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# Independent Power Producers: The Long And Short Of It

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# Independent Power Producers: The Long And Short Of It

Golf, they say, consists of two altogether different games--the long driving game and the short putting game. A player must master both to succeed. As the power industry goes through the largest fuel-switch in its history, credit drivers in the short and long horizons (in our case, time, not distance) will influence the economic viability of independent power producers (IPP). This is because unlike utilities, which supply power under a rate-based compact with regulators, IPPs must recover the cost of generation from the markets, which are witnessing a disruptive technology-driven oversupply and slowing demand trend.

We have long argued that merchant power can be divided into two different markets. It's critical for merchant power generators to separate the cyclical, short-term fundamentals of the power markets from the structural, long-term factors. Weather-influenced demand and natural gas inventory levels largely dictate power prices in the short term, while secular demand trends, energy efficiency, growth of distributed generation/storage, and the cost structure of the highest-cost power producer propel structural power prices. In other words, the near-term prospects for IPPs are influenced by seasonal demand and supply trends, while renewable proliferation and supply--the marginal cost of natural gas production and delivery--will eventually dictate their long-term viability.

While short-term headwinds can turn favorable with one severe winter/summer, it is becoming increasingly evident that IPPs need to hunker down and adapt to factors driving long-term market fundamentals. In this industry update, we explore strategies that various IPPs have contemplated to protect against adverse market conditions and the relative success they are achieving.

**Overview**

- The commodity markets continue to remain challenged for IPPs.
- Companies have now pivoted to reducing debt, controlling costs, and focusing on contracted and/or nonrecourse financed generation.
- We believe deleveraging will continue to take center stage in 2017. We also expect refinancings that push maturity walls out into the future to continue.
- We expect cost-cutting initiatives to be undertaken by all companies, either brought about by activist shareholders or from management actions, which are driven by peer/stakeholder pressure.
- We now see asset-backed retail power operations as not only desirable but increasingly vital for the IPP model.
- As the wholesale business shrinks, we see retail operations as a great defense against renewables and storage.

## 'Til Debt Do Us Part

We think 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, higher capacity prices, or a disallowance of the zero emission credits (ZEC). We believe deleveraging will continue to take center stage in 2017. Also, we expect to see refinancings that push maturity walls out into the future to continue.

The idea of volatility in the natural gas 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. In other words, prices must mean revert to the marginal cost of natural gas production, which lately has been a moving target, drifting lower and lower.

Moreover, with power prices already low as a consequence of significant new gas supply, any effect on demand could upset an already tenuous equilibrium. We think the power industry is now not only exposed to shifting fuel economics, but also to the risk that renewable and storage proliferation, and technology improvements in energy efficiency, are better than earlier expectations. The specific risks are that technology-driven efficiencies could continue to nip at demand as disruptive technological advances result in asset substitutions and the economic life of conventional generation assets is diminished. For instance, one example that worsening power markets continue to erode and disrupt base load economics is the Bruce Mansfield I coal-fired unit, where FirstEnergy Solutions Corp. raised over a $1 billion in the form of a leveraged lease in 2007. This unit is unable to run economically in the current environment and its collateral value does not support the outstanding lease balance, in our view.

Despite the fact that merchant power is a "price taking" business (i.e. most generators control neither the prompt price of power nor the shape of the forward price curve), IPPs have historically shrugged away volatility over the next one to two years by hedging their expected generation in the forward physical or financial markets. Because we now expect natural gas prices to remain subdued in the longer-term, this is no longer a tenable strategy, in our opinion. Still, a ratable hedging strategy does provide insulation from near-term market forces. In a market that is seeing volatile swings, hedging future production potentially allows time to revise capital structures that are compatible with the evolving commodity dynamics.

In 2016, as balance-sheet risk remained a priority through the volatile cycle, many companies actively focused on paying down debt. Most companies still have positive free cash flow after maintenance capital spending, and capital-allocation plans included debt repayment. Some companies have sold noncore assets with divestments designed to deleverage the capital structure. Fortunately for IPPs, private equity companies continue to provide the source of incremental capital. We think the deviation between private and public valuations for power generation assets has emerged because a number of publicly listed companies are pivoting to their core markets and shedding noncore assets. Also, private equity players do not have to respond to volatility in quarterly earnings that publicly listed companies are sometimes held hostage to and can take a longer-term view on asset valuations.

