Key Takeaways

- **Ratings Outlook:** Almost 80% of our independent power producers (IPPs, or merchant generators) have stable outlooks, compared with 55% at this point last year. This mostly reflects capital structure corrections as IPPs have shed debt to counter the backwardation in expected future cash flows. The business outlook still reflects demand slowdown because of energy efficiency and distributed generation. Energy margins remain under pressure as wind and solar generation has shaved off peak price formation.

- **Forecasts:** We expect modest to flat growth in 2019: We think power prices could strengthen in the Pennsylvania-Jersey-Maryland (PJM) Interconnection because energy price reforms appear likely. The Electric Reliability Council of Texas (ERCOT) will likely see some upside as retirements continue and new supply is delayed. We expect California markets to reflect the increasing impact of renewable deployment through ‘peakier’ ramp on and ramp off hours for solar generation, even as intraday margins for conventional generation turn negative.

- **Assumptions:** While regional differences persist, on average, we expect IPPs to have weather-adjusted demand growth of about 0.25%. The one exception is the ERCOT market, which we expect to see grow at 1%, albeit this view could be upended by a potential slowdown in economic activity, the probability of which has inched up.

- **Risks:** Regulatory risks have declined for nuclear generators after the second and seventh circuit courts ratified District Court decisions on zero emission credits (ZEC) litigation. Regulatory risks have also abated after PJM’s recommendation to the Federal Energy Regulatory Commission (FERC) to implement energy price reforms. If implemented as proposed, we expect round-the-clock energy prices to recover $3.00-$3.50 per MWh; this would be a favorable development for PJM base-load (predominantly nuclear) generators.

- **Industry Trends:** We see IPPs that are shifting toward retail power businesses and/or contracting a meaningful proportion of their generation as those best placed for the evolving commodity environment. On the other hand, IPPs with modest retail business, exposure to coal-fired generation, and limited regional/fuel diversity are vulnerable to further credit deterioration. Power prices remain under pressure from depressed natural gas prices, proliferating renewables, and increasing distributed generation. Disruptive forces like energy efficiency and advancing battery storage add to these risks.
Compared with last year, our median rating distribution in the IPP sector has moved up to the 'BB' from the 'B+' rating level (see charts 1-3). Partly contributing to the move is consolidation in the industry -- for instance, the Vistra/Dynegy merger and the acquisition of Terraform by subsidiaries of Brookfield (lower rated Dynegy ratings were withdrawn). However, 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 September 30, 2018.
We expect ratios to stay flat or improve as companies aggressively shed debt concomitant with expected declines in future cash flows. We note that debt reduction is a stated objective for a number of IPPs. A year ago, aggregate debt to EBITDA and FFO to debt were forecast above 4x and about 15%, while current forecast point to 3.9x and 18%, respectively, for 2019. The business environment 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 (see charts 4–7).
Industry outlook

Key assumptions

1. Lower load growth rates

Demand assumptions, as reflected in year-over-year and compound annual growth rate (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. ERCOT remains the one exception where we expect robust growth to continue.

2. Lack of demand growth affects capacity markets

Our regional transmission organization (RTO)-wide capacity price assumptions are influenced by the lack of demand growth balanced by near-term retirements. We see flat prices in Independent System Operator--New England (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 meaningful 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. Yet, retirements have started affecting ERCOT prices.

Demand assumptions are key drivers of credit

Growth rates in electric demand are well below multiyear historical trends of 1.2%-1.4%. As a rule of thumb, electric demand had a coefficient of about 0.6 to GDP, i.e., we expected growth of about 1.2% for our long-term GDP growth assumption of about 2.0%. According to industry experts we spoke to, energy efficiency gains have taken about 70 basis points of this growth, resulting in net growth of about 0.5%. Distributed generation and renewables (particularly solar) have constrained growth and many regions are witnessing no growth. We’re still assuming weather-normalized demand at about 0.25% in PJM, ISO-New York, and ISO-NE and at about 1.0% in ERCOT in our base-case forecasts. If we do not see any load growth in 2019, we’re likely to assume a flat growth rate in PJM for our forecast modelling. Our downside scenarios, which currently assume flat to marginally negative growth, will correspondingly decline too.

We have revised our capacity price assumptions and will review them in 2019

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 (gigawatts per hour), 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 $4.30/kilowatt-month (kW-mo.) for at least the next three auctions, unless static delists significantly increase. We also envision New York City Zone J summer prices to remain depressed below $10/kW-mo. until summer 2020.

