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North America

A Short Gas Bridge to Renewables: Commodity/Equity View

- Commodities
- Equities

Creative Destruction of the US Power Sector; Retirements and Survival of Coal Plants and Uplift From Gas Prices

Commodities Strategy

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With thanks to
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Commodities Strategy View

- **The evolution unfolding in the electricity sector is the result of two disruptive changes: regulatory and technological**. Regulations help to accelerate the retirements of older, inefficient coal power plants, while older nuclear units face increased safety measures post-Fukushima. Technological advances improve efficiency, sharply reduce electricity demand growth, unleash the power of shale gas and reduce costs of renewables, enabling them to proliferate. But the resulting change to the electricity sector may not be all that straightforward.
- **Between coal retirements and the rise of renewables, gas generation may be a very temporary bridge.** Gas demand may rise by 2-Bcf/d from now to 2020, or ~2% of total gas demand then. Rising renewables generation should erode shares of coal-/gas-fired generation, particularly in a slow demand growth environment.
- **Amid profound changes in the power sector, the economics of gas production has a major impact on the economics of generation**. High gas prices should lift power prices and widen profit margins of low-cost power plants: some coal plants consuming low-cost coal could also benefit in this environment. With strong gas demand growth for exports and industrials, higher gas prices could result from oil/gas producers unwilling to produce more gas so long as oil/liquids drilling provide higher returns. See the report "The New American Gas Century" for details.
- **The transition period from now to 2020 could give utilities time to evolve until new technology and a new paradigm begin to play a much larger role in energy consumption and power generation**. At first glance, more rooftop solar and distributed generation, along with slowdown in power sales, and lower peak power prices and heat rates, are headwinds to merchant power generators. But it still takes time for new sources to fully develop and integrate into the market.

Equity Research View

- **We project total coal retirements of 61.5Gw, driven by evolving environmental policies and capital considerations.** While industry projections vary greatly and generally take into account commodity price movements and profitability, it is important to note that even though the first wave of retirements in 2015-16 will largely be driven by the MATS deadline, future retirements will be dictated by future environmental regulations, tightening compliance standards and capital costs. See inside for details on key environmental rules
- **To some extent, market tightening from coal retirements will be mitigated by the additions of renewables**. CA ISO will have the highest amount of renewables added into the generation mix. In MISO/ PJM, where existing renewable pipelines are relatively small, incremental solar/wind will have only modest impact on pricing.

Commodities Strategy View

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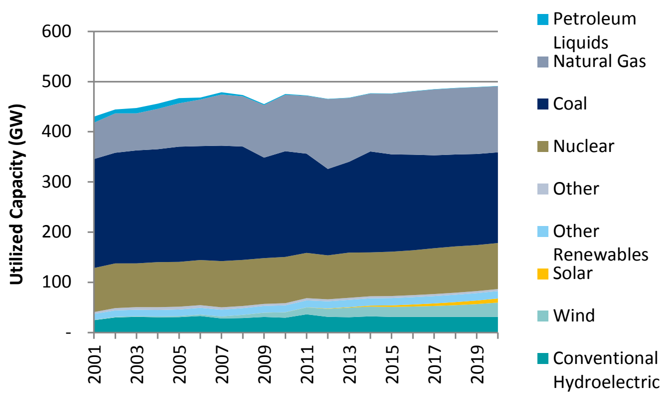
Edward Morse

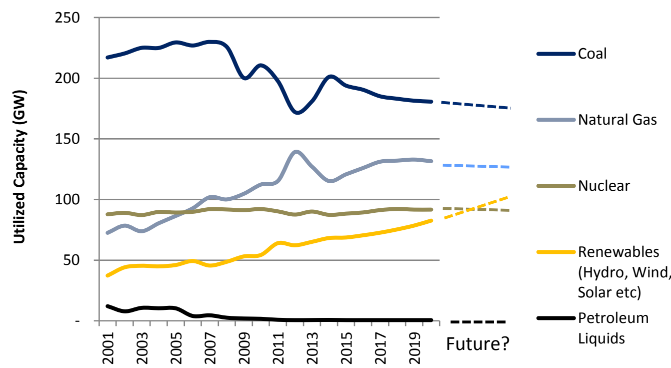
The evolution unfolding in the electricity sector is the result of two transformations: regulatory and technological. Regulations help to push older, inefficient coal power plants into retirements, while nuclear units, most having run for decades, face increased safety measures post-Fukushima. Technological advances improve efficiency and alter electricity demand, lower costs of renewables for them to proliferate, and unleash the power of shale gas. But the resulting change to the electricity sector may not be all that straightforward.

Figure 1. Total generation in utilized capacity (GW) only showing modest growth as demand growth stalls, but coal could remain resilient



Source: EIA, Citi Research

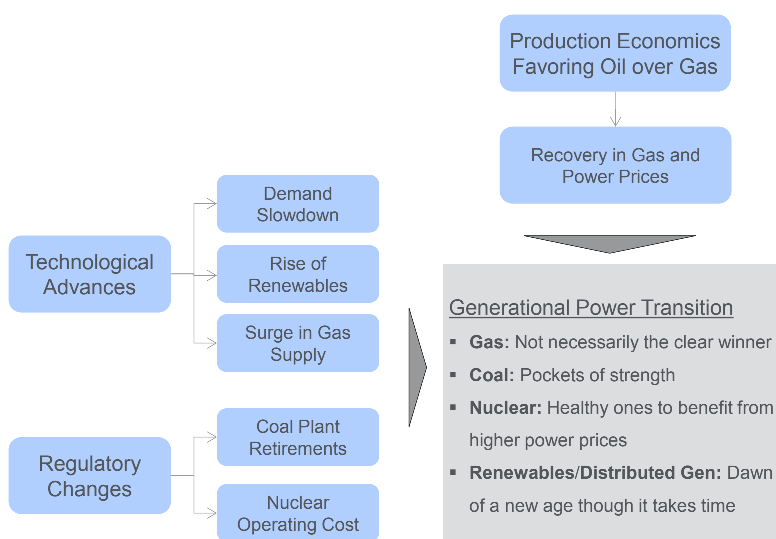
Figure 2. Rapid rise of renewables limit the potential for much stronger gains in gas demand



Source: EIA, Citi Research

The economics of gas production and the resulting rise in gas prices should give power prices a lift, thereby improving the profit margins of some fossil power plants that manage to stay on. While this would by no means stop the revolution happening in the electricity market, **potentially better profit margins for generators and the extended time needed to better integrate renewables could give utilities the opportunity to evolve**. Integrating renewables and distributed generation would not happen overnight, as we highlight in this report several issues regarding the integration process and grid reliability.

Figure 3. Factors Driving the Generational Power Transition in the US



Source: Citi Research

1. Gas-fired generation may be only a temporary bridge between the age of coal and the age of renewables

The growth in gas demand for power generation could be less significant than is commonly believed. Gas is commonly thought of as the substitute fuel for coal in power generation once coal plants retire. But rising renewables generation should increasingly take over market shares of coal- and gas-fired generation, particularly in an environment of slow electricity demand growth.

Citi expects only 2-Bcf/d of gas demand growth for power generation between now and 2020, much smaller than most expectations and with further downside, despite 43-GW of coal retirements still to go that are equivalent to ~3.4-Bcf/d of gas burn. While a suite of environmental rules could force a total of 61.5-GW of coal retirements (with 18-GW already retired), deriving the gas impact goes beyond an analysis of coal to include how total electricity demand and other fuel sources are changing over time.

Figure 4. US Electricity Demand and Generation Balance

Utilized Capacity (GW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
All Fuel	**466**	**459**	**462**	**470**	**470**	**475**	**478**	**481**	**483**	**485**
Coal	198	172	181	201	194	190	185	183	181	181
Petroleum Liquids	1	1	1	1	1	1	1	1	1	1
Natural Gas	115	139	127	115	121	126	131	132	133	132
Nuclear	90	88	90	87	88	89	91	92	92	92
Renewables (Hydro, Wind, Solar)	50	48	51	54	54	56	58	61	64	68
Conventional Hydroelectric	36	31	31	32	31	31	31	31	31	31
Wind	14	16	19	19	20	21	22	23	25	28
Solar	0.2	0.8	1.0	2.0	3.0	4.0	5.0	6.1	7.1	8.1
Other	12	12	12	12	12	12	12	12	12	12
Load Growth (%)		-1.5%	0.5%	1.9%	-0.1%	1.0%	0.8%	0.5%	0.4%	0.4%
NG Consumption (bcf/d)	20.60	24.77	22.21	21.2	22.2	23.2	24.2	24.3	24.5	24.2
Incremental Gas Consumption (bcf/d)				(1.0)	1.0	1.0	1.0	0.2	0.2	(0.2)

Source: EIA, Citi Research

Multiple forces should have an impact on overall gas demand

(I) **Electricity demand growth**: Gas demand should initially benefit more from electricity demand growth than other fuels, as gas-fired power plants populate both the baseload and peaking parts of the electricity generation stack. However, power demand growth may turn out to be much slower than expected and could even be negative in some regions due partly to demand-side management programs, efficiency gains, behavioral changes and the rise of distributed generation.

(II) **Coal-fired generation retirements**: At first glance, emission rules, by inducing coal-fired generation retirements, and the persistently high cost of coal mining, compared with gas prices that are held down by efficiency gains in production, should drive out coal. Citi expects 43-GW of coal retirements still to go after having 18-GW of coal power plants retired. Note: Coal demand fell to 890-MM tons in 2012 from 997-MMtons/yr in 2009 due to a combination of coal power plant retirements and coal-to-gas switching on low gas prices.

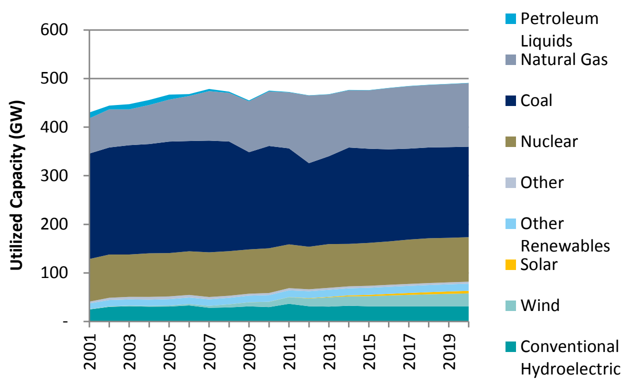
(III) **Potential nuclear reactor retirements:** Additional nuclear plants could retire due to the high cost of operation and maintenance, with four already taken offline in the last two years. Nuclear retirements

could be a greater long-term driver of gas demand growth because of its high capacity utilization. Nonetheless, new plants and uprates (i.e., incremental expansions of existing capacity), made even more economic by higher expected gas prices towards the end of the decade and beyond, could more than offset the impact of retirements, reducing the need for gas plants to act as baseload generation.