While we saw the significant market appetite for refinancings by merchant power over the past three years as opportunistic, we see the current focusing by the industry on lowering debt not as a bondholder-friendly move but rather as a market economics-driven imperative. Given the increasing risk of reductions in the economic asset life of the fleet due to acceleration of renewable penetration or storage technology adoption, we think IPPs need to reset their leverage levels. We believe that IPPs will need to recalibrate their capital structure to an eventual 4.5x-5x adjusted debt to EBITDA; a level consistent with current expectations of the forward commodity curves. To be clear, we think this threshold is not a ratings target but one that would allow an IPP to withstand any potential future attenuation of EBITDA from disruptive technologies, the biggest of which is likely advancements in storage. We note that both Dynegy Inc. and Calpine Corp. have leverage levels that are currently north of 7x. NRG Energy Inc.'s adjusted debt to EBITDA is at about 5x but this calculation deconsolidates significant amount of debt that is financed on a nonrecourse basis. Only Vistra Energy Corp. is currently capitalized appropriately with leverage levels at about 3.5x but that is only because the company shed substantial legacy debt when it emerged from bankruptcy.

Almost all IPPs have engaged in some form of deleveraging. The AES Corp. retired an additional $300 million in 2016, taking its aggregate parent-level recourse debt down by over 25% to $4.8 billion from $6.5 billion since 2012, and has no maturities until 2019. Similarly, in September 2015, NRG Energy announced that it would dedicate 75% of its 2016 parent-level capital allocation to debt reduction. Over the course of the past 18 months the company has reduced its NRG-level recourse debt to $7.8 billion from about $8.9 billion. We expect debt levels to decline a further $500 million by year-end 2017.

While NRG Energy was ahead of its peers in initiating a deleveraging strategy, it needed to do so because it was responding to unsuccessful forays into certain businesses that had stretched its balance sheet. Recently, other IPPs have announced explicit efforts to reduce balance sheet debt since commodity risks for the sector remain into 2017. At its 2016 full year earnings call, Calpine Corp. announced a $2.7 billion accelerated debt pay-down program through 2019, which will reduce its debt-to-EBITDA leverage by about 1.5x and bring it down to levels of about 6x adjusted debt to EBITDA by 2018. According to the company, the plan is not contingent on proceeds from asset sales.

On the other hand, Dynegy Inc. grew substantially over the past four years as it gained scale and scope economies to reduce its exposure to coal-fired generation and to the Midwest Independent System Operator (MISO) region. However, it is now confronted with a $2.1 billion maturity in 2019 and has announced a plan to reduce debtto about 4.5x debt to EBITDA by that year. However, we believe free cash flow over the next two years will not be enough and we look for efforts for the company to sell assets to ensure de-leveraging targets are met. The company has recently announced the sale of two peakers to private equity firm, LS Power Equity Partners II L.P. Still, we believe it will need to sell assets in its core markets of New England and Pennsylvania-Jersey-Maryland to meet its leverage targets. Even if it achieves its targets, maintaining them may be tough if forward energy margins or capacity prices are not supportive.

Other IPPs may find it even more difficult to overcome market challenges. While FirstEnergy Corp. was able to monetize the assets at its Allegheny Energy Supply subsidiary (with a recently announced a sale to LS Power) given the low quantum of debt and marketable gas-fired assets, unregulated generation subsidiary FirstEnergy Solutions has substantial outstanding debt but base-load coal-fired and nuclear assets that are increasingly stranded in the current commodity environment. Based on the forward curve, we see the company to be free cash flow negative (cash flow from operations will be negative after capital spending is removed) by 2018. However, FES has two key upcoming decisions relating to a coal contract arbitration and potential zero emission credit support for its nuclear units that could affect its fortunes in 2017. Finally, GenOn Energy Inc. is faced with a large maturity in June 2017. While it has meaningful cash-on-hand, it is also faced with a similar refinancing in 2018 that could well serve as the last straw on the camel's back, resulting in a decision by the company to file for bankruptcy by June 2017.

