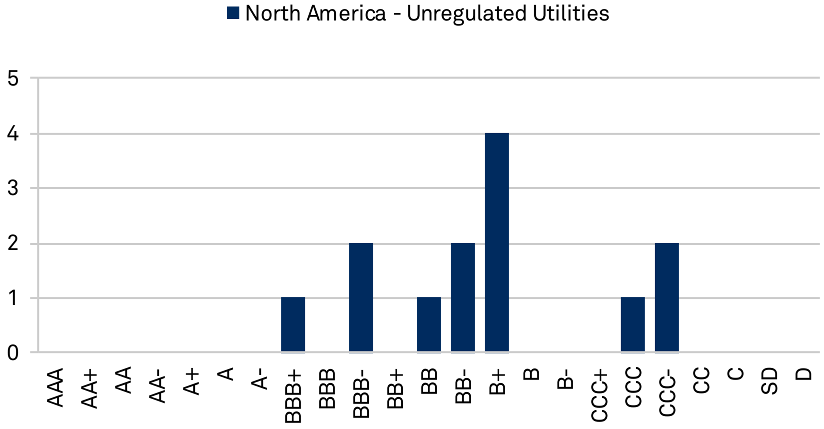


Chart 2 – Ratings outlooks

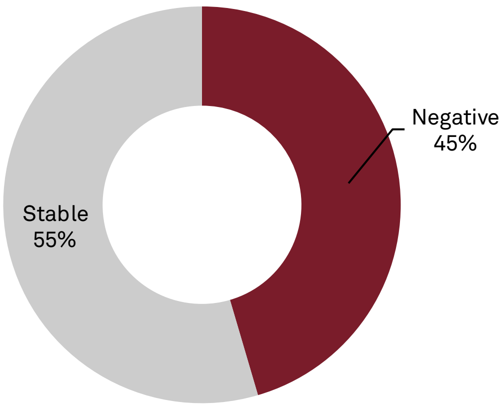
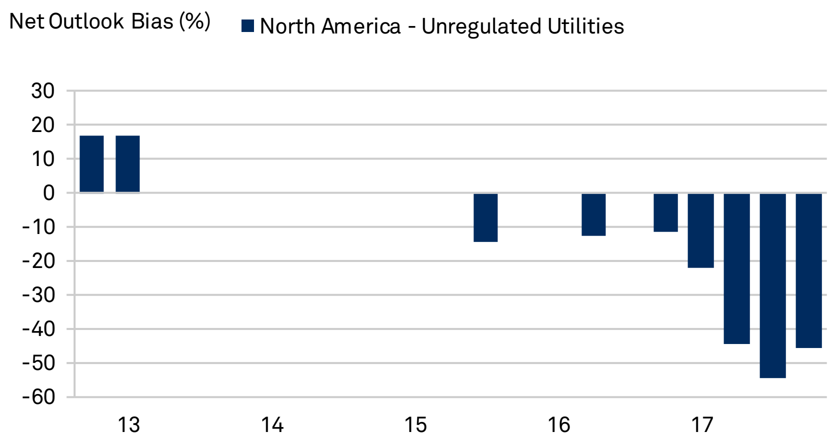


Chart 3 – Ratings outlook net bias



Rating distribution in the IPP sector remains skewed to the 'BB' category, but biased to the downside. This reflects risks to wholesale power margins, buoyed to an extent by countercyclical retail power margins. Aggressive cost cutting and the presence of many private equity sponsors (that emphasize cost discipline) have helped maintain financial ratios. Our investment-grade credit quality continues to drift lower, with pressure on the 'BBB' rated companies.

Source: S&P Global Ratings. Ratings data measured quarterly with last shown quarter ending December 31, 2017

Industry credit metrics

Utilities - North America Unregulated (Merchant Power)

Chart 4 – Debt / EBITDA (median, adjusted)

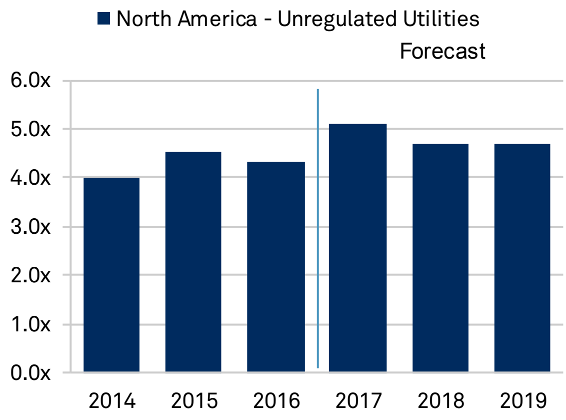
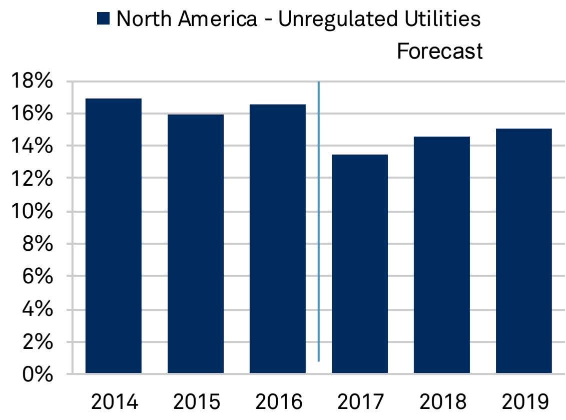