(IV) **The rise of renewables and distributed generation**: New sources should bring about a sea-change in the power generation mix, especially with falling costs. Nonetheless, a stable grid operation (i.e., grid reliability) becomes critically important as variable generation increasingly constitutes a larger share of the generation mix and substitutes retiring baseload power plants. Operating characteristics of these two sources are very different from each other.

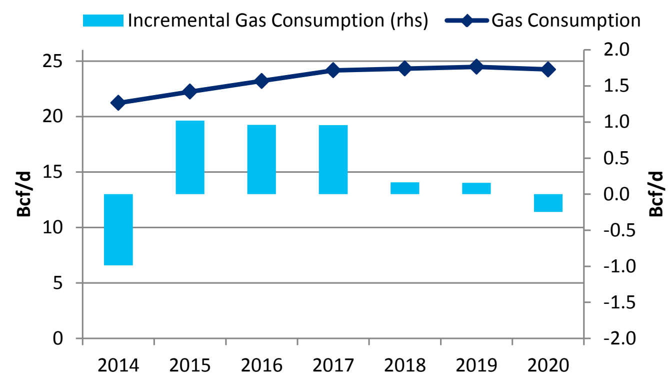
To derive the gas and coal impacts, the analysis starts with forecasts of regional electricity demand, followed by expected changes in the rest of the power generation supply "stack" in each region. A stack is a list of power plants or generation sources arranged based on their marginal costs of generation. Due to the dynamic nature of the stack, losing coal power plants as a source of baseload generation does not necessarily mean that gas power plants would fill the gap. The analysis incorporates changes in nuclear, renewables and other sources.

Figure 5. Generation demand to grow slowly…



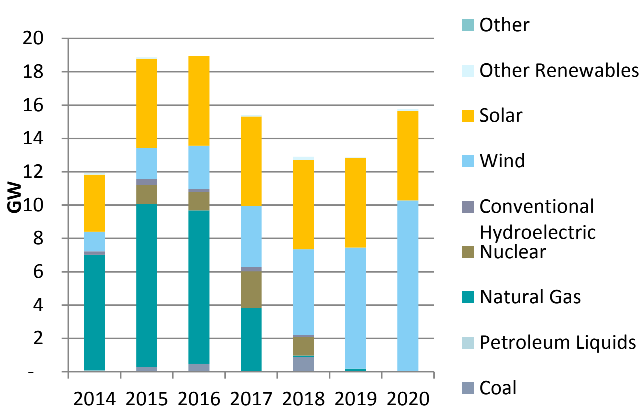
Source: EIA, Company Reports, Citi Research

Figure 6. …With gas receiving a boost in 2015E/16E before tailing off



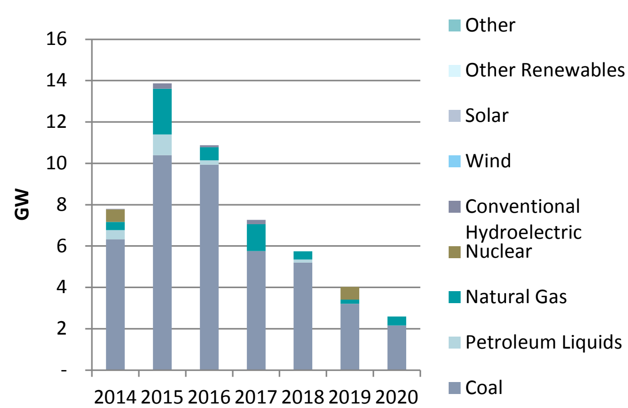
Source: EIA, Citi Research

Figure 7. New capacity dominated by renewables and some gas



Source: EIA, Company Reports, Citi Research

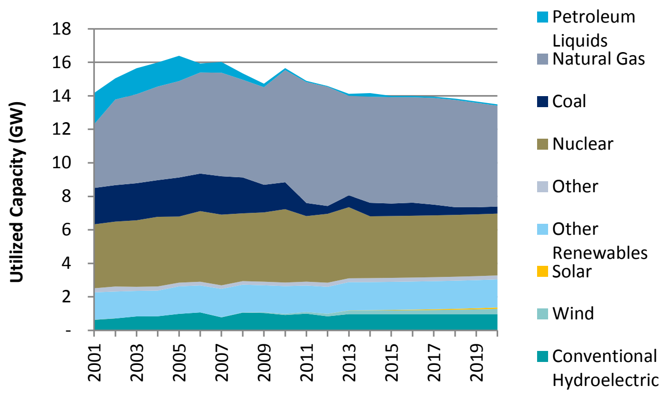
Figure 8. Inefficient coal plants retire but efficient ones stay on (weighted average for each year)



Source: EIA, Company Reports, Citi Research

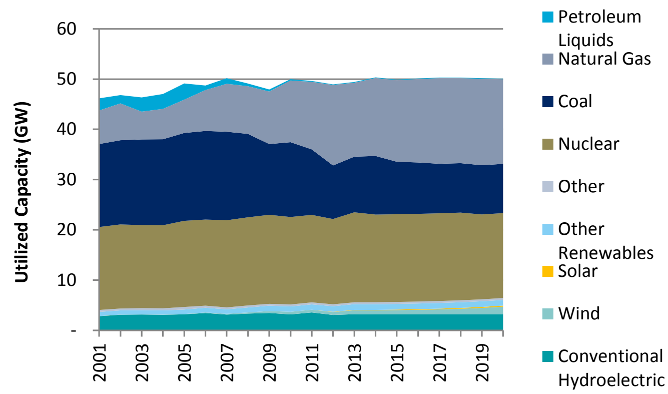
Regional Generation Outlook

Figure 9. Generation (New England): Lack of expansion in energy-intensive industries could lower electricity demand over time



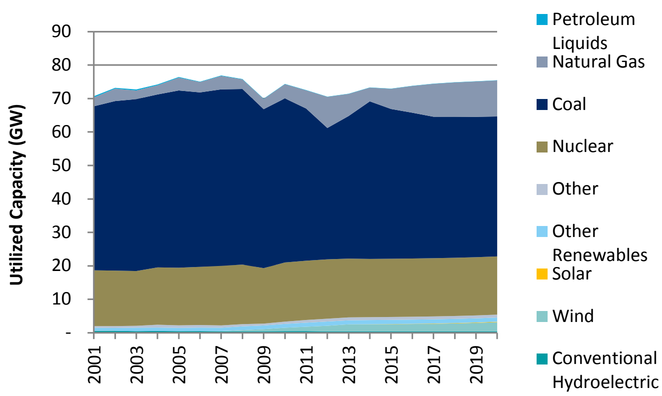
Source: EIA, Citi Research

Figure 10. Generation (Mid-Atlantic): stagnant overall growth but gas to gain as coal plants retire



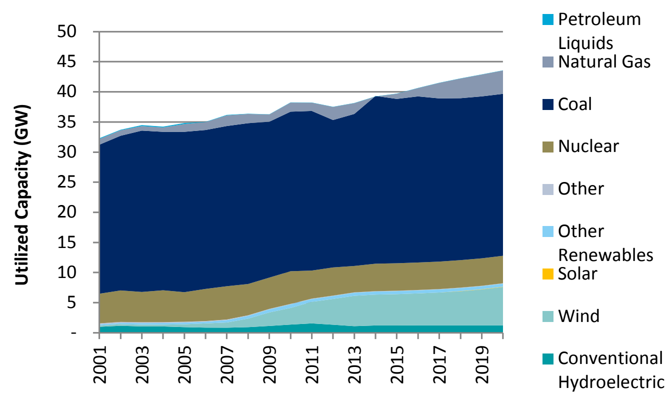
Source: EIA, Citi Research

Figure 11. Generation (East North Central): Return of industrials could boost demand



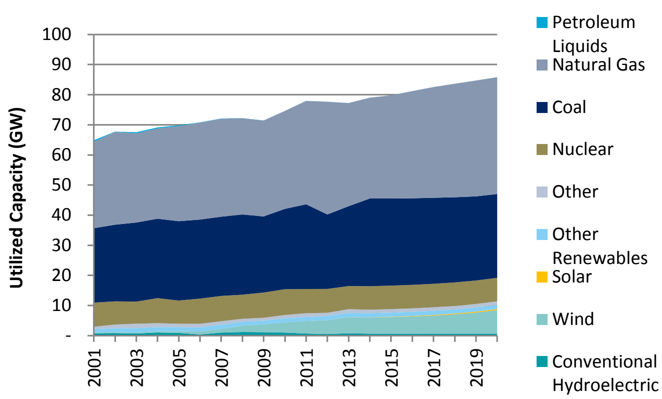
Source: EIA, Citi Research

Figure 12. Generation (West North Central): wind capacity growth could remain strong, with overall demand rising thanks partly to the Bakken



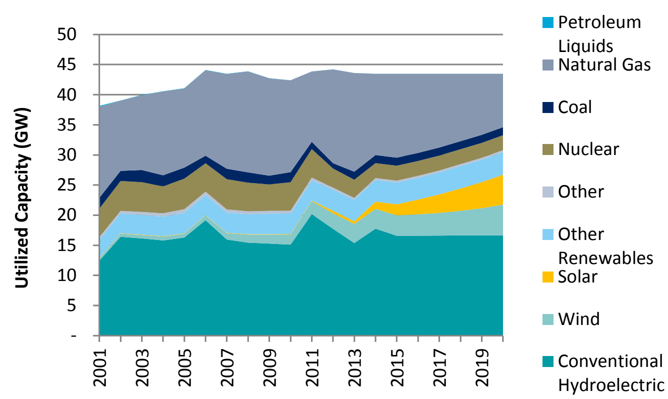
Source: EIA, Citi Research

Figure 13. Generation (West South Central): strong demand growth due to oil/gas activities, industrial expansions; strong renewables growth



Source: EIA, Citi Research

Figure 14. Generation (Pacific): Renewables should make up a greater share of generation amid continued economic expansion (hi-tech etc)



Source: EIA, Citi Research

Electricity demand growth

But gas demand for power generation may not grow much further after mid-decade because…

Gas demand should benefit more from electricity demand growth than other non-renewable fuels, as gas-fired power plants populate both the baseload and peaking parts of the electricity generation stack. As the economy recovers, power demand should rise.

