

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

November 2010



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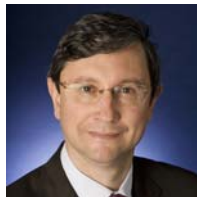
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With a Republican controlled House of Representatives, we can now expect a significant change in approach to US energy policy for at least the next two years. There is likely to be, for instance, more resistance to renewable energy incentives in a 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 CO₂ 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 CO₂ 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 electricity generation portfolio. We envisage wind and solar energy, for example, increasing to 14% of US electricity generation 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

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 CO₂ 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 CO₂ 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.¹ 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 2020².
- 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%.

¹ 480,000 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

² 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 Sector³

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

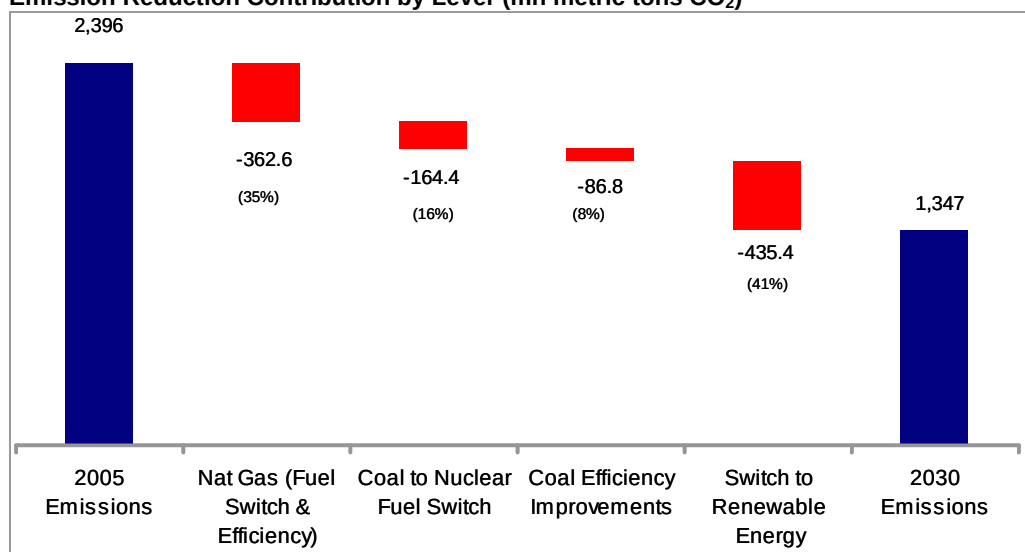
US Electricity Supply (% total kWh)	2005A	2009A	2020E	2030E	Comment
Coal traditional	50%	47%	34%	21%	Reduced to meet emissions target and comply with EPA regulation
Coal CCS	0%	0%	0%	1%	Limited deployment 2020-2030 with government R&D support
Natural gas	19%	23%	30%	35%	Coal to gas fuel switch, underutilized 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
Total	100%	100%	100%	100%	
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.

³ 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 CO₂)⁴



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.

⁴ **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 CO₂ 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.⁵ 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.⁶ **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 CO₂ 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-CO₂ 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 CO₂ 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 CO₂ emissions per MWh compared to coal and virtually none of the other emissions that come from coal-fired power generation;
 - o 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;
 - o 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.
 - o In our modeling, **we assume that long-term natural gas contracts⁷ 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.**
 - o **More flexible generation resource** than coal or nuclear for ramping to pair with variable wind and solar capacity additions;

⁵ See: http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm.

⁶ Note: CO₂ 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.

⁷ 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

- o **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;
- o **Energy security** from abundant domestic resource. According to MIT⁸, 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.⁹
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?**
 - o 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.
 - o Federal regulation (EPA) is intensifying to curtail criteria pollutants such as Mercury, SO₂ and NO_x. And other regulatory issues such as cooling water intake and ash disposal have the potential to layer additional costs;
 - o EPA is legally mandated to regulate CO₂ 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.

⁸ *The Future of Natural Gas*, MIT, June 2010

⁹ <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 fluids¹⁰, 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 American Electric Reliability Corporation (NERC) released a major study assessing the resource adequacy impacts of potential US Environmental regulations on system reliability.¹¹

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

¹⁰ 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.

¹¹ 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.¹² 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.

¹² 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.

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A Low Risk Approach to a Low Carbon Fuel Mix

Summary

- From a power system perspective, natural gas and renewable energy deployment is a low risk strategy for dramatically reducing power sector CO₂ emissions over the next 20 years when we envisage a halving of coal's contribution.
- A coal to gas fuel switch is a key factor in achieving this fuel mix shift, along with significant expansion of wind and solar and a moderate increase in nuclear energy. Notably, better utilization of the existing natural gas power generation can achieve about 2/3rds of the increase in the natural gas fuel mix shift.
- There are no fundamental or technical barriers inhibiting this fuel mix shift from happening at a systems level.
- An aging coal fleet and EPA regulation are catalysts for the fuel switch.

The Low Carbon Pathway

Our initial step was to model a reduction in CO₂ emissions that puts the US on a pathway to significant reductions. In order to do that we took a practical view of what we believe can be seen as a low risk approach to the electricity sector generation fuel mix based on known technology and ease of deployment. In effect, this analytical framework looks at the power system issues around low carbon deployment. We tackle the economics and policy drivers of the low carbon pathway in the next sections of this study and demonstrate that the low carbon pathway we are showing is a least cost approach and indeed can be driven by those economics, even in the absence of an explicit price on carbon.

We primarily focused on what the power sector can deliver in terms of emissions reductions in 2020 and 2030. We chose the power sector because it is the largest source of CO₂ emissions and is the subject of regulation from federal agencies. We chose these two time periods because 2020 is the near-term planning horizon for utilities and also matches the capital stock runoff of many of the older coal plants. And 2030 is when a sizable share of today's most productive coal, nuclear and natural gas generation fleet will be retiring or close to retiring and will need to be replaced.

Our base case modeling assumption is pragmatic and has “something for everyone.” In our forecast, renewables, nuclear energy and natural gas gain share through 2030. Efficient coal plants remain viable, although aging and inefficient coal units are retired and replaced with incremental natural gas capacity additions and a step-up in the utilization rate of the existing fleet. We also anticipate that energy efficiency, operational improvements and demand side management programs play a complementary role and restrict aggregate growth in electricity demand, limiting the compound annual growth rate of electricity consumption to just 0.5% from 2009 through 2030 versus EIA's projection of 1%.

Switching coal to natural gas and renewable energy with a modest buildup of nuclear energy is achievable and could lead to a 29% reduction in CO₂ emissions from the US power sector by 2020 and a 44% reduction by 2030 compared to a 2005 baseline.¹³ The coal to gas fuel switch is a practical lower carbon alternative over the next 20 years for the US power sector. This fuel mix would put the US electricity sector roughly at the midpoint of the 80% aggregate reductions in CO₂ emissions required by 2050 compared to a 2005 baseline. By way of comparison, the Waxman-Markey American Clean Energy and Security Act (ACES Act—H.R. 2454) has proposed economy wide emissions reductions of 17% by 2020 and 83% by 2050 compared to 2005 baseline emissions. And the Obama Administration made a Copenhagen Accord pledge to reduce greenhouse gas emissions in the range of 17% below 2005 levels by 2020 using regulatory tools already available to Federal agencies

In the Exhibit that follows we show the energy and fuel switch options and constraints in terms of the power system, illustrating that from a feasibility and emission reduction standpoint, the coal to natural gas switch complemented by the addition of renewables is more practical and achievable than large additions of nuclear energy or coal with CCS.

¹³ Note: a 40% reduction is still below the 51-64% reduction range (vs a 2005 baseline) necessary to remain on a 450 ppm climate stabilization target to avert an average global temperature increase of 2 degrees centigrade. However, such a reduction leaves room for technology leapfrogging and more drastic reductions from 2030 to 2050 from technologies and actions that are not feasible today.

A Low Risk Approach to a Low Carbon Fuel Mix

Exhibit 1: US Future Energy Pathway: Fuel Switch Mix Ease of Deployment in the Electricity and Power Sector¹⁴

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.

We then look at the changes in the US electricity supply mix that we forecast for 2020 and 2030 and the underlying assumptions of baseload coal retirements, new builds and utilization improvement in natural gas generation to achieve a 44% reduction in CO₂ emissions from 2005. As illustrated in the Exhibit below the three large changes in fuel mix between 2009 and 2030 that impact this emissions reduction are 1) a 26 percentage point reduction in the supply of electricity from coal; 2) a 12 percentage point increase in the supply from natural gas and 3) a 12 percentage point increase in the supply from wind and solar.

Exhibit 2: 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
Total	100%	100%	100%	100%	
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

These fuel mix estimates are supported by a detailed fundamental assessment of the power generation sector starting on page 68 of the paper. The conclusions from this analysis are:

¹⁴ 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.

A Low Risk Approach to a Low Carbon Fuel Mix

- Nuclear energy gains modest share because of the expected success of the Department of Energy's (DOE) loan program and regulatory support in the US Southeast, where regulators see nuclear power as an important contributor to the state and local economies and hedge to the coal-dominated supply mix. (Please see page 58)
- And renewables grow substantially, encouraged by state renewable portfolio standards (RPS), possibly a national renewable energy standard (RES) and renewed incentives that are added cost issues now, but, a reduction in learning curve capital costs (for solar and CSP) will reduce these costs over time and drive deployment. We believe that integration issues will still keep renewables penetration at a measured pace to 2030 as the smart grid and transmission infrastructure scale up. (Please see page 68 for a focus on integration issues)
- Carbon capture and storage (CCS) is assumed to be an extremely modest contributor to emissions reductions through 2030. We reach this conclusion because there are only a very few demonstration facilities on the ground today and barriers are substantial. CCS scale-up faces a wide range of regulatory, cost allocation, liability and technical challenges that as a practical matter will be difficult to overcome. We believe that on a \$/MW basis it will be more economic to apply CCS retrofits to natural gas plants than to retrofit post combustion coal plants with CCS. However, by 2030 CCS will be an important technology option for both coal and natural-gas fired generation in order to reach the 80% decarbonization target by 2050. (Please see pages 42 and 49)
- Coal generation loses significant share because the capital stock is aging and close to its depreciable life—average age 45 years versus 26 years for the generation sector as a whole—, faces significantly regulatory policy risk and is likely to become a costlier and riskier generation source. (Please see page 42)
- Natural gas generation gains share because there is an underutilized capital stock that is ready to be tapped, manageable infrastructure requirements, minimal regulatory impediments, relative ease for new builds and, we believe, a structural change in the cost of fuel supply due to domestic shale reserves that can be tapped at reasonable cost. (Please see page 49)

The Coal to Gas Switch

As we assessed the probability and constraints of what it would take to achieve a low carbon fuel mix we had to ask and then answer some fairly simple but fundamental questions to see whether in fact such a change in the supply mix is feasible. Since coal and gas are the two generation resources most at play, the first question is what are the various power system issues associated with this switch? Simply put, how easy is it to swap the fuels and under what time scale could the switch occur? This in turn, requires us to answer the following more detailed questions:

1. How do utilities and independent power producers (IPPs) do a fuel switch? What factors affect their generation choice?
2. What are the average age, utilization rates, efficiencies and environmental footprints of the coal and gas fleets?
3. What is the coal retirement schedule? What factors might accelerate the capital stock runoff?
4. How do EPA policy action, environmental litigation risk and regulatory action affect the fuel switch?
5. Is there enough natural-gas fired power generation available and is it in the right place to make up for the share gain?
6. How hard is it to permit, site and build new generation? What are the infrastructure requirements?
7. Is there enough secure natural gas supply?

While our focus in this section is primarily on the power system itself, we need to look at some basic economics when assessing fuel switch choices in terms of capital spending requirements for generation plants.

Question #1: How do utilities do a fuel switch? What factors affect their generation choice?

This least-cost utility planning (LCUP) framework leads to a refined version of a complex set of parameters and analysis that coal-generators are presently evaluating. The options coal generators have as they evaluate their coal units include:

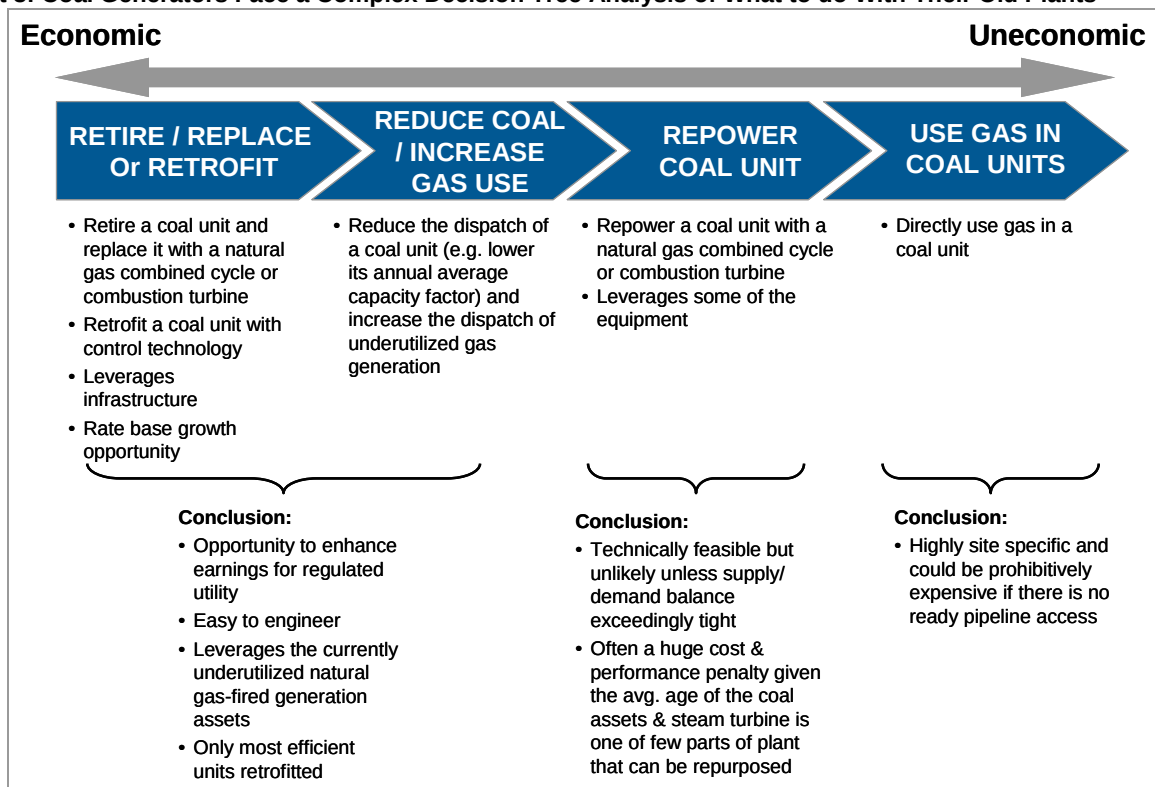
- 1) **Retire a coal unit** and replace it with a natural gas combined cycle or combustion turbine;
- 2) **Repower a coal unit** with a natural gas combined cycle or combustion turbine;
- 3) **Reduce the dispatch** of a coal unit (e.g. lower its annual average capacity factor);

A Low Risk Approach to a Low Carbon Fuel Mix

- 4) **Increase the dispatch** of underutilized gas generation or;
- 5) **Directly use gas** in a coal unit.

Of these five choices, 1) retire coal and replace with gas and/or 3) reduce the output from coal and 4) increase the output of existing gas assets are likely most likely. Repowering a coal unit with a gas unit is generally uneconomic since there is often a huge cost and performance penalty given the average age of the coal assets and the steam turbine is one of the few parts of the plant that can be repurposed. Whether or not gas can be used in a coal unit is highly site specific and could be prohibitively expensive if there is no ready pipeline access. A schematic representation of this decision tree process is illustrated below.

Exhibit 3: Coal Generators Face a Complex Decision Tree Analysis of What to do With Their Old Plants



Source: DBCCA analysis 2010

Question #2: What are the average age, utilization rates, efficiencies and environmental footprints of the coal and gas fleets?

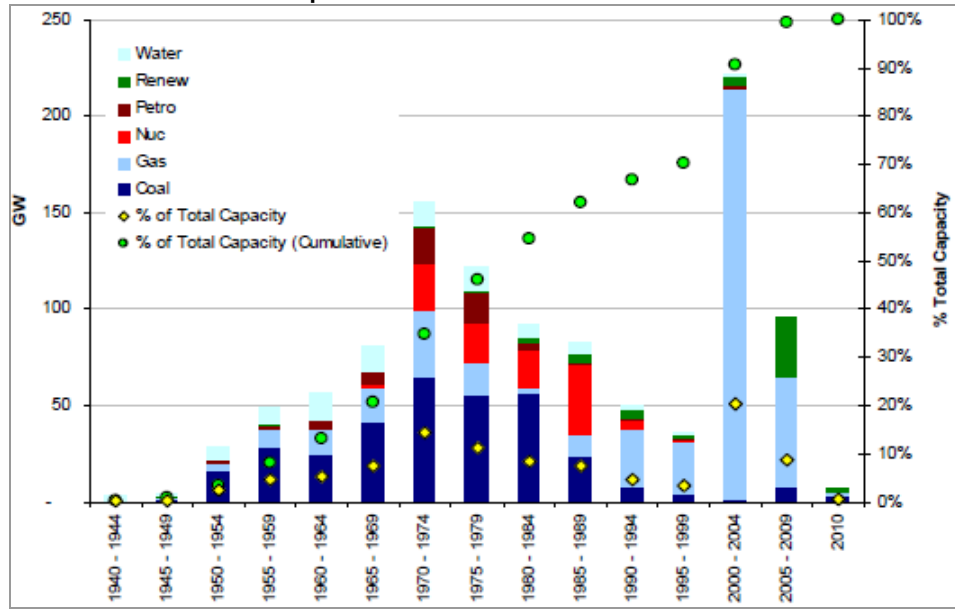
The average age of the US coal fleet is 43 years old based on an average plant-in-service date 1967. More than 50% of the US coal fleet, or ~159 GW, was built before 1967 as illustrated in the Exhibit below. The coal fleet in aggregate operates at a fairly high utilization rate of about 60%. By contrast, the natural gas fleet has an average age of about 25 years but most of the capacity additions occurred between 2000 and 2004. In contrast to coal, the average utilization rate of the natural gas fleet has been about 25% on average on an annual basis over the past few years. This compares to higher seasonal utilization rates of up to 40% during the summer peak for a smaller portion of the installed natural gas capacity.¹⁵ Natural gas plants have had a much lower capacity factor than coal generation despite a thermal efficiency of about 7,100 mmBtu/kWh compared to an average thermal efficiency of about 14,000 mmBtu/kWh (skewed by old plants). And from an

¹⁵ Congressional Research Service, *Displacing Coal with Generation From Existing Natural Gas-Fired Power Plants*, January 2010, p. 8

A Low Risk Approach to a Low Carbon Fuel Mix

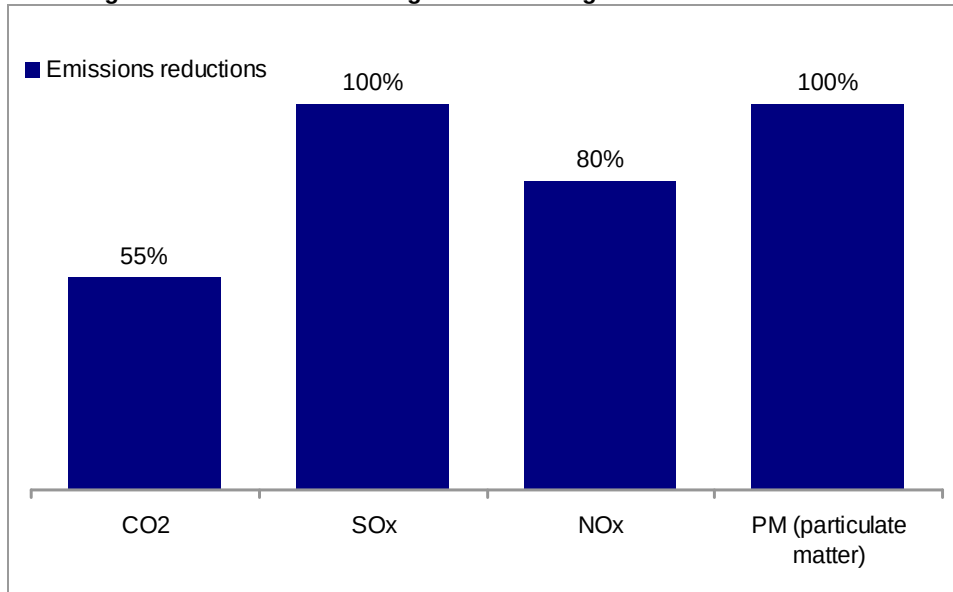
environmental footprint perspective, natural gas generation is superior to coal on all fronts with ~60% less CO₂ per MWh, ~80% less SO₂ and no Mercury or particulates as illustrated in the Exhibit below. Natural gas generation also requires less water and waste handling. (Please see the natural gas generation section on page 49 for more details)

Exhibit 4: US Power Sector Generation Capital Stock



Source: EnergyVelocity, Credit Suisse

Exhibit 5: There Are Large Environmental Advantages in Switching from Coal to Gas



Source: EIA

Question #3: What is the coal retirement schedule? What factors might accelerate the capital stock runoff?