Chart 5 – FFO / debt (median, adjusted)



We expect ratios to stay flat or improve as companies aggressively shed debt concomitant with declining cash flows. Debt reduction is no longer optional but imperative for economic viability given the disruptive forces at play.

Chart 6 – Cash flow and primary uses

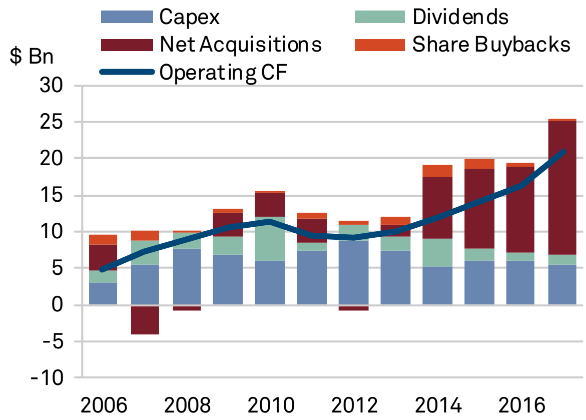
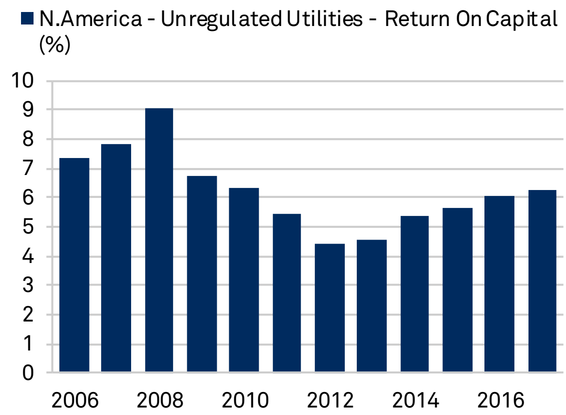


Chart 7 – Return on capital employed



Source: S&P Global Ratings. All figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate.

The $3.00-$3.50 per million Btu (mmBtu) price level currently seen in natural gas are reminiscent of gas market trends in 2002. However, despite pricing commonalities between 2017 and 2002, there are many differences between now and then.

In 2002, we would have come to the following conclusions about the market: demand exceeded supply, inventory levels were low or falling, and gas contracts' time spreads were tightening (i.e., first month as a percentage of third month contract was shifting into backwardation [the market condition wherein the price of a commodities' forward or futures contract is trading below the expected spot price at contract maturity]), which are all classic signs of a bull market.

In 2017, supply exceeds demand, inventory levels are high or rising, and the forward curve is flat (or in mild contango [when the futures price (or forward price) of a commodity is higher than the anticipated spot price at maturity of the futures contract.]), which are all definitions of a bear market. The only thing different in this otherwise bear market is this $3.00-$3.50/mmBtu price level, because all of these bear market conditions had historically occurred at prices above $8.00/mmBtu. However, if we acknowledge that the long-dated natural gas price is driven by the decreasing costs resulting from structural factors like the exploitation of low-cost shale resources, then what we are seeing is a classic bear market that is simply centered on a $3.00/mmBtu price instead of a $8.00/mmBtu price.

The merchant power markets in the U.S. are witnessing the domino effect of lower gas prices--the marginal fuel for power generation translates into lower power prices--and, simultaneously, witnessing the largest fuel-switch in the industry's history. Add to this the impact of proliferating renewables (largely wind but now also solar), distributed generation (behind-the-meter solar), and energy efficiency, and you have disruptive forces adding to an unregulated power generator's misery.