However, the overall electricity generation industry is unlikely to return to the historical growth rate of 2%pa. Long-term power load growth looks likely to be limited by developments in four different areas: (1) the wider use of demand management and load response; (2) improvements in energy efficiency standards; (3) behavioral changes across sectors; and (4) new off-grid generation with "Prosumers" such as large industrials or even individual households. They would generate energy off-grid for their own use, be it some form of distributed generation or a more sophisticated microgrid, taking away electricity demand growth from utilities.

…Demand-side management is curbing demand, especially during peak hours

(1) Load response and demand-side management can reduce peak and baseload power demand. In all of these programs, participating industrial or commercial facilities receive payments for reducing their power consumption. Alternatively, they could save money by not buying power when demand is high, when generation is scarce or when electricity prices are high. These economic incentives encourage facilities to reduce demand. Modest to negative power demand growth in industrial-heavy areas in the power market PJM in the Mid-Atlantic region of the U.S. are signs of increased use of demand management practices.

…Energy efficiency standards are also improving in many states

(2) Energy efficiency standards also in the long term reduce power demand growth. Improvements in energy efficiency also limit any prospect of load growth. Twenty-five states already have binding energy efficiency resource standards, which could lead to 236-TWh of energy savings by 2020.

…Consumer behavior may also have changed to embrace more conservation

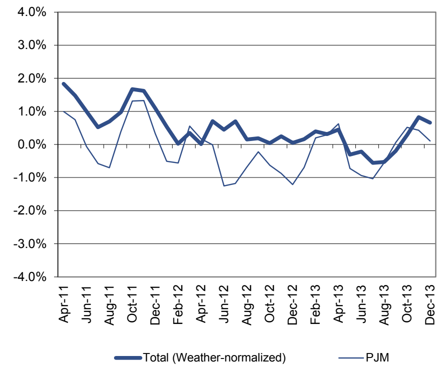
(3) Behavioral changes across sectors are another factor in slowing power demand growth. In the residential sector, there are few to no formal ISO-level[1] programs. But weak economic conditions and conservation, perhaps brought on by previously high energy prices and severe recession, appear to be curbing demand growth. In the commercial and industrial sectors, energy consumption is no longer a cost center, as demand reduction becomes another revenue source, turning procurement into a partial profit center. Deloitte reported in a recent study that 9 in 10 companies have goals on energy management practices.

Of course, power demand is also a function of weather, although it is difficult to predict where the climate and weather might lead. Rising temperatures should raise summer demand for cooling but curb winter demand for heating. But if temperatures were to become more extreme, then demand could rise on net.

(4) Beyond these factors are dramatic changes impacting power generation, and among these perhaps none is more powerful than the creation of "prosumers," or consuming entities that are producing their own electricity through wind or solar use and breaking themselves away from grids while eroding the monopoly model of power generation by utilities. We expected this factor along with other disruptive technology changes, including in storage, to limit power demand growth and hence the power sector's appetite to increase natural gas use.

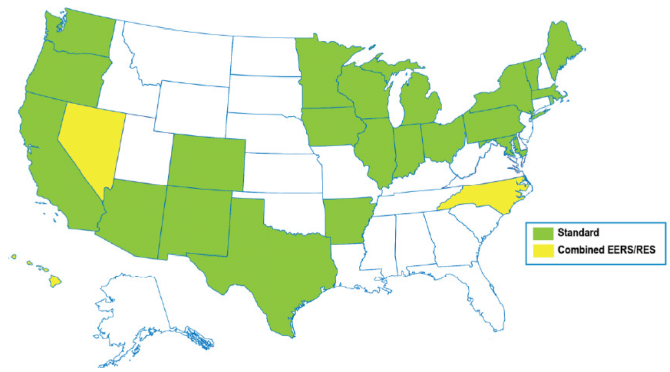
[1] ISOs are non-profit Independent System Operators of electricity grids that manage the dispatch of generation facilities to meet power demand, among other responsibilities.

Figure 15. Weather-normalized power demand growth has been relatively flat in North America and the key power market PJM



Source: Citi Research

Figure 16. States with Energy Efficiency Resource Standard



Source: ACEEE

"Prosumers" going off-grid and generating their own electricity could further reduce demand for utility power

For further implications on how competing energy sources, such as renewables and shale, are bringing about disruptive changes to the energy complex, please refer to the Citi GPS report "Energy Darwinism" (Oct 2013) for details.

On the other hand, the use of electric vehicles (EVs) could certainly increase baseload demand for power, but high costs, technological hurdles and the search for a more competitive and viable business model have slowed the penetration of EVs so far and we do not believe that there will be significant penetration of EVs in the passenger vehicle fleet of the US in the next seven years or so.

Coal-fired generation retirement

Emission rules, particularly MACT[2], by inducing coal-fired generation retirements, should lead to an increase in baseload gas demand. By law, emission standards have to tighten starting in 2015 due to previously enacted National Ambient Air Quality Standards[3]. If gas-fired power plants were to completely replace retired and retiring coal plants, between 3- and 4-Bcf/d of additional gas demand could result, given the 45-50 GW of retirements expected. Further, if carbon regulations ever come into existence, they would favor gas over coal, given that an efficient gas combined cycle plant emits less than half of the carbon as a coal plant.

Further, the US Environmental Protection Agency issued a rule limiting the amount of carbon emissions that all new power plants must comply with in EPA's New Source Performance Standard (NSPS). The level is set at 1100 lb of CO_2/MWh, which is generally half of the amount a typical coal plant would emit and the full amount from an efficient combined cycle natural gas power plant. This new rule, if implemented, essentially mandates that power plants must use Best Available Control Technology (BACT) to control emissions, or else its construction would not be approved. Although the Obama administration stated publicly that the Administration's goal is to reduce greenhouse gas emissions, the brunt of the rule's impact would fall on new coal plants. Citi Commodities Research examined various aspects of the President's Climate Action Plan in the report "Much Ado about Climate Change" (Jun 25, 2013)

[2] MACT or MATS, which stands for "Maximum Achievable Control Technology" or "Mercury and Air Toxics Standards," respectively, refers to the EPA rule, with a previously expected implementation date in the middle of this decade, to "reduce emission of toxic air pollutants...from new and existing coal and oil-fired power plants."

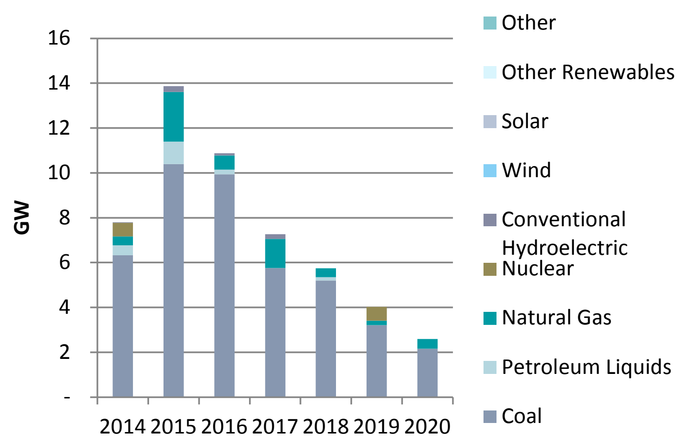
[3] NAAQS refers to the National Ambient Air Quality Standards. These standards were established by the Environmental Protection Agency (EPA) under the Clean Air Act (CAA).

The more important ongoing development is the rule by the EPA regulating existing power plants' emissions. This rule is expected to come out in mid-2014. The rule is expected to restrict the amount of GHG emissions to about half of their unrestrained emission level, or similar to the amount of emissions coming from a gas-fired combined cycle power plant.

The opposition to this proposed rule could be much stronger, since it involves plants currently in operation. The comment and draft-rule-revision periods are expected to be long, with lengthy litigation even if the final rule is implemented.

Legislatively, Congress is expected to be divided for the foreseeable future, making the passage of legislations with carbon tax or programs unlikely. Even if such measures were to pass, subsequent litigations should further delay any implementation of a carbon program, if at all. With obstacles along both the executive and legislative pathways, it is possible that there would be no enforceable carbon program in the next five to ten years or beyond.

Figure 17. Planned Power Plant Retirements (GW) – weighted average for each year



Source: EIA, Company reports, Citi Research

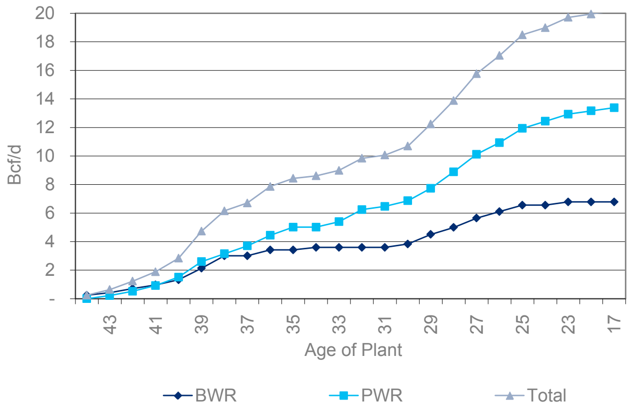
Potential nuclear reactor retirements

If more nuclear reactors were to retire, gas-fired generation could be the main replacement, boosting gas demand

Longer term, the age of a nuclear unit, lackluster power demand growth and the potential for low power prices could pose challenges to nuclear operations. Current nuclear capacity is equivalent to 20.2-Bcf/d of gas demand, assuming the use of 8 heat rate combined cycle units. Exelon, with the largest nuclear fleet in the US, canceled plans to spend $2.3-billion on upgrades due to low power prices and demand. More stringent post-Fukushima safety measures also raised capital and operating costs. In 2013 alone, four nuclear units retired: Crystal River in Florida, Kewaunee in Wisconsin and two units at the San Onofre nuclear station in Southern California. Vermont Yankee is about to retire as well at the end of 2014.

