VENOR
CAPITAL MANAGEMENT

Power Play: The Calm before the Storm

October 2012*

I. Introduction

Over the course of the next three to four years we believe there is an unprecedented opportunity to invest in the merchant power industry. This opportunity is a direct consequence of both the proliferation of U.S. land based shale drilling for natural gas and a handful of key environmental regulations proposed by the Environmental Protection Agency (EPA) to address emissions control. Shale based drilling has become an increasingly important source of natural gas in the U.S. over the past decade, increasing from only 1% of production in 2000 to over 20% by 2010.[1] This paradigm shift, coupled with recent macroeconomic pressures, caused a precipitous decline across the entire natural gas commodity complex, which resulted in uncertainty and dislocation across the power industry. The resulting downward pressure has made it difficult for incumbent and dirty assets to earn a substantial profit, let alone recapture their cost of capital. Adding fuel to this dynamic and complicating economic decisions of industry executives are the EPA rules at the forefront of industry debate, most notably the Mercury and Air Toxics Standards (MATS) and the New Source Performance Standards (NSPS), both of which will change the landscape of electricity generation forever. Not only will these rules require incumbent generators to deploy billions of capital dollars for compliance, they will likely prevent a new coal or nuclear fired generation plant from being built in the U.S. ever again.

The implementation of these key EPA regulations is a game changer. Not only will they establish a new baseline for emissions control standards to protect our environment, they also have forced all owners of generation assets to make a decision regarding environmental controls well ahead of the compliance period. Scrubbing technologies can cost upwards of $600 per kilowatt, require long project and permitting lead times, and entail extensive coordination among the providers of capital, stakeholders, engineering and construction firms and key regulatory bodies. In addition to generation assets, the antiquated infrastructure and national grid system requires a significant upgrade. Estimates from *The Brattle Group* suggest that over $1 trillion of investment in the electricity system will be required to upgrade the transmission, distribution, advanced metering infrastructure and energy efficiency tools needed.[2] All of these forces suggest that the time to deploy capital in this space is now – in anticipation of the resulting supply and demand tightening as electricity markets approach equilibrium. Waiting for this watershed event will prove unprofitable for complacent investors.

According to a study conducted by Standard & Poor's, there exists over $350 billion in investment and speculative grade credit related to the merchant power industry that will mature in the next four years.[3] While on a standalone basis these maturities provide the foundation for a significant "wall of worry," there are also interest rate swaps, power purchase agreements, capacity revenue streams, and power and commodity hedges that serve as catalysts for a massive restructuring wave. This investable theme is most relevant for opportunities within single asset structures or small portfolios in the middle market. They often have simple capital structures which are small, illiquid and off the traditional institutional investor radar screen. It is likely that this theme will not be highly recognized within the broader investment community until Energy Future Holdings (the largest leveraged buyout in history) files for Chapter 11 bankruptcy protection, at which time investors may begin to focus on the broader electricity generation industry. By then the opportunity may have dissipated. Shortly after compliance with these critical EPA regulations

*See IMPORTANT DISCLOSURES at the end of this document.
[1] The Shale Gas Revolution: Developments and Changes (August 2012).
[2] *The Brattle Group,* Transforming America's Power Industry: The Investment Challenge 2010-2030 (November 2008).
[3] Standard & Poor's, U.S. Refinancing Study: Rising Maturities Could Increase Refinancing Risk (July 2011).

takes effect and natural gas prices (and correspondent power prices) have normalized, we expect a sharp increase in valuations.

The sweet spot of this investable theme is the senior debt portion of the merchant power companies' capital structure, which should offer the best risk adjusted returns. Senior debt, such as loans and corporate bonds, provide investors with a "margin of safety" and significant downside protection due to the underlying "brick and stick" value of the companies' collateral. Debt also provides investors with protection from the volatility of the equity markets and typically contains affirmative and negative covenants that protect investors from equity friendly corporate action. Under the worst case scenario, creditors have a priority right of payment and often represent the fulcrum security within the capital structure. In the event of a capital restructuring, creditors also have the ability to manage process risk and are responsible for steering stakeholders through the restructuring, often gaining control and all of the equity upside upon emergence. In addition to the senior debt portion of the capital stack, there will be a significant number of post reorganized equity investments with the possibility of making multiples on invested capital in an upside case.