In PJM, despite the fact that the reliability pricing model (RPM) auction outcomes are still volatile, we see capacity pricing heading toward some stability, at least in the ranges of expected outcomes. This is evident from the auction outcomes over the past few years. Auction outcomes in two representative load deliverability areas (LDAs)--the RTO and Eastern Mid-Atlantic Area Council (EMAAC)--have mean-reverted around levels of $115/MW-day and $160/MW-day, respectively, and volatility around these outcomes has also diminished in recent years (see chart 8).

We expect pockets of higher capacity pricing in PJM. We expect prices in certain LDA to remain separated from the broader RTO region. A decline in energy margins in the east and an increase in implied peak load should result in elevated prices for EMAAC and Public Service (PS)-North, which are smaller, more congested zones. We also think that the prices may also be 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.

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 somewhat once the Eugene Dequin 346kV line, the limiting facility for ComEd CETL, is fully 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.
There have been substantial transmission upgrades from the PECO Energy zone into the Maryland area, allowing Calpine’s fleet to deliver into SWMAAC (Southwestern Mid-Atlantic Area Council). Consequently, we expect that SWMAAC will converge with MAAC (Mid-Atlantic Area Council) 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.

While there is no material constraint in the Duke Energy Ohio Kentucky (DEOK) and the American Transmission Service Inc. (ATSI) LDAs relative to the broader RTO, these regions are experiencing, or could experience, retirements of generation units that are relatively large compared to the LDA size. Consequently, we expect these areas to remain separated from RTO pricing for the next two to three years.

Key risks and opportunities

1. Legacy generation could offer power price upside

Retirement of legacy generation, such as those recently announced in ERCOT and in the PJM Interconnection.

2. Weather-dominated demand

Regional risks pertain either to milder weather-influenced demand destruction, or negative demand trends, such as in the PJM and ISO-NE. As a market without a capacity price construct, ERCOT is significantly influenced by weather patterns.

3. Some catalysts building (beyond weather influenced spikes or FERC reform)

Some positive catalyst--like retirements of legacy generation and delays in new supply--are brewing in the power space. We also see overwhelming gas production (e.g., Dominion south, Leidy, and Waha hubs) as offering pockets of high spark spreads.

4. A sharp downturn in the global economy in 2019

Historically, an economic slowdown has sent demand sharply lower by 5%-6%, which is meaningful enough to result in negative cash flow generation for some IPPs. A secular demand decimation would dominate credit concerns, especially if weather turns out to be mild too.

5. Credit Cycle Exposure

Our base case outlook for credit quality reflects our view that North American merchant power will remain stable despite a confluence of intensifying headwinds, largely because of a concomitant shedding of debt from balance sheets. These concerns are ameliorated by a trend toward lower capital spending and focusing on businesses that are less capital intensive (e.g., retail power) and transitioning to a cleaner emissions profile.

Yet, there is increasing exposure to the developing credit cycle. Inflationary pressures are now accelerating and the yield curve has turned noticeably steeper. Companies that are still not hedged against wholesale power markets--through retail and renewable businesses--could yet see significant erosion in their current free cash flow positions. Nevertheless, we expect that companies will continue to aggressively seek operations and maintenance cost reductions to generate free cash flow for capital allocation decisions that continue to include debt reduction.
Regional Risks Persist

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. Still, after years of declining to flat growth, PJM appears to finally show signs of life (see table 1) as reserve margins have declined some.