Key assumptions

Utilities - North America Unregulated (Merchant Power)

1	**Lower load growth rates** Demand assumptions, as reflected in year-over-year and CAGR, in load growth will drive tightening in reserve margins and potentially stronger power prices. Our load growth rate assumptions are materially lower than many sponsor assumptions because we see energy efficiency meaningfully eroding load growth.
2	**Lack of demand growth** Our RTO-wide capacity price assumptions are negatively influenced by the lack of demand growth. We see flat prices in ISO-NE, a modest increase in PJM, and declining prices in New York Zone J. We expect to see pockets of elevated capacity prices in the PJM relative to the RTO capacity price assumptions.
3	**No pricing uplift until FERC reforms implemented** We expect energy price reform in PJM but have not factored in any uplift in prices until any FERC directed reforms are implemented.

Demand assumptions are key drivers of credit

We're still assuming weather-normalized demand at about 0.25% in PJM, ISO-New York, and ISO-NE and at about 0.5% in ERCOT in our base-case forecasts. We note that these levels are well below multiyear historical trends of 1.3%-1.4% given continued energy efficiency gains. However, we have not actually seen this level of growth in the recent past. If we do not see any load growth in 2017, we're likely to assume a flat growth rate in PJM in 2018 for our forecast modelling. Our downside scenarios, which currently assume flat to marginally negative growth, will correspondingly decline too.

Demand has also influenced our capacity price assumptions

A generator wants return of capital and a return on that capital. It does not care where it makes the money. Typically, revenues from energy sold in the wholesale market pay for a generators' variable costs and some portion of fixed costs. The unrecovered portion of fixed cost (missing money) is recovered through capacity market revenues. As a result, power demand affects capacity prices in two competing ways. As peak load decreases, a lesser amount of generation is needed to serve that load, and lesser capacity clears the auction. But as average energy consumption declines (GWh), energy margins of a generator decline, resulting in higher bids in the capacity market to supplant the diminished returns in the energy market.

Over the past three years, the negative impact of declining peak demand on capacity prices has been much more than any positive effect from lower average energy consumption. This is evident from cleared capacity prices for the broader PJM RTO region, rest-of-pool ISO-NE, and New York City Zone J. We expect rest-of-pool ISO-NE capacity prices to stay at, or below, the dynamic delist price of $5.50/kW-month for at least the next three auctions. We also envision New York City Zone J giving back some of the recent high prices in the summer auction ($11.70/kW-month in summer 2017) and expect to revise our market price assumptions (see "Market Assumptions Used For Power Project Financings", published June 5, 2017) for New York City Zone J downwards from our previous assumption of about $13.00/kW-month for summer 2018 to about $10.00/kW-month currently.).

However, we see lower energy margin offsets as resulting in somewhat higher PJM RTO prices compared to the $76/MW-day result in the 2020/2021 auction. Our assumption for the 2021/2022 auction is $100/MW-day. This is higher than the latest test capacity print of $76.53/MW-day and $86.04/MW-day for the RTO and MAAC regions, respectively, for 2020/2021. We believe the 2020/2021 price was partly influenced by bidding behavior (see *"PJM Capacity Market Update: So Who Will Blink First?"*, published June 5, 2017) and because of higher energy margin offsets as described below. Eventually, we expect RTO prices to revert to about $100/MW-day for the 2021/2022 auction. At the same time, we expect capacity prices to be range-bound and do not expect prices to surge, or fall significantly.

We expect pockets of higher capacity pricing in PJM

Eastern MAAC (EMAAC)

EMAAC cleared at $187.87 this year, approximately $68/MW-day above last year's auction price of $119.77/MW-day. We note that some of the underlying dynamics happening in this LDA have been because of announced deactivation notices that were then subsequently revised. We also think that the EMAAC is being influenced by the uncertainty on how the PSEG/ComEd wheel will be handled going forward (transfer of supply between New York and PJM).We think that the latest auction results may also have been somewhat influenced by the bidding behavior of Limerick (2,375 MW) and Peach Bottom (2,550 MW). Nuclear power provides as much as 40% of New Jersey's requirement and these units appear to have started bidding some of their fixed costs into their capacity bid. We expect EMAAC prices to stay separated from the RTO at about $150-$165/MW-day.

ComEd

Unlike EMAAC, which we think has only recently seen the impact of bidding behavior of nuclear units, capacity prices in ComEd are clearly influenced by the bidding strategy of nearly 10GW of nuclear generation in the LDA. Prices for this LDA have separated as nuclear units continue to bid their fixed costs. However, high prices are their own solution, which have resulted in an increase in cleared capacity. This incremental supply should have brought prices down, but there has been also a decrease in the import limit. For now, the lower capacity emergency transfer limit (CETL) into the LDA has delayed the effects of greater cleared capacity, resulting in an overall price that is relatively similar to that of the previous year's auction. We see ComED capacity prices declining once the Eugene Dequin 345kV line, the limiting facility for ComEd CETL, is upgraded. We expect ComEd to come off its high but stay elevated at about $165/MW-day. We note, however, that FERC's response to the negative energy price formation problem could result in higher round-the-clock energy prices and lower capacity prices.

