

# Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States

**Extract: Executive Summary and Key  
Research Findings**

**November 2010**



Whitepaper available online: <http://www.dbcca.com/research>



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# Editorial Letter

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With a Republican controlled House of Representatives, we can now expect a significant change in approach to US energy policy for at least the next two years. There is likely to be, for instance, more resistance to renewable energy incentives in a constrained budget environment. Attention is likely to focus on expanding the use of natural gas which President Obama has identified as an area of bipartisan agreement. The ideas outlined in this report could, we believe, deliver a realistic, low carbon energy pathway over the next 20 years, with a mix of natural gas, renewables, and nuclear replacing old and inefficient coal plants. This energy plan provides a credible, low risk and affordable way for America to achieve a 44% reduction in CO<sub>2</sub> emissions from the power sector by 2030 from 2005 emissions levels.

Our key finding is that a significant switch by the US electricity sector from coal to natural gas would be the most secure, least cost approach to lower emissions. (Burning natural gas creates approximately half the amount of CO<sub>2</sub> compared with coal). When combined with further renewables and nuclear deployment, this plan would involve a reduction in coal's share of energy generation from 47% currently to 22% by 2030. This would make the Obama Administration's targets of a 17% over all economy-wide reduction in greenhouse gas emissions by 2020 and an 83% reduction by 2050, realistically achievable. And these reductions would be realized by using domestically abundant and secure sources of energy based on known technology that can easily be deployed at reasonable cost. Importantly, our energy plan ensures a reliable electricity system that is not only much cleaner but also more environmentally sustainable.

We emphasize, however, that efficient coal units, renewable and nuclear energy must remain as important components of the over all energy mix portfolio. We envisage wind and solar energy, for example, increasing to 14% of the US energy mix by 2030 compared to just 2% today.

A large-scale switch from coal to natural gas in the US has become possible largely thanks to the major increase in supply from unconventional shale gas. Increasing supply is causing a long term fall in the price of natural gas, making it a far more economic fuel than in the past. We believe shale gas is environmentally sustainable with best practices. And because it is domestically abundant it also provides a high level of energy security.

# Executive Summary

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## DB Climate Change Advisors (DBCCA) Identifies Pathway to Significantly Reduced Emissions

Coal-fired generation supplies almost half of US electricity today. The focus of this paper is the evolution of the US electricity system through 2030 and concludes that in the short term (defined as the next 20 years), the U.S. is capable of almost halving its CO<sub>2</sub> emissions by 2030 (up to 44 percent) through a secure and reliable fuel mix that is based on known technology that can easily be deployed at reasonable cost. Longer term, a power system can be constructed that will deploy Carbon Capture and Storage (CCS) with gas, which DBCCA believes is more economical than coal, and/or pair gas with a further significant build-up in renewables, nuclear energy and efficient coal plants with CCS if the final goal of an 80 percent reduction in emissions is to be reached by 2050.

This was arrived at based on the following:

- Looking at what fuels/technologies can be easily deployed based on current knowledge while maintaining the reliability and integrity of the power system; and
- Looking at the economics that would drive such a pathway to ensure it was as much as possible the least “cash cost” solution, while making a reasonable assumption that energy efficiency measures and technology keep electricity demand growth subdued.

## Key Drivers and Enablers

From an emissions perspective, coal usage has to be replaced by lower carbon fuels over the next 20 years. We expect both renewable and nuclear energy to noticeably increase their share of generation, by 12 percentage points and 3 percentage points, respectively, over that timeframe. We expect natural gas to increase its share of generation by 12 percentage points and account for about 35% of total electricity sector emission reductions by 2030. Of that, about two thirds can come from increasing the utilization rate of the existing stock of gas plants as old and inefficient coal plants are retired.

For the coal to gas switch, a key driver is a \$4-6/mmBtu natural gas price due to the major increase in supply coming from unconventional shale gas, which DBCCA believes will prove to be environmentally sustainable with best practices and is domestically abundant. A further addition to this strategic energy transition would be a return to natural gas producers agreeing to sell forward production under long-term contracts to electricity producers in order to mitigate price volatility.

This switch yields a secure and low-cost alternative to coal. Through the middle of 2010, the economics of gas have already caused about a 3 percent increase in natural gas fired generation fuel mix in the past 2 years ended 2Q10. Calculating accurately the cost of major changes in energy production is never easy, however, in our view, a coal-to-gas switch that is suitably based on raising utilization rates of existing plants in the face of massive new unconventional shale supply will certainly help keep this a least-cost pathway.