As shown in the previous Exhibit, the peak building years for new coal generation occurred between 1965 and 1984. The units brought online before 1970 are at or close to the end of the depreciable lives. The incremental capital cost of environmental retrofits is likely to accelerate the retirement of coal units. We identified 60 GW of inefficient coal generation

A Low Risk Approach to a Low Carbon Fuel Mix

and equally retired the capacity between now and 2020. We then identified a further 92 GW that we expect will be retired between 2020 and 2030. We identify the age and efficiency (Btu/KWh) of the coal units that we retire as expressed by “heat rate” in the Exhibit below.

Exhibit 6: Almost Half of the US Coal Fleet is Old and Inefficient

Future Coal Retirements	Total GW	Average Unit Age	Average Unit Heat Rate
2010-2020 Period	60	62	16,990
2020-2030 Period	92	47	12,654

Source: Ventyx, DBCCA analysis 2010

As these units are retired the issue of stranded costs is likely to emerge. Assets that are retired before the end of their depreciable life can be considered to be stranded if there is minimal salvage value. In regulatory accounting, when the value of capital investments, purchase power agreements, fuel supply contracts and other assets can no longer recover their costs through the sale of electricity as allowed under a rate agreement, these assets are considered stranded. To put this in financing terms, the net present value of the future cash flows of the asset fail to cover the current value of the asset. Such stranded costs are highest for newer assets that have not yet been depreciated¹⁶. The issue of stranded costs is particularly germane to the coal to gas fuel switch scenario because of the issue of who pays, which assets are retired and when. We do not anticipate the first wave of coal retirements—e.g. the first 60 GW or so between 2010 and 2020—to be eligible for stranded cost recovery since these assets are depreciated and at or near the end of their useful lives and can be largely accommodated from a capacity generation perspective with an increase in the utilization of natural gas plants. Moreover, the recent recession has impacted reserve margins and delayed the need to add new generation capacity since there is adequate excess capacity in the aggregate power system. And even the next wave of 92 GW that we have identified as retiring between 2020 and 2030 are well beyond their depreciable lives. **Therefore, we suspect that state public utility commissions are not likely to allow utilities to reclassify these assets as stranded regulatory assets.**

Question #4: How do EPA policy action, environmental litigation risk and regulatory action affect the fuel switch?

The short answer is that regulatory policy in terms of the EPA and litigation risk for coal generation has increased substantially. The Sierra Club has made shutting coal a number one priority in terms of litigation. We address the policy issues in depth starting on page 36 in the policy section. In summary, when looking at the phase in of heavy EPA regulation between 2010 and 2015 and the associated impact on environmental remediation control equipment, the probability of a carbon price in the next 10 years, plus headwinds from the non-government organization (NGO) environmental advocacy groups keen on shutting down coal, the risks for the coal to gas fuel switch are to the upside.

Question #5: Is there enough natural-gas fired power generation available and is it in the right place to make up for the share gain?

In terms of the power system being able to actually deliver more gas-fired generation based on currently installed capacity, it is basically a question of increasing the utilization rates of existing plants. The Congressional Research Service looked at the issue in January 2010 and concluded the following on an unconstrained basis:

¹⁶ In the 1980s a large number of nuclear power plants became stranded assets, for example, when they were shut down before they even became operational.

A Low Risk Approach to a Low Carbon Fuel Mix

Exhibit 7: Congressional Research Service Estimate of Theoretical Coal to Gas Fuel Switch Potential

1	2	3	4	5
Actual NGCC Generation, 2007 (MWh)	Hypothetical NGCC Generation at an 85% Capacity Factor (MWh)	Hypothetical Surplus Generation Available for Coal Displacement (MWh) (2) – (1)	Actual Coal Fired Generation in 2007 (MWh)	Hypothetical Surplus NGCC Generation as a Percentage of Coal Generation (3) / (4)
630,358,373	1,270,487,153	640,128,780	2,016,456,000	32%

Source: CRS estimates based on EIA-906/920 and EIA-860 electric power databases, and EIA, Electric Power Annual 2007, Table ESI, http://www.eia.doe.gov/cneaf/electricity/epa/epa_Sum.html.

In terms of an actual switch from coal to gas this would equate to about a 15% percentage point decrease of coal in the aggregate fuel mix based on coal having a 47% share of total power generation in 2009. However, a fuel switch of this magnitude is not all that simple because there are a number of intractable barriers including geographic location, isolation of electricity grid interconnects and transmission constraints which make it difficult to move power from the west to the east. So the Congressional Research Service (CRS) then looked at coal plants with hypothetical generation displaced by natural gas units that are located within 10 and 25 miles of the coal plant. This then limited the bulk of the fuel switch essentially to the eastern part of the US as illustrated in the Exhibit below.

Coal Plants with Hypothetical Generation Displaced by a NGCC Plant Within 25 Miles



Source: CRS estimates, mapped using the Platts Powermap system

Coal Plants with Hypothetical Generation Displaced by a NGCC Plant Within 10 Miles



The range of contribution of the coal to gas fuel switch based on geographic proximity analysis limited the amount of coal generation displaced as a percent of total coal generation to a range of 5-9%. Based on coal having a 47% share of total generation this would amount to a 0.8% to 4.2% contribution to the aggregate fuel mix shift.

Exhibit 8: Congressional Research Service Analysis of Coal to Gas Displacement by Location

Natural gas proximity hypothetical to coal	Amount coal displaced (TWh)	Amount displaced as % maximum potential displacement of coal by gas	Amount displaced as % total power sector coal generation (TWh)	Percentage point contribution of the coal to gas fuel switch to total supply
Within 10 miles	101.8	16%	5%	0.80%
Within 25 miles	181.5	28%	9%	4.20%

Source: CRS, DBCCA analysis 2010-10-15

In our modeling, we have taken a pragmatic approach to the fuel switch based on our fundamental analysis of the power sector. 8% of the contribution to our 2030 estimated coal to gas fuel switch comes from an improvement in utilization rate of the existing gas assets as illustrated in the Exhibit below. While this is about twice the estimate of The Congressional Research report's constrained analysis above, we believe it is feasible as it incorporates known pipeline expansions already

A Low Risk Approach to a Low Carbon Fuel Mix

underway and the need for relatively modest incremental pipeline capacity additions compared to what is currently planned¹⁷. (See page 33-34).

Exhibit 9: DBCCA Coal and Gas Generation Forecast 2009-2030

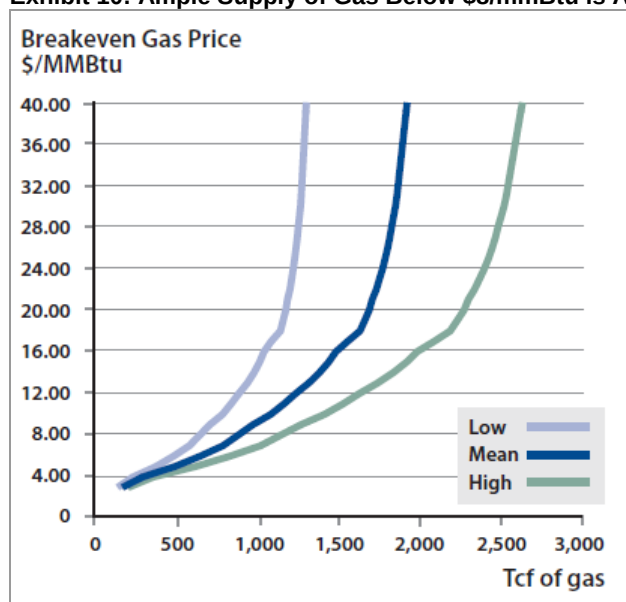
	Coal		Gas		Contribution to Share Gain
	2009A	2030E	2009A	2030E	
Capacity (GW)	337.3	185.6	454.6	480.6	4%
Capacity Utilization (%)	60%	54%	23%	35%	8%
Energy generation (TWh)	1,778	878	770	1,463	
% US Supply	47%	22%	23%	35%	12%

Source: EIA, DBCCA analysis 2010

Question #7: Is there enough secure natural gas supply?

Estimates of proven and recoverable natural gas reserves in the US have continued to grow over time—with an accelerating trend in recent years. The application of horizontal drilling and hydraulic fracturing to shale resource plays has caused resource estimates to increase substantially over the past several years. In June 2010, the Massachusetts Institute of Technology completed a comprehensive assessment of the future of natural gas.¹⁸ As illustrated in Exhibit 10 from their study there is ample supply at a reasonable price. The chart shows the supply cost curves for all US natural gas resources, depicting the mean estimate and the uncertainty around those estimates. There appears to be 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 at a price of \$8-9/mmBtu assuming an average of 28 Tcf per year in demand, which we anticipate based on increased demand from the power generation sector (see page 52). The latest estimates are that the US has about 200 years of natural gas supply.

Exhibit 10: Ample Supply of Gas Below \$8/mmBtu is Available in the US From Shale



Source: MIT

¹⁷ As of 2010 there were an estimated 40,000 of natural gas pipeline miles under construction according to Quanta Services and Underground Construction Magazine. This incremental pipeline supply should cover the expected ~3 Tcf of annual natural gas demand through 2030 from our fuel switch estimate based on the infrastructure requirements.

¹⁸ The Future of Natural Gas: An Interdisciplinary MIT Study, June 2010

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Coal to Gas Fuel Switch Conclusions: The Power System Can Do It

These framing questions lead us to believe that a substantial coal-to-gas fuel switch is possible from an analytical systems perspective. In power system terms the coal to gas fuel switch can be achieved because there is ample underutilized capacity and virtually no physical impediments. The CRS analysis identified about a 4% percentage point fuel switch from coal to gas that can be easily achieved. Achieving a further 4% percentage point fuel switch as we have modeled is achievable simply by increasing the average utilization rate of the natural gas fleet from 23% to 32%. This would likely require modest infrastructure investment and is not really a constraint. Over the longer term, the fundamental factors that we identified, which include aging coal generation fleet on the cusp of retirement, heightened EPA regulatory action, and vast increases in the supply of domestic natural gas all flex in favor of the fuel switch.

Recent action from large industry players are a clear sign post that the fuel switch is happening. Traditional coal-fired generators such as Southern and Company (SO), Xcel Energy (XEL), Duke Energy (DUK) and American Electric Power (AEP) have begun to talk more about using natural gas as a generation resource for new builds and shutting down inefficient coal plants.¹⁹ At its October 2010 analyst day AEP released new disclosures stating that on environmental issues they identify nationally 64 GW of coal generation as "fully exposed" and very probable to retire and then 86 GW as "partially exposed" and likely to retire. At the November 2, 2010 Edison Electric Institute Financial Conference Exelon Corp. showed that its internal analysis concluded that as much as 11GW of PJM coal plants are likely to be retired as EPA implementation dates approach, with a potential corresponding increase in PJM RPM Capacity prices of \$400-\$800 million in the 2014 and 2015 auction.²⁰ And we have seen evidence of fuel switching based on the EIA's usage data, which show about a 3% increase in natural-gas fired generation from the power sector in the two years ended 2Q10. **We expect to see a return to natural gas producers agreeing to sell forward production under long term contracts to mitigate price volatility** just as was the case in the 1970s and early 1980s prior to the deregulation in the gas industry. This is an **absolutely essential market development** to support our coal/gas switch fundamental call and is a factor that regulators will be looking to in approving new natural-gas fired capacity additions in order to ensure reasonable electricity rates for customers.

The Emissions Effect of a Low Carbon Fuel Mix

Modeling the emissions and investment implications of the coal to gas fuel switch and build up in renewable energy capacity was an integral part of this research study. We constructed both a tops down and fairly detailed bottoms up model based on our view of industry fundamentals to assess the impact. The principal constraint of our top down model was achieving at least a 25% reduction in power sector CO₂ emissions by 2020 and 40% reduction by 2030 versus a 2005 baseline. In fact, we observe that a 29% and 44% reduction by 2020 and 2030 is potentially achievable. And while we have not explicitly assumed a carbon price in our tops down model, a carbon price would clearly help in achieving this fuel switch forecast by 2030. The key to achieving this reduction is the coal to gas fuel switch as shown in the Exhibit below, which illustrates coal's share of electricity diminishing by 26 percentage points compared to a 12 percentage point increase from natural gas between 2009 and 2030. We then unpack the emissions data in more detail from our model to illustrate the contribution to emission reduction based on our capital stock turnover assumptions. The combination of increased renewables with the coal to gas fuel switch makes up the largest contribution and incremental deployment of nuclear generation is significant, too.

Exhibit 11: The Coal to Gas Fuel Mix Shift Greatly Reduces Coal's Share of Sector CO₂ Emissions

	2009A	2009A	2030E
Generation Type	% Generation	% Sector CO ₂	% Generation
Coal	47%	82%	21%
Natural Gas	23%	18%	35%

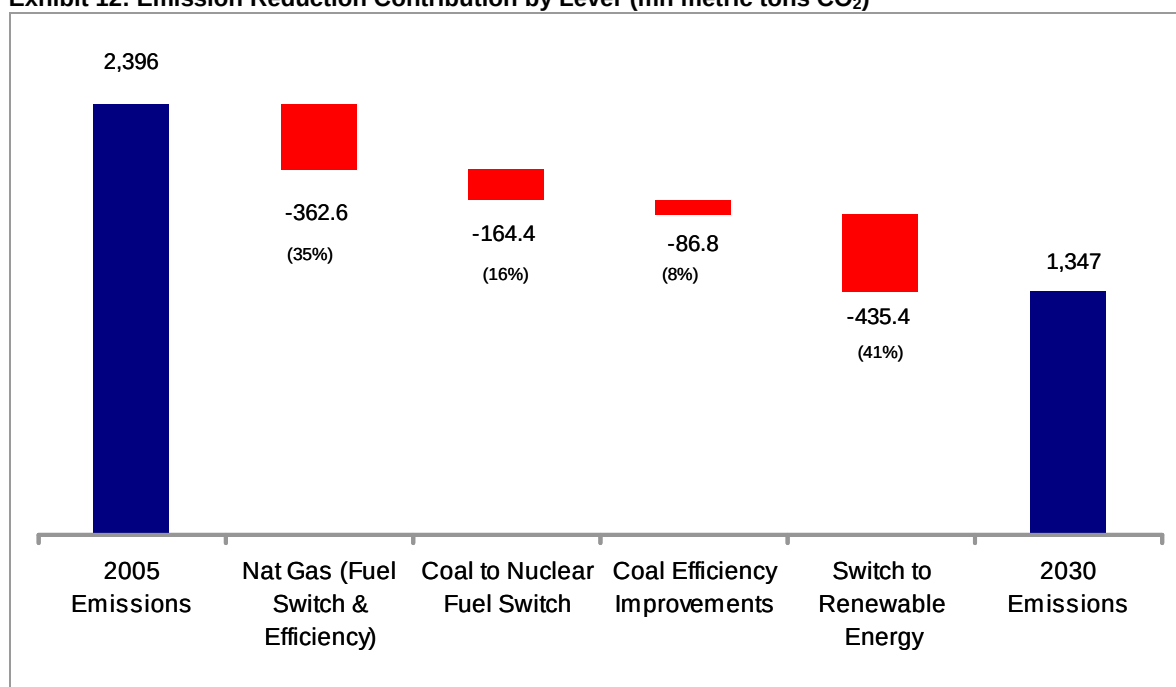
Source: DBCCA analysis 2010

¹⁹ This observation is based on meetings with company management teams at industry conferences over the past year.

²⁰ www.exeloncorp.com

A Low Risk Approach to a Low Carbon Fuel Mix

Exhibit 12: Emission Reduction Contribution by Lever (mn metric tons CO₂)²¹



Source: EIA, DBCCA analysis 2010

²¹ **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.

Economics

Summary

- Levelized cost of electricity (LCOE) is a narrow measure for comparing electricity generation costs across technologies but an important starting point.
- In our study we build on an LCOE framework by adding system integration and known environmental retrofit costs to reach what we call “total cash” costs.
- We then apply the fully loaded “total cash” cost framework to look at the economics of deploying renewables, nuclear generation and the coal to gas fuel switch and the fundamental factors that influence the switch using a decision tree matrix.
- The total industry costs of the new fuel mix are manageable and represent just a 1.6% CAGR total increase in cost from 2009 to 2030, due in large measure to an improvement in utilization of already built natural gas plants.
- We expect a prolonged investment cycle in the power sector driven by the intersection of economics, policy and the infrastructure requirements that come with a changing fuel mix.