Southwest MAAC (SWMAAC)

There have been substantial transmission upgrades from the PECO Energy zone into the Maryland area, allowing Calpine's fleet to deliver into SWMAAC. Consequently, we expect that SWMAAC will converge with MAAC pricing, at least for the next few auctions. Also, we expect MAAC and RTO prices to converge because we think there are still pockets of regions in MAAC where generators can earn adequate energy margins.

Duke Energy Ohio Kentucky (DEOK)

While there is no material constraint in this LDA relative to the broader RTO, this region was modelled as a separate LDA because of the number, and relative size, of generation units in this region that are at risk of retirement. We expect the LDA to remain separated from RTO pricing for the next three years.

Key risks and opportunities

Utilities - North America Unregulated (Merchant Power)

1	**No positive catalysts beyond spikes or FERC reform** There is no real positive catalyst in the power space at this time, with any upside likely to be due to spikes in natural gas or FERC energy price formation reform.
2	**Secular trends and weather** Regional risks pertain either to milder weather-influenced demand destruction, or negative secular demand trends, such as in the PJM and ISO-NE. Alternatively, risks have emerged from incremental supply such as in ERCOT.
3	**Legacy generation could offer power price upside** Retirement of legacy generation, such as those recently announced in ERCOT and the FERC's decision on energy price reforms, could offer upside to power prices.

Power price formation is currently biased to the downside

The idea of volatility in the power markets is not a statistical condition, but rather an economic reality. If commodity prices did not revert to the highest cost producer's cost structure, then that producer would drop out, creating a price increase. Conversely, if there is too much production relative to demand, then the marginal producer must exit. Thus, power prices must revert to the cost of the marginal fuel that is used to generate power. Historically, this fuel has been natural gas. The marginal cost of natural gas production has lately been a moving target, drifting lower and lower. As a result, power prices have witnessed a secular decline since 2012. Now, the added downward pressure on energy prices from the proliferation of renewable energy sources has completely decimated any possibility of sustained high power price formation.

To illustrate, let's assume the cumulative generation supply capacity along the x-axis and the marginal costs of these units along the y-axis. The plot of dispatch costs along these axes (or power prices bid by the units in the day-ahead market) represent the generation supply stack. So what's happening is that along the horizontal (supply) axis, the entry of new, near-zero marginal cost renewable resources has pushed the curve to the right, resulting in lower clearing prices at the same level of demand, all else being equal. At the same time, reductions in the marginal fuel costs of natural gas (vertical axis) have lowered the slope of the curve.

We note that diminishing energy market returns increase the role of the capacity market in resource entry and exit decisions. These effects accumulate over the longer term to create unintended bias toward low capital-cost resources with high operating costs. So not only has the curve flattened, it has effectively flipped; less-flexible units, like coal-fired and nuclear generation, formerly committed as base and/or mid-merit power supply, are now more regularly the marginal resources needed to meet demand. With a flattened generation supply curve, energy prices are likely to stay low most of the time without the variation and price spikes seen historically, making it difficult for the energy market to fully capture the economic rent for profitable conventional base-load generation.

Regional risks for merchant generators

We see risks for ISO-NE and the PJM Interconnection as mostly demand-driven. While we are continuing to see incremental generation supply additions, we do not see the potential for significant new entry, because PJM does not have ideal solar conditions and wind is largely a factor in the western part of the region. In fact, PJM is still seeing gas-on-gas competition, with wind encroaching on base-load nuclear economics.

On the other hand, ERCOT is witnessing risks largely from the addition of generation supply because this market has significantly higher renewable deployment so competition is now between natural gas-fired generation and renewables generation, which is why we are seeing gas-fired units like Panda Temple Power LLC and ExGen Texas Power LLC filing for bankruptcy. We also think renewables and batteries are going to be significant challenges for this energy-only market, especially since it has ideal conditions for both wind and solar. We think the risk here is that scarcity pricing can largely be shaved or shifted, and with no capacity markets, conventional generation can come under significant stress.

California's aggressive renewable portfolio standards and energy efficiency have resulted in its now-famous duck-shaped supply curve. With battery deployment, we expect renewables to dominate this market. Even as California's duck curve has resulted in negative intraday spark spreads, these IPPs have not seen margins erode because of the higher demand peaks (and spark spreads) seen during solar ramp up hours. However, with batteries coupled to solar PV systems, and units now having the ability to peak shift for up to four hours past (when intraday demand has subsided), those peak spark spreads could quickly disappear. More broadly, the rapidly falling prices for batteries could be devastating for energy-only markets.