## A Lean, Mean Fighting Machine

We expect cost-cutting initiatives to be undertaken by all companies, either brought about by activist shareholders or from management actions, which are driven by peer/stakeholder pressure.

It's a human condition that one becomes more focused only when confronted with imminence or adversity. To illustrate, how many days before an exam did you study?. It's similar with companies. Given the adverse market environment, IPPs are aggressively cutting costs and becoming more efficient. Some of these cost reductions are low hanging fruit. For instance, in a market that is oversupplied with generation, it is unlikely that many development efforts will be undertaken. Others can be more subtle, which while beneficial in the short term, i.e., that boost short-term earnings or cash flow, may be detrimental to the company in the long-term because they may impair growth or require significant investment in improvements.

Already, a number of companies have achieved significant cost-cutting run rates. In its annual call, AES Corp. reported achieving a run-rate of $250 million of cost savings during 2012-2016 and an extended program to achieve an incremental $150 million savings by 2020. Similarly, NRG Energy reported achieving about $540 million of cost reductions through 2016, while Dynegy reported a beneficial effect on its EBITDA of about $150 million from its PRIDE initiatives. In particular, Vistra Energy was able to add an incremental $1 billion to its August 2016 debt financing because its cost-cutting initiatives resulted in about $210 million of cost improvements, with nearly 950 positions closed since 2015 from exits and attrition in support functions.

The current round of cost reductions began when a private equity firm, Riverstone Holdings LLC , entered into a joint venture with PPL Energy Supply LLC to form Talen Energy Supply LLC and subsequently took it private. An interesting recent development was NRG Energy's agreement with Elliot Management Corp. and Bluescape Energy Partners. There are increasing expectations of potential cost cuts for NRG, with estimates of anywhere from $250 million to as high as $750 million in sales, general and administrative (SG&A) and operations and maintenance (O&M) cuts. Based on a top level comparison across IPPs, it would appear that Dynegy and Calpine do exhibit a lower cost structure than NRG. A rough estimate of O&M and SG&A costs suggest that Calpine's are about $37-$39 per kilowatt (KW) and $5-$5.20 per KW, respectively, while Dynegy's are about $34-$36 per KW and $5 per KW, respectively. With NRG, the cost comparison becomes a trifle difficult because of a corporate structure that is more spread out across several project and corporate subsidiaries. We believe maintaining separate organization structures to benefit from nonrecourse financings does result in higher O&M costs compared with peers that have leaner corporate structures. Similarly, maintaining five to six different retail power brands (Reliant, Green Mountain, Cirro, Pennywise, and Everything Energy), compared to Vistra's two brands (TXU Energy and 4Change) would also likely result in higher SG&A costs. We believe NRG's O&M costs are low at $40 per KW and SG&A costs are in the $12-$14 per kW range.

In our view, it matters less to credit quality what the actual O&M and SG&A costs are relative to peers, but depends more on how NRG's management frames this discussion. The facts are that there are activist shareholders (with seats on the board) who think that cost cuts are possible and the company's management needs to respond to that expectation. From a credit perspective, we note that company management has often obliged activist shareholders with cost cuts that have an immediate effect on cash flow. We think these initiatives result in a classic agency problem between management, which has a long-term view on business prospects, and the activist shareholders, who are looking for immediate gratification and are likely to exit their investment over a shorter time period.

Separately, yet related, we expect NRG's cost-cutting initiative to be subdued for now as it deals with GenOn's mid-2017 maturities. We expect that will keep management distracted with a potential restructuring at that company.

## Retail Businesses Have Gained Significance

We now see asset-backed retail power operations as not only desirable but increasingly vital for the IPP model. As the wholesale business shrinks, we see retail operations as a great defense against renewables and storage.