Economics Matter—“Cash Cost” and “Full Cost”

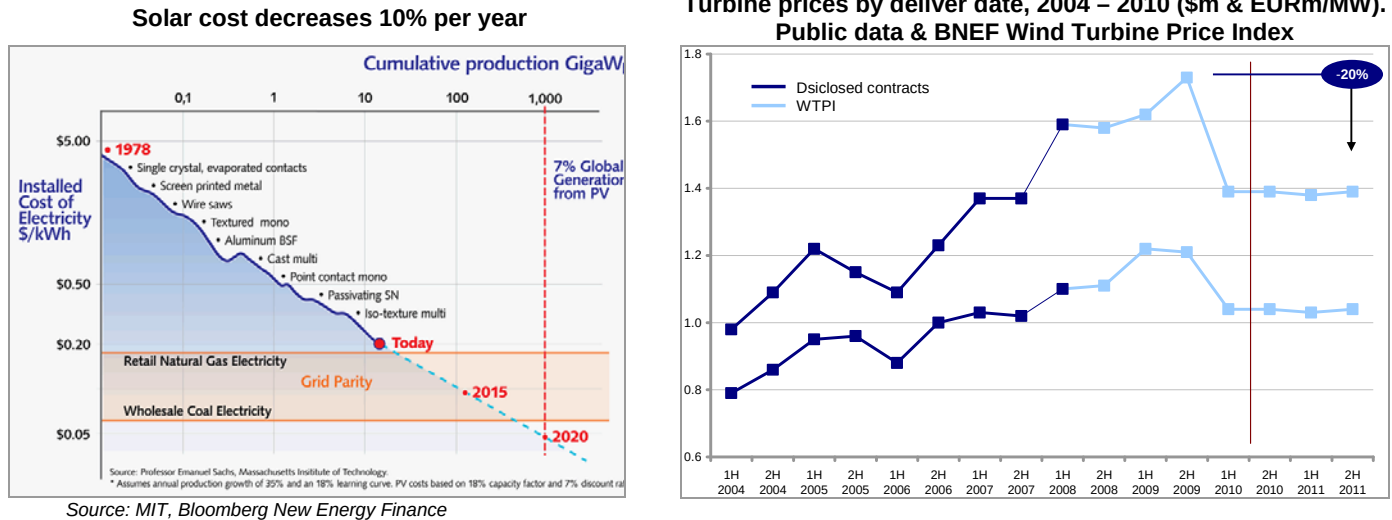
US policy makers and electricity rate payers naturally want to achieve the lowest cost approach to de-carbonize the power system. If the costs are considered too high, the progress could be slow. However, in many senses the question is, “which costs?” Analysts like to use the levelized cost of electricity (LCOE) (see below) which is a narrow measure of “costs” that does not include any of the externalities such as environmental impacts or other system integration costs such as backup power for renewable or incremental transmission and pipeline capacity additions that might be required with large additions of natural gas power plants. For our study, we have generally stayed with LCOE but added in system integration and legislated environmental impacts to address the “cash cost” approach which is most prevalent but do point out further longer term environmental externality costs. (See below for a discussion of full costs) LCOE is fairly well known at any point in time. However, over longer planning horizons LCOE of course varies as the relative costs of fossil fuels shift and capital costs that are influenced by technological developments and credit/financing conditions change. Also of note, LCOE does not always capture the relative “value” of a technology over a shorter time horizon. For instance, while \$0.15/kWh may be considered expensive versus average electricity prices it could be a relatively low clearing price on the dispatch curve of electricity during a particular day, while even \$0.01/kWh would be expensive during a period of curtailment.²²

As we look out to 2020 and the learning curve trajectories that suggest costs will fall substantially, we believe the economics of renewables will rapidly change the dynamics and pace of adoption. So the challenge is really getting through the next 5-10 years when capital costs are still high and policy support at the federal level is wavering. We have taken a fairly conservative approach looking at what we know now and assuming a gradual cost reduction over time for these technologies. However, looking at learning curves, we expect many renewable technologies will likely be as cheap as fossil fuel-fired power generation on an LCOE basis within the next 5-10 years as illustrated in the graphic below, which details solar PV installed cost cheaper than today’s wholesale coal electricity before 2020 as the supply chain scales. In addition, even relatively mature renewable technologies such as onshore wind have seen significant declines in their capital cost based on a more mature and competitive industry structure. Bloomberg New Energy Finance estimates that turbine prices for 2H11 delivery are about 20% cheaper than they were in 2009 as illustrated below.

²² In Germany, for example, the merit order effect of avoided electricity generation of the most expensive fossil fuel plants is estimated to have saved about €9.4 billion between 2004 and 2006. These electricity savings were due to the proliferation of large supplies of renewable energy from the country’s Feed-in Tariff program. DBCCA, *Paying for Renewable Energy: TLC at the Right Price*, December 2009, p.9

Economics

Exhibit 13: Solar Learning Curves Have Grid Parity in Sight by 2020; Wind Turbine Prices Have Compressed since 2008



Calculating Power Generation Costs

For our research, we adapted an algorithm provided by the National Renewable Energy Lab (NREL) to analyze new build costs across a broad spectrum of generation technologies. (Please see the Appendix at the end of the document for the core inputs and a description of our LCOE modeling and methodology.) In the Exhibit below, we show our overall unsubsidized LCOE new build estimates for key baseload and intermittent generation sources. Natural gas and wind are the most economically advantaged resources today. Nuclear energy, hydro power and solar generation are most expensive. Coal generation is still relatively inexpensive and significantly cheaper than nuclear. However, the increased regulatory and permitting headwinds and unknown cost for CO₂ controls increase the risk profile of building coal-fired power plants. Natural gas generation LCOE is highly sensitive to gas prices. We assume a \$6 mmBtu normalized gas price in line with the futures curves through 2020 in our models.

What Does LCOE Mean?

There is no singular perfect tool for comparing technology costs of power generation technology given the wide range of variables that impact cost and performance. However, an accepted metric commonly used within the finance and power industry communities for evaluating different types of generation on as much of an apples-to-apples basis as possible in general terms is the life cycle costs of electricity, typically expressed as the levelized cost of electricity (LCOE).

An LCOE model is a net present value analysis. The model calculates the present value of the lifetime cost of electricity required for an investment to breakeven, using detailed financial and operating input assumptions. Expressed differently, on average electricity would need to be sold at an equal or higher value to the LCOE over the lifetime of the generation asset for the investment to earn a positive return. **A word of caution:** LCOE model outputs represent averages for a given technology and are highly dependent and sensitive to the modeling assumptions used. In particular, the model is especially sensitive to the capital cost, capacity factor and fuel price assumed.²³ Moreover, the “value” of different generation resources to the grid system is highly location specific and can change over time. Finally, LCOE only captures cash costs required to build, maintain and operate the electric generation facility. Costs for enabling infrastructure expansions that

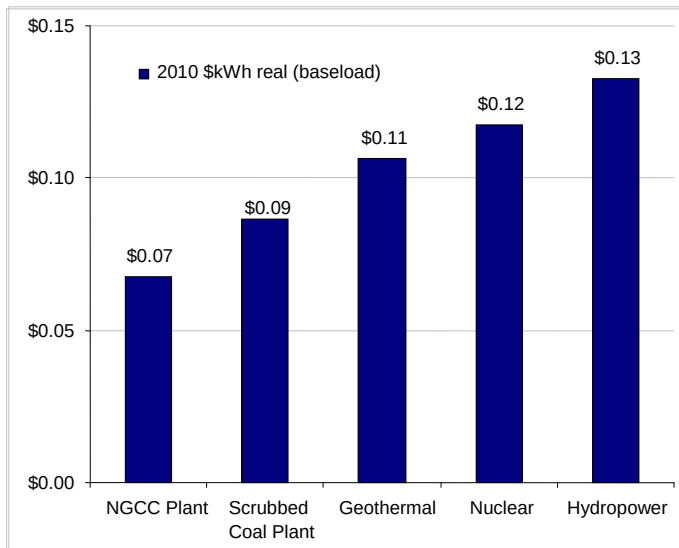
²³ Additional costs such as the capital cost to deploy environmental remediation retrofits are priced into rate cases and the fully delivered price of electricity. If these costs are included as inputs in LCOE analysis, they can materially change the LCOE rankings of generation technologies.

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might be necessary such as transmission, incremental natural gas pipeline additions, or gas storage, are not included in conventional LCOE discussions and are often spread over a larger customer base for cost allocation purposes.

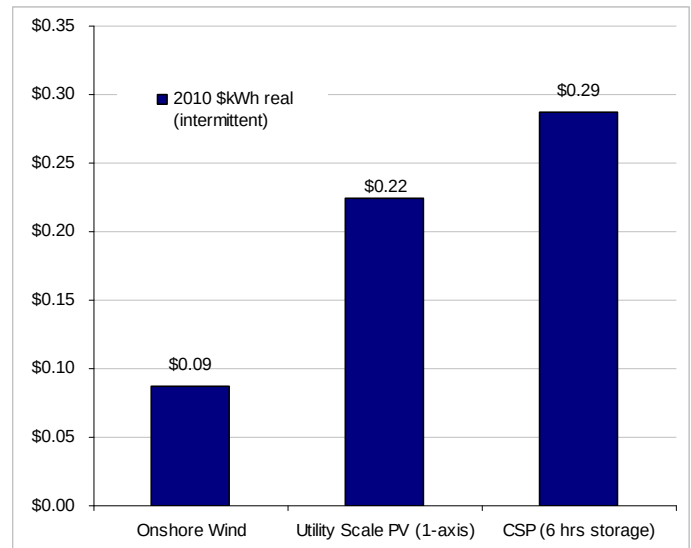
The key take home message is that aggregate investment decisions made by utilities and independent power producers are not made on cost alone—although cost certainly matters quite substantially. Equally important are the requirements to have a flexible and diverse portfolio of generation resources for energy security and grid stability purposes that are also compliant with state and federal environmental regulations. Layering in the expected impact of long term resource planning assessments is also vital, such as a forward looking assessment of the electricity supply/demand dynamics. A new auto factory, for instance, might require the addition of a new generation station. It is important to also not lose sight of the fact that because electricity is a critical infrastructure with no ready substitutes, the key deliverable or “circle of life”²⁴ for regulated utilities is to provide **safe, reliable and reasonably priced** electricity with environmental concerns often a fourth²⁵ priority. In a regulated context, this means keeping the customers and public utility commission satisfied and maintaining high degrees of reliability and reasonably priced electricity. When rates rise dramatically, there are often political ramifications.

Exhibit 14: 2010 Baseload power: LCOE \$/kWh Unsubsidized Cost



Source: DBCCA, NREL

Exhibit 15: 2010 Intermittent power: LCOE \$/kWh Unsubsidized Cost



Cash Costs and Externalities

Putting aside external costs and the incremental costs that might be associated with a carbon tax or CO₂ cap-and-trade regulation, there are still layers of cost that extend beyond simple LCOE in resource planning and will impact electricity customers in the future. Of course, the fully loaded costs of generation technologies vary widely as do a particular generator's value to the grid system. Older coal plants—even ones that are fully depreciated for accounting purposes—are likely to require capital intensive upgrades to control for NO_x, SO_x and particulates due to regulation; new gas plants may require incremental natural gas pipeline capacity additions, particularly if they are displacing coal plants in the Midwest where there may be inadequate last mile gas pipeline infrastructure; new nuclear generation requires loan guarantees to

²⁴ Southern Company uses “circle of life” to describe the key elements of its regulatory compact in the regions it serves, which is to deliver safe, reliable, environmentally sustainable and reasonably priced electricity

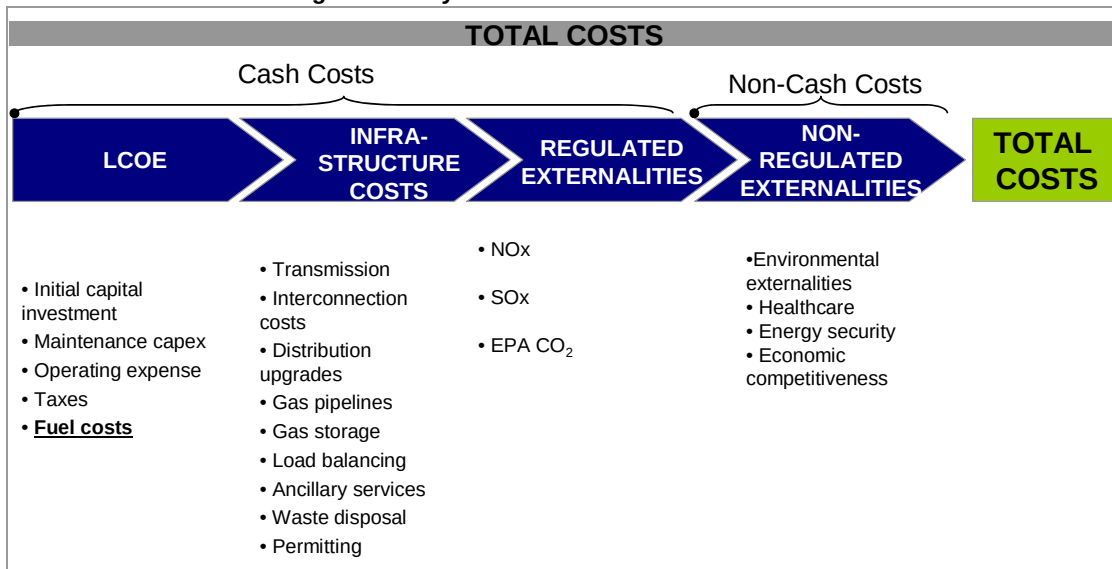
²⁵ For example, an unplanned forced outage of a baseload nuclear plant running at a high 91% capacity factor could have a material impact on wholesale power prices in that particular region given the large contribution of the plant to total supply

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buy in the high capital costs and long term PPA off take arrangements to reduce the financing risk and also has other challenges such a siting, public acceptance, water requirements and long term waste storage solutions; and wind and solar require transmission and ancillary services backup (at higher penetrations), which layer additional costs.

An honest assessment of fully loaded costs, the approach that is fundamentally necessary to take from a rigorous systems thinking perspective set on dissecting a system of inherent complexity, such as the electricity grid and planning for the evolution to a lower carbon emitting network infrastructure and energy supply paradigm, is often lacking. We show a graphic of these costs in the Exhibit below. The framework extends at least this far, however, in general the electricity market, regulators, companies and analysts have often focused on the LCOE cash cost component for decision making purposes rather than on the fully loaded cash costs or, the system wide costs which include non-cash costs to the electricity customer.

Exhibit 16: A Framework for Looking at Total System Costs²⁶



Source: DBCCA analysis, 2010.

In the Exhibit that follows we present a model that assesses some of the fully loaded cash costs represented in the previous Exhibit that are often excluded from analysis. What we have done for now is concentrate on fully loaded cash costs, which represents LCOE, infrastructure costs and regulated externalities. We look at costs for both old assets and new builds.

²⁶ Depreciation, a non-cash accounting cost, is not included in this graphic but would also impact true cost economics

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Exhibit 17: Fully Loaded Cash Costs: It's not just about LCOE, There Are Other Costs Too (No Carbon Price Assumed)

	<u>LCOE</u> (\$/kWh)	<u>Other Cash</u> <u>Costs</u> (\$/kWh)	<u>Fully</u> <u>Loaded</u> <u>Cash Cost</u> (\$/kWh)	<u>DBCCA Comment</u>
Old coal (\$3/mmBtu)	.04-.06	.02-.03	.06-.09	Retrofit costs required to be EPA compliant; only newer and more efficient coal plants are likely to be upgraded; no carbon price assumed. See Exhibit 19, pg 29.
New coal (\$3/mmBtu)	.07-.09	.03-.05	.10-.14	EPA regulation on multiple pollutants pending; compliance costs uncertain; almost impossible to get air permit because of unknown Best Available Control Technology (BACT) for CO ₂ ; retrofit for CO ₂ could add incremental 30-50% to the capital cost; no carbon price assumed. See Exhibit 19, pg 29.
Old gas (\$6/mmBtu)	.05-.07	.01	.06-.08	Older gas plants were designed to run as baseload and often lack digital instrumentation; to pair with renewables new instrumentation and fast start optimization controls may be required; economics improve substantially with \$4-\$5mmBtu gas. See Exhibit 19, pg 29.
New gas (\$6/mmBtu)	.06-.08	.00-.02	.06-.10	An estimated 50 GW of gas assets are co-located next to inefficient coal plants; replacing additional coal with gas could require substantial gas pipeline additions. See Exhibit 19, pg 29.
Old nuclear	.07-.09	.04	.11-.13	Cooling water retrofits and steam turbine replacements may be necessary for lifecycle extensions.
New nuclear	.12-.14	??	??	New nuclear requires loan guarantees; massive scale-up from 2020-2030 would require substantial government support and a long term storage option for spent fuel. Fully loaded costs hard to measure.
Wind	.09-.11	.03	.12-.14	The best on-shore wind resources are far from the major cities that constitute demand and therefore require substantial transmission and fossil backup because wind often blows at night when demand is low; revitalization of under utilized gas plants may diminish the need for as much transmission capacity additions.
Solar	.22-.30	.02	.24-.32	The best solar CSP sites are in the desert, far from load centers, requiring incremental transmission; however, solar is peak coincident and therefore in scale can displace expensive and inefficient fossil generation, particularly if located close to the load, so there is a merit order effect that could be beneficial for rate payers in that large solar additions would diminish the need for dispatching expensive high variable cost fossil peaking generation.

Source: DBCCA analysis, 2010. Note: See Appendix for detailed assumptions of LCOE and fully loaded costs.

Note: Please see the Appendix for a Detailed Look our Fully Loaded Cost Economic Assumptions. Our assumption of \$3/mmBtu is higher than the EIA AEO 2010 forecast, which projects the cost of coal increasing from \$2 in 2010 to \$2.50 in 2020 and \$3 by 2030.

Applying the Fully Loaded Cash Cost Framework to the Economics of the Coal to Gas Fuel Switch

This strategic "system-based" approach to looking at costs drives the economic argument for the coal to gas fuel switch. An understanding of the factors that influence the fully loaded cash cost of electricity supply is important in terms of seeing how policy and the changing economic relationship between coal and gas tie to our fuel switch thesis.