## Beltway Involvement

Policy will need to continue to play an important role in renewable and nuclear deployment until they reach cost parity with coal and gas at \$6/mmBtu. That cost calculation should include a full “cash cost” approach including infrastructure needed to deploy them, while longer-term potential costs to the environment should be considered in terms of “full cost.” Additionally, in the short-term, the relative costs of wind and solar technologies are likely to slow down their deployment versus potential and longer-term as renewables face the challenge of stable integration into the grid at significant scale even after their costs have declined substantially as we expect. Nuclear faces public safety and waste issues at further scale.

# Executive Summary

The role policy plays in the fuel switch is in regulating the health-related pollutants associated with coal. Most importantly, in DBCCA's analysis, the pending regulation by the Environmental Protection Agency that phases in through 2014 will render old (greater than 45 years) and inefficient coal plants uneconomic compared to dispatching existing or indeed building new gas plants. Litigation and potential congressional resistance could delay implementation in the short term.

## Do Coal Plants Collect Social Security?

There are 60 gigawatts (GW) of coal plants that are over 60 years old and are expected to be retired by 2020. On top of that, there is a further 92 GW of coal plants over 45 years old, inefficient and ripe for retirements. Collectively, this represents about 45 percent of total current coal capacity.

Even a modest carbon price would further enhance the economics of this switch. While DBCCA has not formally included this in our modeling, we believe the utility industry will continue to factor this possibility into their risk analysis in coming years.

## Conclusion

In essence, by deploying "low risk" fuel solutions such as gas, wind and solar in the next 20 years, the power system remains reliable and flexible keeping options open beyond 2030, by which time technology advances unknown today could still prove to be "game changers."

## Investment Conclusions

- We expect coal's share of power generation to decrease to 22% by 2030 compared to 47% in 2009, while the share of natural gas generation increases from 23% in 2009 to 35%. Wind and solar increase from 2% in 2009 to 14% in 2030.
- Renewables, natural gas and nuclear energy contribute 41%, 35% and 16%, respectively, to the reduction in power sector CO<sub>2</sub> emissions by 2030.
- Total electricity sector natural gas demand increases to 9.7 Tcf per year in 2030 versus 6.9 in 2009, a 2.8 Tcf incremental increase.<sup>1</sup> US aggregate natural gas consumption increases to 27 Tcf in 2030 compared to 22.6 Tcf in 2009. Total electricity sector coal demand decreases from 930 million tons per year in 2009 to 460 tons per year in 2030.
- We forecast total installed US renewable capacity to increase from 34.7 GW in 2009 to 126 GW in 2020 and 219 GW in 2030. Transmission grid improvements need building out to accommodate renewables and are expected to total \$41 billion through 2020 and will reach \$158 billion by 2030.
- We expect that at least 32,000 miles of transmission lines will be built by 2020<sup>2</sup>.
- Capital investment in new gas generation to replace retiring coal fleet totals \$39 billion between 2010 and 2030, resulting in 13,000 MW of cumulative natural gas additions from 2010-2020 and 20,500 MW of cumulative additions from 2020 to 2030.
- Incremental natural gas pipeline capacity additions of about 10-12% of the total current pipeline network will likely be necessary.
- Total cumulative power sector generation capital spending for new units is \$858 billion from 2010 to 2030, with peak spending occurring in 2020.
- The total industry costs of the new fuel mix are manageable, due in large measure to an improvement in utilization of already built natural gas plants. We expect annual generation cost of delivered electricity to increase from \$272.8 billion in 2009 to \$384 billion in 2030, a compound annual growth rate (CAGR) of 1.6%.