Restructuring the capital structure and operations of a merchant power generator is highly complex. These structures often involve: (i) multiple stakeholders, (ii) complex credit facilities both on and off balance sheet, (iii) opaque regulatory bodies, (iv) engineering and structural challenges, and (v) esoteric financial contracts such as legacy power purchase agreements, hedges and capacity revenue streams. Being entrenched with all of the key operators, restructuring advisors, legal counsel, regulatory counsel and regulatory agencies is paramount to keeping one's finger on the pulse of the industry and remaining informed about key developments and the flow of information for new and existing investments. This paper will walk through a brief history and background of the merchant power industry, basic building blocks of the industry, core supply and demand drivers, the regulatory landscape, and the key value drivers for investment.

II. Electricity Industry

A. Short History

In its infancy, the electricity industry consisted of firms that were state regulated, vertically integrated monopolies. One firm generated, transmitted, and distributed electricity and was subject to regulation by a state regulatory commission. Under state regulation, economics governed the design and operation of electric generation facilities. For example, the cost of generating power decreased with plant size, and the cost of producing steam from coal was cheaper than producing it from oil or natural gas. As a result, large coal fired plants generated base load power used all the time. Smaller (and older) coal, oil, and natural gas fired units were used to generate peak load during the day and summer when use exceeded base load levels. Four important factors changed this division of base load and peak load responsibilities: (i) the development of the national electric grid; (ii) the construction of nuclear power plants; (iii) high fossil fuel prices during the energy crisis; and (iv) the development of gas turbine technology.

The development of the interconnected nationwide electricity grid, which was historically inhibited by federal regulations for years, made it technologically possible to develop an interstate market for electricity. In competitive markets, the price differential for identical commodities in two places cannot exceed the costs of transporting the commodities between the two places. Analogously, the price differential for electricity in different areas of the country cannot exceed the cost of electric transmission between those areas. Until the development of long distance transmission, however, the price of electricity could differ greatly between regions because the cost of transportation was infinite. The development of the national grid created the possibility of reducing the price differences for electricity.

Since then, the electric utility industry has undergone a massive operational and financial transformation. After the successful transition to competition of the natural gas interstate pipeline industry, regulators and politicians in a number of high cost states started to implement deregulation plans for the electric utility industry. Naturally, states with low power cost structures were not as interested in pursuing deregulation. Furthermore, states have primary jurisdiction over electric utilities and state priorities do not always match federal mandates for competitive markets. Subsequent to deregulation, newly adopted regulations drove improved reserve margins and power market conditions. However, the Great Recession drove looser supply and demand paired with decreasing power prices and market conditions. We are currently on the precipice of the next, and perhaps the most transformational phase for the industry. We anticipate that supply and demand conditions will once again improve dramatically for generators as upwards of 100 gigawatts of plant retirements drive meaningfully tighter power markets and increased valuations in connection with the implementation of these key EPA regulations.

B. Mega What?

Merchant generation is at the foundation of the supply chain and is typically the costliest component of power prices, as it commands the most capital investment. The size or capacity of a power plant is expressed in some denomination of watts as follows:

1,000 watts = 1 kilowatt (kW)
1,000 kW = 1 megawatt (MW)
1,000 MW = 1 gigawatt (GW)
1,000 GW = 1 terawatt (TW)

Most operators and investors express the capacity of a plant in megawatts, although gigawatts are sometimes used for large projects (nuclear or hydroelectric projects) and kilowatts are often used for very small projects (solar or wind projects).

According to SNL Energy, there are 7,896 power plants in the U.S (Exhibit A) with over 1 million MW of installed capacity (Exhibit B). Of the total, 1,837 are natural gas fired plants representing over 443,000 MW of capacity. Coal fired plants represent 563 plants and over 313,000 MW of installed capacity and there are 63 nuclear power plants in the U.S. which represent roughly 100,000 MW of installed capacity. The balance of the domestic power supply comes from oil fired generation, geothermal geysers, hydro electric power and renewable resources such as solar, wind, biomass and others.

Exhibit A
U.S. Power Plants by Fuel Source

	Gas	Coal	Nuclear	Other	Total
CAISO	246	9	2	825	1,082
ERCOT	143	20	2	137	302
ISO-NE	85	9	4	509	607
MISO	224	169	9	940	1,342
NYISO	94	9	5	308	416
PJM	232	133	20	631	1,016
SPP	214	53	2	241	510
Other	599	161	19	1,842	2,621
Total	1,837	563	63	5,433	7,896

Source: SNL Energy.