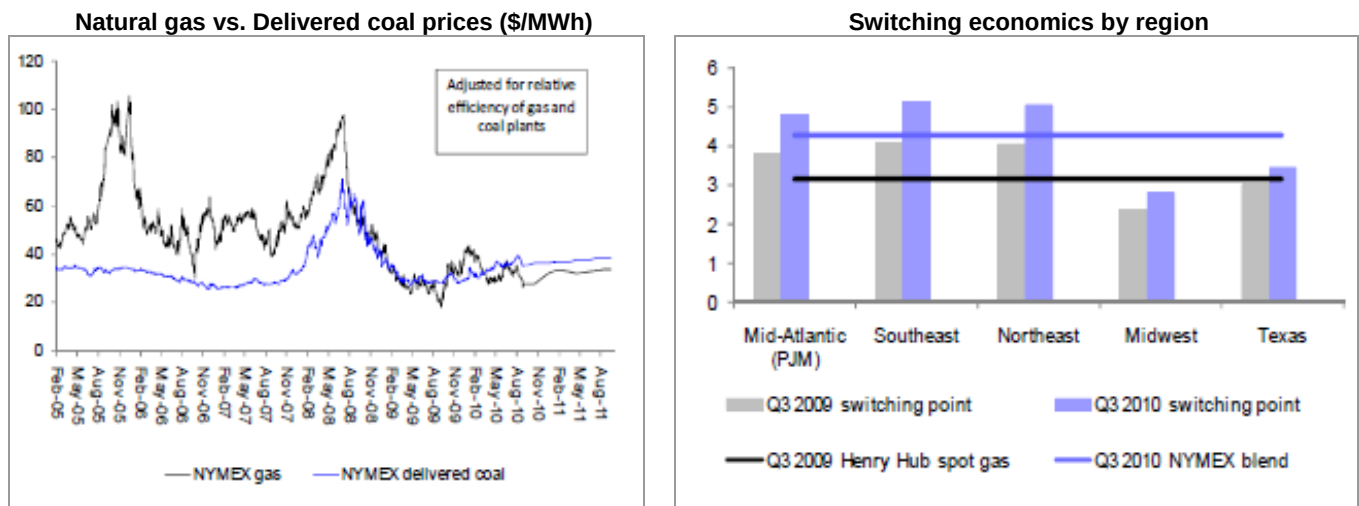
What's Happening Now? Relative Fuel Price Btu Arbitrage: The single largest determinant of baseload power producers' margins is the fully loaded gas to coal spread, or generation cost differential. This spread includes the cost to deliver gas and coal to the power plant by pipeline or rail. In the forward markets as of 3Q10, natural gas prices do not reach \$5/MMBtu until 2012 and \$6.50/MMBtu until 2020. Coal prices, by contrast, are higher on a \$/MWh basis over the same time periods. Since the March 2009 market bottom, gas prices have been in a fairly tight trading range while coal

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prices have increased more substantially consistent with the forward curves, with the sharpest increases in Central Appalachian Coal prices. Appalachian coal marginal costs are likely to continue to trend higher as a result of more restrictive environmental compliance and safety requirements. Exhibit 18 below charts NYMEX gas prices in blue and NYMEX coal prices in gray adjusted for heat rate and transportation costs and expressed in \$/MWh. Starting in May 2009 the prices converged and gas fuel switching began. Indeed gas burn in the utility sector was up an average of 6% year over year for the first half of 2010 compared to 2009. The right hand chart then looks at the relative switching points for coal and gas across five different regions.

As a practical matter these price based fuel switches can only go so far based on changes in gas and coal utilization rates alone. This is because there are logistical and transactional constraints toward reaching a truly efficient priced based fuel switch without significant changes in the asset mix—e.g. retiring coal. Utilities and merchant generators typically make power dispatch decisions across their operational fleet a month ahead based on relative fuel prices, margin expectations and contractual obligations. For integrated regulated utilities, new build investment decisions are based on long term LCOE, cost recovery and regulation expectations. Consequently, NYMEX forward commodity prices are an important indicator for dispatch and new generation build decisions but by no means the end all. Such decisions also incorporate a host of other industry factors including: supply/demand balance—e.g. reserve margins, infrastructure limitations, capacity prices, full requirements obligations, forward hedging prices, different coal specifications and environmental compliance.

Exhibit 18: Coal to Gas Fuel Switching Began in 2008 with Gas Between \$3 and \$4/mmBtu



Source: Bloomberg Finance LP, Deutsche Bank

Economic Framework Analysis for Making the Coal to Gas Fuel and Asset Switch

As discussed, there are two factors at play in terms of the relationship between coal and gas prices:

1. Relative spot and contracted prices for immediate dispatch decisions and
2. Long term relative price expectations that impact asset decisions

Over the longer term fuel price expectations are a part of a much broader and more fundamental assessment of the fully loaded cash costs of coal generation versus gas generation which we discussed previously in our framing analysis on page 27, where we examined all the factors including cash and non cash items that affect the coal to gas fuel switch. In the Exhibit below we take a look at the factors that contribute to both a fuel switch and an asset switch under different pricing scenarios. We assume a constant \$3/mmBtu price for coal and then look at how this compares to natural gas prices at

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\$4/mmBtu, \$6/mmBtu (our normalized expectation based on the forward curves) and \$8/mmBtu. These pricing assumptions are then applied to three different categories of generation scenarios which are:

1. Partially or fully depreciated coal or natural gas plant
2. Depreciated coal plant that spends incremental capex for environmental control remediation to comply with forthcoming EPA regulations (CO₂ control is excluded)
3. A new build coal or gas plant that is compliant with forthcoming EPA regulation

Exhibit 19: 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

As is clear, environmental retrofit costs weigh heavily in this decision tree analysis for coal generation with costs increasing by 50%. The key incremental costs for existing uncontrolled coal units are adding scrubbers and selective catalytic reduction (SCRs) systems in light of the EPA Transport and hazardous air pollutants (HAP) rules. Other costs include the possible addition of carbon injection and baghouses to control for Mercury. Other huge capital costs that have to be weighed in the decision tree analysis include the possible replacement of cooling towers and “dry” landfills for coal ash disposal. So there may be large layers of capital costs piling up on coal units. Given the size of these potential investments, the effective age of the unit becomes quite important since the costs are amortized over the remaining useful life of the asset. Age and efficiency are therefore important determinants of whether it makes sense to upgrade coal assets to be environmentally compliant with more restrictive EPA regulations or retire the asset and rebuild with natural gas-fired generation. (Please see Appendix for more details on this cost analysis)

Our base case normalized long term expectation for natural gas is \$6/mmBtu and is highlighted in the yellow section of the matrix above. Such a long term gas view means that the only time coal is cheaper than gas in this hypothetical is comparing old coal to old gas on a current LCOE basis. Older gas plants are cheaper than coal retrofits under a variety of natural gas pricing assumptions (\$4-\$8/mmBtu range) since they do not require costly capital equipment additions and cheaper versus new fully scrubbed and EPA compliant new coal plants, which face high environmental control costs and are difficult to permit.

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Conclusion

In the current regulatory environment, the most rational economic decision for a power producer is to build gas power plants for new builds and retrofit the most efficient coal plants for fuel diversity purposes where the LCOE of such capital investment is on par with new gas generation, which would generally be the case at a normalized price of \$6/mmBtu. Finally, even assuming an \$8/mmBtu natural gas price, it would make sense to selectively replace inefficient coal plants with gas as a hedge against future carbon prices. Therefore, fundamentally the economic argument supports a lower carbon generation pathway with natural gas-fired plants replacing coal generation.

Implied Economic Costs of Moving to the Low Carbon Fuel Mix

We applied our total cash cost frame work and estimates to see how the change in fuel mix between 2009 and 2030 would impact aggregate annual generation cost as illustrated in the Exhibit below. To be sure, there is a cost to the lower carbon fuel mix shift, particularly in the 2020 to 2030 time frame when 92 GW of coal are retired. Clearly, both average and marginal generation costs will increase both because of the forced roll off of dirty coal plants that produce electricity today at \$0.04-\$0.06 and the incremental additions of more expensive wind and solar to meet RPS targets which have an LCOE that are at least twice as expensive on average before reaching a competitive level by 2020 and 2030, depending on the technology. Still, from a cost standpoint, the fuel switch is manageable. We expect annual generation cost to increase from \$272.8 billion in 2009 to \$384 billion in 2030, a CAGR of 1.6%. Importantly, just as old coal produces cheap electricity today, the 14 percentage point increase in gas utilization rate that we expect from 21% in 2009 to 35% in 2030 makes gas about the cheapest generation resource in 2030 apart from hydro and geothermal. The fact that there is so much underutilized gas generation is significant and is beneficial from a generation portfolio perspective. We estimate that there is about a \$34.5 billion annual savings (\$.02/kWh) in 2030 that comes from increasing the utilization rate of natural gas assets versus what it would cost if all the generation were from new builds. In other words, without the benefit of the increase in utilization rate the cost of generation from the natural gas fleet in 2030 would be \$102.4 billion versus our estimate of \$67.9 billion.

Exhibit 20: Impact on Generation Cost from Change in Electricity Generation Mix²⁷

	Supply TWh 2009A	2009 Avg LCOE (\$/kWh)	2009 Estimated Cash Costs (\$bn)	Supply TWh 2030E	2030 Cash Costs Fully Loaded (\$/kWh)	2030 Cash Costs Fully Loaded (\$bn)
Coal	1,778	\$0.06	107	920	0.09	83
Gas	870	\$0.07	61	1,463	0.07	68
Nuclear	757	\$0.08	61	962	0.12	115
Wind and solar (intermittent)	76	\$0.15	11	585	0.15	88
Baseload renewables (geothermal & hydro)	303	\$0.11	33	251	0.12	30
Total	3,784	\$0.09	273	4,181	0.11	384

Absolute \$/bn increase 2009-2030	111.2
Absolute % increase 2009-2030	40.7%
CAGR cost increase 2009-2030	1.6%

Source: DBCCA analysis 2010

Note: Our calculation for the cost of natural gas generation is based on a weighted average assumption that looks at the % of new generation in 2030 supplied by depreciated gas plants versus the % of generation supplied by more expensive plants that represent fully loaded cash costs.

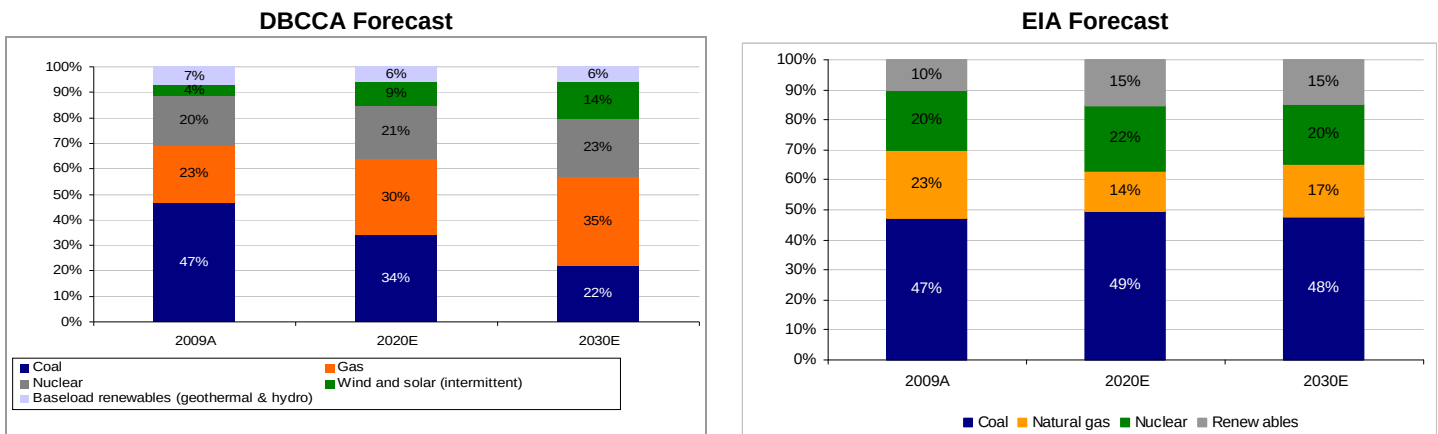
²⁷ Assumptions are in nominal terms

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Many caveats to this analysis are needed. Calculating the total cost of the fuel switch on a national level over long time scales dramatically oversimplifies an incredibly complex system. Electricity prices vary significantly from state to state. The moving parts that affect generation cost include: generation source, regional market constraints, geographic limitations, risks of change in regulatory policy and the potential for technical innovations. In addition, there may be energy value for fuel savings and demand side management programs. However, we believe this total cost framework is a reasonable approximation at what it might cost to execute the fuel switch as a rough approximation based on what we know today.

Our low carbon fuel mix forecast is clearly not a consensus view when contrasted to the EIA's base case generation mix forecast for 2020 and 2030. As illustrated in the Exhibit below the EIA expects coal to maintain share through 2030 at about 48%, whereas we are much more optimistic about growth in natural gas generation in particular but also growth in renewables and nuclear energy.

Exhibit 21: DBCCA vs EIA Electricity Supply Forecast % TWh



Investment Implications

The investment implications of our lower carbon future energy pathway are fairly straightforward to identify, but that does not diminish their likely impact. We have framed what we believe to be a least cost strategy for lowering emissions that centers on a coal to natural gas shift—driven in large part by improving the utilization rate of existing natural gas plants—in combination with increased penetrations of renewables and a modest build up in nuclear energy. However, the sheer size of the US electricity sector and magnitude of the spending required to move forward along this pathway will have major implications for many companies and a diverse set of industries.

In our model we capture the capital stock turnover implications of retiring 152 GW of coal capacity. We forecast that as these units are retired the utilization rate of the natural gas fleet will increase and where necessary new capacity additions will come from the next generation of natural gas power plants, which are being designed by the leading original equipment manufacturers (OEMs) for fast start and quick ramps with a minimal environmental emissions footprint to meet the cycling requirements that will eventually be necessary with greater fractions of intermittent wind and solar additions into the grid system. We also modeled the projected impact of state renewable portfolio standard (RPS) programs to see how many wind and solar capacity additions would be necessary to achieve the 2025 targets of about 486 TWh on a national basis, which is the compliance period for all the programs that we analyzed.

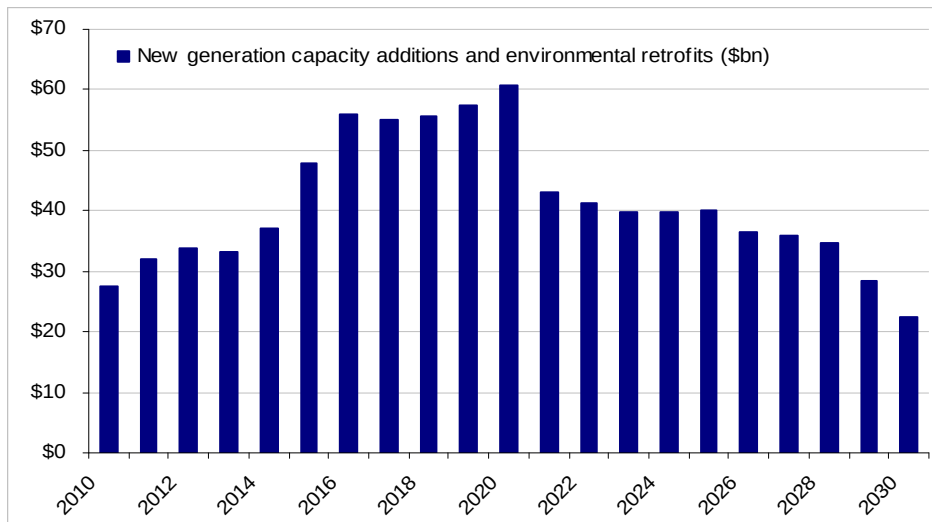
Based on our model, the largest increases in capital spending for new generation occur between 2016 and 2020 with the buildup in renewables, new nuclear and natural gas generation to replace coal. **In addition, we believe significant value**

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will also accrue to natural gas power plants that are currently underutilized and co-located within reasonable proximity to old coal plants.

Prolonged capital investment cycle: We expect a prolonged investment cycle in the power sector driven by the intersection of economics, policy and the infrastructure requirements that come with a changing fuel mix. As we discuss in more detail in the next Policy section of this paper, regulation efforts will add hugely to US power sector capital spending. We estimate that cumulative total capacity additions and environmental retrofits to coal units will lead to an incremental cumulative generation capex of \$858 billion between 2010 and 2030, with the peak spending occurring in 2020.

Exhibit 22: Annual Power Sector Generation Capital Spending 2010 to 2030



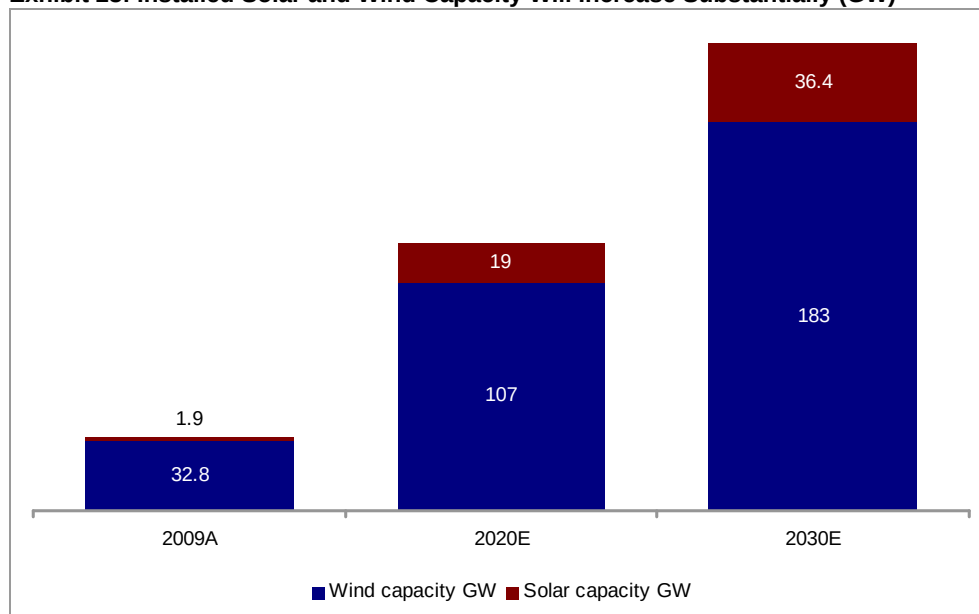
Source: DBCCA analysis, 2010.

Renewables and transmission will post significant growth: Within our generation forecast, wind and solar capacity additions have the largest growth rate from 2010 through 2030 from a small base due to state government support for renewable portfolio standard (RPS) mandates and targets. Combined, wind and solar accounted for just 2% of total electricity supply in 2009 and we expect their combined share to increase to 14% by 2030. We forecast total installed 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 2020²⁸. 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.