Table 1
Demand, Uncleared Capacity, And Reserve Margins

<table>
<thead>
<tr>
<th>Auction delivery year</th>
<th>Cleared capacity resources (MW)</th>
<th>New generation (MW)</th>
<th>Uncleared capacity (MW)</th>
<th>Reserve margin (%)</th>
<th>Implied load (MW)</th>
<th>Total offered (MW)</th>
<th>Reserve margin inc. uncleared load (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014/2015</td>
<td>149,975</td>
<td>416</td>
<td>10,512</td>
<td>18.8</td>
<td>126,241</td>
<td>160,486</td>
<td>27.1</td>
</tr>
<tr>
<td>2015/2016</td>
<td>164,581</td>
<td>4,899</td>
<td>14,027</td>
<td>19.3</td>
<td>137,939</td>
<td>178,588</td>
<td>29.5</td>
</tr>
<tr>
<td>2016/2017</td>
<td>169,160</td>
<td>4,282</td>
<td>15,220</td>
<td>20.3</td>
<td>140,615</td>
<td>184,380</td>
<td>31.1</td>
</tr>
<tr>
<td>2017/2018</td>
<td>167,004</td>
<td>5,927</td>
<td>11,659</td>
<td>19.7</td>
<td>139,519</td>
<td>178,839</td>
<td>28.2</td>
</tr>
<tr>
<td>2018/2019</td>
<td>166,837</td>
<td>2,919</td>
<td>13,054</td>
<td>19.8</td>
<td>139,263</td>
<td>179,891</td>
<td>29.2</td>
</tr>
<tr>
<td>2019/2020</td>
<td>187,306</td>
<td>5,374</td>
<td>18,256</td>
<td>22.4</td>
<td>136,688</td>
<td>185,540</td>
<td>35.7</td>
</tr>
<tr>
<td>2020/2021</td>
<td>165,109</td>
<td>2,389</td>
<td>18,242</td>
<td>23.3</td>
<td>133,909</td>
<td>183,352</td>
<td>36.9</td>
</tr>
<tr>
<td>2021/2022</td>
<td>163,627</td>
<td>893</td>
<td>22,878</td>
<td>21.5</td>
<td>134,673</td>
<td>186,505</td>
<td>38.5</td>
</tr>
<tr>
<td>Average</td>
<td>164,197</td>
<td>3,387</td>
<td>15,500</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: PJM Interconnection, S&P Global Ratings

While ERCOT is currently witnessing tighter reserve margins from delayed supply and retirements, it is likely to see longer-term risks from higher renewable deployment, so competition is now between natural gas-fired generation and renewables generation. 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.

Yet, opportunities emerge for merchant generators

In our opinion, 2019 represents the last stand for vintage coal-fired generation and will likely bring substantial changes to the resource mix in PJM. We expect to see numerous coal-fired generation retirement announcements even though results for this capacity auction are stronger. We note that West Virginia, Ohio, and Pennsylvania are the largest operators of coal-fired generation, with about 15 GWs of installed capacity each.

While we do not know what companies plan for specific units in their fleet, based solely on their cost structure and location of operations, we think several plants are “at risk” and could be retired (Bruce Mansfield [2.5 GWs], Pleasants [1.3 GWs], Chalk Point 1 and 2
[670 MW], Dickerson [520 MW], Homer City [1.9 GWs], Waukegan [670 MW], and Will County [520 MW]). That said, the higher prices in ComEd resulted in higher cleared coal-fired capacity for NRG Energy. Conversely, tighter wastewater discharge standards (effluent limitations guidelines) could compromise Conemaugh (1.7 GWs) and Keystone (1.7 GWs). Overall, we expect about 15 GWs coming over the next two to three years. This compares to the 75-80 GWs of coal retirements since 2006 and about 275 GWs of remaining coal-fired capacity nationwide as of 2018.

PJM is now seeing higher spark spreads at various hubs. With coal-fired generation setting marginal pricing for an increasing number of hours and with shale production continuing to overwhelm, there is distressed natural gas at hubs like Leidy and Dominion South and even further west like the MichCon region. As a result, spark spreads have begun to rise. Depressed spark spreads continued through the third quarter of 2017 before they gradually started picking up. We also note that market heat rates have stabilized and have started increasing from about the third quarter of 2017 and that implied load has increased for the first time in five years in PJM for the 2018 auction.

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

In late 2017, Vistra Energy announced that over 4 GWs—or about 5% of the peak installed capacity—of coal-fired generation will retire in 2018. About the time Vistra announced its retirements, market participants woke up to the prospect that ERCOT could face scarcity should a normal summer return. With an incremental 2 GWs load added in the Freeport region, expected run-up in demand has topped 71 GWs-72 GWs in 2018. Summer 2018 load has come in well above actual 2011 peak load levels of about 68 GWs. Moreover, demand/supply is much tighter in 2019-2020 than in 2011, and the market now also has a much higher-priced system-wide offer cap than 2011. As a result, there has been a significant spark spread rally for 2018-2020 led by the summers (see chart 9).