Exhibit B
U.S. Megawatts by Fuel Source

	Gas	Coal	Nuclear	Other	Total
CAISO	35,631	3,514	6,182	20,640	65,966
ERCOT	56,834	19,363	5,008	11,242	92,447
ISO-NE	15,913	2,514	4,677	13,829	36,932
MISO	40,636	69,877	8,359	21,999	140,871
NYISO	21,160	2,255	5,460	14,293	43,167
PJM	58,031	75,284	36,465	30,929	200,709
SPP	34,288	31,844	1,977	10,751	78,861
Other	181,186	108,785	31,990	100,154	422,115
Total	443,678	313,436	100,117	223,837	1,081,068

Source: SNL Energy.

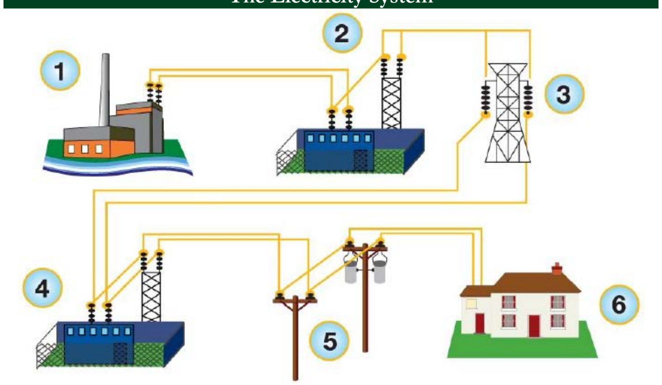
Capacity is not the whole story. We do not consume capacity, we consume volumes. Electricity volumes are expressed in capacity per hour, with the two most common units being megawatt hours (MWh) and kilowatt hours (kWh). A 100-watt light bulb, commonly found in most U.S. homes, would use one kWh of electricity to light up a room for ten hours. According to the U.S. Department of Energy (DOE), the average U.S. household uses 11.2 MWh (equal to 11,202 kWh) of electricity every year.

Capacity factors measure how often a power plant runs. Take for example two 500 MW coal plants. While they are identical, Plant A is in Pennsylvania, while Plant B is in Texas. Plant A has a capacity factor of 40% while Plant B has a capacity factor of 70%. In this example, Plant A will produce 1,752 GWh while Plant B's output will be 3,066 GWh. We obtain these volumes by multiplying the capacity (500 MW) by the number of days in a year (365), the number of hours in a day (24), and the respective capacity factor (40% or 70%). Finally, we divide the result by 1,000 to reach our volume in GWh. Conversely, for a given capacity and volume, we can determine a plant's capacity factor.

The last two key concepts are heat rate and spread. The heat rate of a power plant is also known as its efficiency ratio. It is the amount of British thermal units (Btu), a measure of energy; it takes to produce one kWh. A 7,000 heat rate plant is more efficient than a 12,000 heat rate plant, as it only takes 7,000 Btu to produce one kWh for the first plant, whereas it takes 12,000 Btu for the second plant to produce the same output. The spread is essentially the gross margin of a plant. Assume that the marginal price of power in Texas is $50 per MWh. A 7,000 heat rate natural gas plant producing power at $35 per MWh will book a $15 per MWh spread.

Exhibit C traces the path of electricity from generation at the power plant to the end-user. An integrated or regulated utility owns each link of the chain. In some states, deregulation has separated the generation business and, to a lesser extent, the retail business from the chain. Transmission and distribution (the wires to which substations belong) have remained regulated, as the advantages of a monopoly structure outweigh any benefit that competition could add.

Exhibit C
The Electricity System



Source: Edison Electric Institute.

Exhibit D
NERC Regional Map

Source: North American Electric Reliability Corporation.

The North American Electric Reliability Corporation (NERC) works with eight regional entities (Exhibit D) to improve the reliability of the bulk power system in the U.S. The members of the regional entities come from all segments of the electric industry including investor owned utilities, federal power agencies, rural electric cooperatives, state, municipal and provincial utilities, independent power producers, power markets, and end use customers. These entities account for virtually all of the electricity supplied in the U.S. and Canada.