²⁸ ITC Holdings Corp 2010 Investor Day Slides, p.7

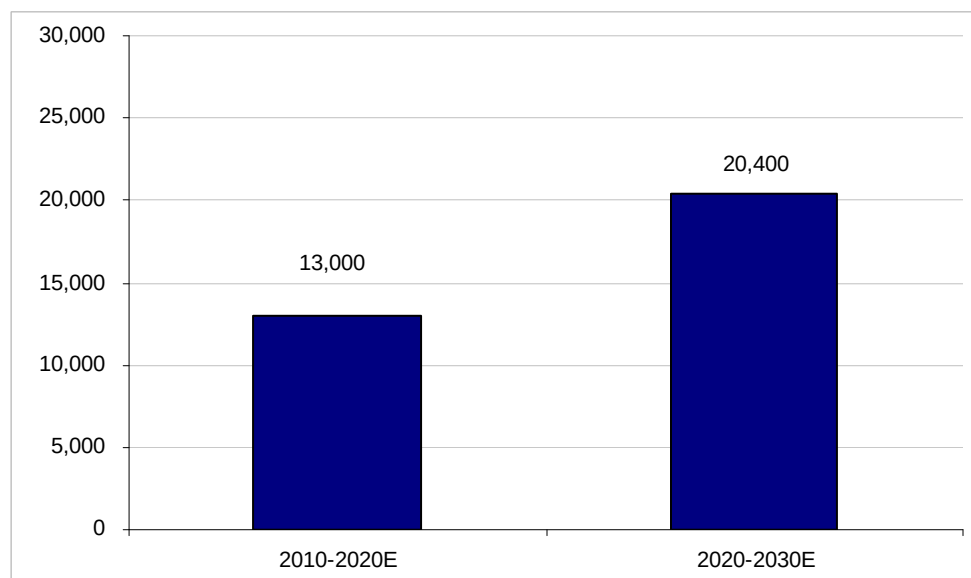
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Exhibit 23: Installed Solar and Wind Capacity Will Increase Substantially (GW)



Source: DBCCA analysis, 2010.

Exhibit 24: Natural Gas-fired Generation Replaces Coal: Cumulative Additions (MW)



Source: DBCCA analysis, 2010.

Gas Infrastructure Expands; Coal Volumes Decrease

We expect to see modest expansion to the already mature US natural gas pipeline system as new trunk lines are added to connect the emerging shale plays. In addition, incremental natural gas pipeline capacity additions of about 10-12% of the total current pipeline network will likely be necessary, particularly in the Midwest where the gas infrastructure is unlikely to be sufficient to fully support the large fractions of coal power plants that are retired and replaced with natural-gas fired capacity additions. Fortunately, the US has significant underutilized natural gas capacity already due to the large expansion underway from 2007-2012, much of which is located in areas with “at risk” old coal-fired power assets. In addition, there appear to be about 40,000 pipeline miles currently planned and under construction, which would adequately cover this

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incremental demand from the power sector.²⁹ Moreover, adding new interstate natural gas pipeline capacity is relatively easy in terms of infrastructure investments given favorable regulatory oversight, permitting and allowed ROEs, which facilitates financing the investments. EIA notes that from the announcement to the completion of a pipeline project generally takes just three years, which is significantly faster than the 10-years or more necessary to add large scale electricity transmission to the grid system. An incremental cumulative investment of about \$129 billion in pipeline capacity additions is likely to be necessary to support the coal to gas switch. This would support increasing the US natural gas pipeline capacity from about 130 Bcf today to 155 Bcf by 2020. Based on our total cash cost estimate, this level of infrastructure spending would be an average of less than \$0.01/kWh to the cash cost of natural gas generation between 2010 and 2030.³⁰

We derive at this estimate by calculating the incremental gas supply requirements to meet our 2030 natural gas generation forecast. In 2030, we estimate that there will be about 481,000 MW of natural gas power plants running at 35% capacity factor. We then assume that at an average heat rate of 6,900 mmBtu/kWh for the fleet would result in total electricity sector natural gas demand of 9.7 in 2030 versus 6.9 in 2009, a 2.8 Tcf incremental increase.³¹ US aggregate natural gas consumption increases to 27 Tcf in 2030 compared to 22.6 Tcf in 2009.

In July 2010, the Aspen Environmental Group published a report looking at the implications of a coal to gas switch in the electricity sector. As part of the study, Aspen Environmental Group compiled a range of forecasts of incremental natural gas demand from a variety of studies, including the Interstate Natural Gas Association of America, (INGAA), the EIA and their own extreme model. As illustrated in the Exhibit below our natural gas demand scenario is at the low end of the more extreme scenarios that they have modeled.

Exhibit 25: Infrastructure and Cost Impact of Incremental Natural Gas-Fired Generation: Comparison of Various Studies

Case	2030/2036 Incremental EG Gas Demand	Equivalent number of 1000 MW Coal-fired plants	Pipeline transmission Capacity Requirement	Miles of Pipe	% Increase over current interregional flow	Cumulative cost
INGAA Low	-0.5 Tcf		21 Bcf per day	28,900 Miles	16%	\$108 Billion
INGAA Base	3.8 Tcf	88	25 Bcf per day	37,700 Miles	20%	\$129 Billion
INGAA High	6.6 Tcf	153	37 Bcf per day	61,600 Miles	28%	\$163 Billion
AEO 2010	1.9 Tcf	44				
Alt 1	6.9 Tcf	160	<i>Note that this is virtually identical to INGAA's High Case</i>			
Convert Existing Coal	14.1 Tcf	328	70 Bcf per day			\$348 Billion

Source: Aspen Environmental Group

Meanwhile, coal demand in the power sector decreases from 930 mn tons per year in 2009 to 460 mn tons per year in 2030 which is likely to be a large challenge for coal producers and rail companies as they will see a large drop in annual volumes and will therefore need to be judicious in managing their capacity in order to maintain margins. Such a large scale industry dislocation could potentially trigger a government response, given how politically important coal is in many parts of the country.

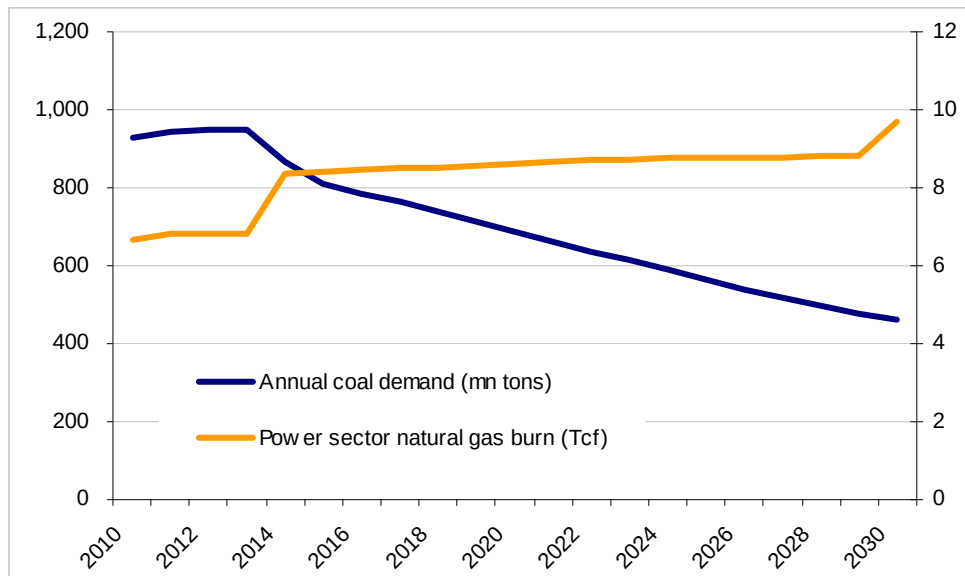
²⁹ http://www.quantaservices.com/SiteCollectionDocuments/presentations/Quanta%20Roadshow%202Q10_Full%20slides.pdf, p. 17

³⁰ Implications of Greater Reliance on Natural Gas for Electricity Generation, Aspen Environmental Group, p 45 (2010)

³¹ 480,000 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

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Exhibit 26: Coal Demand Falls While Natural Gas Demand Rises



Source: EIA, DBCCA analysis, 2010.

Policy

Summary

- Policy is important to our power market thesis. For renewables while LCOE costs are higher than fossil fuels this is well understood and we revisit the key drivers. Federal renewable energy policy in the US looks set to remain volatile in the short term given political considerations. State and local programs, mandates and incentives can still remain supportive, particular in states with binding penalties for noncompliance with renewable portfolio targets.
- For gas the key question is the cost comparison to coal. Here, there are two elements of policy in play: 1) regulating health-related general pollutants and 2) regulating CO₂. The key role in 1) is the EPA and this can significantly impact coal costs and we expect to proceed over time, while the key to 2) is either Congressional legislation or EPA regulation and represents a key potential cost that is likely to influence power markets.

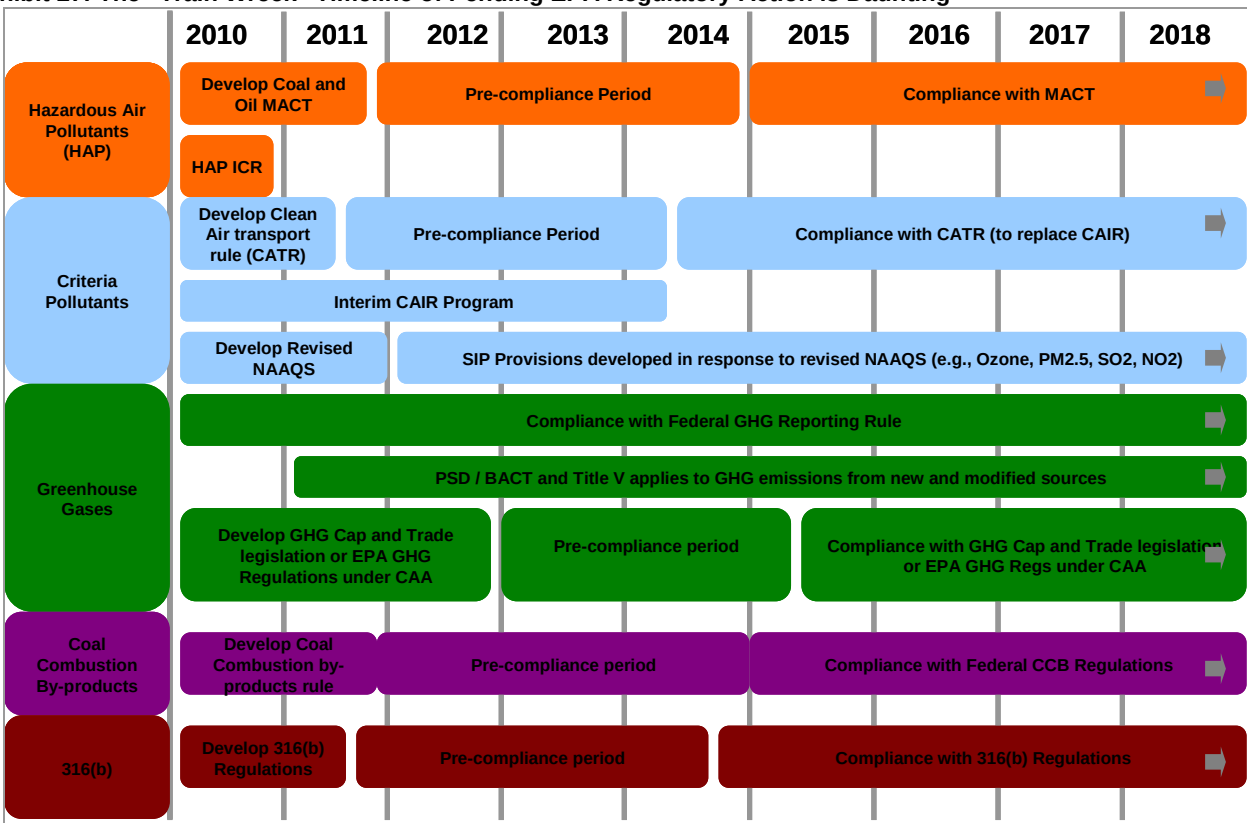
EPA Regulatory Action: An Important Fuel Switch Driver

The state of policy needs to be addressed since it is a key regulatory driver for the electricity sector. The US electricity sector is on the cusp of a profound period of change and capital stock turnover driven by regulatory policy, which will persist for the next 10-15 years and is at the heart of our core investment thesis. Coal-fired power generation is the dominant source of US electricity supply, providing about 47% of total electricity. Coal's large share is because it has historically been the cheapest source of electricity. Compared to other fuels on a \$/mmBtu basis coal has historically been cheaper and much less volatile than natural gas.

However, the power generation sector now faces a "perfect storm" of federal and state regulatory and legislative action focused on hazardous air pollutants and GHGs from coal-fired power plants, which will reduce coal's share of electricity to 34% by 2020 and 22% by 2030, we estimate, as coal-fired generation becomes less economic by our reasoning relative to natural gas-fired generation. A series of court decisions and budget appropriations have given the Environmental Protection Agency (EPA) greater authority and funding to effectuate much greater levels of regulatory restrictions on coal power plants than in the past. Mercury and acid gases are part of the "hazardous air pollutant" (HAPs) regulations that will likely require what the EPA calls maximum available control technology (MACT). MACT sets required performance standards equal to the best 12% of operating plants. Broadly for mercury this will require about a 90% removal rate, although sub-categorizations could lower this number for some plants and raise it for others. Other upcoming regulations include the Clean Air Transport Rule (CATR), which was formerly called the Clean Air Interstate Rule (CAIR), and updates to the National Ambient Air Quality Standards (NAAQS), coal combustion residuals, cooling water intake structures and, finally, new source review permitting.

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Exhibit 27: The “Train Wreck” Timeline of Pending EPA Regulatory Action is Daunting



Source: Exelon Corp

The timeline and details of pending EPA regulatory action is relatively aggressive and fairly daunting from an industry compliance perspective, since the “drop dead” date for full compliance is 2015. There is also the potential of a multi-pollutant bill passing sometime in the next few years that would cover all the EPA regulations on criteria pollutants. Senator Tom Carper (D-Delaware) has proposed such a bill.³² Five years within the context of the planning horizon for utilities when final rulemaking has not yet been promulgated leaves considerable uncertainty and requires a thorough evaluation of generation options and compliance strategies.

The lack of clarity of what the final rules entail creates uncertainty in decision making—although it is not that difficult to dimension a range of outcomes in terms of the impact on the cost structure. The likely industry response will be to seek the most economic mechanism of assuring system reliability while meeting the social and environmental goals dictated by the EPA. Unit by unit decisions will be based on:

- Electricity supply and demand dynamics—e.g. reserve margins;
- State-by-state legislative and Public Utility Commission (PUC) directives;
- Transmission bottlenecks and basis spreads between power hubs;
- Optimizing a balance between capital, fuel switching, operational controls and emissions allowances;
- Expectations of the future outlook/normalized view for energy and relative fuel prices and;
- Material condition, age, size and performance of units.

³² <http://carper.senate.gov/press/record.cfm?id=321361>

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We expect that the EPA's new regulations will result in a significant reduction in US coal-fired generation as capital allocation decisions dictate that it is cheaper not to run plants or even shut them down than to upgrade them to meet costly new emissions standards. We estimate that there are about 120 GW of "at risk" coal plants representing about 38% of the current coal fleet that is relatively inefficient with a heat rate greater than 11,000 Btus/kWh and older than 40 years. Moreover, these plants make up a large percentage of the approximately 185 GW of coal generation that have not yet installed control technology.³³ The region with the most "at risk coal" is the Midwest. Fortunately, the average capacity factor of natural gas plants in these regions is well below the national average (because coal is on the margin) and could potentially increase the utilization rate substantially from the 10-20% range to 40-50% with limited infrastructure requirements. In addition, there is slack in the Midwest natural gas pipeline system from the three major pipelines controlled by Natural Gas Pipeline Company of America (NGPL), Southern Union and Transcanada, which means that at least for the first wave of retirements through 2020 there should be adequate natural gas pipeline infrastructure to support the coal to gas fuel switch.

Under the new regulations, coal plants will need to be equipped with emission control technologies such as dry flue gas desulfurization (FGD) systems, selective catalytic reduction (SCR) systems, lower NOx burners, fabric filters (e.g. baghouses) and sorbent injection systems. In addition, some units may be required to make expensive conversions from wet ash to dry ash waste handling systems and from once-through cooling to recycling cooling systems. Fuel handling and coal procurement may also change. For reliability, environmental and economic purposes, we expect natural gas-fired generation to largely replace coal units that are retired as a consequence of these more restrictive environmental regulations. In 2010, the Congressional Research Service commissioned a study which determined that increased utilization of the existing gas fleet could theoretically displace 32% of coal generation.³⁴

Exhibit 28: Glossary of Regulatory Drivers that Impact Coal to Natural Gas Fuel Switch

Pollutant/Emission/ Environmental Issue	Common Name	Regulator	Region Covered	Industry Options
Sulfur Dioxides (SOx)	Acid Raid	EPA	31 States & DC	Fuel switch, install controls, reduce output, retire unit
Nitrogen Oxides (NOx)	Smog	EPA	31 States & DC	Fuel switch, install controls, reduce output, retire unit
Fine Particulate Matter (PM)	Soot	EPA	National	Fuel switch, install controls, reduce output, retire unit
Mercury (Hg)	Mercury	EPA	National	Fuel switch, install controls, reduce output, retire unit
Coal combustion residuals (CCRs)	Fly ash, bottom ash, slag	EPA	National	Retrofit or retire unit
Carbon Dioxide (CO ₂)	Greenhouse Gas (GHG)	EPA	National	Fuel switch, install controls, reduce output, retire unit, repower unit to supercritical pulverized coal
316 (b)	Cooling water intake structure (CWIS)	EPA	National	Retrofit or retire unit

Source: EPA, DBCCA

CO₂ Regulation Will Start with EPA: What about a carbon Price?

CO₂ emissions represent the major risk factor for the utility industry, particularly for coal generators. Key utilities such as Duke Energy, Xcel Energy and American Electric Power (among many others) would like to see clearly defined rules and regulations rather than regulation by the EPA under the Clean Air Act, which is seen as a suboptimal way to regulate CO₂ emissions because it focuses on individual point sources and Best Available Control Technology (BACT), which will be determined by state implementation plans (SIPs) based on EPA guidelines and is likely to emphasize efficiency³⁵. An

³³ Interstate National Gas Association of America (INGAA), *Coal-fired Electric Generation Unit Retirement Analysis* (May 2010), <http://www.ingaa.org/File.aspx?id=10371>, p1

³⁴ *Displacing Coal with Generation from Existing Natural Gas-Fired Plants*, Congressional Research Service, January 2010, p.13

³⁵ On 11/10/2010 the EPA released prevention of significant deterioration (PSD) and title V permitting requirements for greenhouse gases (GHGs) that begin to apply on January 2, 2011.

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unresolved and complicating factor is how EPA will define and propose implementing BACT. In fact, the EPA has repeatedly stated that it would favor an amendment to the Clean Air Act specifically addressing GHG emissions, and is being deliberately cautious and methodical, recognizing that there is likely to be litigation challenging its authority and implementation of the Title V Tailoring Rule³⁶. Final determination of BACT for a particular source is likely to be made by individual permitting authorities on a case-by-case basis.