<sup>1</sup> 480,000 MW x 6.9 mmBtu/MWh x 24 hours x 365 days x 35% capacity factor; then divide by 1.05 to convert to Tcf and then divide by 1,000,000,000

<sup>2</sup> ITC Holdings Corp 2010 Investor Day Slides, p.7

# Executive Summary

## Key Exhibits

### US Future Energy Pathway: Fuel Switch Mix Ease of Deployment in the Electricity and Power Sector<sup>3</sup>

DBCCA Taxonomy	CO2 Abatement Potential	Capex Financing Requirement	2020 Deployment Limitations	2030 Deployment Limitations	DBCCA Feasibility Assessment
Renewable Power- Wind	Moderate	High	Moderate	Moderate	High
Renewable Power- Solar	Moderate	High	Moderate	Moderate	High
Renewable Power- Other*	Moderate	High	Moderate	Moderate	High
Nuclear Energy	High	High	High	Moderate	Moderate
Coal CCS	High	High	High	High	Low
Fossil Fuel Switching (coal to gas)	High	Low	Low	Low	High

Source: DBCCA analysis 2010. \* Other includes hydro, geothermal and biomass. See page 14 for further discussion.

### DBCCA Electricity Supply Mix Forecast

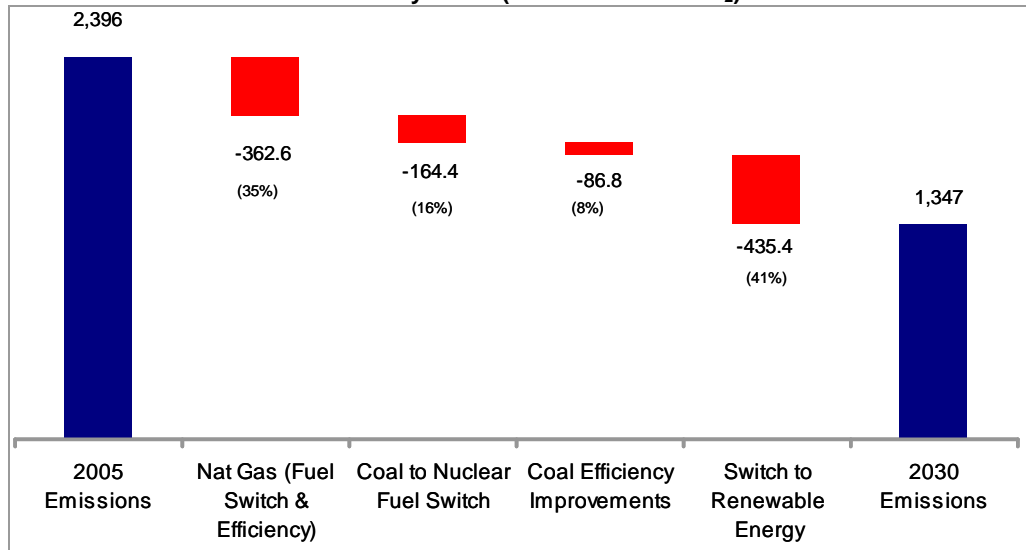
US Electricity Supply (% total kWh)	2005A	2009A	2020E	2030E	Comment
Coal traditional	50%	47%	34%	21%	Reduced to meet emissions target and comply with EPA regulation
Coal CCS	0%	0%	0%	1%	Limited deployment 2020-2030 with government R&D support
Natural gas	19%	23%	30%	35%	Coal to gas fuel switch, underutilized assets, strong new build
Natural gas CCS	0%	0%	0%	0%	No deployment, assume that gas CCS is viable post 2030 and cheaper \$/MWh than coal
Petroleum	3%	0%	0%	0%	No additions; existing capital stock remains for reliability but hardly used
Nuclear	19%	20%	21%	23%	Modest gains from nuclear steam generation "uprates" and limited new builds
Wind and solar (intermittent)	0%	2%	9%	14%	Large capacity additions; transmission and dispatchability limit growth vs potential
Baseload renewables (geothermal & hydro)	7%	8%	6%	6%	Share decreases modestly as only very limited new builds
<b>Total</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	
Renewables share total (intermittent and baseload)	9%	10%	15%	20%	Doubling of share 2010 to 2030 due to wind and solar additions to meet RPS
Electricity Demand (kWh)	4,055	3,784	3,978	4,181	0.5% CAGR growth due to energy efficiency and operational improvements
CO2 emissions (mn metric tons)	2,397	2,200	1,691	1,347	Emissions reduced substantially due to the coal to gas fuel switch and build-up in renewables
% CO2 emissions reduction vs. 2005		-8%	-29%	-44%	

Source: EIA, DBCCA analysis 2010. See page 14 for further discussion.