Still, opportunities exist for merchant generators

Much awaited retirements in ERCOT offer a market-based solution...

Over the past five years, ERCOT witnessed risk largely from incremental generation supply, even as the retirements that many investors had expected didn't materialize. In fact, coming into 2017, ERCOT was the only market that had not seen any meaningful coal-fired retirements and market fundamentals deteriorated substantially. This market has also witnessed significantly higher renewable deployment. Wind generation has witnessed a substantial increase in capacity utilization and now constitutes about 17% of all supplied load. To illustrate this impact, we note that ERCOT's implied forward market heat rates for 2019 and 2020 had declined by 1.4 mmBtu/MWh, or about 12%-13%, between September 2017 and November 2016.

There have been dramatic developments since then. During October 2017 alone, Vistra Energy announced that over 4 GWs--or about 5% of the peak installed capacity--of coal-fired generation will retire in 2018. We now expect about 5 GW of total coal retirements and only 2.3 GW-2.5 GW of new gas-fired capacity in 2017-2020 (see table 1)--in a market realizing roughly 0.75 GW-1 GW per year of peak load growth. We note that none of the delayed plants are under construction.

Table 1

Changes to ERCOT power supply stack

Plant	Capacity (MW)	In-service date	Status
Colorado Bend	1090	2017	COD in July
Wolf Hollow	1070	2017	COD in July
PH Robinson	325	2017	COD in September
Friendswood	120	2017	
Halyard Henderson	450	2018	Delayed
Halyard Wharton	420	2018	Delayed
Indeck Wharton	650	2019	Delayed
FGE Texas Project	725	2019	Delayed
Pinecrest Energy Center	775	2020	Delayed

Source: S&P Global Ratings, S&P Global Market Intelligence

In table 2 below, we also present recent announced closures as well as units that we consider "at-risk". We believe these incremental coal retirements have tightened fundamentals and forecast reserve margins could decline to approximately 10%-12% by 2019/2020 compared with ERCOT's last capacity, demand, and reserves (CDR) published view of 18%-19%. We see these retirements as supporting scarcity pricing events in 2019 that support a rally in forward implied market heat rates, despite only modest moves in natural gas prices. We note that the recent supply retirements resulted in half of the lost implied market heat since November 2016 (about 0.75 mmBtu/MWh), climbing back up by December 2017.

Table 2

At-risk generation in ERCOT

Plant	Capacity (MW)	Owner	Comments
J K Spruce 1	555	CPS Energy	
Gibbons Creek 1	455	Texas Muni Power Agency	On Seasonal Operations
Fayette 3	460	LCRA	
Coleto Creek 1	595	International Power	
Martin Lake 3	800	Luminant	
Martin Lake 1	805	Luminant	
Martin Lake 2	805	Luminant	
Total	**4475**		
Announced Retirements			
Big Brown	1150	Luminant	Completed 120-day PUC Review and will close in 2019
Monticallo ST (1-3)	1865	Luminant	Completed 90-day PUC review and will close
Sandow 4-5	1200	Luminant	Completed 120- Day PUC review and will close in 2018
Barney Davis	330	Talen	Gas-fired unit
J T Deely 1	445	CPS Energy	Retirement in 2019
J T Deely 2	485	CPS Energy	Retirement in 2019
Fayette 2	615	LCRA	
Fayette 1	615	LCRA	
Total	**5475**		

Source: S&P Global Ratings, S&P Global Market Intelligence

....while FERC's decision on energy price reform in PJM is increasingly likely

On Sept. 28, 2017, DoE submitted a NOPR to the FERC for evaluation. The initiative intended to address grid resilience and support needed for coal/nuclear units. Specifically, the DoE requested the FERC to ensure that the reliability and resiliency attributes of generation units with on-site fuel supplies are fully valued. Even before the publication of the PJM energy price formation proposal, PJM issued a response to the FERC on the DoE's NOPR. In its response, PJM proposed that the FERC should not adopt the remedies set forth in the NOPR and instead require all RTOs and ISOs to give an assessment of any needed price formation reforms, or alternatively, file tariff proposals in a timeframe that should not extend beyond 180 days.

Earlier, on Nov. 15, 2017, PJM had also issued a formal proposal for energy price formation. PJM's proposal to the FERC would allow energy market clearing prices to be set by inflexible units prospectively to avoid scenarios where the locational marginal price (LMP) is set below the marginal cost of a market clearing inflexible unit--generally because of the zero marginal cost of wind. Under current rules, only flexible units (natural gas units and renewables) can set the marginal price of power paid to all generators. This is an issue primarily for coal and nuclear power plants, which currently must often run "out-of-the-money" relative to their variable costs due to their operating constraints in certain hours even as they are required for reliability purposes.