C. Daily Power Cycle

Demand for overall electricity in the U.S. is closely correlated with GDP growth. The exact correlation varies and is dependent upon the level of industrialization in the U.S. economy as a whole. Power demand falls into three categories: (i) base load; (ii) intermediate load; and (iii) peak load. Early in the morning, at approximately 4:00 AM, seems to be the low point in power usage. Most residential electricity customers are sleeping, although some of their appliances like refrigerators and air conditioners may remain running. Factories who are engaged in around the clock shifts are also consuming electricity. Power that is used on a permanent basis, or base load, is constantly running throughout the day. As we approach 5:00 AM or 6:00 AM, people wake up and prepare for work. The public transportation system runs more electric trains to accommodate the movement of rush hour. By noon, the power activity picks up before hitting a lull until rush hour picks up again. Most of the variability during the day is intermediate load. Finally, the working population gets home and begins to cook dinner (using largely electric appliances) while watching television, causing an abrupt surge in electricity demand. This leads to a peak in demand by approximately 8:00 PM.

Base load demand This kind of demand is the bottom rung of the electric dispatch curve, as it embodies the "base" or threshold level of consumer demand. Base load generation typically represents approximately 60% of generation volume. In the U.S., coal and nuclear fired capacity are the primary fuel sources for base load generation because of their low variable costs and the static nature of demand. The higher fixed costs can also be easily distributed given the particular demand profile.

Intermediate load demand Plants that serve the intermediate load (also known as "mid-merit") are load following plants – output is adjusted during the day in line with demand. As the load increases, the most efficient plants are brought online first. The intermediate load typically accounts for 30% of generation volume. One type of plant that is used for intermediate load demand is a combined cycle gas turbine. Although, when natural gas prices are low enough, they can also act as base load plants. Intermediate load plants typically feature moderate fixed and variable costs and some operational flexibility.

Peak load demand As indicated by its name, this demand rests at the top of the demand spectrum and represents approximately 10% of generation volume. Demand at this level is reached occasionally during a "peak" in customer usage. Extreme demands on the system, such as extreme temperatures, could cause generators to dispatch peak as a last resort. Unexpected demand can also prompt peaking plants to be dispatched even if some intermediate plants are available, as speed to market becomes critical. Internal combustion and simple cycle gas turbine plants are often used to meet this level of demand because their low fixed costs and short lead times allow for maximum operational flexibility. However, peaking plants generally suffer from high variable fuel cost and lack of durability.

D. Fuel Supply

No individual fuel source is capable of meeting all of the nation's electricity demands. Maintaining the diversity of available fuel resources helps to ensure that we do not become too dependent on one fuel source. Fuel diversity also protects consumers from contingencies such as fuel availability, price fluctuations and changes in regulatory practice. Fuel prices greatly affect the price of electricity. Fuel choices allow environmental impacts to be balanced and still assure reliable, cost effective power supply to consumers. Any fuel source for generating electricity involves some environmental impact. Environmental effects can be air emissions, water quality impacts, fish and wildlife impacts, waste disposal concerns and aesthetics. Environmental impacts are significantly less than they were a decade ago and will continue to improve provided the EPA and other regulatory bodies remain keenly focused on improving emissions control and repowering our existing generation fleet. Three types of fuel sources are discussed below.

Coal Almost half of the U.S. electricity is produced using coal as the primary fuel source given its large domestic supply and low variable cost. Although the installed capacity of natural gas fired generation is greater, coal plants typically run more often than natural gas plants due to coal's low variable cost. However, coal fired plants have many drawbacks. For example, coal plants are very expensive to build (new build economics of roughly $2,500 per kW), have long build cycles and some of the highest pollutant emission rates. However, there have been significant improvements in pre- and post-combustion emission reduction technology. Developing clean coal technologies, including carbon capture and storage technologies, resolving coal delivery problems and maintaining coal's ability to compete on costs are key drivers to future use of coal. There are varying types of coal – Appalachian (Northern, Central), Interior and Western (Powder River Basin) – each with different applications, economics, and qualities, including emission compositions.