<sup>3</sup> In assessing all of the potential electricity sector pathways, we analyze the regulatory, permitting, cost allocation, system constraints/limitations and technology barriers of each portfolio of options. The coal to gas fuel switch has the lowest deployment limitations based on these metrics compared to coal CCS or nuclear energy between 2010 and 2030, largely because there are so many gas plants that are already built and simply underutilized. We therefore believe that the coal to gas fuel switch is the most feasible pathway option for baseload electricity generation.

# Executive Summary

**Emission Reduction Contribution by Lever (mn metric tons CO<sub>2</sub>)<sup>4</sup>**



Source: EIA, DBCCA analysis 2010. See page 22 for further discussion.

**Coal to Gas Fuel and Asset Switch Decision Tree Matrix and Commodity Price Sensitivity**

Coal / Gas Scenarios	1	2	3	DBCCA Comment
Power Generation Type (\$/mmBtu Fuel)	Existing Coal/Gas Plant LCOE	Depreciated Coal Plant EPA Retrofit Fully Loaded Cash Cost	New Build Coal/Gas Scrubbed EPA Compliant Plant Fully Loaded Cash Cost	
Coal @ \$3.00	0.04-0.06	0.06-0.09	0.10-0.14	Coal fully loaded cash costs rise with greater EPA compliance
Gas @ \$4.00	0.03-0.05	N/A	0.05-0.07	At \$4/mmBtu, gas displaces coal across all scenarios
Fuel switch	Yes	Yes	Yes	Hedge a carbon price
Asset switch	Yes	Yes	Yes	Hedge a carbon price; build new gas assets to replace inefficient coal
Gas @ \$6.00	0.05-0.07	N/A	0.06-0.10	At \$6/mmBtu, only old unscrubbed coal beats gas on LCOE but not based on fully loaded cash cost
Fuel switch	No	Yes	Yes	
Asset switch	No	Yes	Yes	Hedge a carbon price; build new gas assets to replace inefficient coal
Gas @ \$8.00	0.06-0.08	N/A	0.07-0.09	At \$8/mmBtu, old coal beats gas on LCOE and new EPA compliant builds are breakeven with gas
Fuel switch	No	Yes	Selectively	Hedge a carbon price; dispatch efficient gas assets
Asset switch	No	Yes	Selectively	Hedge a carbon price; build new gas assets to replace inefficient coal

Source: DBCCA analysis 2010. See page 29 for further discussion.

<sup>4</sup> **Natural gas emissions:** Calculated by looking at the difference between emissions intensity of coal and natural gas as applied to new build natural gas. New build natural gas is assumed to displace coal generation MWh on a 1:1 basis. Thermal efficiency improvements in the installed asset base are added to the total. Here we assume that heat rates of gas assets improve over time, which reduces overall emissions. **Nuclear energy:** Calculated by looking at the difference between emissions intensity of coal and nuclear as applied to new build nuclear. New build nuclear is assumed to displace coal MWh on a 1:1 basis. **Coal efficiency improvements:** For legacy coal assets, emissions intensity improvements drive a quantifiable value. **Renewables:** Remaining emissions reductions are attributed to renewables, as no other emissions reduction 'levers' remain. **Note:** 2005 has higher emissions than 2009 because of the impact of the recession. This means that the amount of emissions reduction plugged by renewables is larger than it would have been with 2009 as the base year. Other generation sources remain relatively constant between 2005 and 2009, so renewables picks up a substantially larger attributed share of emissions using 2005 anchor emissions data compared to what would be the equivalent with 2009 as the base year.

# Key Research Findings

## A Low Risk, Least Cost, Reliable Pathway to a 44% Reduction in CO<sub>2</sub> Emissions from the US Power Sector by 2030