The Edison Electric Institute (EEI), the industry association of shareholder-owned electric companies, has endorsed federal climate change legislation, including cap-and-trade, in an effort to clearly define the ground rules to more efficiently deploy capital over the next investment cycle. Grandfathered emission allowances, credit for early action and a carbon price would obviously help from an industry perspective but can't be depended on over the next few years, particularly in light of the change of control in Congress following the November 2010 midterm elections. However, we believe there is a possibility that in 2011 and 2012 there could be a move driven by EEI to advocate for federal utility-sector only GHG legislation, rather than a comprehensive economy wide bill given the large amounts of investment at stake.

Coal power plants are the largest emission point sources in the US and clarity on how these plants will be regulated to reduce CO₂ emissions would be helpful for planning and investment purposes. Clearly, without a solution to the CO₂ emissions problem, coal-fired power generation is not a viable longer term option. In the absence of a coherent federal legislative solution to combat CO₂ emissions, EPA is moving forth at a measured but steady pace and is preparing to regulate CO₂ emissions. In 2007 the Supreme Court determined that damages associated with climate change are serious, well understood, a detriment to human health and deemed a pollutant under the Clean Air Act, which gives the EPA the statutory authority to regulate CO₂ emissions. A summary of Federal regulatory action on GHGs is shown in Exhibit 29 below.

Exhibit 29: Timeline of EPA Regulatory Action on Greenhouse Gas Emissions

Agency	Action	Status	Description
EPA	Endangerment Finding	Final 74 Fed. Reg. 66496 (11/15/2009)	Declares GHG emissions from mobile sources a threat to human health and welfare; outgrowth of US Supreme Court decision in Massachusetts v. EPA, 549 US 497 (2007)
EPA	GHG Mobile Source Rule	Final 75 Fed. Reg. 25324 (5/7/10)	Rule establishes first regulatory program constraining GHG emissions through new emissions standards for motor vehicles
EPA	"Johnson Memorandum" Revisited; "Trigger Rule"	Final 75 Fed Reg. 17004 (4/2/10)	Interprets term "subject to regulation" for purposes of NSR/PSD program and establishes 1/2/11 as date GHGs will be "subject to regulation"
EPA	"Tailoring Rule"	Final 75 Fed Reg. 31514 (6/3/10)	Creates de minimis thresholds for regulation of GHGs, at least as a first step towards a comprehensive regulatory program
EPA	GHG Reporting Rule	Final 74 Fed. Reg. 56260 (10/30/09)	Requires annual GHG emissions from identified source categories starting in 2011 with data from 2010
EPA	Amendments and Additions to GHG reporting rule	Proposed: 75 Fed/Reg. 18455 (proposal to require additional information), 18576 (reporting of GHG injection and geologic sequestration), 18608 (petroleum and natural gas systems), 18652 (additional sources of fluorinated GHGs) (4/12/10)	Requires additional information and reporting of source categories
Council on Environmental Quality (CEQ)	Guidance on addressing climate change under NEPA (National Enviro. Policy Act)	Proposed: 75 Fed. Reg. 8046 (2/23/10)	Requires consideration of impacts of GHG emissions and sets presumptive threshold of 25,000 metric tons CO ₂ e

³⁶ "Tailoring Rule," 75 Fed. Reg. 31514 (June 3, 2010) promulgated by the EPA does not require small sources that emit less than 25,000 tons per year of CO₂ to immediately require permits.

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Agency	Action	Status	Description
Securities and Exchange Commission	Guidance on Reporting on Impacts of Climate Change	Interpretive: 75 Fed. Reg. 6290 (2/8/10)	Calls for reporting of impacts of climate change and GHG regulation

Source: EPA, SEC, Ballard Spahr, DBCCA

By January 2011, the EPA will release its proposed rule making for power plants and define Best Available Control Technology (BACT). Since there is no commercially available capture technology for CO₂ regulation is likely to focus on efficiency standards initially with tougher rules imposed phased in over time. Today, the easiest and only viable way to reduce CO₂ emission from coal-fired power plants is to improve their thermal efficiency, increasing the output per unit of coal burned. Since CO₂ emissions per unit of coal are constant, increasing thermal efficiency increases electrical output relative to emissions. Plants can increase thermal efficiency by switching to higher-quality coal, increasing steam temperature and pressure and increasing the utilization of the plant. Accordingly, plants for which neither of these solutions makes economic sense will progress toward mothballed status and will likely be replaced by natural-gas fired plants.

Carbon Price: For now, the EPA GHG regulatory path does not incorporate a carbon price. However, it is possible that the EPA may push regulation to the states, in which case regional cap-and-trade regimes may emerge. Of note, even a few \$/ton/CO₂ helps the coal to gas fuel switch.

US Renewable Energy Policy Framework (See Appendix for further details)

When looking over a twenty year time frame, policy has to be split into a short term and longer term context. We know what policy might look like over the next 2-5 years but after that it is harder to forecast policy mechanisms with as much certainty. For renewable energy, it is crucial over the long term that these technologies can compete against fossil-fuel fired generation at "grid parity." Up to that point, renewable energy technologies require incentives. Importantly, in our view, most renewable energy will reach grid parity over time as the relative costs to conventional energy become more competitive as we discuss in the Renewable Energy Fundamental View Section starting on page 63. Over the next 5-10 years, onshore wind and solar PV incentives only need to be supported on a shorter term basis, while offshore wind and solar CSP may need longer term incentives given their more nascent commercial state. From this perspective, the set of renewable incentives policies currently in place which are described in detail in the Appendix are on less steady footing on a short term basis.

Recent statements from President Obama and members of Congress indicate that an overarching economy-wide federal climate and energy bill is not on the agenda. In the absence of climate policy, renewable energy can still find support in energy policy. However, 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 with more resistance to the incentives for renewable energy in a constrained budget environment at the Federal level. .

Overall, the US renewable energy policy framework is comprised of federal-level tax and accounting incentives and credit enhancement programs such as government loan guarantees, as well as state and local-level mandates and targets. Although support at the Federal level is waning near term, which is particularly problematic for wind energy, there is still "demand pull" from state policies and programs.

In this respect, Federalism is still alive and well. State RPS programs are a near-term driver in states with binding penalties for non-compliance and other state-specific incentives that buy down the higher upfront capital costs for renewable energy. Indeed, certain technologies such as thin-film solar PV are widely expected to be competitive with fossil-fuel fired generation in states with good solar irradiance within the next 2-3 years. This is supported by the production tax credit (PTC) and investment tax credit (ITC), which do not expire until 2013 and 2017, respectively, although these are dependent on a weak tax equity market. So there is some but not much support for renewable energy over the next 2-5 years.

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Longer term, we would hope that both climate and energy policy would continue to support renewable technologies until they reach cost competitiveness and grid parity with conventional fossil-fuel fired electricity generation.

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Summary

- Coal generation faces rising costs and will see its share erode to natural-gas fired generation over the next 20 years.
- Environmental issues and more restrictive regulation are putting pressure on older, inefficient coal plants, accelerating what is likely to be a massive capital stock turnover of as much of a third of the coal fleet between now and 2030.
- On the supply side, the historic advantages relative to natural gas are less robust.
- Coal carbon capture and storage (CCS) is highly uncertain and unlikely to be a viable option between now and 2030.

Economics of Coal: LCOE, Infrastructure and Environmental Retrofit Costs

Today, pulverized coal-fired power plants are among the least expensive base load technologies for new builds, costing about \$2,890 per kilowatt of capacity, which compares favorably to new nuclear at \$6,100 but is more expensive than new natural gas combined cycle plants, which cost around \$1,230.³⁷ Integrated gasification combined cycle (IGCC) the coal generation technology that is expected to become an option for new builds capable of eventually capturing CO₂, is much more expensive and costs about \$4,750 per kilowatt. The higher relative cost for IGCC plants is the result of very few units having been deployed—for dedicated use for power generation—and the fact that the facilities have a larger footprint and require more steel, piping and equipment compared to a traditional coal plant. We estimate that the LCOE of a new coal plant equipped with capital equipment to control for SO₂ and NO_x but not CO₂ is about \$0.06 to \$0.09 a kWh. Older, unscrubbed coal plants have an LCOE of \$0.04-0.06 because their capital cost is largely written down. Retrofitting the most efficient coal plants to be compliant with pending EPA regulation, adds about 30-50% to the LCOE making the total fully loaded cash cost of these plants \$0.06-\$0.09 per kWh. For a more complete description of our total cash cost calculations and assumptions please refer to the Appendix at the end of the report.

Clearly, coal generators face a wide range of pending regulatory actions that will raise the marginal cost of generation and force difficult investment decisions. And while CO₂ emissions tend to get the headline attention because of their contribution to climate change, it is actually other emissions that pose more of a near term threat to coal generators. To control hazardous air pollutants, sources must install Maximum Achievable Control Technology (MACT). For acid gases, and possibly mercury, MACT could comprise a costly combination of SO₂ scrubbers, NO_x emissions controls and fabric filters. Already, we are seeing a growing number of utilities choosing to shutter older coal plants as the most efficient economic option based on today's industry fundamentals.

Industry backdrop: supply costs increasing

Coal generation supplies about 47% of US electricity today. Many of the plants are old and inefficient. But because they have been completely depreciated, they are cheap to run. In general, the US coal fleet operates near the low end of the 34%-43% thermal efficiency range typical for most modern coal units. The percent of electricity supply from coal generation has remained stable for the past few decades for coal because of its low cost. However, more stringent environmental regulations and discipline from coal miners who are shutting in inefficient capacity is putting upward pressure on cost.

The marginal extraction costs of coal are increasing across the board but particularly for underground mining, where there has been a greater focus on safety. We estimate that on average the \$/cost per ton for coal for a low cost producer in Central Appalachia has increased from about \$27 per ton in 2003 to about \$55 per ton today and is set to rise to at least \$60 per ton by 2012. For the Powder River Basin (PBR) producers (which accounts for ~70% of all US coal production) the increase in marginal cost has been less significant because it is largely a surface mining operation. However, even there the fully delivered costs have ratcheted up steeply owing to rising rail and transportation costs which accrue to the utility coal buyer. The coal contracts in the PBR were not well priced by the rail companies in the late 1990s—with little or no indexing—and are now being repriced typically at 30-50% higher with cost indexing. Rail contract escalations and higher tariffs for coal-generators without contracts have become a pinch point. We have seen a number of recent examples where

³⁷ DBCCA \$/kw capacity cost assumptions are based on a comprehensive market survey

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merchant coal generators that do not have a guaranteed price for their power, do not have captive retail or wholesale customers and cannot make use of automatic fuel cost pass-through mechanisms have chosen to curtail production due to margin compression associated with rising coal and transportation costs.³⁸

Moreover, recent disasters such as the accident at the Upper Big Branch coal mine in Montcoal, West Virginia, in which 29 miners lost their lives, has drawn greater attention to the industry's safety practices. The trend of relatively lax compliance, regulatory loopholes and modest financial penalties that was prevalent in the Mine Safety and Health Administration (MSHA) in recent years has gained public scrutiny and is being toughened. Finally, mountain top mining practices are being pressured under the Clean Water Act. We estimate that a small fraction of the 50-60 surface mining permits currently in the approval queue for permitting will likely move forth. At least one large coal buyer, Duke Energy, has stated specifically in its request for proposals for coal contracts that it will not buy coal from mountain top mines. Netting all these factors together raise the production costs of coal at the margin, potentially motivating producers to shut-in higher cost mines.

Advantages

Coal has had many powerful advantages relative to other power generation technologies. Chief among them is that the commodity itself is abundant and widely available and hence has been persistently cheaper than other fuels. At current consumption rates BP Statistical Review estimates that the US has a reserve to production ratio (R/P) of 245 years for coal, compared to 10.8 for oil and 11.7 for natural gas. And here we would note that the central tendency of the reserve forecast for coal is to the downside and the BP Statistical Review data dramatically understates the “true” R/P estimates for US natural gas which are now estimated to be more than 100 years based on the latest estimates from the Potential Gas Committee. And the Colorado School of mines believes that there could be 200 years supply.

The historic advantages that have made coal generation a dominant source of electricity supply are set to weaken. Coal generation is “under attack” and faces a “train wreck” of regulation as the industry cost structure rises in response to more stringent environmental requirements. Indeed, it is becoming increasingly clear that the economic challenge for coal generators will become more acute over the next few years driven by more restrictive regulation and shifting energy industry fundamentals, which are more favorable for natural gas generation in particular. In concert, these forces have ground new coal builds to a halt³⁹ and are hastening the retirements and lowering the utilization rates of the existing fleet. The changing fundamental landscape and regulatory uncertainty threaten to accelerate the forced retirements of potentially as much as a third of the existing coal generation fleet over the next ten-fifteen years. In addition, the forward commodity curves are indicative of a coal to gas switch as shown below as we illustrated earlier in the paper.

Disadvantages: The Environmental Cost of the Externalities

The principal shortcomings of coal generation are the negative environmental consequences compared to other power generation resources. Although these damages are widely known, their long term risks and impact have never been properly costed on a fully loaded basis. Heretofore coal has been given a mostly free ride from an externality perspective, which has enabled it to persist as a dominant generation resource. The problems with coal generation are its emissions (Exhibit). Burning coal produces more CO₂ and other criteria pollutants per megawatt-hour of electricity generated than any other source and almost twice as much as natural gas. As a consequence, coal power plants are leading contributors to acid rain, smog and greenhouse gas emissions. Coal-fired power plants currently account for 80% of CO₂ emissions from the electric power industry and about 33% of all US CO₂ emissions.⁴⁰

³⁸ In particular, NRG Power Marketing LLC, a wholly owned subsidiary of NRG Energy, Inc has filed a petition against CSX Transportation, Inc before the Surface Transportation Board to contest the terms of the new rail contract for \$27 per ton to deliver coal from Chicago to Western New York. See: <http://docs.stb.dot.gov/?sGet&DI1WTH1WXw1zAAkDXBRcV0x6Sw1xfAEAXAIIICW4CH3UCdXADWAQJDmckHQgJdBdTAI9IcUsOS1FELBdAO1dKS0ZcQQ0AfQUFS1RRVEpdTI1VcAMCWgMNCQoBamB0C20yODgvMy8wME0xMAw%3D>

³⁹ In 2002, 36,000 MW of coal capacity was planned to be installed by 2007; after the fact, only 4,500 MW or 87.5% less was actually installed. See: <http://www.netl.doe.gov/coal/refshelf/ncp.pdf>, p.5

⁴⁰ Energy Information Administration (EIA), Annual Energy Review 2008, Tables 12.1 and 12.7b,

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Exhibit 30: Natural Gas Generation is much Cleaner than Coal Generation

Emissions tons CO ₂ /MWh		Fossil fuel emissions levels (lbs per mmBtu)		
			Natural Gas	Coal
Coal	0.93	Carbon Dioxide	117	208
Petroleum	0.79	Carbon Monoxide	40	208
Natural gas	0.47	Nitrogen Oxides	92	457
Nuclear	0	Sulfur Dioxide	1	2,591
Hydro	0	Particulates	7	2,744
Wind	0	Mercury	0	0.016
Solar PV & CSP	0			
Geothermal	0			

Source: EPA

Source: American's Natural Gas Alliance

Coal combustion by-products: A growing problem

Coal power plants produce prodigious quantities of solid waste materials that include heavy metals such as arsenic, lead, mercury and selenium. These by-products are stored in earthen ash dam impoundments or wet lagoons, so called “dry” or “wet” storage facilities. The amount of coal ash stored close to power plants has ballooned over the past decade thanks in part to improvements in air pollution controls. While large volumes of the coal ash is often put to beneficial use for construction fill, mine reclamation, wall board and use in aggregates, demand for waste fly ash is economically sensitive, has slowed with the recession and pales relative to the high volumes generated from coal combustion. An estimated 1,300 coal ash dumps exist in the US and are mostly unmonitored and unregulated.⁴¹ The EPA has been studying the fly ash issue for almost 30 years but up to now has not settled on a regulatory standard. Consequently, the power industry has largely self-regulated within local and state guidelines. But this too is about to change and there is a high degree of likelihood that many wet ponds may have to convert to dry storage.

Going forward, coal ash dams face greater regulation from the EPA, which will decide how to regulate fly ash in the beginning of 2011. The heaviest regulatory response from the EPA would be to classify fly ash as hazardous waste under Subtitle C of the Resource Conservation and Recovery Act. The EPA's principal objective in doing so would be to facilitate the permitting of coal ash storage facilities and wrest control from what has been seen as ineffective local oversight.

This comes as part of a broad regulatory response to the failure of a wet ash holding pond at the Kingston Fossil Plant, owned by the Tennessee Valley Authority (TVA). In December 2008, the dam gave way following heavy rains and spilled 1.1 billion gallons of coal ash across 300 acres in one of the worst environmental disasters in state history. The net effect of pending EPA action is the likely conversion of wet storage systems to dry storage. This will result in a significant cost increase for the industry. As an example, the TVA recently announced that it will convert all of its wet ash impoundments to dry ash storage over the next ten years at an estimated cost of \$1.5 to \$2 billion.⁴² We expect the conversion cost per plant would be on the order of \$20-\$30 million per coal plant.

“Full” Cost

Adjusting for the environmental damages from coal power generation raises the “true cost” substantially. The National Academy of Sciences (NAS) estimates that the annual external damages from sulfur dioxide, nitrogen oxides and particulate matter represent about \$0.032 kWh.⁴³ In this regard, normalizing our LCOE expectations for the environmental damages from coal raises the cost per kWh by about \$0.02 kWh⁴⁴ to \$0.10-0.12 kWh, which is significantly more expensive

<http://www.eia.doe.gov/emeu/aer/envir.html>

⁴¹ <http://www.nytimes.com/2009/01/07/us/07sludge.html>

⁴² http://www.coalpowermag.com/environmental/New-Coal-Ash-Rules-May-Focus-on-Conversion-to-Dry-Storage_256.html

⁴³ <http://www8.nationalacademies.org/onpinews/newsitem.aspx?RecordID=12794>

⁴⁴ We estimate the damages to be about \$0.02 rather than \$0.032 because a reasonably small percentage of the existing coal fleet---10%---accounts for ~43% of the externality. Accordingly, it is logical that these plants will eventually be shut down with more stringent environmental regulation.

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than new natural gas-fired power plants and on par with new nuclear generation. Moreover, these estimates do not include the discounted future cost of damages from CO₂ emissions that will accrue to future generations from emissions today nor the damages that occur further down the supply chain with mining deaths and the lingering human health impact of black lung disease.⁴⁵ The Earth Policy Institute in Washington DC - a nonprofit research group founded by influential environmental analyst Lester R. Brown - estimates that air pollution from coal-fired power plants causes 23,600 U.S. deaths per year. It's also responsible for 554,000 asthma attacks, 16,200 cases of chronic bronchitis, and 38,200 non-fatal heart attacks annually.⁴⁶ The U.S. health bill from coal use could be up to US\$160 billion annually, according to the institute. Assuming this figure is accurate, it would be the equivalent of another \$0.09 a kWh in cost for all the electricity produced from coal in the US in 2009, making coal generation the equivalent of \$0.20 to 0.22 per kWh on a fully loaded "true cost" basis that incorporates all of the external damages.