**Chart 9**

**Summer Peak Pricing: Houston Hub July-August On-Peak Pricing**

![Chart 9](source: S&P Global Ratings, Bloomberg)

We believe a combination of factors have resulted in the significant uptick in spark spreads for forward years through 2020:

- Summer risk premiums have blown out in expectation of a hotter-than-normal summer.
- The large amount of installed wind creates uncertainty with regard to available reserves. Wind also tends to be uncorrelated to demand.
- Low reserves will require less reliable assets with infrequent runs to be online, increasing the risk of higher-than-expected outages.
New builds will be needed to serve load in 2019, but they are far from certain because investors have balked at taking ERCOT exposure (see table 2).

### Table 2

**At-risk generation in ERCOT**

<table>
<thead>
<tr>
<th>Plant</th>
<th>Capacity (MW)</th>
<th>Owner</th>
</tr>
</thead>
<tbody>
<tr>
<td>J K Spruce 1</td>
<td>1,300</td>
<td>CPS Energy</td>
</tr>
<tr>
<td>Gibbons Creek 1</td>
<td>470</td>
<td>Texas Muni Power Agency</td>
</tr>
<tr>
<td>Fayette 1-3</td>
<td>1,600</td>
<td>LCRA</td>
</tr>
<tr>
<td>Coleto Creek 1</td>
<td>595</td>
<td>Dynegy</td>
</tr>
<tr>
<td>Martin Lake 3</td>
<td>800</td>
<td>Luminant</td>
</tr>
<tr>
<td>Martin Lake 1</td>
<td>805</td>
<td>Luminant</td>
</tr>
<tr>
<td>Martin Lake 2</td>
<td>805</td>
<td>Luminant</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4475</strong></td>
<td></td>
</tr>
</tbody>
</table>

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

### Changes to ERCOT power supply stack

<table>
<thead>
<tr>
<th>Plant</th>
<th>Capacity (MW)</th>
<th>In-service date</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Colorado Bend</td>
<td>1090</td>
<td>2017</td>
<td>COD in July 2017</td>
</tr>
<tr>
<td>Wolf Hollow</td>
<td>1070</td>
<td>2017</td>
<td>COD in July 2017</td>
</tr>
<tr>
<td>PH Robinson</td>
<td>325</td>
<td>2017</td>
<td>COD in September 2017</td>
</tr>
<tr>
<td>Friendswood</td>
<td>120</td>
<td>2018</td>
<td>Dec-18</td>
</tr>
<tr>
<td>Denton Energy Center</td>
<td>225</td>
<td>2019</td>
<td>In construction</td>
</tr>
<tr>
<td>Halyard Henderson</td>
<td>435</td>
<td>2018</td>
<td>Delayed until Dec. 2020</td>
</tr>
<tr>
<td>Halyard Wharton</td>
<td>420</td>
<td>2018</td>
<td>Delayed</td>
</tr>
<tr>
<td>PHR Peakers (Baicliff)</td>
<td>325</td>
<td>2019</td>
<td>In litigation,</td>
</tr>
<tr>
<td>Indeck Wharton</td>
<td>650</td>
<td>2019</td>
<td>Delayed; likely to be abandoned</td>
</tr>
<tr>
<td>FGE Texas Project</td>
<td>745</td>
<td>2019</td>
<td>Delayed until Dec. 2020</td>
</tr>
<tr>
<td>Pinecrest Energy Center</td>
<td>775</td>
<td>2020</td>
<td>Delayed; likely to be abandoned</td>
</tr>
</tbody>
</table>

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

In table 2 above, we list units that we consider "at-risk." There are four coal-fired power plants in ERCOT representing an additional approximately 4 MWs or approximately 6% of ERCOT generation capacity that remain at risk of retirement. They are the 600 MW Coleto Creek plants located near Fannin, Texas. Other at-risk plants include the 1,600 MW Fayette Power Project located near La Grange, Texas, the 470 MW Gibbons Creek plant located near Carlos, Texas, and the 1,300 MW J.K. Spruce Unit 1 and Unit 2 located near San Antonio, Texas.