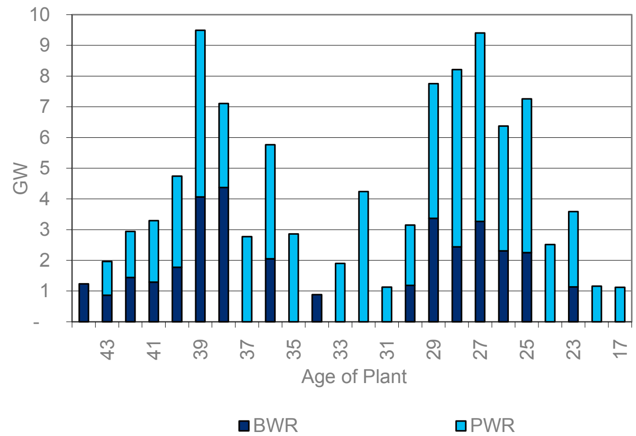
Although new plants or expansions bring on additional capacity, such as the Vogtle plant in Georgia, Watts Bar in Tennessee and V.C. Summer in South Carolina, nearly 14% of nuclear units are over 40 years old, representing 2.8-Bcf/d of gas demand. Both the Mid-Atlantic and Southeast have a higher concentration of older units. Any further retirements could have far-reaching impacts, as outlined in a Citi Commodities Research report published on Feb 12, 2013. Citi's utility analyst published an in-depth report "Nuclear Shutdown" (Sep 18, 2013) focusing on nuclear units owned by merchant generators.

Figure 18. Cumulative gas impact based on the age of nuclear plants



Source: NRC, Citi Research

Figure 19. Size and age of nuclear plants



Source: NRC, Citi Research

The rise of renewables and distributed generation

New sources should bring about a sea-change in the power generation mix, especially with falling costs. The capacity of renewable generation sources continues to climb rapidly due to the implementation of Renewable Portfolio Standards (RPS or the likes), environmental rules and falling costs of these generation resources. More locations and states have RPS, where a certain amount of electricity must be generated from renewable sources such as hydro, wind and solar. In addition, the emergence of alternative financing vehicles (i.e. Yieldco's) and fuel diversity needs (state regulators putting pressure on regulated utilities to look at renewables - this has happened in several cases) are two other drivers for renewable growth.

Nonetheless, a stable grid operation (i.e., grid reliability) becomes critically important as variable generation increasingly constitutes a larger share of the generation mix and replaces retiring baseload power plants. Operating characteristics of these two sources are very different from each other. See the section on “Equity Research View” for details.

Conclusion

Gas-fired generation may be only a temporary bridge between the age of coal and the age of renewables. Slow growth in power demand already limits the prospect of demand growth. Coupled with strong growth in renewables generation, the share of generation from coal and gas would be squeezed as a result. Meanwhile, rising renewables generation could help replace the loss from coal-fired generation retirements.

2. Gas production economics drive gas/power price outlooks

Although gas demand may not rise as much as expected, gas prices could have a major impact on power prices as well as the survival and profitability of power plants. Power prices are directly affected by gas prices because gas power plants tend to operate at the margin and set power prices. Heat rates, or power prices divided by gas prices, are often traded instead of power prices, as power generators pass the costs of fuels to consumers. Therefore, the level of gas prices essentially determines power prices and the profitability of power plants. The section below illustrates how gas prices affect power prices and a power plant's profit margin.

Examples of generation economics

How gas plants often set power prices: at $4/MMBtu gas, a gas power plant with a heat rate (an alternate representation of thermal efficiency) of 10-MMBtu/MWh (as it takes 10 units of energy in MMBtu to produce 1-MWh of power) could be at the margin, setting power prices at $40/MWh. At $5.50/MMBtu gas, the same plant could be on the margin and set the power price at $55/MWh.[4]

Profitability (Gas): For a more efficient gas power plant with a heat rate of 8-MMBtu/MWh, the cost of generation at $4 gas is $32/MWh. The fuel-only profit margin, or spark spread, is the power price minus generation cost, or $40/MWh - $32/MWh = $8/MWh. Theoretically, a 500-MW plant that runs for 50% of the time in these conditions earns $17.5 million in a year. In contrast, at $5.50 gas, the generation cost would be $44/MWh but the power price, if a 10-heat rate plant is at the margin setting power prices, would be $55/MWh. The profit margin, or spark spread, becomes $11/MWh. At 50% capacity utilization in these conditions, an 8-heat rate gas plant could earn $24 million. Hence, a rise in gas price from $4 to $5.50/MMBtu could raise a plant's profit by $6.5 million.

Profitability (Coal): For a generic 10-heat rate coal plant burning Central Appalachian coal at $60/ton would have a fuel-only marginal generation cost of $32/MWh, competitive with a gas unit but not as much as in years back when coal prices were much lower. In this case, the profit margin, or dark spread, would be $8/MWh, same as an 8-heat rate gas plant. In a $5.50 gas environment but with coal prices unchanged, this coal plant's fuel-only profit margin rises to $23/MWh.

Suppose environmental rules cause the efficiency of the coal plant to fall (because electricity has to be diverted to run emission abatement equipment though the impact is typically minimal) and the variable cost to rise by $3/MWh, then the profit margin would be $20/MWh at $5.50 gas vs. $8/MWh at $4 gas.

Some coal plants have also switched to using lower cost coal, such as Illinois Basin coal at between $45 to $50/ton (though with 6% less in heat content per ton at 23.6-MMBtu/ton vs. the benchmark Central App at 25-MMBtu/ton). As long as the increase in transport costs is smaller than the decrease in coal costs, the generation cost should fall, improving profit margins.

Profitability (Nuclear): Each nuclear unit is different. Fuel costs make up a very small portion of the marginal cost of generation. Fixed operating and maintenance (O&M) costs consist of a larger share, spread over the entire year and become part of the "variable" cost of generation for simplicity. As it is unlikely that O&M costs

[4] Note that as gas prices rise, the heat rate of plants setting the margin (i.e., the traded heat rate) tends to fall a bit as expensive plants tend to run less.

would be significantly higher, a sharper rise in gas and power prices should also benefit a number of existing nuclear power plants that do not have to undergo expensive retrofits.

Examples above show the direct impact gas prices have on power prices and profit margins of various types of power plants. The next section highlights where gas prices might be heading.

Outlook on long-term gas prices

Amid changes in the power sector, the economics of gas production have a major impact on the economics of generation. Holding all else equal, high gas prices should lift power prices and widen profit margins of low-cost power plants: some coal plants consuming low-cost coal could see wider profit margins as long as coal prices remain the same or lower. Higher gas prices could be a result of oil/gas producers being unwilling to produce more gas so long as oil/liquids drilling still provide higher returns. (See the report "The New American Gas Century" for details on the price-setting mechanism.)

With prices boosted by an expected surge in demand at home and for US exports, long-term US natural gas prices could settle in the $5-$5.50/MMBtu range starting in 2018, a level that would be above production costs at marginal gas fields. As demand and exports begin to ramp up, prices in 2016 and 2017 could rise to $4.90 and spike higher from current levels in the $3-$4 range. Prices could moderate over time as more producers switch back to gas.

Market structure and severe regional imbalances between production and demand, rather than just the marginal cost of production, could determine future gas prices. A common belief is that long-term gas prices would fall to the marginal cost of production. This is true if gas producers have no other options but to drill for gas. Although many gas plays are supposed to be economic at $4 or below, one critical consideration is whether shale gas-only producers have the production capacity to produce enough gas to not only replace the annual decline of existing production but also meet the need of rising demand. We do not think this would be the case.

Productivity gains are helpful in boosting production but they are not enough to meet "demand" growth

Although productivity and efficiency improvements, along with associated gas production, should push domestic production upward, the increase in demand and exports would call for additional gas supply. This call for additional supply and the need to motivate producers to switch back from liquids drilling to gas drilling are what could drive prices higher.

As long as liquids production remains more profitable than dry gas, capex allocation should be more heavily allocated toward liquids most of the time. To attract additional gas supply, gas producers who have both liquids and dry gas plays would have to see returns attractive enough to return to dry gas drilling. Gas prices would have to rise to yield a sufficiently large return on gas drilling at least close to that of liquids drilling, so that more resources could be reallocated to gas pads.

To illustrate, if Brent were $100/bbl, or $16.7/MMBtu, then the NGL basket, which historically trades at 50% Brent, would be $8.3/MMBtu vs. $4 gas. With a glut of NGLs, the basket price at 35% Brent, as seen recently, would be equivalent to about $5.8/MMBtu. Stressing the downside further, if Brent were to be $90/bbl, or $15/MMBtu, then an NGL basket at 35% Brent would be $5.25/MMBtu, again vs. $4 gas. Unless dry gas becomes competitive with liquids drilling again, the superior returns from liquids production should still draw more capital. The question is how much more costly are liquids than dry gas drilling.

Gas prices are derived by breaking down the source of the gas and gas prices needed to entice a switch away from oil/liquids

Indifference Gas Price: We conducted an extensive play-level analysis comparing the returns of drilling at major oil/liquids plays vs. major gas plays. We then derive gas prices needed for returns from drilling at shale gas plays to be equivalent to returns from drilling at oil/liquids plays, given different oil price assumptions, as seen in the following tables. For example, with $90/bbl oil, the gas price would have to reach $5.5/MMBtu to make the returns equivalent as between drilling at a typical Bakken oil-heavy well and drilling at a generic Marcellus gas-heavy well.

Indifference gas price matrices show the gas prices needed for production to switch from a liquids play to a gas play

The low-gas price environment over the last few years has forced many gas-focused producers to move towards oil and liquids drilling. The following graph shows that the concentration of companies with over 80% of their hydrocarbon production coming from gas has fallen sharply. Instead, the concentration of firms by 2012, the latest set of full-year data available, was closer to 50%.