- **The Obama Administration** has proposed a 17% overall economy-wide reduction in greenhouse gas emissions (GHGs) by 2020 and an 83% reduction by 2050 from 2005 levels, in line with the emissions abatement considered necessary to achieve climate stability.<sup>5</sup> This paper looks at how realistically this policy target could be put in progress by 2030 based on dramatic emissions reductions in the electric power sector.<sup>6</sup> **Importantly, we start by looking at the system engineering issues to find a low risk, easily deployable and reliable system. We then combine this with the economics** to find a least cost approach and show how the economics drive the result.
- **A coal to gas fuel switch** will need to be a main component of any climate stability target and a 29% reduction in power sector CO<sub>2</sub> emissions by 2020 and a 44% reduction by 2030 versus a 2005 baseline is feasible, most importantly at reasonable cost while maintaining the integrity and reliability of the grid and energy security. Such a fuel switch also offers local air quality benefits and is a less costly and less risky regulatory compliance pathway for many utilities.
- **At the policy level**, we continue to hope for a fully comprehensive set of measures including a carbon price to emerge over time. However, the key assumptions in our paper are that the EPA regulates non-CO<sub>2</sub> coal pollutants and that renewable incentives are maintained in some form over the next five years or so. We also believe that even the possibility of a carbon price in the next 10 years will cause utilities to want to hedge against this in their generation portfolio.
- **In terms of basic economics**, we see low natural gas prices due to unconventional shale supply and an eventual decrease in many renewable energy costs to grid parity as key drivers of our thesis.
- **Coal generation** supplies 47% of US electricity today, emits more CO<sub>2</sub> per MWh than any other source and has no choice but to become a lower part of the energy mix given that carbon capture and storage (CCS) is still unknown at scale;
- **Natural gas generation is key for reducing emissions at scale while ensuring system reliability and/is frequently referred to as a “transition” or “bridge” fuel.** For those that believe it is a “destination fuel”, gas carbon capture and storage (CCS) is the critical element over the longer term. There are immediate advantages in the shorter term. Natural gas has about 60% less CO<sub>2</sub> emissions per MWh compared to coal and virtually none of the other emissions that come from coal-fired power generation;
  - Underutilized generation resource: there is ample capacity, stranded from the 1998-2003 “dash to gas” overbuild and the recession has increased reserve margins, reducing pressure on adding new plants in many regions. **We assume that at least two-thirds of the coal to gas switch** can be achieved by increasing utilization;
  - Future natural-gas fired generation economics are driven by **unconventional, abundant shale supply** and a recent step-change in productivity improvements in exploration and production (E&P), which will **keep prices more stable** than in the past. In effect, at a gas price of **\$4-6/mmBtu**, we believe that a coal to gas switch makes sense, particularly on the basis of coal power production costs rising after EPA regulation around pollutants, not specifically carbon, which take effect by 2014. In our view, gas offers a least cost approach to decarbonization, with renewable power costs falling to pair with it.
  - In our modeling, **we assume that long-term natural gas contracts<sup>7</sup> with reasonable price escalation clauses become more standard** between producers and power generators to allow for greater certainty given the historically high volatility of natural gas prices compared to other fuels. **We also assume that environmental issues such as waste water treatment and disposal related to the completion techniques used in shale gas extraction are manageable and publicly accepted.**
  - **More flexible generation resource** than coal or nuclear for ramping to pair with variable wind and solar capacity additions;

<sup>5</sup> See: [http://www.ipcc.ch/publications\\_and\\_data/publications\\_ipcc\\_fourth\\_assessment\\_report\\_synthesis\\_report.htm](http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm).

<sup>6</sup> Note: CO<sub>2</sub> emission reductions in the power sector alone would not be sufficient to meet the overall economy wide targeted emissions reductions by 2050. Emission reductions from other sectors such as industry and transportation will also be required.

<sup>7</sup> A long-term gas supply agreement is an agreement with a term generally not less than three years or more than twenty years between a gas producer and a load serving entity—e.g. utility generator. All long term gas supply agreements may be filed with a utility commission for review and approval. The commission will then determine whether the utility acted prudently by entering into the specific agreement and whether it is in the public interest. If a long-term gas supply agreement is approved, the utility is entitled to recover the costs that it incurs under the approved agreement and the commission is generally prohibited from reversing its approval of the supply agreement even if the agreement price is higher than a future price of natural gas.