What about CCS?

Finding ways to economically and efficiently capture and store CO₂—so called carbon capture and storage (CCS)—will be critical longer term in 2020 and beyond for coal generation to remain viable. However, the scale of the challenge is large. To think that the infrastructure will be put in place and the market barriers will be overcome within a decade is not practical. Therefore, the notion that CCS could be a 2020 climate change solution has been largely oversold to the public and government and we are just beginning to see more recognition that this is the case. To put this in perspective, capturing, compressing and storing CO₂ will add at least 60% to the cost of coal electricity, we estimate. Therefore utilities are unlikely to employ these methods unless they can recoup the cost via regulatory rate recovery or have other incentives that make the investment worthwhile. And even once the CO₂ is captured and compressed it must be transported and stored, which is an added cost. Moreover, the pipeline infrastructure does not exist to transport the CO₂ for beneficial use or long term storage. And the volumes will be massive. A 1,000 MW coal plant, for instance, produces about 6mn tons of CO₂ per year. Scaling the pipeline infrastructure to accommodate the volumes of gases would require recreating the equivalent of the US natural gas pipeline infrastructure, which has evolved over 70 years not to mention hundreds of integrated gathering and processing facilities.

To be fair, there is an estimated \$9 billion planned for deployment through 2017 according to a data base maintained by the Center for American Progress (CAP) directed toward CCS projects (See Exhibit 31). Of these projects, the most advanced is the American Electric Power (AEP) Mountaineer retrofit project which began as a 20 MW test run and is being scaled to a 235 MW commercial operation by 2015, at which point it will capture and store 1.5 million tons of CO₂ per year in the "well to hell" at the West Virginia facility. We expect modest capacity additions of demonstration coal CCS projects through 2030. Thereafter, the most efficient coal plants are likely to be targeted for CCS.

⁴⁵ According to the Centers for Disease Control (CDC), black lung disease or advanced pneumoconiosis has caused more than 10,000 deaths during the past decade.

⁴⁶ http://www.earth-policy.org/images/uploads/book_files/pb4ch10.pdf, p 248

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Exhibit 31: A Number of CCS Projects are in the Planning Stages

Name of project	ACCCE members	Location	Est. total project cost (millions)	Private funding (millions)	Public funding (millions)	Notes	Years (project implementation)
Plains CO2 Reduction Project Phase II	ACCCE, Ameren Corporation, Basin Electric Power Cooperative	North Dakota (Amerada Hess oil field in western North Dakota), South Dakota, Alberta Canada	\$161.6	\$78.7	\$82.9		2005-2017
Missouri Carbon Sequestration Project	Ameren		\$3.0	\$0.6	\$2.4		2006
Mountaineer Plant	American Electric Power	New Haven, West Virginia	\$800.0	\$193.0	\$607.0	Total project cost is based on estimated levels as per statements from AEP officials and on AEP website.	2009
Consortium for Clean Coal Utilization	Arch Coal, Ameren, Peabody Energy	Washington University, Missouri	\$12.0	\$12.0	\$0.0	Announced on December 2. Money paid over five years, proposals accepted starting January 2009.	2008
Chamolis Power Plant flue gas-algae research	Associated Electric Cooperative	Jefferson City, Missouri	\$0.6	\$0.1	\$0.5		2008
Antelope Valley Station carbon capture project	Basin Electric Power Coop	North Dakota and Weyburn Saskatchewan	\$375.0	\$75.0	\$300.0	Cost is average estimate, public funding figure is DOE loan.	2009
Williston Basin demonstration phase III	Basin Electric Power Coop	North Dakota and Weyburn Saskatchewan	\$3.2	\$2.2	\$1.0		2008
Big Sky Regional Carbon Sequestration Partnership	CONSOL Energy Inc.	Liberty, Pennsylvania	\$9.3	\$2.3	\$7.0		2003
Central Appalachian Coal Seam	CONSOL Energy	Fayette, McDowell, Raleigh and Wyoming Counties in West Virginia	\$2.7	\$0.5	\$2.2	Non-DOE spending is provided by total of 18 industrial partners.	2007-2009
Michigan Basin Geologic Test	DTE Energy	Otsego County, Michigan	\$23.7	\$6.3	\$17.5		2006
Cincinnati Arch Geologic Test	Duke Energy Corporation	Rabbit Hash, Kentucky	\$23.7	\$6.3	\$17.5		2006
Edwardsport Integrated Gasification Combined Cycle	Duke Energy Corporation	Edwardsport, Indiana	\$2,350.0	\$1,890.0	\$460.0	DOE funding is through local, state and federal tax incentives	2007-2012
MRCSP Phase III Large Scale Geologic Injection Test	Duke Energy Corporation	Edwardsport, Indiana	\$93.0	\$32.0	\$61.0		2008
FirstEnergy Fund for Advanced Energy Research	FirstEnergy	University of Akron, Ohio	\$2.0	\$2.0	\$0.0		2008
RE Burger Plant	First Energy	Shadyside, Ohio	\$23.7	\$6.3	\$17.5		2005
BP Carson carbon capture and Storage project	General Electric	Carson, California	\$2,000.0	\$110.0	\$90.0		2008
Mississippi Power IGCC plant	Mississippi Power (Southern Company subsidiary)	Kemper, Mississippi	\$2,200.0	\$1,100.0	\$1,100.0	Other private funding from Kellogg, Brown and Root. Applications for over half government funding still pending; money spent beginning 2009	2010-2013
Black Warrior Basin Coal Seam Project	Southern Company	Tuscaloosa, Alabama	\$2.4	\$0.5	\$1.9	Non-DOE spending is provided by total of 5 industrial partners.	2007
Gulf Coast Stacked Storage Project	Southern Company	Cranfield Oil Field, W Natchez, Mississippi	\$7.8	\$3.2	\$4.6	Non-DOE spending is provided by 15 industrial partners and the University of Texas.	2007
Phase III Early and Anthropogenic CO2 Injection Field Tests	Southern Company	Tuscaloosa, Alabama	\$93.7	\$28.7	\$64.9	Projected to begin in FY '09.	2008-2017
Plant Daniel- Saline Reservoir Field Test	Southern Company and Duke Energy	Escatawpa, Mississippi	\$6.8	\$1.6	\$5.1	Listed funding shares are based on average reported levels.	2006-2009
Big Brown	Luminant	Fairfield, Texas	\$400.0	Not found	Not found	Total cost based on estimated similarity to cost of scrubber.	2007
KYCCS Western Kentucky Deep Test	E. On US and Peabody		\$5.0	\$0.6	TBD	E. On US providing \$625,000	2008
Sunflower Integrated Bioenergy Center Algae-to-biofuels	Sunflower Electric	Holcomb, Kansas	\$417.0	Not found	Not found		2007
Northeastern Station	American Electric Power	Oologah, Oklahoma	N/A	N/A	N/A	Installation of technology is contingent on success at WV Mountaineer plant	2012
Total			\$9,016.2	\$3,552.0	\$2,842.9		

Source: Center for American Progress

Power Generation: Coal – Fundamental View & Outlook

Exhibit 32: Carbon Capture and Storage Project at AEP's Mountaineer Facility

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV



PHASE I – Validation
Captured CO₂ – September 2009
Injected CO₂ – October 2009

Source: American Electric Power, May 2010.

CO₂ Capture:

Project employs Alstom's chilled ammonia process for post-combustion CO₂ capture.

CO₂ Storage:

Compressed CO₂ is injected about 1.5 miles below the earth's surface.

PHASE I – Validation:

20 MWe scale validation project designed to remove 90% of CO₂ from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II – Commercialization:

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO₂/year. Awarded 50% DOE funding. Commercial operation in 2015.

Coal conclusions

The increased capital spending on coal power needed to retire, retrofit or replace existing coal plants to capture CO₂ emissions and to compensate for the reduction in power output at plants that will be retrofitted will be massive. We expect companies to retrofit their largest and most efficient pulverized-coal plants and replace smaller, inefficient plants that do not justify the expenditure. Based on today's energy fundamentals the rational economic decision is to shutter inefficient coal plants and replace them with natural gas combined cycle power plants. In short, the business case for an aggressive fuel switch from coal to gas is compelling because of the age and inefficiency of the capital stocks as shown in the Exhibit below. We expect 60 GW of coal capacity to be retired between 2010 and 2020 and another 92 GW to be retired between 2020 and 2030. Consequently, we expect coal's share of US electricity to supply to decrease from 47% in 2009 to 34% in 2020 and 22% in 2030. Consequently, we expect the annual power sector coal burn to decrease from about 930 mn tons per year in 2009 to 460 mn tons per year in 2030.

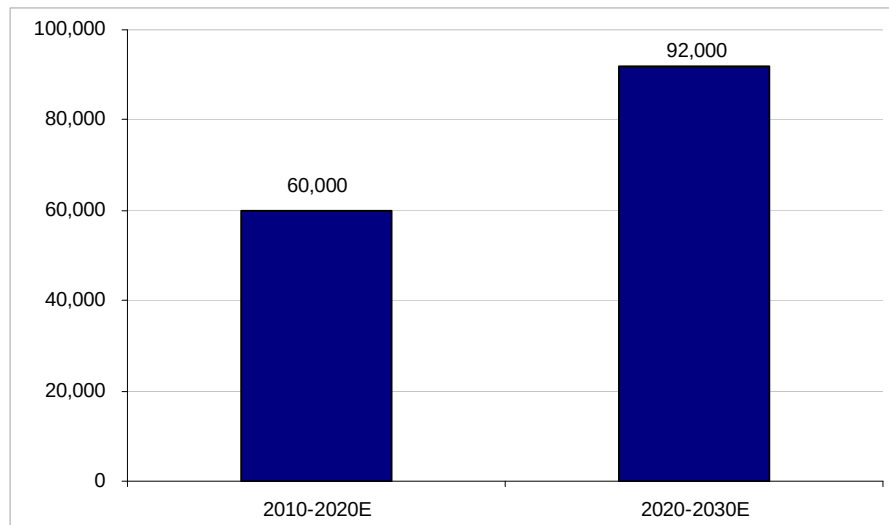
Exhibit 33: 45% of the Coal Fleet is Old and Inefficient and Ripe for Retirement

Future Coal Retirements	Total GW	Average Unit Age	Average Unit Heat Rate
2010-2020 Period	60	62	16,990
2020-2030 Period	92	47	12,654

Source: Ventyx, DBCCA analysis, 2010.

Power Generation: Coal – Fundamental View & Outlook

Exhibit 34: We expect massive capacity reductions from coal generation (MW)



Source: EIA, DBCCA

Power Generation: Natural Gas – Fundamental View & Outlook

Summary

- Natural gas power generation is uniquely positioned to be a key energy resource, displacing coal and complementing renewables in the multi-decade transition to a lower carbon energy system.
- Strong fundamentals support this energy shift and we expect natural gas to be one of the fastest growing energy sources for power generation through 2020 and possibly beyond supported on the supply side by an abundance of low cost unconventional resource plays and by more restrictive environmental regulation on the demand side.
- The US has a unique and highly developed natural gas industry structure, value chain and infrastructure which can expand fairly quickly to support the scale-up.
- Environmental issues on the supply side are considerable but manageable with best practices.
- Carbon Capture and Storage (CCS) natural gas retrofits are likely to be at least 10-15% less expensive than coal retrofits.

Economics: Improving Long Term Price Outlook

Combined cycle natural gas power plants are the least expensive base load technology option, costing about \$1,230 per kilowatt of capacity, which compares favorably to new nuclear at \$6,100 and new scrubbed pulverized coal power plants at about \$2,490. We estimate the LCOE of combined cycle natural gas new builds to be \$0.06-to \$0.08 assuming a \$6/mmBtu normalized gas price (in line with the forward commodity curves), making natural gas among the most attractive options for new builds. In addition, there are underutilized natural gas assets that are currently trading in the \$350 kW range compared to \$640 kW in the 2003-2008 time period and \$1,230 for new build. We estimate that the LCOE for used natural gas plants is in the \$0.05-\$0.07 kWh range. On a fully loaded cash cost basis old gas plants cost about \$0.06 to 0.08 per KWh, due to digital instrumentation retrofits. Fully loaded new natural gas plants cost \$0.06-\$0.10 depending on how much incremental pipeline additions are required. (See cost estimates in the Appendix)

Industry backdrop

Natural gas generation supplies about 24% of US electricity today and accounts for 42% of total power sector capacity. The plants are among the most modern and efficient in the US power sector as a whole and there is more natural gas capacity in the US than coal capacity—an estimated 455 GW vs about 337 GW of coal; however, natural gas plants typically run about 20-40% of the time compared to 60-75% for coal.

The discrepancy reflects the fuel's benefits and drawbacks. Natural-gas plants can be built quickly and at a low cost relative to coal or nuclear plants and can be cycled on and off with relative ease to meet peak demand and balance load. However, until recently the historic fuel price volatility and lack of long term contracting has made electricity from natural gas more costly and variable than generation from coal or nuclear.

But economics alone—while certainly an overarching driving factor in the decision process—is not the sole factor in determining value. Other attributes supporting natural gas as the transition fuel of choice over the next ten years or more include:

1. **Short lead times:** Natural gas generation is the only option with short enough construction lead times and capable of relieving short term pressure on reserve margins. A natural gas plant can go from planning to steel in the ground in about 2 years compared to 3-5 for coal and 5 years plus for nuclear plants;
2. **Flexibility:** Wind and solar represent that largest share of capacity additions; “operational flexibility” is the new mantra in power markets and is becoming more highly valued. Natural gas generation is much more flexible than coal generation and therefore a logical complement to renewables additions, which require faster ramps and quick dispatch of fossil generation to balance load;

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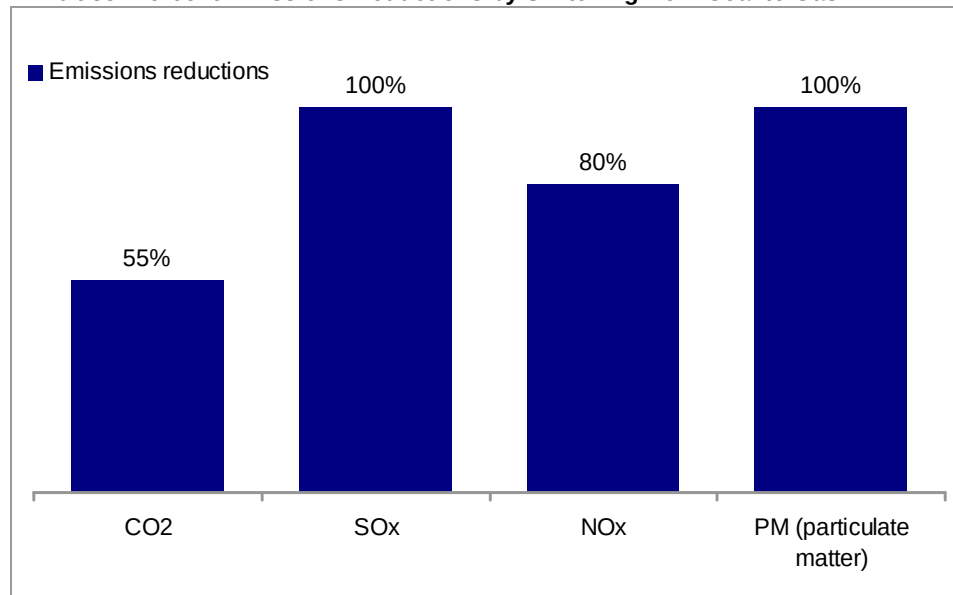
3. **Politically acceptable:** It is no secret that in the absence of comprehensive climate change legislation at the federal level, the US government and the EPA in particular are pressuring coal generation to a significant degree as we showed earlier in the policy section of this report. Natural gas generation is the most immediate least cost and least risky fallback option for utilities and independent power producers;
4. **Underutilized assets:** Ten years after the “dash to gas” bubble fueled by deregulation, ample and underutilized natural gas assets still exist. These plants were designed to run primarily as baseload and will therefore be repurposed as mid-merit cycling units or will run as baseload with higher capacity factors as needed provided there is the right coal/gas fuel arbitrage net of emissions compliance costs.

Advantages

As we showed earlier in this report in the Regulatory and EPA section, natural gas generation has a superior environmental footprint compared to coal generation and will be advantaged with tougher environmental regulation. The environmental benefits of a coal to gas fuel switch are substantial. For example, shutting down the dirtiest 33% of coal power plants and replacing them with natural gas plants would eliminate the following annual estimated pollution: 500 million tons of CO₂, 700,000 tons of nitrogen dioxide, 1.5 million tons of sulfur dioxide, and millions of tons of particulates.⁴⁷ Fortuitously, the existing coal and natural gas capital stock match well for this fuel switch.

Natural-gas plants emit roughly half as much CO₂ and far less mercury and other hazardous pollutants than coal plants, which has made them attractive.