Figure 20. Indifference gas price matrices: gas prices needed to have a similar return as a corresponding oil/liquids play based on different oil price assumptions

$90 Oil	Haynesville	Barnett	Marcellus			$100 Oil	Haynesville	Barnett	Marcellus
Niobrara	5.3	5.0	2.9			Niobrara	5.8	5.4	3.1
Permian	5.6	5.3	3.1			Permian	6.2	5.8	3.4
Eagle Ford	8.6	7.8	4.0			Eagle Ford	9.5	8.7	4.4
Bakken	8.2	7.7	4.5			Bakken	9.1	8.5	4.9
$85 Oil	Haynesville	Barnett	Marcellus			$95 Oil	Haynesville	Barnett	Marcellus
Niobrara	5.0	4.7	2.8			Niobrara	5.5	5.2	3.0
Permian	5.3	5.0	2.9			Permian	5.9	5.5	3.2
Eagle Ford	8.1	7.4	3.9			Eagle Ford	9.0	8.2	4.2
Bakken	7.8	7.3	4.3			Bakken	8.7	8.1	4.7

Source: Citi Research

Further, some producers have gas production forming a greater share of their total US hydrocarbon production than gas' share of their total hydrocarbon reserves. (i.e. gas production could be 70% of a producer's total oil and gas production but gas may only form 50% of that producer's total reserves.) What this means is that some producers could potentially be favoring gas production over oil/liquids by producing more gas as a share of total than its share of gas reserves would have indicated. *Hence, these producers' ability to ramp up gas production even more is questionable*. In fact, with continued higher oil and liquids prices, more of these producers could move to oil/liquids drilling in future years. Their commitment to gas drilling now may be due to the "drilling carry" they received from joint ventures, drilling to hold acreages and other contractual obligations.

Severe regional imbalances in supply-demand and Northeast basis

Pipeline constraints could limit Marcellus/Utica production growth and keep Northeast prices low

Much of the gas production growth has taken place in the Northeast (Marcellus/Utica) over the last few years but much of the demand growth in the future should be coming from the Gulf Coast. Insufficient amount of pipeline takeaway capacity capable of alleviating the regional production glut is already physically limiting production growth. With infrastructure constraints and price discounts vs. Henry Hub prices, it is possible that shale gas production growth from the Marcellus and Utica shales may not be as strong as some of the more optimistic forecasts.

In contrast, much of the gas demand growth between now and 2020 should occur on the Gulf Coast. Most of the LNG export terminals, which should reach ~8-Bcf/d or more, are located on the Gulf Coast; pipeline exports to Mexico, where 3-Bcf/d (a doubling) of additional capacity is set to come online in late'14/early'15, with more

coming by 2017, should boost gas outflow by an additional ~4.5-Bcf/d or more between now and 2020; most of the industrial expansions are happening on the Gulf Coast and demand growth is expected to be ~5-Bcf/d or more; additional gas demand of ~2-Bcf/d also comes from having to produce and transport more across the nation. Together, gas demand on the Gulf Coast alone could rise by 18 to 20-Bcf/d, without counting the demand increase from power generation and transportation (CNG/LNG trucks). See the report "US Northeast Gas: Glut Unresolved" for details on the infrastructure constraints in the Northeast.

Hence, higher-cost shale plays on the Gulf Coast might need to boost their gas production to meet the surge in demand there.

Risks to the price outlook

Other than weather-related drivers, here are some of the risks to this outlook:

1. If consumption and export growth were not as strong as expected, then the demand for gas production from non-gas-only producers could moderate, driving prices down closer to levels of marginal production costs. However, if gas prices are sufficiently low vs. oil and coal, then consumption will continue to be stimulated.

2. If gas consumption and export growth were much stronger than expected because many of the new "demand" sources are baseload, then prices should rise even further, but gas would quickly lose its competitive edge in sectors that are much more sensitive to gas price, limiting the size of the price surge. These sectors include power generation and LNG exports.

3. Gas-only producers could be much more prolific, driving gas prices down. But productivity improvements seem to be strongest in the Northeast, which is constrained.

4. Lower well costs should bring down overall production costs, theoretically driving prices lower. But downward cost pressure should apply to oil/liquids wells, too. Therefore, decisions on capital allocation remain critical.

Prices could soar perhaps as a result of weather or other disruptive events. But high prices should curb exports substantially as global LNG prices are likely on a downward trajectory. As prices rise, the uptick of gas in transportation should also slow as gas might no longer be an attractive alternative to diesel or other existing liquid fuels. Industrial facilities could slow their plans for expansion or fuel-switching. Gas demand for power generation could fall as gas becomes expensive while renewables generation continues to climb amid stagnant electricity demand growth

Conclusion

Higher power prices and the likely improvement in power plant profitability could come as a result of higher long-term gas prices. Despite the possibility of lower drilling, completion and production cost, the relatively inferior economics of gas production vs. oil/liquids could be the driver that lifts gas prices, as more gas production is required in the year ahead. With higher power prices, the profitability of existing power plants could improve for a number of years before a sufficient amount of renewables in the system subsequently erode the profitability of existing power plants significantly. It could be some years before this inflection point is reached. Before then, power generators should seize on this time period to transform themselves for a new era.

3. There is still time for utilities to evolve but challenges lie ahead

While the share of renewables in power generation is rising, a wholesale change is not happening, yet. Higher expected gas prices could buy utilities time and give them additional revenues to prepare for changes ahead. Nonetheless, changes are coming, from managing renewables (or so-called variable generation) and microgrids, to coping with capacity adequacy, gas-electric integration and overall grid reliability. The "Equity Research View" section later on covers the pipeline of renewables coming online in the next few years. We highlight below some of the challenges facing the industry.

Challenge 1: Variable Generation

The capacity of renewable generation sources continues to climb rapidly due to the implementation of Renewable Portfolio Standards (RPS or the likes), environmental rules and falling costs of these generation resources. More locations and states have RPS, where a certain amount of electricity must be generated from renewable sources such as hydro, wind and solar.

In addition, the emergence of alternative financing vehicles (i.e. Yieldco's) and fuel diversity needs (state regulators putting pressure on regulated utilities to look at renewables - this has happened in several cases) are two other drivers for renewable growth.

As variable generation penetrates more rapidly into the electrical system, integration to the Bulk Power System (or the broader electricity network) requires changes in the traditional way of planning and operating the electrical grid. NERC recently published a report examining how the California Independent System Operator (CAISO) is coping with increased renewable and other variable generation resources. According to NERC, "increased amount of solar photovoltaic (PV) generation leads to decreased system inertia and frequency response capabilities that could potentially result in reliability impacts on the BPS." How California ISO manages this could become a model for other regions.

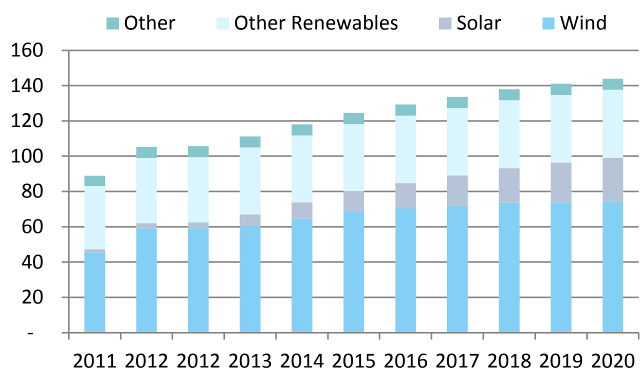
The ability to forecast generation contributions from renewables and distributed generation sources is critical to system reliability. Technical advances and significant deployment of wind and solar have in some cases surpassed the broader industry's ability to accurately model their impacts. Although for renewable resource to be added to the grid, technical assessments must be made to ensure that these resources could be safely incorporated. At times the complexity of the power network makes a robust analysis of all possible effects very difficult.

A lack of sufficient backup resources provided by fossil generation could force some of these variable generation resources to shut in order to maintain system integrity: due to operational stability, wind resources have at times been curtailed. For example, NERC specifically underscored the potential reliability impact of rising solar PV leading to "decreased system inertia and frequency response capabilities that could potentially result in reliability impacts on the [grid.]" To avoid these instances or domino effects from happening, electrical system operators and other physical market players need to have accurate forecasts and flexible generation resources to handle changes in voltage and frequency.

Policy support on renewable power plant development varies by region, with a more aggressive Renewable Electricity Standard mandate in the Northeast region, South Central region and along the West Coast.

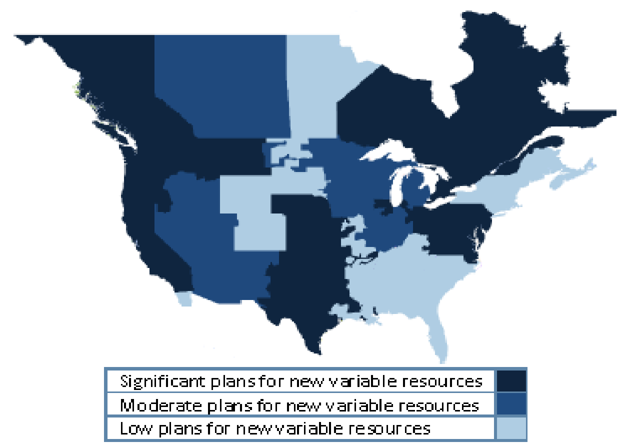
Nonetheless, an increasingly effective way of deploying renewables is the use of small-scale energy storage that provides energy only for a short time, particularly for solar. Suppose solar generation is strong in late afternoon so much so that the electricity generated could more than satisfy demand, the extra energy could be stored in batteries or other short-term energy storage. In early evening when solar power falls but demand remains strong, energy stored earlier could be released to meet demand in part of the evening. This reduces the need for bulk power generation in the afternoon and early evening. However, in this scenario, both power generated and power prices from the existing generation grid would not be as high as before, thereby compressing profit margins of existing power plants. While this kind of renewables deployment is not as widespread, it is being adopted in an increasing number of places.

Figure 21. Renewable fuel power gen capacity is expected to grow



Source: EIA, Citi Research

Figure 22. Assessment of impact from plans for new variable resources



Source: NERC, Citi Research

Microgrids: Another ironic development of microgrids is the claim that microgrids are more reliable by isolating themselves from the broader power network. But the whole concept of power pool developed many decades ago (e.g. the current PJM power market was initially started as the Pennsylvania, New Jersey and Maryland power pool) was to increase reliability by linking individual power networks together, so that there would be adequate backup generation and system to serve demand in cases of interruptions in the power grid. By moving away from the bulk power system, the pendulum seems to be swinging the other way, encouraging isolated, vertically integrated systems to develop.