PJM has also recommended using the extended LMP method for price formation (that means keeping dispatch unchanged) so that prices reflect the entire cost of the inflexible nuclear or coal-fired unit were it be needed on the grid. This allows all market participants to benefit from higher prices and for the flexible units to get uplift payments for the opportunity cost of not generating power. We believe that addressing this inefficiency would increase market energy prices for power, all things being equal. PJM estimates the enhancements would increase wholesale energy prices by $3.50/MWh. This correction would be a significant development for large base-load nuclear units (and perhaps some efficient coal-fired units) that are struggling from increasing negative energy price events caused by increasing levels of wind generation on the grid.

On Jan 8, 2018, the FERC rejected the NOPR and opened a new proceeding to evaluate the resilience of the bulk power system in the regions operated by the RTOs and ISOs. The FERC's stipulation seeks to develop a common definition of bulk power system resilience, understand how each RTO and ISO assesses resilience in its own footprint, and then use that information to evaluate whether additional commission action on resilience is currently appropriate. We believe the FERC will ultimately pursue a dual path, allowing RTOs to move forward with their proposed price reforms while pursuing a longer-term solution on resiliency through a separate proceeding. Given PJM's white paper, we see the development as favorable for nuclear generators like Exelon Generation but likely unfavorable for coal-fired generation. We see a further 20 GW of coal-fired generation retiring through 2020.

Industry developments

Demand is the key credit driver in 2018 and beyond

We think electric demand growth, or the lack thereof, will likely exert the greatest influence on merchant generators' credit quality in 2018, and for now it is hard to estimate how severe this impact could be. While mild weather over the past two to three years in some U.S. regions has contributed to much of the demand loss, we believe a decline in secular demand growth has emerged as the most significant risk to merchant energy margins and capacity price assumptions.

In the May 2013 PJM auction, total cleared unforced capacity resources were nearly 170 GW, while the reserve margin was 20.3%, resulting in an implied load of about 140 GW (see table 3). By the 2017 auction, cleared capacity had declined to 165 GW but the reserve margin had increased to 23.3%. In other words, implied load has declined to 134GW. Implied load has declined for the past four years, representing a negative 1.2% compound annual growth rate (CAGR). The decline in demand has caused capacity prices to decline, in turn resulting in incremental supply (18 [GW]) not clearing the auction. Adding this uncleared capacity (which has not yet announced an intention to retire) increases the reserve margin to well over 35%.

Table 3

Cleared unforced capacity (UCAP) by resource type (MW)

Auction delivery year	New Gen'n (A)	Gen'n Uprate (B)	Imports (C)	Demand Response (D)	Energy Effic'y (E)	Total (A through E)	Aggregate Cleared Resources	Uncleared Capacity	Reserve Margin (%)	Implied Load	Total Offered	Reserve Margin Inc. Uncleared Load (%)
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1	18,713.6	149,974.7	10,511.6	18.8	126,241	160,486	27.13
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5	25,036.9	164,561.2	14,026.5	19.3	137,939	178,588	29.47
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3	26,471.0	169,159.7	15,220.3	20.3	140,615	184,380	31.12
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9	23,106.5	167,003.7	11,834.8	19.7	139,519	178,839	28.18
2018/2019	2,919.3	587.6	4,687.9	11,084.4	1,246.5	20,525.7	166,836.9	13,054.3	19.8	139,263	179,981	29.17
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1	21,268.2	167,305.9	18,233.6	22.4	136,688	185,540	35.74
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2	16,351.6	165,109.2	18,242.3	23.3	133,909	183,352	36.92
Average	**3,743.7**	**498.2**	**4,503.0**	**11,655.3**	**1,238.9**	**21,639.1**	**164,278.8**	**14,446.2**				

Source: PJM Interconnection, S&P Global Ratings

We've witnessed a similar trend in other markets. The ISO-NE is a roughly 30 GW market but has grown at negative 0.5% for the past three years. Another major load pocket, New York Zone J (or New York City) has witnessed a similar trend, giving up about 500 MW over the past three years on a 11.75 GW market.

For now, generation owners have dismissed the lack of demand as largely weather influenced. For instance, we see almost all generation forecast models factor in 0.75%-1% demand growth, but we see this assumption as increasingly optimistic. Based on the past four years, a 1% demand growth assumption appears more hope than a business strategy. This is also the most contested discussion we have with generation sponsors these days.