Nuclear Nuclear fuel is another fuel source with low variable cost. However, nuclear power plants have the highest fixed costs (new build economics of roughly $4,000 per kW) and long lead times with construction cycles of over ten years. Although their pollutant emission is minimal and nuclear is the cleanest form of energy outside of renewable energy, nuclear waste is a dangerous byproduct if improperly handled. Options for safe and long term storage for nuclear waste in the U.S. remain unclear. The public's fear of nuclear power plants stems largely from the infamous Three Mile Island scare and the more recent events at the Fukushima Daiichi plant in Japan. Existing nuclear power plant performance continues to improve, yet the high new build construction costs and used fuel disposal are two of the major hurdles to building new plants.

Natural Gas Approximately 40% of the installed power generation capacity in the U.S. utilizes natural gas as a fuel source. Although natural gas does not possess a uniform composition, the method of power generation is uniform. In other words, whether the power plant is configured as a simple cycle (SCGT) or combined cycle (CCGT) gas turbine, natural gas is the primary fuel source for each. SCGT plants have low fixed costs (roughly $500 per kW), shorter lead times, and quicker construction cycles of approximately six to nine months. The flexibility of a SCGT comes at a cost, however, as these plants are highly inefficient and have brief run time life cycles and high variable costs. By comparison, CCGT plants have lower fixed costs (roughly $1,000 per kW) and are more efficient with lower variable costs and pollutant emission levels.

E. Independent Power Producers

Independent power producers (IPPs) operate a fleet of primarily U.S. power plants. An IPP generates revenue from two major sources: (i) energy sales and (ii) capacity payments. In its simplest form, the two factors that drive power pricing are natural gas and heat rates. As natural gas prices increase, so typically do power prices, given that natural gas fired power plants often set the marginal price of power. The marginal heat rate (measured in Btu per kWh) represents the "multiplier" applied to natural gas prices (measured in $ per MMBtu) to arrive at a power price (measured in $ per MWh) for a given region. The marginal heat rate will expand in tight supply and demand conditions (*e.g.*, hot summer days, if a market lacks sufficient generation) but contract in loose supply and demand conditions (*e.g.*, colder months, if oversupply exists in a market).

Power plants that operate in certain competitive power markets (*e.g.*, PJM, New England, New York) receive a payment simply for committing to deliver if called upon in the future. These capacity payments help to ensure adequate generation exists to meet peak demand. In many regions, Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), created price caps on electricity spot pricing in order to reduce political risk from competitive markets. These caps, together with regulatory needs to ensure adequate generation supply (where MW supply equals demand, plus a reserve margin around 15%) in future years, drove the development of formal capacity markets. New England and PJM, which serves the Mid-Atlantic and parts of the Midwest, operate the only formal forward capacity markets, and in both markets, auctions are held to "procure" supply three years in the future in order to meet reliability requirements. New York maintains a capacity market, but it is short term only and not forward looking.

Capacity payments are determined via auctions, with pricing typically a function of supply and demand. Thus, the higher the projected oversupply, typically the lower the capacity prices in an auction. In PJM, the largest capacity market in the U.S., these auctions take place in May for payments realized three years in the future. As more coal plants retire we would expect to see continued increases in PJM capacity prices in future auctions. Retirements will likely require additional price signals to add generation when market conditions become tight. We would anticipate other markets (most notably ERCOT) to adopt a capacity market structure in order to support efficient operations and resource adequacy.

III. Drivers of Change

A. Natural Gas

Rising production and storage volumes of natural gas and the correspondent depressed natural gas prices, have been driven by the significant shift towards land based shale drilling. Increased deliverability of gas from associated oil wells and low cost shale could influence a relatively tight trading range for gas prices over the next three to four years, maintaining North America's relative cost advantage. Barring any surprises from weather or rig efficiency, it is unlikely that gas prices will break out of this narrow channel until we see a supply response from the industry, further developments for liquefied natural gas (LNG) exports or the continued announcement of plant retirements in connection with the EPA regulatory overhaul. The U.S. gas market is currently oversupplied, which must be addressed through either lower prices and demand stimulation or shutting in production. Analysis of the power markets, as well as coal and gas economics, suggest that at prices below $3.00 per MMBtu, incremental gas power demand (coming at the expense of coal) could help alleviate some of the technical supply and demand imbalance. There is a high degree of uncertainty as we approach the key shoulder period in which there is a risk that we breach maximum potential storage levels.