Yet, because ERCOT has an energy-only market, the forward curve price in risk premiums each time there is an expectation of hot weather. However, when actual weather disappoints, it causes significantly lower liquidations sparks. The ERCOT day-ahead market has liquidated substantially lower than what the forwards have suggested in the past six years. It is this exposure to high volatility that makes ERCOT more risky from a credit perspective. An energy-only market holds the investor hostage to the vicissitudes of the weather.
The forward curve also shows backwardation in spark spreads after 2020. In fact, even as spark spreads in 2018 through 2020 have firmed up, round-the-clock peak spark spreads in 2021 and 2022 are lower and are below the level required (see chart 10) to create incentives for new builds (the horizontal lines represent the band where spark spreads need to remain). We think two to three years of strong prices are not enough of a signal for new projects to move forward. A number of projects that ERCOT’s December 2017 capacity, Demand and Reserves report (CDR) expected to start commercial operations by 2020 have been delayed by sponsors and some are even at risk. We also note that compared to new build expectations in the 2016/2017 CDRs, wind and solar builds have averaged only about 50% and 60%, respectively. We think the renewables new build may also lag expectations.

Still, the very fact that the forward curve beyond 2021 is in backwardation implies that the market expects someone to build. We think it will take a brave sponsor to be the first one to take the plunge. We see renewables (mostly wind) backed by peaking gas capacity as the most likely build in ERCOT. Still, our view is that with significant base-load retirements, ERCOT will need new base-load generation and this will likely result in volatility in the market. We saw this earlier in October 2019 when the forward strip inched up for 2020 on American Electric Power unexpected announcement that it will shutter its 650 MW Oklaunion coal-fired unit in 2020.

ERCOT’s backwardated forward curves suggest that the market expects someone will step in and build. However, our conversations with incumbent players suggest no real enthusiasm for new builds. We believe that the difficulties experienced by Panda (Temple I) and Exelon (ExGen Texas) could have driven the market to a higher level of financial responsibility.

**Minimum offer pricing rule (MOPR) extension to existing assets should assist prices**

Thus far, PJM’s ability to provide competitive impetus to the markets has been reasonably successful. We think the battle for the IPP model has moved to nuclear generation. In the past two years, a number of nuclear units have received state regulatory relief in the form of ZECs. That has raised the possibility that these subsidized...
units could distort future capacity auction outcomes, if left unmitigated. We note that the substantially higher outcome of the 2018 auction suggests that the subsidized nuclear units did bid in their full costs (and therefore, a MOPR-style mitigation may not be necessary). However, industry participants believe, and the FERC agrees, that an extension of MOPR to existing subsidized generators is required to eliminate the possibility of influencing future auction outcomes.

To recall, MOPR screens apply to subsidized new gas-supply generation that is bidding into the auction. If the asset fails the MOPR screen, it cannot influence capacity price outcomes because the PJM restricts the asset from bidding significantly below the established net cost of new entry (CONE) price. Thus, a MOPR screen prevents a subsidized generator (subsidized through alternate payments by a state or an ISO) from placing a non-competitive bid and, in the process, distorting the outcome of the auction.

On June 29, 2018, the FERC rejected both PJM’s capacity repricing (two-stage) proposal and the Independent Market Monitor’s MOPR-Ex proposal, saying that neither was just and reasonable. It noted that rising state subsidies for renewable and nuclear power require PJM to revamp its MOPR to address price suppression in its capacity market. It directed PJM to expand MOPR to all new and existing capacity receiving out-of-market payments, such as renewable energy credits for renewable generators and zero-emission credits for nuclear plants. The FERC also recommended creating a mechanism similar to the fixed resource requirement, allowing states to pull subsidized resources--and associated loads--from the capacity auction.

In August 2018, PJM proposed a two-stage auction that it believes will minimize the price suppression impacts. The first step of this proposal will be to identify what will constitute an actionable subsidy that would result in the application of the MOPR. Then a resource specific carve-out will be an alternative to the MOPR. To set the price, the carved out resources would be removed while the demand curve would remain unchanged--i.e., the subsidized resources will be bid in at zero in the auction and then the carve-out of the resource would be accomplished through a settlement adjustment after the auction is completed. The PJM has requested an order from the FERC by January 2019 to implement rules for its 2019 RPM auction.

Regardless of the final form of the order, from a credit perspective, the FERC has now directed PJM to refine rules that effectively "mitigate" the impact of subsidized existing generation on capacity prices. We note that in all its earlier decisions (the Long-Term Capacity Agreement Pilot Program [LCAAP] in New Jersey, mitigation of Astoria Energy and Bayonne in New York, and its recent remand of the Mystic decision in New England), the FERC has tried to preserve the fundamental principles of supply and demand. We think an extension of MOPR to existing assets (including renewables) will buoy future capacity prices, all else being equal, because it will preclude any downward pressure on prices should any of the subsidized units choose to bid below costs. In effect, the extension will serve as buyer-side mitigation rules.
Industry developments

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

On Nov. 15, 2017, PJM issued a formal proposal for energy price formation. PJM’s proposal to the FERC allows 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 other 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.