From a credit perspective, the profitability of the retail and wholesale businesses moves up and down in countercycles. Capital charges that typical retail businesses use--including the cost of working capital, credit facilities, contingent collateral, and equity costs required to cover risk capital requirements--increase roughly in proportion to commodity prices. With high power prices, capital charges are also high and cut into gross margins. Yet customers are less inclined to lock in prices at these levels. As a result, at elevated prices, we expect fixed-price sales to fall, reducing total capital requirements and lifting average margins on existing retail volumes. At low power prices, capital charges decline. Although customer migration ensues, gross margins for retail volumes rise due to increasing headroom between locked-in retail prices and wholesale prices. Thus, although the generation business' profitability declines when prices are low, the retail business' profitability improves, and vice versa (See "In The U.S. Merchant Power Space, A Stable Business Climate Has Become An Oddity," Feb. 2, 2016). We note that while no company requires its retail supply business to source its hedges from the company's wholesale business, they are sometimes incentivized to do so and we expect a natural evolution toward wholesale hedges greater than 50%, reducing the need for collateral support for the retail operations.

Most companies hedge their economic generation on a ratable basis two to three years ahead of time. Eventually though, they are exposed to volatile commodity prices when the hedges roll off. However, for merchant generators that have assets serving loads, an attendant retail power business generally provides an additional avenue to hedge wholesale market operations. As a result, we are now seeing IPPs and diversified power companies expanding retail offerings in an effort to provide complementary revenue streams to their otherwise volatile businesses.

We see an asset-backed retail business as core to a wholesale generation platform, which typically insulates market risk for two years (the average length of a retail contract). Merchant generators have increasingly mitigated the impact of declining wholesale prices by expanding their customer facing retail business. For example, in October 2015, NRG increased the EBITDA guidance for its retail business to $750 million from $605 million at the start of that year. The counter-cyclicality of NRG's retail business relative to its wholesale business is no coincidence and is just an economic result of falling wholesale power prices. Similarly, we note that other major IPPs are also expanding, or entering, retail businesses. In 2016, Calpine entered into a retail venture with Champion Energy Corp. While we believe this is a strategically sound decision given reduced liquidity in power markets, the ability of Calpine's commercial team to match its wholesale generation with retail load will determine its success. In 2017, Calpine bought the commercial and industrial (C&I) operations from Noble Energy Inc. and has housed them under Calpine Energy Solutions (CES). The company expects to run the three customer channels (direct large C&I, indirect small C&I, and residential mass markets) through two platforms (Champion and CES). The company estimates an average uplift in margins of about $5.85 per megawatt hour (MWh) and expects almost $225 million-$235 million in margins from this segment in 2017. Another example of retail becoming an important component of overall strategy is PSEG Power's decision to enter the C&I segment. After what appears to be some hesitation, the company eventually dove into retail power markets to offset the loss of its basic generation service (BGS) power auction volumes, which have declined to 11 GWH in 2016 from 20 GWH 5 years ago.

Investor appetite for these retail power offsets appears to be high, with companies still seeking to expand margins with further acquisitions. We believe that in a shrinking wholesale power market environment, the only significant way that IPPs will grow is from expanding their retail businesses. We underscore that the business provides a great defense against renewable penetration. As another example, we highlight that Dynegy has entered the retail business with Homefield Energy LLC. It is the company's drive on retail aggregation in the MISO that has been supporting a significant amount of its fleet in that region. The company had developed a modest 17 terawatt hour (TWh) C&I portfolio by year-end 2016 and is leveraging its Illinois experience to expand its muni-aggregation model in new communities in Ohio. Given its experience in C&I, we expect the company to consider expanding its retail strategy the way Calpine and Exelon Corp. (former Constellation Energy Group Inc. business) rather than the approach taken by NRG Energy or Vistra in the residential retail markets.

Still, we think the retail power business will see more competition. While large incumbent players have pointed at their past performance in dismissing any suggestions that market shares will come under threat, we believe that since retail is one of the few avenues left for growth, it will experience increasing interest. We also think residential margins are at such levels that they can witness underpricing attacks. For example, we estimate that the major brands achieved retail residential margins between $30 and $40 per MWh in Electric Reliability Council of Texas (ERCOT) last year. In comparison, midtier players made about $15-$25 per MWh and flanker/attacker brands made between $5 and $20 per MWh. Stated differently, major brands have prices that are about 50% higher than the average "Power To Choose" price in ERCOT. Since we are economics purists, we subscribe to the theory that long-term abnormal returns eventually ebb away and think there will be significantly higher competition in the retail space in the next two years.