## Key Research Findings

- **Time-to-market:** natural gas power plants can be built in 2 years compared to 4-5 years for coal and 7-10 years for nuclear, although permitting can further extend these times;
- **Energy security** from abundant domestic resource. According to MIT<sup>8</sup>, with unconventional shale gas supplies, the US has potentially 20 years supply below a marginal breakeven price of \$6/mmBtu assuming an average of 25 Tcf of annual demand and then enough supply for the next 20 years after that through 2050 assuming an average of 28 Tcf per year at \$8-9/mmBtu. The latest estimates are that the US has about 200 years of natural gas supply.<sup>9</sup> **The longer term challenge** is that to become sustainable for a lower carbon future energy system, base load and mid-merit natural gas electricity generation requires CCS post 2030 to stay on a 450 ppm emissions trajectory. **At this point, load following natural gas plants without CCS will likely become more of a backup generation source for ever increasing penetrations of renewable power.**
- **Why reduce coal generation?**
  - Costs are going up and the capital stock is aging and largely inefficient. Our modeling scenario assumes the retirement of older (45 years and above) and largely inefficient (12,000 Btu/kWh and above) coal generation capital stock, so the cost impact is minimized.
  - Federal regulation (EPA) is intensifying to curtail criteria pollutants such as Mercury, SO<sub>2</sub> and NO<sub>x</sub>. And other regulatory issues such as cooling water intake and ash disposal have the potential to layer additional costs;
  - EPA is legally mandated to regulate CO<sub>2</sub> and will promulgate first rules by the end of 2010. In our analysis we have not assumed a carbon price explicitly. However, we assume the eventual possibility of a carbon price influences market decisions;
- **Carbon capture and storage (CCS) as a viable technical solution for coal generation is still unproven;** CCS for natural gas looks more promising and is less expensive on a \$/MWh of power produced than post-combustion retrofit coal plants, although demonstration projects are needed;
- **The cost impact of the transition to a lower carbon electricity sector is manageable within the context of the size of the US economy,** particularly because of the structural change in natural gas supply, declining renewables cost and an increased focus on energy efficiency and demand side management programs. A key consideration is making better use of the existing infrastructure, particular the underutilized fleet of natural gas plants. We apply our “cash cost” model to the cross section of generation technologies to market size new builds and retirements. Coal generation costs increase due to rising fuel costs and higher environmental compliance costs as the externalities are priced into generation. Nuclear remains expensive but will get deployed where there is favorable regulatory support. In aggregate we expect the total annual cost impact on the US generation fleet to be \$384 billion in 2030, compared to \$272 billion in 2009, a 1.6% compound annual growth rate (CAGR).
- **Nuclear energy** can only scale so far, given its high cost, long lead times for deployment and barriers around waste disposal and public perception in some regions of the country;
- **Renewable energy** needs policy support shorter term given cost differentials and has integration challenges with the power system as it scales longer term so will increase steadily but gradually given these constraints. As a maturing technology with high upfront capital costs but low variable operating costs, we expect the economics of renewables to become broadly competitive with on peak fossil fuel-fired generation in the coming years—even in the absence of regulatory support—and an important energy security and system reliability hedge. Integration issues will be solved by improvements in distribution architecture, a more flexible and intelligent “smart grid” and transmission additions over time.
- **Beyond 2030 will require further decarbonization to get to at least an 80% reduction in emissions** over the next investment cycle through 2050. This is beyond our investment time horizon but likely comes with a massive increase in renewable energy paired with natural gas CCS, or a substantial build up in nuclear energy, or even possibly a geo-engineering or technology breakthrough. The key is the energy pathway outlined in this report is an achievable and reasonable roadmap that leaves open all options.

<sup>8</sup> *The Future of Natural Gas, MIT, June 2010*

<sup>9</sup> <http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base>

# Key Research Findings

## Risks to Thesis

Our coal to gas fuel switch thesis hinges on the intersection of economics, changing industry cost fundamentals and regulation. We assume that **the environmental issues associated with non-conventional shale extraction are manageable** even with more restrictive environmental regulation, which we view as likely and probably even necessary to ensure best practices. At this time this is not a consensus view. There are shale detractors in the environmental advocacy community. And to be fair the industry practices and potential feedback loops are still not well understood and there are sure to be learning curves given its nascent state.

Sustainable shale extraction is a key assumption because non-conventional shale resources will represent marginal natural gas supply over the foreseeable future. If for some reason this supply can not be tapped at economically attractive price levels with reduced price volatility then the economic case for the coal to gas fuel switch would be challenged without a significant carbon price in place. There are numerous federal studies underway to examine the environmental and human health impacts of non-conventional gas extraction. If “produced water” is found to be a danger to human health because of contact with the natural gas itself, fracking fluids<sup>10</sup>, seepage into groundwater or even naturally occurring radioactive materials and heavy metals, then there could be a strong regulatory response, which could mean added environmental costs. This would diminish the environmental advantages that we foresee for natural gas versus coal-fired generation.