However, a microgrid is very useful in locations where large power plants or networks prove to be too expensive or inconvenient to build. Distributed generation is most suitable in remote locations where the infrastructure needed to bring the community into the broader network may be too large and electricity demand there may be too small for grid connection to be cost-effective.

Nonetheless, advances in storage technology and software in helping how distributed and variable generation sources could be integrated effectively could help with the further penetration of these new energy resources.

Even during periods of normal operation, some of the current incentive structure encourages richer households to adopt solar or distributed generation, leaving those households who elect not to or cannot afford to install relying on grid-connected power. The maintenance cost of the broader power grid hence falls on a smaller base on customers who might generally be less well-off. Some jurisdictions have begun to address this problem by imposing a small fee on the use of solar or distributed generation, though the fee is relatively small in many cases.

Challenge 2: Capacity adequacy

Reserve margin in ERCOT (~Texas) is expected to drop below NERC's regional reference levels, requiring additional capacity and demand-side management (DSM) resources. Driven by increasing activities in oil and gas drilling in Texas, power demand is expected to increase at a rapid rate in ERCOT compared to the rest of the country. Although DSM programs have grown to 2.2-GW for the 2014 summer peak, in addition to new generation capacity coming online, the reserve margin in ERCOT could soon fall below NERC's reference level of 13.75%, necessitating additional programs to shave peakload and increase generation capacity. However, ERCOT and the Public Utility Commission of Texas indicated that ERCOT's reserve margin won't be breached until 2018 at the earlier. Nonetheless, generation adequacy is a critical issue that the Public Utility Commission of Texas is moving ahead to address. For details on the Texas market, please refer to Citi Utility team's recent report "Annual Texas Power and Gas Trip Takeaways" published on May 5, 2014.

MISO (Midwest ISO) also faces challenges, especially when coal plants begin to retire. NERC has highlighted the shortfall in this power market when compared with a reference reserve margin level of 14.2%.

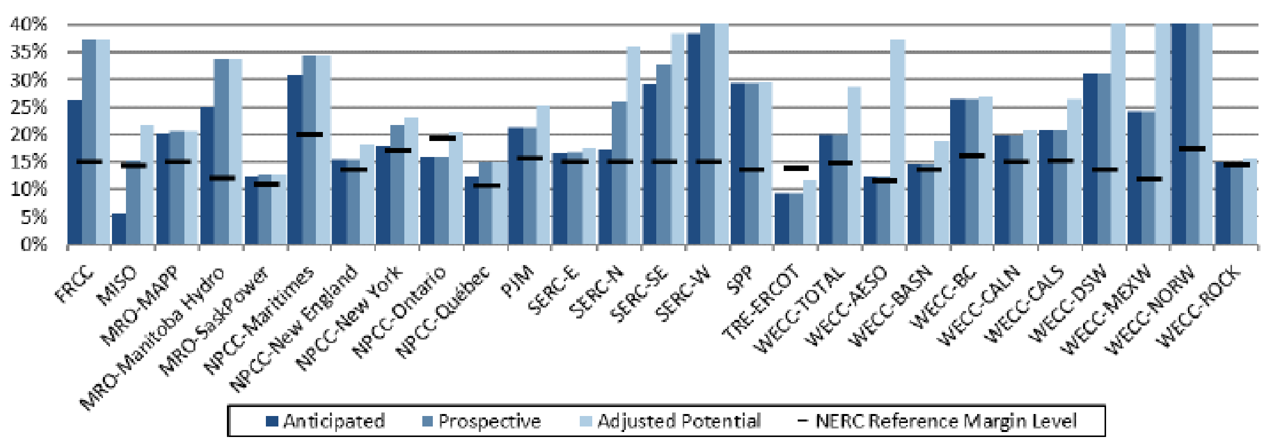
Figure 23. Anticipated Reserve Margin below Reference Margin in 2018 (in black)

Source: NERC, Citi Research

Figure 24. Anticipated Reserve Margin below Reference Margin in 2018 (in black) and 2023 (in blue)

Source: NERC, Citi Research

Figure 25. 2018 Peak Planning Reserve Margins



Source: NERC

Challenge 3: Grid Reliability

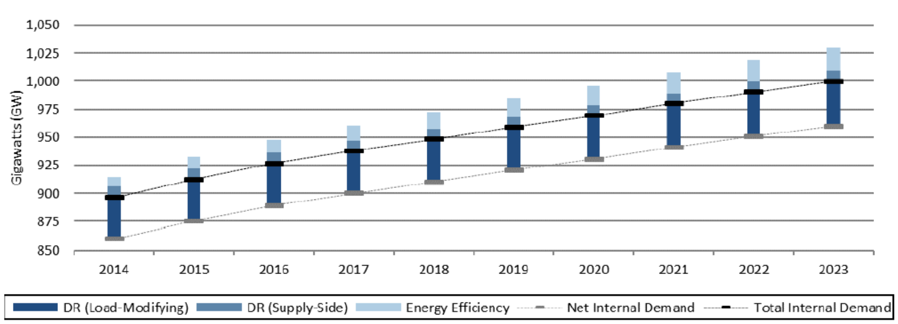
New challenges are emerging amidst the current structural evolution in the power generation industry. As discussed above, permanent fuel-switching and plants retirements/additions are challenging grid reliability from both the fuel supply and power transmission sides. In addition, the integration of demand-side management and new generation sources pose other challenges. Although the use of Demand-Side Management (DSM) reduces overall demand and capacity needs, the availability of DSM over the short term and long term could create more uncertainty for load and generation resource forecasting. More time is needed to collect empirical data to realize the benefit from changes.

In particular, the accuracy of electricity demand forecasting has been decreasing since the late 2000s. Empirical models based on correlation between utility and economic and technology factors are suffering from variations generated by the development of smart grids, the PHEV industry as well as changes in customer behavior.

Historically, electricity demand growth was generally correlated with changes in economic activities but in the last few years, despite positive real economic growth, electricity demand growth has either stayed flat or trended negative for some regions. As discussed above, the impact of load response, efficiency and behavioral changes has become more significant. What is challenging is measuring and estimating how they would react by the hour or day, as well as how they would grow and respond in the years ahead.

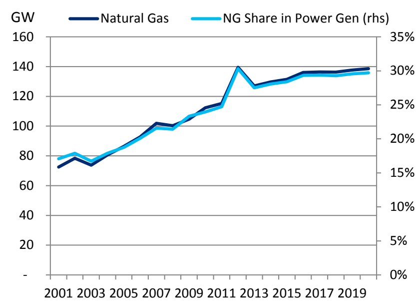
The impact is not insignificant: if demand growth were cut by 1%pa (i.e., if demand growth is supposed to be 2% but is now 1% because of DSM), then the decline is equivalent to about 4-GW, or nearly eight new gas-fired power plants at 500-MW each running at 100% capacity. Based on NERC's assessments, total DSM could account for ~14.8% of NERC-wide, noncoincident total internal demand, with Demand-Response (DR) programs responsible for ~3.8% of total internal demand.

Figure 26. Available demand response vs. noncoincident peak demand across NERC regions



Source: NERC

Figure 27. Natural gas share in power gen



Source: Citi Research

Challenge 4: Gas-Electric coordination amid an increased dependence on gas in some regions

With natural gas prices under pressure since 2008, its use in power generation has grown rapidly. With low fuel prices, coal plant retirements, new builds and favorable policy, the share of natural gas in electricity generation has increased from 17% in 2001 to just under 30% as of 2013 but the growth should now slow. Although gas-fired plants are expanding at an average rate of 7.6GW per year between 2014 and 2016, roughly compensating the 21GW capacity reduction from coal and liquid plants, capacity utilization could be lower than planned. A significant number of gas plants were built in the late 1990s to early 2000s but their subsequent capacity utilization rates fell much below planned levels. The availability of these plants allowed large-scale coal-to-gas switching to take place in 2012 to absorb the excess gas.

Challenges have also emerged, especially in gas-electric coordination. At the day-to-day operating level, the increased consumption of natural gas for power generation requires enhanced coordination and physical connections with the gas network. This gas-electric coordination[5] is important because of the growing reliance on gas-fired generation in some locations and problems created due to differences in trading and scheduling hours between electricity and gas. Gas may also not be traded on some days that electricity is transacted, thereby creating further mismatches in the demand and pricing of electricity and gas. The problem could be exacerbated when gas is withdrawn by a more-than-expected amount at an upstream portion of a pipeline but users downstream, such as power plants, might not be expecting cuts in gas delivered for consumption/generation. A mismatch between gas required and delivered would affect the amount of generation, particularly during periods of very high demand. Price spikes and stresses on the grid could tax the electrical system, affecting its reliability.

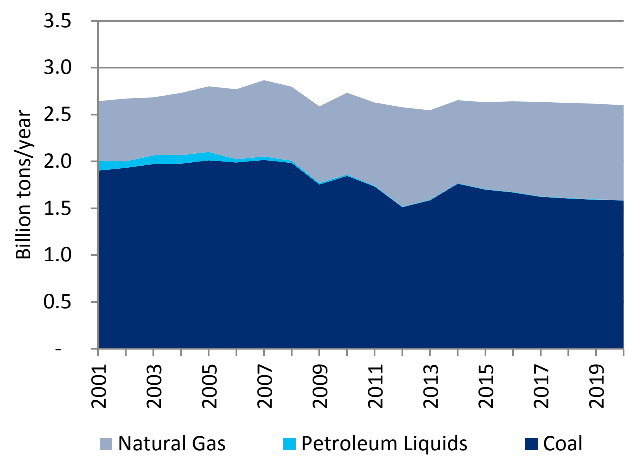
This also translates to the investment level. Although the growth of gas-fired generation necessarily requires more gas deliveries, power plants' dispatch decisions on a day-to-day basis reduce their desire to sign long-term, 10 to 20-year contracts that gas pipeline companies require to build new pipes. A prominent example is the gas shortage in New England. High gas demand for both heating and power generation caused prices there to be elevated, with frequent spikes, but getting new gas pipes to be built was arduous. Besides regulatory hurdles, some power plants seemed unwilling to commit to new pipes that need long term contracting, when they base their dispatch decisions on fundamentals within the next few days. Extra pipe capacity appears to only help when spikes occur – a phenomenon that is hard to quantify.