The energy efficiency juggernaut is an underappreciated headwind

Market participants are still not appreciating the impact of energy efficiency. We view the impact of energy efficiency on demand as not just a risk but as the uncertainty, and its impact can be huge. We'll back our assertion of the ongoing onslaught on demand from efficiency with an example. Industry experts expect the U.S. lighting market to increase to about $16.5 billion by 2020 from about $13.5 billion in 2016, propelled by the 15% CAGR in LED sales. LED penetration is still low, at about 8% with adoption in the commercial and industrial segments at about 13% and 25%, respectively. Roughly 15%-17% of total U.S. power demand comes from lighting. With LEDs potentially increasing penetration from 8% of current installed lighting to about 25% by 2020, market experts expect that we could see a 4% decline in power demand, all else being equal. This is no small number. For perspective, a September 2016 DoE report estimates LED lighting related savings in 2015-2030 at about 325 terawatt hours (TWh). In comparison, the S&P Market Intelligence group estimates passenger car and light truck electric vehicles power demand in the U.S. at 172 TWh by 2035.

Solar and wind generation has affected round-the clock power prices

Technologies typically experience cost reductions as their deployment grows due to technology improvements and increasing economies of scale. This becomes a cycle--subsidies and lower investment costs spur further deployment. That time has come for both solar and wind generation. Since 2009, solar PV installed system costs have fallen approximately 60% on a per kilowatt (kW) basis for residential and commercial systems. They fell 70% for industrial utility-scale systems. The risk is that power prices have declined and will remain range-bound; the uncertainty is how much of incremental renewables will the market see and how much power prices can fall further. We note that the ERCOT forward market heat rates have remained depressed since 2012, even when reserve margins were not as high as they are today. We think the market was subsuming the risk of rampant renewable proliferation, some of which has been borne out.

As wind generation has proliferated, instances of renewables affecting all-hours pricing have increased. For example, in 2016, wind comprised 17% as a percentage of load in ERCOT. Importantly, 1% and 4.1% of all-hours in ERCOT North and West, respectively, experienced negative pricing. This erosion of value can be significant. For example, Exelon Generation estimates that some of its nuclear units witness round-the-clock prices that are about $3.00/ MWh lower because of wind, all else being equal.

Battery technologies are advancing

Battery cost curves continue to trend down. Since we have the clearest view of lithium-ion economics, we'll take that as an example. First, when we think in terms of capital costs for batteries, units are in kWh of operation--i.e., it's in $/kWh because we expect batteries to be duration products for peak shifting (or peak shaving) solutions.

Utility scale battery economics are currently at about $250/kWh price point, or $1,000/kWh for a battery peaker plant that provides a four-hour peak shift. Costs for the balance of system are about $400-$500/kW for equipment like inverter/rectifier, transformers, and power control equipment, and various safety equipment. So a utility scale battery would currently cost about $1,400-$1,500/KW (250*4+$400/$500)--we think those costs are comparable to the cost of building a natural gas-fired peaker plant in California.

This should be concern for IPPs that operate in that state because these cost economics imply that there will be no gas-fired peaker plant additions in California. The whole point of batteries is that they take electricity directly from the grid and do not draw electricity from wind turbines or solar panels. As a result, batteries allow combine cycle gas turbines (CCGTs) to operate as combustion turbines in peaker plants. This means that a 54%-56% thermal efficiency power plant is going to be able to provide peaking power attached to batteries, instead of the ISO calling upon 30%-32%

efficiency combustion turbine. This, in itself, results in substantial carbon reductions and fuel cost savings. In fact, by turning all CCGTs into flexible peaker plants in addition to being base load plants, batteries allow much more renewable penetration onto that grid.

Decarbonization in the power sector

Although the Trump Administration continues to dismantle the environmental decisions of its predecessor, we do not expect the decarbonization of the U.S. power sector to slow materially during the next few years, for a variety of reasons.

First, state-level policies continue to provide incentives for the decarbonization of the sector, and these have been advancing, not retreating, in much of the Northeast, upper Midwest, and West Coast. Renewable portfolio standards have continued to not only strengthen (in terms of final goals) but also broaden to capture new asset classes, such as offshore wind and battery storage.

In addition, California has also added two Canadian provinces to its carbon allowance market, while many onlookers believe incoming New Jersey Gov. Phil Murphy will seek to add his state to the northeastern Regional Greenhouse Gas Initiative alliance, potentially bringing the tally of states pricing carbon to 11--further evidence of states seeking to bypass Trump's decision to leave the Paris Agreement.