Our analysis of the power market suggests that coal to gas switching economics should create a floor for natural gas prices, limiting the need for shutting in production. Eastern coal, in particular, remains extremely vulnerable to the $3.00 per MMBtu gas threshold with significant gas generation capacity remaining (in particular in PJM). Furthermore, gas prices below the $2.50 per MMBtu level on a sustained basis would bring an even greater amount of switching across the Eastern and Western power grids, a volume far greater than what we believe is needed to balance the market. PRB coal starts to become vulnerable below $2.50 per MMBtu, which should also put a floor under gas prices. Not only would we begin to see even greater demand for gas from natural gas fired generation in the Mid Atlantic and Southeast, but generation will also become competitive against PRB fired coal plants in Texas, the Midwest and the West. As PRB coal moves out of the money, the incremental power demand would quickly balance even a significantly oversupplied gas market. Because cash costs for gas production are generally below $2.00 per MMBtu, large scale production shut-ins should not be required to balance the market. The ultimate recovery in natural gas and the bullish signal for merchant power remains at risk to some of the market's key drivers including production, demand, peak weather patterns, and coal to gas switching. Higher gas prices, an improving picture for the U.S. gas rig count, and increased shale transportation needs are all positive signals for the merchant power industry going forward.

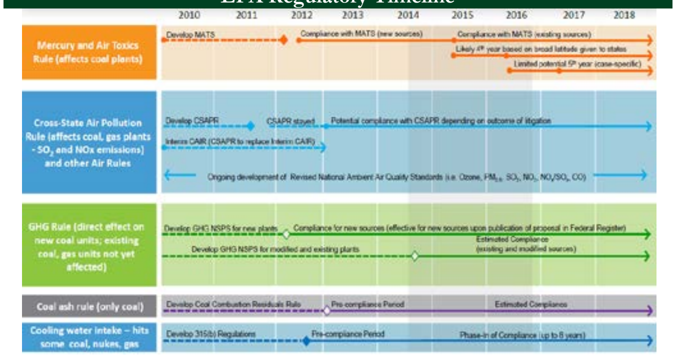
B. EPA Regulatory Framework

On December 16, 2011 the EPA finalized the first ever national standards to reduce mercury and other toxic air pollution from coal and oil fired power plants. More than 20 years after the 1990 Clean Air Act Amendments, some power plants still do not control emissions of toxic pollutants, even though pollution control technology is widely available. There are approximately 1,400 coal and oil fired units at 600 power plants covered by these standards. Power plants are currently the dominant emitters of mercury (roughly 50 percent), acid gases (over 75 percent) and many toxic metals in the U.S. We expect two key emerging environmental rules to address these issues and serve as the catalyst for tightening supply and demand conditions for electricity economics: (i) Mercury and Air Toxics Standards (MATS), the rule for mercury and acid gas emissions; and (ii) the New Source Performance Standards (NSPS), the rule that governs all new power generation. MATS finalized standards to reduce air pollution for existing resources that are at least as stringent as the emission reductions achieved by the average of the top 12 percent best controlled sources. NSPS marks the EPA's first step toward controlling carbon pollution and contribute towards an environment where the vast majority of new power plants will be fueled by natural gas or renewable energy. Over the next three to four years, we expect these and other clean air requirements such as the Clean Air Interstate Rule (CAIR), the Cross State Air Pollution Rule (CSAPR), and regulations regarding water, fly ash and coal ash output will (i) drive retirements of approximately 50-100 GW of coal generation capacity, (ii) tighten power markets with significant exposure to coal fired generation (most notably MISO and PJM), and (iii) provide a long term boost to natural gas and power prices.

MATS and NSPS are expected to drive coal plant retirements, reducing the supply surplus ahead of the key compliance dates (Exhibit E). These regulations will primarily impact fossil fuel plants, especially older coal fired plants, which are approaching the end of their useful life, and smaller coal fired units which are uneconomic to scrub. In fact, we have already seen MATS standards: (i) driving owners of older, smaller and less efficient coal plants to retire these units; and (ii) increase capital spending on larger, existing plants that need incremental pollution controls such as dry and wet scrubbers.