In addition, hydraulic fracturing has been associated with some amount of increased seismic activity. Complaints about earthquakes believed to be caused by hydraulic fracturing have arisen in California, Texas and Switzerland. Notably, in each of these cases the seismic activity was due to fracturing being used for deeper geothermal energy wells in which the fractures would be used to pump water down to hot rock which would return to the surface as steam. There have also been incidents in which dissolved methane has appeared in well water and there has been suspicion that this was due to fracturing. Upon closer scrutiny, most of these situations appear to be the result of natural origin and were not caused by fracturing.

Most of the environmental issues and fines that have been levied by state regulators that we have come across with fracturing for shale gas appear to be the result of operational error rather than due to technical impediments. As with any fast growth industry, there are bound to be learning curves. Over the course of 2010 we have witnessed a massive increase in recycling water used in hydraulic fracturing in the Marcellus Shale, for instance, with some operators now recycling about 100% of all water. This suggests to us that with best practices the environmental issues associated with shale extraction can be managed so that there is minimal impact to the local ecosystems.

Another factor that would potentially soften our fuel switch thesis would be a reversal of the current trend toward more restrictive EPA-led regulation targeted predominantly at the coal industry. Challenges in the courts to EPA regulation could undermine the aggressive timeline of expected regulatory action which is driving the retirements of coal units. Moreover, future presidential administrations might be less forceful in their support of EPA led regulation. In addition, there is the potential that our coal retirement forecast may not be realized as quickly as we anticipate if it is deemed that there might be a reliability impact in the form of deteriorating reserve margins in certain power markets. For example, on Oct 27, 2010 the North America Electric Reliability Corporation (NERC) released a major study assessing the resource adequacy impacts of potential US Environmental regulations on system reliability.<sup>11</sup>

The NERC report argues that the 2015 and 2018 mandated periods for the phase in of EPA action is aggressive, raises reliability risk and puts significant pressure on industry to add sufficient replacement capacity. Our own view is that the utility

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<sup>10</sup> There has been significant discussion about the chemicals used in the fracking process as being considered proprietary. Individual states mandate disclosures as does the Occupational Safety and Health Administration (OSHA), which requires this information to be kept at every well site and made readily available to first responders in the case of an emergency.

<sup>11</sup> North American Electric Reliability Corporation (NERC) 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations, October 2010

## Key Research Findings

industry is capable of rising to this challenge, capable of adding sufficient generating capacity and will likely have the regulatory support to ensure that this happens. This is supported by research from M.J. Bradley and Analysis Group, which released a report in August 2010 concluding that the industry is well positioned to respond to proposed EPA standards since the electricity system has over 100 GW of excess capacity.<sup>12</sup> By virtue of its mandate, NERC is generally exceptionally conservative in its recommendations and guidelines. Nevertheless, the NERC report argues that the pace and aggressiveness of these environmental regulations should be **risk adjusted** to consider the impact on system reliability rather than a one size fits all approach. Toward this end, NERC makes the case that all federal and state agencies and affected stakeholders including EPA, FERC, DOE, state utility regulators and industry should employ a broad array of tools to moderate reliability impact. Such tools include potential delay of implementation, ensuring that reserve margins are maintained and capacity markets operating in regions with deregulated wholesale power function effectively to ensure an adequately high enough cost of new entry (CONE) price signal to encourage new replacement capacity where needed. Similarly, stakeholders in regulated markets should work to insure that investments are made to retrofit or replace retiring capacity—e.g. regulators should allow regulated utilities to spend what they need to spend to maintain adequate reserve margins. Clearly, though, if it is deemed that EPA regulation will have an adverse impact on system reliability, then coal generation could potentially be less vulnerable by 2015 and 2018 without a carbon price relative to natural gas-fired generation compared to our investment thesis.

Electricity rate shock is also a risk. Given the large amounts of industry capex that is coming, 1-2 year rate case cycles between the utilities and the state public utility commissions (PUCs) are likely to become more of the norm compared to the past few decades when rate cases occurred with much less frequency. Therefore, the era of very cheap and stable electricity prices will likely be challenged in some states, which could have adverse political consequences and might retard the pace of capital stock turnover.

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<sup>12</sup> M.J. Bradley & Associates, LLC and Analysis Group. 2010. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*. Full study available at [www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf](http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf).

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