We note that retail power companies do not provide only net attrition levels (i.e. gross attrition offset by customer gains). For the major players this is between negative 1.5% and positive 1%. However, as per ERCOT's retail transaction reports (source: http://www.ercot.com/mktinfo/retail), the competitive ERCOT residential market experiences a switch of about 700,000 and move-out transactions of about 2.3 million annually for a total of about 3 million transactions on a base of about 6 million residential customer meters. This implies a 50% switch/move-out rate for ERCOT (including transfers of service, i.e., a customer moving from premise A to premise B with the same residential energy provider). In other words, about half of ERCOT's residential customers complete a switch/move-out transaction each year. While we expect relatively higher customer stickiness (customers remaining with the same provider) for the larger players, we still estimate that the switch out rate is about 20%-23%. We will present more credit views on this topic in an upcoming article on retail power markets.

## Of ZECs And ZENs

More ominously, the IPP sector appears to have lost its long-term investor group (pension funds and long buy-side funds)and this has happened for reasons not limited to the volatility in commodities.

We opine on credit quality and do not take public policy views. However, we remain disinterested, but not uninterested, observers because credit quality can be influenced if approved subsidies affect the fortune of large capital investments made on legacy assets.

Deregulation works best, in our opinion, when competitive markets are left to decide the lowest-cost reliable provider. Lately, winners and losers have been chosen for a variety of reasons such as fuel diversity, clean generation, impact on local economies, and reliability issues, etc. An example of this are the nuclear subsidies recently approved in New York and Illinois, through the states' Clean Energy Standard (CES) and Future Energy Jobs Bill, respectively. IPPs have been on the losing side of these outcomes because many of their assets have been left stranded when beleaguered nuclear assets were granted a new lease on life in an environment that had become increasingly challenging. We note that Dynegy was at the losing end when Clinton and Quad Cities were awarded Zero Emission Credits (ZEC) subsidies.

Fuel diversity and a clean environment are two of several important reasons to support nuclear generation. However, from a credit perspective, we feel that a uniform federal standard, either through a cap and trade mechanism or a carbon tax, could work better than individual states working out subsidies through nonbypassable rates imposed on ratepayers (we note that a cap or trade, or tax, imposes costs on the generator or its shareholders). Decisions at the state level could also be influenced by the impact on local economies should the generation unit shutter. We cannot help but note the fact that the nuclear units subsidized today were earning abnormal returns from 2006-2011. The benefits of those cash flows accrued to the shareholders and not the ratepayers.

On a separate yet related note, beyond just the immediate market economics of many nuclear plants, there is also a growing focus on funding incremental capital expenditures for many plants (i.e. many nuclear assets are still cash flow positive but questions abound on how to fund their future capital expenditure obligations). With almost 20 GW of new gas-fired generation waiting in the wings (in addition to the roughly 15 GW being constructed) there is a growing focus on how regulatory decisions on nuclear generation support could affect the fortunes of this new generation, which is premised on the exit of not only coal-fired assets but likely some nuclear retirements.

This is now a point of attention for nuclear plants in New Jersey because PSEG Power LLC recently announced that it would likely look for support similar to that provided by Illinois and New York for its Hope Creek and Salem units since they are no longer earning their cost of capital. Discussions also emerged during the FirstEnergy earnings call that a Zero Emission Nuclear (ZEN) program in Ohio may be gaining traction as a possibility for new state legislation. This would mirror the ZECs in New York and Illinois. An approval of the ZEN program will not remedy all economic issues at FirstEnergy Solutions, but it would likely improve the likelihood of a potential sale of the assets.

We see nuclear support as a theme, the question is simply one of timing. We await upcoming regulatory decisions in Connecticut, which should set the tone for developments in New Jersey, Ohio, and Pennsylvania.

## Contracted Generation To The Rescue, But How Much Is Possible?

We see the future of the IPP sector as drawn along a spectrum of risk between lower-risk contracted solar and wind assets on the one end and legacy merchant baseload coal and nuclear assets on the other. What remains to be seen is where each company aligns itself. In the current environment, there is also a bid-ask chasm between what buyers of long-term power are willing to pay, and what sellers of power are willing to potentially leave on the table to contract long-term.