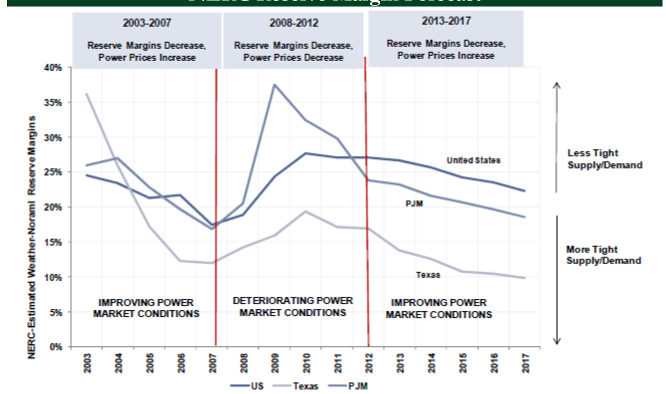
MATS will require installation of expensive pollution controls and remain the primary driver of long term coal plant retirements. Yet, litigation over some of these rules has created uncertainty regarding timing and implementation details. For example on December 2, 2011, the EPA publicized the final rules for the MATS standard which will reduce emissions of mercury and acid gases from U.S. coal generating plants. In late December 2011, the U.S. Circuit Court of Appeals for the District of Columbia issued a stay of the EPA's CSAPR rule regulating sulfur dioxide (SOx) and nitrogen dioxide (NOx) emissions from fossil fuel power plants. This rule was vacated in August 2012 and will likely result in a revised version of CSAPR in 2013 or 2014, after the EPA has resolved a number of disputes. Nevertheless, when and as implemented these rules should drive significant improvements in power prices and spreads as a result of the forecasted decline in reserve margins (Exhibit F).

Exhibit E
EPA Regulatory Timeline



Source: Dynegy Investor Day Presentation, June 2012.

Exhibit F
NERC Reserve Margin Forecast



Source: NERC and Goldman Sachs Research.

IV. Investment Opportunity

We anticipate that the enforcement of MATS and NSPS over the next three to four years – driving record numbers for incumbent power plant retirements – will cause a watershed event. Specifically, we expect to see epic balance sheet restructurings of great assets with over leveraged capital structures, together with an unprecedented wave of mergers and acquisitions as strategic utility and private equity players seek to fill gaping holes within their generation fleets or capitalize on the attractive "buy vs. build" corporate finance conundrum. We can attempt to quantify this opportunity by identifying the number of maturing securities that are components of the CSFB High Yield Index, CSFB Leveraged Loan Index, and iTraxx Investment Grade Index, and by consulting with the investment banking and capital markets teams who underwrite power hedges, interest rate hedge transactions and off balance sheet contingent liabilities. The majority of these assets are secured by single power plants or portfolios embedded within the corporate family of both regulated and integrated utilities, independent power producers or privately held generation operators. We believe that these investment opportunities, where we would anticipate the most disruptive market dislocation, offer the greatest "margin of safety" and downside protection.

One of the key questions we are often asked is, "Why invest in power when you can make a bet on the underlying commodity?" The answer is simple. Merchant power will not only benefit from an improvement in commodity prices, but also, get the geometric upside due to the changing regulatory landscape. More importantly, predicting the future for natural gas curves and prices is both volatile and challenging. We have studied a number of the macroeconomic models that our consultants have developed, which has only led us to one conclusion: "natural gas price forecasters were put on earth to make meteorologists look good." Another attractive aspect of investing in merchant power space is the inefficiency across the varying valuation methodologies. There are a few ways to value merchant power assets because "not all MW are created equal." These inefficiencies have only just begun to compress as the activity for balance sheet restructurings and M&A activity picks up ahead of these key EPA regulations.

As we have discussed above, there is rampant dislocation across natural gas and other commodities markets, as well as illiquidity in the forward markets for procured power and transportation due to the industry challenges and headwinds driven by the EPA regulatory environment. Significant drilling programs across shale basins have caused unforeseen prices across the complex to plummet, driving record storage levels further exacerbated by one of the warmest winters in history. All of these dynamics, coupled with the over $350 billion of debt that will mature in the coming four years and the over $1 trillion of capital expenditures necessary to upgrade the backbone of the entire utility infrastructure, is unprecedented. As a result, we believe that this is a very attractive asymmetric investment opportunity to deploy capital with minimal downside risk and significant upside driven by both fundamentals and catalysts. The key, however, is to identify these investment opportunities ahead of the curve.