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.

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 Department of Energy 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 170 TWh by 2035.

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 kilowatt-hour (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 the system are about $400-$500/kW for equipment like inverters/rectifiers, 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.

Environmental, social, and governance

While we evaluate environment, social, and governance (ESG) risks within different parts of our analytical framework at this stage, S&P Global Ratings does not provide a stand-alone ESG assessment. We expect that independent standards will be developed in the near term that will further assist investors. We expect that this independent framework will incorporate an assessment of the observable ESG risks and opportunities and an entity’s long-term preparedness or its capacity to anticipate and adapt to a variety of long-term plausible disruptions. Such disruptions would likely not be limited to environmental and social scenarios but could also include technology or political changes. Some of these factors may include climate change, carbon emissions, pollution, effectiveness in terms of maintaining employee and community relations, adherence to legal and regulatory requirements, management of human capital, safety, and changing consumer behaviors (i.e., distributed generation). A final ESG evaluation would likely incorporate all of these elements, providing an opinion of an entity’s relative exposure to observable ESG-related risks and opportunities and a qualitative opinion of the entity’s long-term preparedness for opportunities and disruption.

Given that IPPs are in the business of power generation, environmental factors dominate our ESG assessment, with governance and social seen as having a neutral or secondary credit impact to date. For companies that have larger coal-fired fleets, the carbon footprint is significant and weighs on their competitive position and constrains their business risk. Many companies are reconstituting their generation mix. For example, in late 2017, Vistra announced the closure of nearly 4.2 GW of its coal-fired capacity as well as a coal mine, which we viewed as favorable in our ESG review. This is somewhat offset by the social and cost impacts of future asset retirement obligations, which is reflected in our debt adjustment in the financial analysis.

De-carbonization in the power sector

Although the Trump Administration continues to dismantle the environmental decisions of its predecessor, we do not expect the de-carbonization of the U.S. power sector to slow materially during the next few years, for a variety of reasons. The U.S. was one of the few developed economies in 2017 to see its carbon emissions decline, by about 0.5%, as a result of flat secular load growth, milder weather, energy efficiency and fuel switching, including renewable generation.

State-level policies continue to provide incentives for the de-carbonization 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 (with PPAs in New England states) and battery storage. These enhanced standards coincide with improved economics for renewable generation, as well as relatively long-run runway for the solar investment tax credit, creating a renewable heavy and demand uncertain grid that requires more flexibility—weakening the long-term case for baseload generation such as coal and nuclear in wholesale markets.

As evidence of this, California recently signed into law a goal for 100% renewable energy by 2045. While we don’t anticipate that this will have significant credit impacts in the near term, it is likely to be a major disruption to the market. Currently, major IPPs continue to have stakes in California gas-fired assets, but over time these are likely to become less valuable, as the economics of these decline, while the economics of batteries continue to improve, fueled in part by a state level mandate. Most benefitted by the renewable mandate are hydro and geothermal assets in California; these help satisfy the renewable mandate while avoiding intermittency concerns that face solar and wind, and they’re likely to have improved access to cash-flow stabilizing PPAs in years to come.

Still, while we anticipate the de-carbonization 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 three state-level subsidies for nuclear that have sustained a number of assets (and discussions of at least one more), absent these, there could be a wave of closures that, if replaced by CCGTs, as we’d expect, would potentially reverse the trend of de-carbonization. However, by that time, depending on the administration, we could see another federal carbon reduction plan in place.

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 Independent Electricity System Operator (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 30% of Ontario's electricity, is with Bruce Power L.P. (BBB/Stable/---), a nuclear-fired generator. The contract provides price certainty to Bruce Power, 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 2020/21. We believe that this would increase the competition for the incumbent players in the long run. On the other hand, we expect that power price volatility will decrease and that would lessen the re-contracting risk for the IPPs once the remaining Alberta PPAs terminate in 2020. Alberta is one of the last provinces to address the emissions from electricity generation. Alberta has mandated the phasing out of all coal-fired plant (approximately 6,000 MW) emissions by 2030 and replacing two-thirds of the generation with renewables and one-third with gas plants. To achieve the renewable targets, the government has introduced a program.
to procure renewable projects under a fixed price contracts. Alberta has procured 600 MW of the renewable projects in 2007 and has invited bids for another 700 MW in 2018.