Challenge 5: Carbon emissions

In this scenario, carbon emissions from the power sector would still fall from a peak of 2 billion tons in 2007 to about 1.58 billion tons in 2020, but the decline from 2014 to 2020 may only be ~0.2 billion tons, as utilization rates of remaining coal power plants could stay high because they are more efficient than those that have retired.

[5] http://www.ferc.gov/about/com-mem/moeller/moellergaselectricletter.pdf

Figure 28. Estimated carbon emissions from the electricity power sector – modest decline after 2014



Source: EIA, Citi Research

Could the failure to cut greenhouse gas emissions further accelerate the implementation of carbon programs? Possibly, but obstacles abound in carrying out legislative or executive measures, as discussed previously.

Rather than directly regulating carbon, an alternative being applied is mandating the use of more renewables, effectively pushing out more fossil generation over time. By having minimal marginal costs of production, more renewables generation is expected to lengthen the power supply curve, thereby pushing out fossil-based generation that typically occupies the higher-cost end of the power supply curve. However, since coal, which emits more greenhouse gases than gas in the electricity generation process, is not penalized more than gas, more gas than intended might be squeezed out, especially if gas prices were to rise relative to coal prices, making gas plants comparatively less competitive vs. coal. This happens despite the cleaner properties of gas-fired generation vs. coal. The economics of nuclear could also deteriorate. Hence, simply having more renewables may not be the most effective way of cutting greenhouse gas emissions.

Technical note: Variable generation is typically less effective at preventing frequency decline and generally lacks disturbance tolerance. It is possible to create a chain-reaction that brings down other generating sources in rapid succession, causing blackouts. What this means is that if there is some sort of disturbance to the grid, a number of variable generation sources could trip, affecting the broader system if there are substantial numbers of these variable or distributed generation facilities in the system. For example, a sudden loss of wind power causes the voltage to drop. As many distributed generation units may have low-voltage disconnect, a voltage drop causes these units to shut as well, leading to further declines in voltage and cascading failure. (Think of voltage as the pressure that pushes electricity over the transmission line.)

But how could this happen? Many motors operate by having electrical current passing through coils to produce a magnetic field, rather than using permanent magnets to generate the magnetic field. Some devices have minimum working voltage and if the voltage falls below a certain limit, they shut themselves off. Industry standards, such as IEEE 1547, mandate that variable generation resources that are linked to the grid must disconnect from the broader power system shortly

after voltage or frequency from these resources falls outside of the system's range. But this can cause cascading failure if many facilities drop from the grid and voltage declines further.

Maintaining the electrical system's frequency and dealing with reactive power have historically been provided by traditional fossil power plants capable of voltage support. Without the presence of sufficient conventional generation on standby or operating, variable or distributed generation facilities would need to have so-called low voltage ride-through to possibly resume operating after temporarily dropping off the grid, or keep operating and provide support to the grid.

Equity Research View

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Coal retirements and renewable capacity pipeline

While industry estimates for projected retirements vary greatly and generally take into account commodity price movements and profitability, our approach results into estimated 14Gw of coal retirements between 2014-2020 in addition to already announced 28Gw of shutdowns and 18Gw of capacity that retired in 2011-2013.

It is important to note that even though the first wave of retirements in 2015-2016 will largely be driven by the MATS deadline, future retirements will be dictated by future environmental regulations, tightening compliance standards and capital costs.

At-Risk Plants - Citi Score Card
Older than **40 years**
Smaller than **400Mw**
Lacks SCR or FGD controls
= AT RISK OF CLOSURE

We evaluate existing coal-fired capacity based on plants age, size and the presence of environmental controls such as SCR and FGD, which we view as most significant for the plant's viability. We view the plant age of over 40 years old, operating capacity below 400Mw and the lack of either SCR or FGD as negative factors, and we consider plants that have two or more of such negative characteristic to be at risk of closing. The results of our analysis are summarized in Figure 29.

With respect to timing, we expect the first wave of MATS-driven retirements to begin in 2015 following the initial compliance deadline, and continue into 2016 and 2017. In total, operators announced approximately 28Gw of coal capacity retirements across all regions going forward, ~70% of which is scheduled to occur in 2014-2016 timeframe. This equates to ~79Gwh of net generation based on 2012-2013 operating capacity patterns (retiring plants were operating at 39% capacity utilization on average).

Figure 29. Announced and Projected Coal Retirements

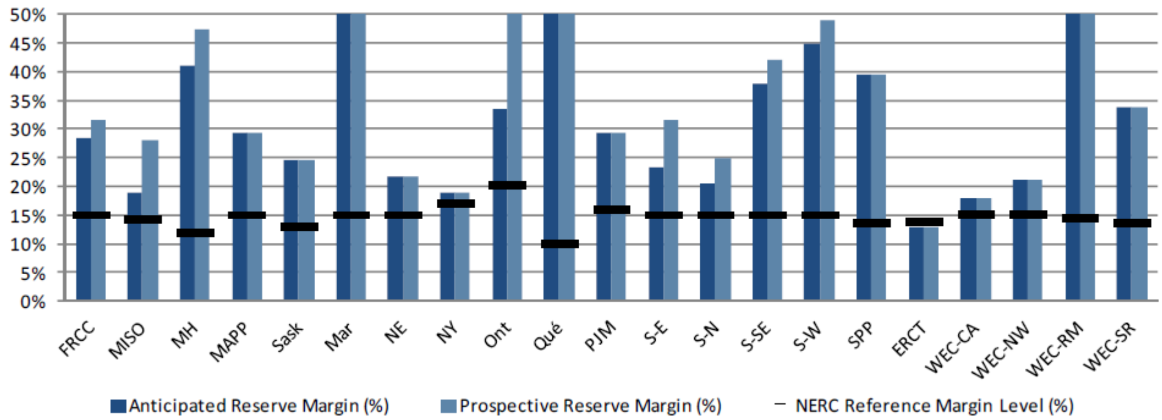
Region	Announced Retirements	Average Utilization	Capacity at Risk	Average Utilization	Total Expected Retirements
	Mw	%	Mw	%	Mw
PJM	11,491	19%	4,353	48%	15,844
CAISO	597	26%	0	NA	597
ERCOT	840	51%	0	NA	840
MISO	1,816	48%	6,113	48%	7,928
New England	1,283	1%	684	NA	1,967
New York	0	NA	130	NA	130
SPP	1,080	69%	335	NA	1,415
SERC	8,146	34%	2,371	19%	10,517
FRCC	0	NA	80	NA	80
WECC (1)	3,025	63%	741	63%	3,766
Total	**28,278**	**39%**	**14,807**	**45%**	**43,084**

(1) Excluding CA ISO and Canada

Source: Citi Research

We expect coal retirements to have most pronounced impact on pricing and reserve margins in MISO and PJM, where our estimated coal retirements will account for 5% and 8% of total generation respectively. As a result, we expect currently wide planning reserve margins of ~28% in both regions (see Figure 2) to tighten should all coal capacity that we view as "at-risk" retire. However, as we show in our dispatch curve analysis in the following section, the impact on pricing should be somewhat limited as planning reserve margins would stay comfortably above reference levels.

Figure 30. 2013 Summer Peak Planning Reserve Margins by Assessment Area



Source: NERC 2013 Summer Reliability Assessment

To some extent, market tightening from coal retirements will be mitigated by the additions of renewables. CA ISO will have the highest amount of renewables added into the generation mix over the next 6 years, largely offsetting the impact of coal retirements which will account for ~1% of CA ISO generation. In MISO and PJM, where existing renewable pipelines are relatively small, incremental solar and wind generation will have only modest impact on pricing. Our pricing analysis holds everything else equal and assumes that CCGTs and other baseload and load following generators will continue to operate at existing capacity utilization factors.

Figure 31. Renewables Pipeline by Region

Region	Solar Pipeline Mw	Solar Pipeline Gwh	Wind Pipeline Mw	Wind Pipeline Gwh
PJM	628	550	5,510	15,928
CAISO	18,128	15,880	2,440	7,054
ERCOT	889	778	6,950	20,091
MISO	140	123	6,985	20,192
New England	235	206	2,010	5,811
New York	36	31	210	607
SPP	89	78	4,100	11,852
SERC	1,710	1,498	650	1,879
FRCC	1,163	1,019	0	0
WECC [1]	11,955	10,473	3,510	10,147
Total	**34,973**	**30,636**	**32,365**	**93,561**

(1) Excluding CA ISO and Canada

Source: Citi Research

Across our coverage, AEP, SO, DUK and D announced the largest coal capacity retirements with AEP retiring as much as 6Gw, SO retiring 3.5Gw, DUK retiring as much as 2.7Gw of capacity and D retiring 1Gw. AEP also leads in our projected retirements at 0.84Gw followed by SO with as much as 0.69Gw of coal capacity at risk. We see potential incremental retirements for approximately 0.4Gw for DUK. For our regulated names, we expect these retirements to translate into incremental investment opportunities as companies seek to replace coal-fired generation with cleaner and more efficient CCGTs and renewable assets. From a stock takeaway perspective, if you are a regulated utility, you will clearly benefit from additional capital spending as you shut down old coal assets. But, if you are a merchant

generator that dispatches assets based on pure economics, coal retirements alone will not be enough to improve your margins given the muted impact on power prices. This actually runs counter to what some integrated utilities have been pitching. In our coverage space, Neutral-rated American Electric Power, Southern Company and Dominion and Buy-rated Duke Energy announced the largest coal retirements to date.

Outline of environmental rules leading to coal-fired generation retirements

MATS

We expect the first wave of MATS driven retirements in 2015 and continue into 2016

The MATS rule which was finalized by the EPA in late 2011 is aimed at curbing various types of air pollutants such as heavy metals (mercury, arsenic, chromium, etc.) and acid gases. The MATS rule applies to coal units with nameplate capacity over 25 Mw and requires compliance by March 2015. In some circumstances, state permitting agencies may grant a one year extension to comply (until 2016) and the EPA may allow compliance by 2017 for reliability critical units.