IPPs are also focusing on increasing the contracted proportion of their aggregate cash flow. Many companies are pivoting to a contracted strategy, with NRG likely continuing to articulate a growth strategy all the more predicated on its YieldCo. strategy, while AES is likely to shift its strategic growth focus toward renewables. Already, both companies have made their intentions clear by opportunistically acquiring some portfolios (the SunEdison Inc. portfolio and sPower, respectively).

We highlight that NRG has less debt (on a NRG parent recourse debt basis) than Calpine or Dynegy and also has a relatively more stable EBITDA given its large retail business and renewable portfolio (the NRG YieldCo distributions). We estimate that nearly 45% of NRG's (formerly YieldCo. and GenOn) 2017 gross margins are capacity or contracted margins. While 95% of Calpine's free cash flow from its California operations are from its geysers and contracted gas assets operations, its overall contracted position is lower than NRG's but it has lower exposure to older fossil fuel assets in its wholesale business. Also, while Dynegy's fundamental value reflects long-term views on power, gas, and capacity prices, its stock price's movements are more pronounced than peers because of a higher exposure to power and gas prices that are weak with no positive near-term catalyst.

While companies are seeking to extend power contracts, there is a distinct focus on contract erosion risk. For example, in September 2014, Atlantic Power Corp. cited a reevaluation of its medium-term plan, including debt maturities and recontracting risk from 2017 to change its distribution payout policy and cut it dividends by 70%. As part of its commercial optimization efforts, Atlantic sought extensions of its existing power purchase agreements at several of its projects before their expiration dates in 2018 and later. We note that there are recontracting risks in California for Calpine's three major asset: Los Esteros and Russell City (both 2023 expiration) and Otay Mesa (2020); however, we believe debt amortization is aligned with the power purchase agreements such that their backwardation in cash flow should be manageable.

Finally, we also expect IPPs to fund large power assets through project financings that are nonrecourse to the parent with distributions upstreamed to the IPP. This form of financing allows the IPP to partake in contracted generation, and also have the flexibility to either monetize the project or drop the asset into a YieldCo. For instance, we expect NRG to fund its Carlsbad and Mandalay new build plants as project financings.

## The Long And Short Of It

In the sports drama movie "The Legend of Bagger Vance", a golfer, Rannulph Junuh, is approached by a stranger, who identifies himself as Bagger Vance and says he will be Junuh's caddy. Bagger helps Junuh come to grips with his demons by helping him focus on both his short and long game, and regain his authentic swing. (As a trivia sidebar, the plot of the movie is loosely based on the Hindu sacred text, the Bhagavad Gita, where the Warrior Arjuna (R Junuh) refuses to fight. Lord Krishna appears to him as God, or Bhagavan (Bagger Vance), to help him focus on the path that he was meant to pursue.)

IPPs are meeting their own Bagger, either in the form of board oversight, activist shareholders, private equity buyers, or the discipline enforced by competitive markets. We believe that this internally initiated, or externally enforced, insight/discipline will likely result in higher hedging levels, potential extension of legacy contracts (albeit at lower prices), and leaner cost structures that help these companies combat the shorter-term vicissitudes of commodity markets. However, there is only so much a company can do against longer-term trends. Their long game is increasingly influenced by several external factors, the most notable of which are storage and energy efficiency. These trends will likely require a recalibration of capital structures.

The winds have picked up, the sun is beating down, and the technological disruption terrain just became more undulating. Making the cut is getting tough for sure.

## Related Criteria And Research

### Related Research

- Merchant Power Update: Something's Gotta Give, March 21, 2017
- Low-Voltage Prices Are Dimming The Future At ERCOT, March 13, 2017
- Power Market Update: Demand Forecast And The Demand Curve Reset Process Dominate Capacity Price Outlook For New York City, Feb. 1, 2017
- In The U.S. Merchant Power Space, A Stable Business Climate Has Become An Oddity, Feb. 2, 2016