Chart 11

Canadian Fuel Mix

Both the IPPs we rate in Alberta have a significant proportion of generation from coal (see chart 11). 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 generation rates from renewables, with hydro being the dominant source, accounting for nearly 60% of total generation in 2017. 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.
Financial policy

Aggressive cost cutting and deleveraging

Free cash flow continues to be used for deleveraging as most IPPs see a backwardated EBITDA profile. Because of a long-term decline in wholesale power margins, most IPPs are now managing their capital structure to lower debt. We see investment-grade companies look to deleverage to around 2.0-2.5x and even the high yield companies look to bring debt levels to around 3.0-3.5x by year-end 2019 and to around 2.5x-3.0x by 2020. For instance, two major IPPs--Vistra Energy and NRG Energy--plan to manage their business to net debt to EBITDA levels of 2.5x-3.0x.

High Cash Flow Conversion

IPPs are using a meaningful proportion of their excess cash flow to retire debt and are able to do so because of the currently high cash flow conversion rates (i.e., EBITDA to free cash flow [FCF] is cash flow after capex and distributions) of almost 50%. We note that the relatively high FCF conversion ratio is primarily attributable to a couple of attributes. First, significant EBITDA comes from the retail power business, which requires very little capital investment (we expect this to be lower as competition intensifies). In addition, as these companies evolve their supply base from older coal-fueled plants to newer CCGTs, their FCF conversion rate has continued to increase. CCGTs are less capital intensive than coal plants and less expensive to maintain than, say, refinery assets, which tend to be older and more complicated than power assets and require more maintenance capital.

Terming out of bank debt into the term loan B market

In the project finance market we are observing two discernible trends--terming out of term loan As/bank loans into the term loan B market and progressively lighter covenants in inked loan documents. Because of fears that interests rates will increase further, we are witnessing high transaction activity, also because power markets have strengthened.

A number of transactions that we are currently seeing in the market are for assets that began commercial operations over the past two years and were originally financed in the bank loan/term loan A market. The bank market has historically borne construction risk better than capital and institutional markets. Many of these single assets have begun operations as power markets have turned for the better, allowing them to be refinanced into term loan Bs. The recent wave of refinancing mostly include assets that started operations in 2017. We expect similar refinancing into at least the first half of 2019.

As capacity and energy prices come off their troughs, lenders are becoming increasingly benign as it relates to financial covenant requirements in loan documents (e.g., incurrence tests and maintenance tests), which have continued to become lighter. We also see the market becoming more accommodating of structural revisions (e.g., allowed asset sales). This is in stark contrast to the financing environment a couple of years ago.

As the environment turned weaker for merchant power in the 2015-2017 timeframe, we saw limited appetite for single-asset financing and instead saw a move toward portfolio financing. Examples of these transactions include Helix generation Funding LLC, Lightstone HoldCo. LLC, Eastern Power LLC; and Compass Power Generation LLC. In 2018, we saw many of these portfolio amend and reprice their loans. Some projects sought waivers to sell assets from the portfolio. It appears that lenders are now more accepting of less-diverse portfolios, suggesting that they believe that power markets are strengthening. This change is also evident from the fact that a number of single assets have been recently financed in the term loan market, including Frontera Generation Holdings LLC, St Joseph Energy Center LLC, and Kestral Acquisition LLC (Hunterstown) etc.
Finally, sponsors have also amended and repriced transactions where they have sought waivers for increasing leverage. Some of these original transactions closed as recently as six months ago. A strengthening capacity market and strong summer pricing have been cited as reasons for the incremental debt capacity. With power markets on a rebound, it appears that the financing market is in a boom as a surplus of funds chases yields. We’ve seen such boom and bust cycles before—which we prefer to call cycles of hubris and contrition. We note that the pace of transaction activity is reminiscent of the environment we saw 11 years ago.

Related Research

- Capacity Market Update: Why S&P Global Ratings Views Energy-Only Markets As Higher Risk From A Credit Perspective, Aug. 7, 2018
- Next Generation: How California’s 100% Renewable Power Mandate Affects Markets, Oct. 22, 2018
- Capacity Market Assumptions Used For Power Project Financings, June 28, 2018

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