Even though compliance options for MATS vary across coal fired assets, in many instances MATS compliance requires installation of a full suite of emission control equipment to control mercury, acid gasses and particulate. PRB plants generally meet MATS requirements for acid gases and require a baghouse (FF) or Electrostatic Precipitator (ESP) and Activated Carbon Injection (ACI) to comply with mercury and particulate limits. Bituminous plants require additional controls for acid gases. An alternative option for meeting mercury reduction requirements is a combination of SO_2 and NOx controls which deliver mercury reductions as a co-benefit.

Various technological options for MATS compliance are outlined in the table below.

Figure 32. MATS Compliance Technologies

Control	Cost $/Kw (1)	Mercury	SO2	Acid Gases	Non Hg Metals	NOx
SCR	$492	x				x
FGD (dry/wet)	$697 - $799	x	x	x		
ACI	$27	x				
ESP	$150	x		x	x	
FF (baghouse)	$438	x		x	x	
DSI	$40		x	x		

(1) Based on 100 Mw unit

Source: Citi Research, EPA, EEI, Companies Presentations, MISO

While emission standards are site-specific, generally units equipped with FGD and SCR can be assumed MATS-compliant. Approximately 81% of all coal units in the US across all regions have SCR with FGD (see Figure 2). CA ISO and FRCC lead the pack with ~96% of all coal units equipped with SCR, and SPP, NE ISO and MISO show lowest level of presumably MATS compliant units at 60%, 71% and 74% respectively.

Beyond MATS: CSAPR Rules

In the recent 6-2 ruling, the Supreme Court upheld the EPA's authority to regulate cross-state air pollution, effectively reviving the CSAPR rules that have been tied up in litigation since 2011. The CSAPR rule sought to limit SO2 and NOx emissions through a cap-and-trade emissions program whereby certain plants emitting these pollutants would be required to pay for pollution permits.

However, we see limited impact from the revival of CSAPR rules at this point in time. We note that most MATS-compliant plants have environmental control equipment in place that would address their NOx and SO_2 emissions as well. On the other hand, non-MATS compliant plants are likely to be retired in 2015-2016 based on MATS standards alone.

Carbon Emission

The industry is focused on the upcoming CO2 regulation

New Coal Plants Regulation Overview

In September 2013, the EPA released its much anticipated carbon emissions proposal for new coal plants. The new proposal set separate emission standards for natural gas and coal fired power plants. Under the proposal, new coal-fired plants would need to meet a limit of $1,100lb of CO2 per Mwh. Coal-fired plants would have an option to average their emissions over a multi-year period (7-year average) allowing for extra operational flexibility. However, such plants would be expected to meet somewhat more stringent emission standards – 1,000lb to 1,050lb of CO2 per Mwh.

If implemented, the rule requires power plants to use Best Available Control Technology (BACT) to control emissions.

EPA Carbon regulation effectively bans new coal power plants.

While the EPA used Carbon Capture & Sequestration (CCS) technology as an example of commercially viable technology allowing coal-fired power plants to achieve the level of CO2 emissions comparable with low heat rate gas plants, CCS's viability commercial viability remains uncertain. The only large-scale coal plant with CCS technology is SO's Kemper plant, currently scheduled for late 2014 startup. Kemper suffered from multiple delays and cost overruns, with the total cost of the 580Mw plant exceeding $5B. Even still, Kemper was made possible by multiple locational advantages such as close proximity to lignite coal deposits and offtake options for captured carbon. Our LCOE Analysis suggests that Kemper is not competitive with other fuels or renewables. As such, the new plant's carbon emission standard effectively bans development of new coal fired plants. Please see our notes EPA Carbon Rule: Commodities/Equity View and President Obama's Climate Action Plan for further background on the issue.

Proposed CO2 regulations for existing plants will be released in the summer of 2014. EPA may attempt to regulate activities outside of power plants to achieve emission targets.

Existing Coal Plants Regulation

As the next step, the EPA is expected to release carbon emission rules for existing plants in the summer of 2014. **The agency has already indicated that it will not mandate CCS for existing assets**. The main controversy surrounding the ongoing debate on standards for existing plants is whether the EPA will target activities outside of the four corners of power plants. Our conversations with industry participants indicate that the EPA may impose restrictive carbon standards with the view that plant operators could offset carbon emission by compensatory activities outside of emitting plants (i.e. by building additional greener generation, instituting demand response and energy efficiency targets, etc.) – the so called "large box" approach. Under the "small box" approach, the EPA would contain its reach to just the operation of the power plant itself. Should the EPA chose the "large box" approach, its authority to regulate activities outside of power plants will almost certainly be challenged in courts.

In either scenario, the timing of compliance will be crucially important to operators making decisions to retire or continue to operate coal fired plants. Importantly, many plants that would come under scrutiny due to the new CO_2 regulation, had just undergone MATS-compliance related upgrades and substantial capital investment. Inability to recoup that investment would be highly punitive to the industry, and as a result we believe that the implementation timeline of carbon rules would have to be substantial.

Coal Ash and Effluents

Coal combustion residuals (CCRs), commonly known as Coal Ash, are byproducts of the combustion of coal at power plants and are disposed of in liquid form at large surface impoundments and in solid form at landfills. Following the TVA coal ash spill in 2008, the EPA proposed a set of rules aimed at regulating the disposal of coal ash on the national level for the first time. The main threat from coal ash comes from leaching into groundwater and eventual migration into drinking water.

The EPA outlined two different options for the regulation – under Subtitle D and Subtitle C of the Resource Conservation and Recovery Act (RCRA). The key difference is that under Subtitle C option the EPA would consider coal ash hazardous material. Such classification would make compliance with the rule substantially more expensive and reuse of coal ash (for example in concrete fabrication) more complicated.

Our industry sources believe the EPA is unlikely to designate coal ash as hazardous

According to 2012 EPA estimate, the number of coal ash pond in the US exceeded 1,160. Approximately half of these ponds were unlined and 80% lacked leachate collection systems. In addition, there were at least 393 landfills in the US, of which 43% lacked liners and 52% lacked leachate collection systems.

Currently, industry participants believe that the EPA will not designate coal ash as hazardous.

Possible ways to address coal ash issue include converting from wet to dry handling, lining existing ponds and other remediation activities. Since the regulation would apply to existing coal ash ponds regardless of the operating status of their power plants, we do not expect coal ash rules to drive substantial incremental retirements comparable in scale to MATS.

Costs of Possible Solutions

Industry sources estimate that the costs to convert a generating unit from wet to dry handling is $23 million per unit for fly ash and $20 million for dry ash. Conversion to dry handling allows coal unit to stop producing environmentally unfriendly wet ash that currently fills coal ash ponds.

However, much higher investment would be required to address already existing coal ash ponds. While site-specific costs of remediating existing coal ash ponds vary greatly depending on the approach and the ultimate engineering solution, industry sources estimate that putting a hybrid cap in place may cost up to $150m per site, while full excavation of landfills may cost up to $550m per site and span over a period of 20 years or more.

As with other environmental regulation, the magnitude of the financial impact on coal plant operators will depend not only on the approach that the EPA takes with respect to setting the standards, but also on the timeline of compliance. Since the costs associated with the conversion of operating units to dry handling are relatively minor, and much larger costs are associated with existing coal ash ponds (including the ones on retired units' sites), we do not foresee a substantial wave of retirements related to coal ash rules specifically.

Regional Haze

Most MATS compliant units are RHR compliant – we do not expect substantial incremental retirements

Under Regional Haze Rule (RHR), coal-fired plants are required to reduce emissions of haze-producing pollutants that affect visibility at national parks and wilderness areas. Unlike CSAPR rule which was predicated on the cap and trade system, the RHR requires best available retrofit technology to be considered as a

control measure, thus reducing compliance optionality for generators. The rule calls on states, in coordination with the EPA and other agencies, to develop and maintain air quality protection plans (state implementation plans, or SIPs) to curb emissions. Typical haze producing pollutants are sulfur dioxide (SOx), oxides of nitrogen (NOx) and particulate matter (PM). **Most MATS compliant plants equipped with SCRs and FGPs would also be compliant with RHR.** However, some units in the West that are burning PRB coal or were able to utilize ACI and other methods to comply with MATS may be at risk from RHR. We do not expect this capacity to be significant.

Rule 316(b)

Under Section 316(b) of the Clean Water Act, the location, design and construction of cooling water intake structure is required to reflect the best technology available for minimizing adverse environmental impact on aquatic ecosystem.

Accordingly, the EPA is preparing the final rule for cooling water intake for existing facilities that will establish guidelines for cooling towers widely used in nuclear and coal power plants (as well as other coastal facilities). While the agency was most recently required to issue section 316(b) rulemaking by April 17 2014, the EPA advised stakeholders that the rule will be once again delayed by a month.

Rule 316(b) will regulate water intake for existing facilities

The proposed rule that was issued in 2011 was aimed at facilities withdrawing at least 2M gallons of water per day and use at least 25% of that water for cooling purposes. At the time of issuing the proposed rule, the EPA estimated that ~670 power plants nationwide would fit that definition. Generally, compliance approaches may include installing modified screens equipped with fish buckets, reducing through-screen velocity, building aquatic filter barriers or converting to closed-cycle cooling system.

Closed-cycle cooling systems, while not required for the existing facilities by the proposed rule, would reduce through-screen velocity to the levels sufficient for compliance. In general, closed-cycle cooling systems use 2-5% of the amount of water used in a once-through cooling system. Some states, namely NY and CA, issued policy statements making closed-cycle cooling the benchmark technology for both existing and new facilities. Due to prohibitively high capital cost of building a closed-cycle cooling system for existing facilities, these state level regulations could lead to future capacity reductions if operators fail to successfully challenge them in courts. The proposed EPA rule imposed an 8-year compliance schedule.

Companies Mentioned: (AEP.N; US$52.32; 2); (DUK.N; US$71.98; 1); (D.N; US$69.86; 2); (DTE.N; US$76.63; 1); (PNW.N; US$55.27; 2); (SO.N; US$43.67; 2); (PPL.N; US$33.63; 1)

Appendix A-1

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