As mentioned earlier, the continued winnowing of natural gas prices has altered dispatch--combined with improved efficiency and durability of natural gas turbines, we have seen coal plants contribute less to overall generation, with lower carbon natural gas advancing. But, DoE's NOPR notwithstanding, this is likely to get worse before it gets better. Based on another weak capacity print in PJM, we anticipate that we could see a number of coal closures during the next 18 months, supplementing those already announced by Vistra in ERCOT. While we note there is some gamesmanship in making and announcing such decisions, they all point in the same direction--a greater influence for gas-fired generation in the American generating grid over time.

Still, while we anticipate the decarbonization of the economy through the early part of the next decade, over a longer horizon, there could be a more serious challenge. In the early 2030s, a flurry of nuclear assets will be due for relicensing. Given the current weak economics of merchant nuclear assets, it's not clear that there'll be a strong incentive to renew these licenses. While there have already been two state-level subsidies for nuclear that have sustained a number of assets (and discussions of several more), absent these, there could a be a wave of closures that, if replaced by CCGTs, as we'd expect, would potentially reverse the trend of decarbonization. However, by that time, we could see another federal carbon reduction plan in place.

Aggressive cost cutting and deleveraging

Free cash flow continues as most IPPs see a backwardated EBITDA profile. Leverage targets continue to be lowered. We see investment-grade companies look to deleverage below 3x, and even the high yield companies looking to bring debt levels below 5x by year-end 2018 and below 4x over the next five years.

New sector

We have recently witnessed the emergence of merchant hydroelectric power, predominantly in the PJM, New York, and New England, as a new asset class increasingly seeking financing in the bond market. While once financed exclusively in the bank market, the flattening of the yield curve between the bank and bond market has contributed to a rise in long-term bullet financings for these assets. Investors and financiers often view them as perpetual assets, assuming associated regular maintenance and capital spending programs. Hydroelectric power in the U.S. generally has an advantage over newer solar and wind financings in that the resource risk is often much more predictable and predicated on many decades of observable data. This leads to lower cash flow volatility and higher forecasting certainty at the time of financing. As such, the long-lived nature of these assets and predictability of cash flows relative to other generators have contributed to the rise of these bullet financings, mostly in the private placement market. We expect the wave of bond financings for hydro assets to continue over the next two to three years.

IPPs are relatively well ensconced north of the border

We believe Canadian IPPs face relatively less risk because of higher federal support as well as a lower perceived impact from disruptive forces. In most Canadian provinces, a significant proportion of power generation is owned by crown corporations that are partially or fully owned by the provincial governments. As a result, power markets are generally highly regulated in these provinces.

In Ontario, the largest power-producing Canadian province, generation is dominated by Ontario Power Generation, a crown corporation. However, Ontario, through IESO (a statutory corporation responsible for operating the electricity market in Ontario), has a number of long-term power purchase agreements (PPA) with IPPs. IESO's major contract, comprising about 18% of Ontario's electricity, is with Bruce Power L.P. (BBB/Stable/--), a nuclear-fired generator. The contract provides price certainty to Bruce, though the company is exposed to performance risk. We believe that generally the PPAs in Ontario have a limited risk of renegotiations.

Alberta is the only Canadian province that has established a fully deregulated electricity market. We rate two pure-play IPPs in Alberta: TransAlta Corp. (BBB-/Negative/--) and Capital Power Corp. (BBB-/Stable/--). Alberta plans to transition to an energy and capacity payment market from an energy-only market by 2021. We believe that this would increase the competition for the incumbent players. On the other hand, we expect that power price volatility will decrease and that would lessen the re-contracting risk for the IPPs once their Alberta PPAs terminate in 2020. We will analyze the impact on the business risk on TransAlta and Capital Power once Alberta announces the capacity market's details.

Alberta is one of the last provinces to address the emissions from electricity generation. A new Alberta policy requires the phasing out of all coal-fired plant (approximately 6,300 MW) emissions by 2030 and replacing two-thirds of the generation with renewables and one-third with gas plants. Both the IPPs we rate in this province have a significant proportion of generation from coal. To conform to the new requirements, we expect these companies to increase their capital spending in the coming years and that could affect their leverage and liquidity, depending on the financing structure. However, we believe that both players will opt for the coal-to-gas conversion that would entail a lower cost than building new gas-fired projects, an advantage over any new entrants. Separately, we note that in order to support a seamless exit from coal-fired generation, Alberta's government has approved payments to IPPs that compensate them for the stranded costs of coal-fired generation through 2030. This support is in stark contrast to the competitive market outcomes we are seeing in the U.S.

Overall, Canada has one of the highest electric generations from renewables, with hydro being the dominant source, accounting for nearly 60% of total generation in 2016. However, despite a number of policies and programs in support of renewables, the non-hydro renewable share, though improved significantly in the past decade, is not very impressive at about 7%. We attribute this low share to low growth in electricity demand and the long operating life of existing facilities.