Exhibit 35: Percent Emissions Reductions by Switching from Coal to Gas



Source: EIA

Structural supply side shift from shale: game changer and further advantage

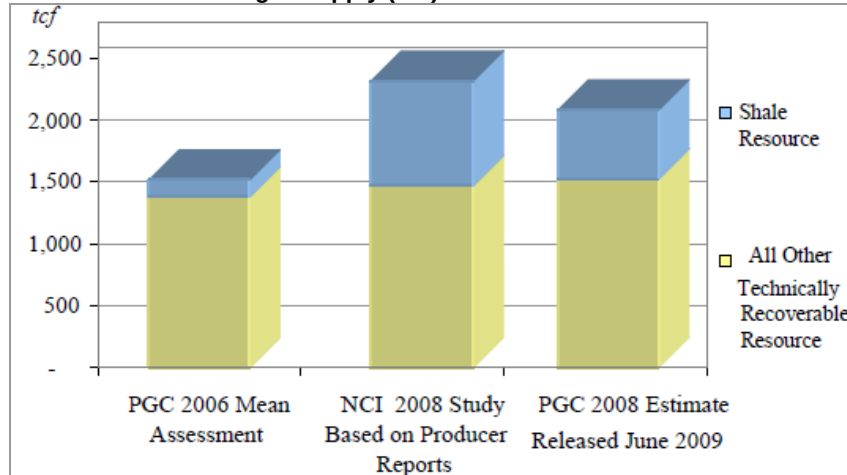
The fuel switch share gain that we expect from natural gas electricity generation relative to coal over the next ten years is supported at its core by economics. In this respect, the future is not what it used to be. A dramatic shift in the North American natural gas supply is unfolding, driven by rapid productivity advancements in horizontal drilling and completion

⁴⁷ 2009 Chesapeake Energy Corporation Annual Report, page 15

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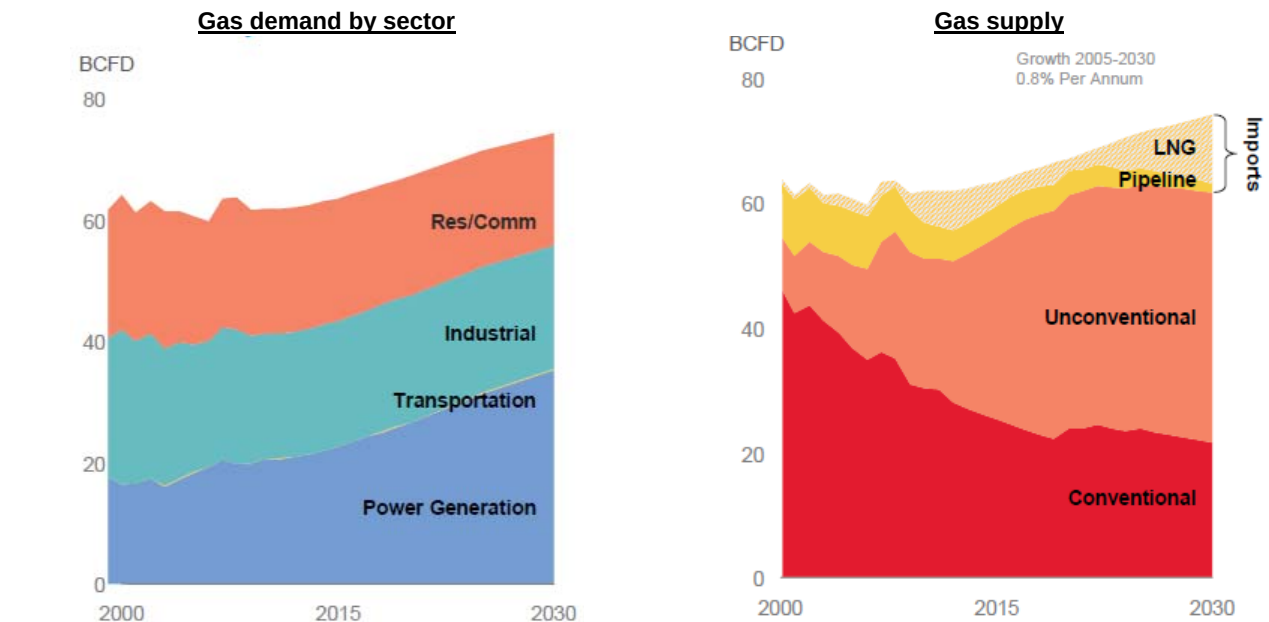
technology capable of tapping unconventional tight sands and shale resources rapidly and at a low cost. Credible supply surveys such as the BP Statistical Review and the EIA's Form 914 pick up reserves and total production but have generally underestimated the contribution from shale plays, often by a wide margin.⁴⁸ According to a 2009 report from the Colorado School of Mines, the US now holds some 1,800 trillion cubic feet of natural gas, one third of it shale, which is the equivalent of 320 billion barrels of oil, or close to a 200-year supply.⁴⁹ As a consequence, over the next few years the US market is likely to see too much natural gas supply and not enough demand, which is a bullish signal for coal to gas switching.

Exhibit 36: U.S. Total gas supply (Tcf)



Source: Navigant Consulting, "Natural Gas Supply The Role of Shale Gas," December 2009.

Exhibit 37: US Incremental Natural Gas Demand Will Come from Power Generation



Source: ExxonMobil - Global Gas Perspective, November 2009.

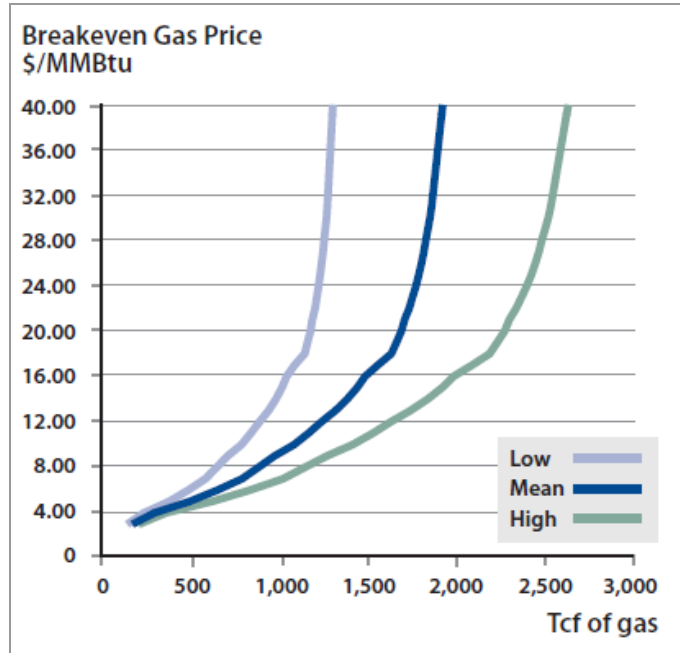
⁴⁸ And here it is important to note that these supply estimates impact long run price expectations for natural gas that drive many of the macroeconomic modelling assumptions in EIA's energy models, which influence the long run energy share mix forecasts. Hence, we believe EIA's estimates for natural gas power generation are understated.

⁴⁹ <http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base>

Power Generation: Natural Gas – Fundamental View & Outlook

We expect these new supply sources to introduce new relative stability in natural gas prices, clipping the tops and tails of the historic price volatility. Accordingly, it appears more likely that natural gas prices will normalize in the \$4.50 to \$6.50 per mmBtu range, as compared to the extreme highs and lows of \$2 to \$14 that played out from the 2000-2008. Looking at the amount of natural gas incremental demand that we forecast due to the fuel switch, there appears to be an adequate amount of gas supply available below \$6/mmBtu to satisfy annual demand in the 25 Tcf range through 2030 with another 20 years supply available through 2050 at \$8-\$9/mmBtu, which would accommodate a step up to 28 Tcf per year from 2030 to 2050.

Exhibit 38: 62% of Mean Production Estimates Are Economic Below \$6/mmBtu



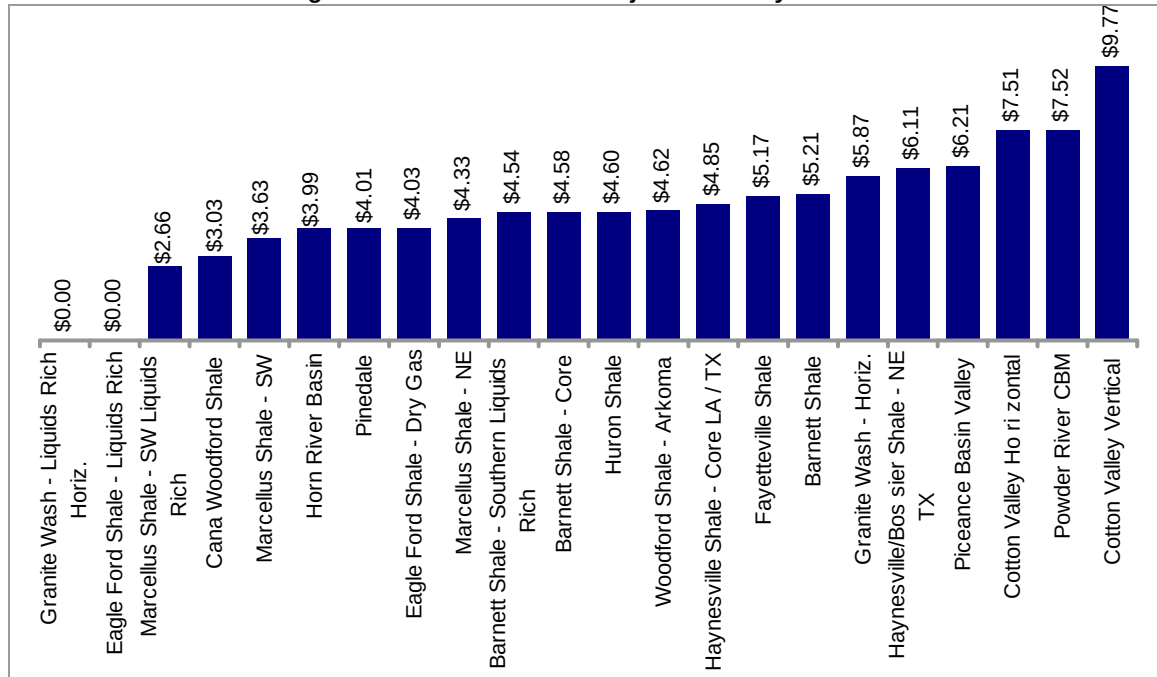
Source: MIT

The pace of shale development depends on drilling activity, not on high capital, long lead time infrastructure investment. This should dampen year-on-year price volatility as gas producers can respond more quickly to market needs. Within this price range, most of the US shale plays are economically viable, which suggests that there should be no supply shortages whatsoever between now and 2020. A recent MIT study concluded that some 62% of the estimated mean projection of the recoverable shale gas resource could be economically developed with a gas price at or below \$6/mmBtu.⁵⁰ Moreover, large swaths of the shale basins are breakeven with natural gas below \$5/mmBtu as shown in the Exhibit below.

⁵⁰ MIT Study on the Future of Natural Gas, p xii, Interim Report, June 2010

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Exhibit 39: Breakeven Marginal Price Points for the Major Shale Plays



Source: Bloomberg and Credit Suisse

The increase in drilling programs to exploit these unconventional resources should continue at an unfettered pace as long as natural gas stays above \$4 mmBtu. And where as in the past it would take up to three years to trigger a supply response to natural gas shortages because most of the incremental US production was coming offshore in the Gulf Coast where there are long lead times, activity has now shifted to non-conventional on shore production sites which have a faster time-to-market and lower cost. These wells have very high initial production rates relative to their long term performance, with significant decline rates there after. However, by applying an industrial “manufacturing” or “mining” model to these resource plays, literally thousands of well can be drilled with very high efficacy.

Natural gas industry structure; US advantaged versus the rest of the world

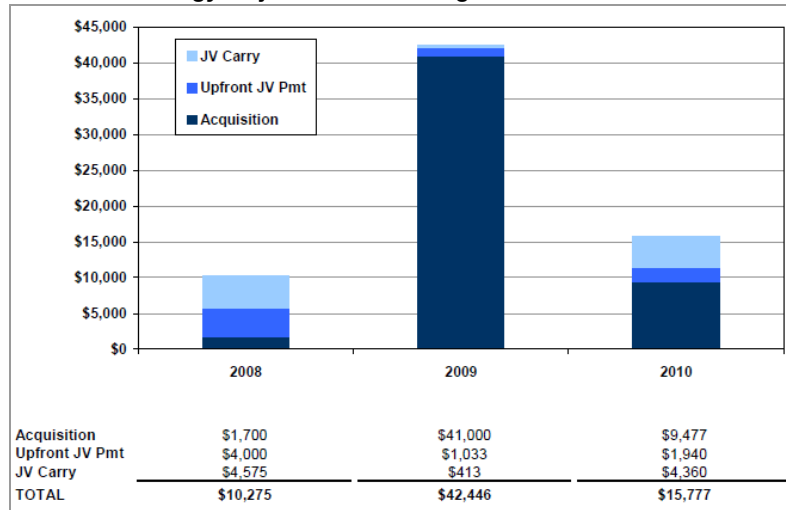
The US is somewhat unique compared to the rest of the world in that it has the most developed natural gas pipeline and storage infrastructure and can also take LNG swing supply at the right price, which provides an additional safety valve to support supply security and price stability. In addition, natural gas pipelines additions are relatively easy to accommodate due to favorable regulatory oversight and regulated returns for pipeline companies. This enabling infrastructure is a key component of the coal/gas fuel switch story and is why we think prices will trend in a more stable and tighter range than they have in the past. Industry structure and fundamentals play a role, too. A large network of competitive independent exploration and production companies are smart enough that they will always be there shrinking and growing as necessary to meet their return thresholds. They are supported in the industry value chain by a competitive network of drillers that will shift work based on where they can earn the best day rates. And the capital markets are fairly liquid out two to three years forward, which means that the large commodity focused investment banks are willing to buy forward production providing an avenue for E&P companies to fund their capex programs.

Of note, the natural gas E&P industry is fractured and scrappy from a competitive standpoint. Although there are some very large players, a far greater number of midsized to smaller firms have accumulated low cost resources. However, the high capital cost and need for environmental stewardship in developing the large shale drilling programs is leading to a shift in

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industry structure and an inevitable consolidation process has begun with the big likely to get bigger.⁵¹ Since the E&P business model is entirely focused on cash margins, we expect that the tougher competitive environment will lead to a larger number of smaller companies that lack capital efficiency to look for strategic exits.

Exhibit 40: Energy Majors Have Paid Big Prices to Enter into US Shale Gas



Source: Credit Suisse, June 2010

Note: consideration paid in shale gas acquisitions and joint venture agreements.

The US has an abundance of natural gas, which means that the suppliers are price takers and will get what ever they can. Indeed many leaseholds have a “use it or lose it” provision, which requires that drilling commence within a fixed short period of time⁵² or else the lease is invalidated. Another factor to consider is that drilling programs are capital intensive and proceed even when there is negative margin because many lease holds have a “use it or lose it” contractual clause. Consequently, there is something of a treadmill phenomenon in which drillers must keep tapping the shale plays, which again contributes to the bias of a supply overhang rather than a truly balanced market.

Accordingly, the market place is very competitive and there is a structural impetus to keep cranking out supply which helps to put a lid on prices. At the margin, this stacks the cards in favor of natural gas power generators who are short gas. And so it is that utilities and IPPs are moving into a relatively more advantaged bargaining position, since prices appear to be more stable and transportation basis spreads are compressing with the build out of midstream processing facilities and trunk lines located closer to the large demand centers on the East and West coasts. Therefore, we expect to see producers sell forward production under long term contracts to mitigate price volatility just as was the case in the 1970s and early 1980s prior to the deregulation in the gas industry. Once power generators can hedge their gross margin on a longer term basis it will become more economical to better utilize their natural gas plants and cycle coal plants. Accordingly, this demand pull should reverse the flat trend in the growth of natural gas demand that has persisted over the past 10 years and also translate into an increase in the utilization rates of natural gas power plants.

Disadvantages: What about the environmental issues with shale? Will cheap prices persist?

Every energy source has limitations and an environmental impact. Natural gas is no different, although more manageable and less severe than coal and nuclear energy, in our view, on a lifecycle basis. Recently, there has been considerable

⁵¹ As an example, in December 2009 ExxonMobil agreed to purchase XTO, the largest independent E&P company focused on shale gas. In addition we have seen a large number of joint ventures announced bringing in the world super majors such as Statoil and Total.

⁵² Generally less than 3 years

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attention drawn to the environmental impacts of hydraulic fracturing and waste water, causing skeptics to question the sustainability of unconventional natural gas extraction.

Commonly referred to as fracking, hydraulic fracturing has been used by the oil and gas industry since the 1940s and has become a key enabler of natural gas development programs worldwide. The process is used for deep horizontal lateral well completions and involves forcing fluids consisting of about 99% water and sand, along with a small amount of special-purpose additives. Normally, a hydraulic fracturing operation is only performed once in the life of a well, which then produces gas for 30-70 years, albeit at declining rates of production. On averaging, “frack jobs” occur more than 1.5 miles below the surface and are separated from shallow groundwater formation by thousands of feet of impenetrable rock. In addition, multiple layers of steel casing and cement surround the wellbore creating further layers of protection. The controversy has been around the chemical ingredients used in fracturing, waste water treatment and disposal and impact on drinking water, since waste water can contain heavy metals.

In 2010, the EPA allocated \$1.9 million to conduct a study assessing the health and environmental impact of hydraulic fracturing with an emphasis on identifying the connection between water and hydraulic fracturing. The EPA is still in the comment/scoping period of the study and is not expected to appoint a lead contractor to write the report until 2011. Consequently, the study is not expected to be released until 2012 and it is far too early to anticipate what recommendations might be included in the final report. In addition, it is possible that hydraulic fracturing may eventually be regulated under the Safe Drinking Water Act, although momentum on this issue may stall given the results of the midterm elections and change in House leadership. The industry would clearly prefer to maintain state level standards. However, over the longer term a federal regulatory solution indeed may be a sensible approach as it would ensure a minimum federal floor of drinking water protection in the more than 30 states where oil and gas production occurs. This would potentially harmonize regulations governing fracking and waste water disposal, which are currently monitored on a state-by-state basis by the respective departments of Environmental Protection, which are often understaffed and under-informed on the issues. That said, state level Department of Environmental Protection (DEP) agencies are aggressively staffing up and adding to inspector jobs due to the rapid proliferation and increase in shale drilling programs. As an example, in Pennsylvania 68 new inspectors are expected to be added in 2010, which compares to a total of 40 water inspectors statewide in 2007. In other words, state regulatory oversight is scaling with increases in natural gas production and there is clearly the view that this is a growing, sustainable industry.

We do not anticipate federal regulation—if enacted—derailing the shale story. In fact, many of the larger shale drillers have already begun to disclose the ingredients used in the fracking process, which consist of off the shelf chemicals. The ~1% of the frack fluid that contains chemicals typically consists of acids, friction reducers, surfactants, gelling agents, scale inhibitors, corrosion inhibitors and antibacterial agents. Almost all of the fluids used in slick water frack jobs consist of water itself. Where there have been issues with ground water contamination, it appears that operator error and failure to adhere to best practices has been more of the cause rather than the practice itself. Poor cementing of casing wells through the water aquifer has been an issue in some incidents. Greater federal oversight would encourage better industry practices at least until such time as states are able to put in place more rigorous environmental compliance requirements to ensure that fracking is sustainable over the long term.

As a practical matter, these issues do not appear to be an impediment to secular growth in shale production. Recycling has emerged as a principal onsite water treatment and is likely to be the preferred long term solution to water given the high cost, inconvenience and risk associated with trucking waste water to disposal facilities. In addition, most all shale areas from a geologic standpoint have the ability to inject waste water if allowed. Indeed, some oil and gas regulators, as well as some energy producers, say their biggest concern is surface spills of fracturing fluids that contain potentially toxic chemical additives.

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Takeaways on Environmental Issues

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. Already, the threat of tougher regulation has motivated the industry to improve its practices. As an example, a number of leading shale developers such as Equitable Resources are now posting the ingredients used in hydraulic fracturing on their websites. Water recycling has also increased substantially, particularly in the Marcellus Shale, with about 80% recycling on average and a host of companies recycling 100% of their water use. Shale extraction and materials/process handling must be proven to be environmentally sustainable at large industrial scale. We believe this will prove to be the case. At this time this is not a consensus view. There are shale detractors. And to be fair, the industry practices and potential feedback loops are not well understood and there are sure to be learning curves given its nascent state. From a regulatory standpoint looking at shale drilling overall, it appears likely that the industry will be required to disclose the ingredients used in hydraulic fracturing and may also face higher compliance cost for waste water disposal and monitoring. As best we can tell these potentially higher environmental costs should not derail the structural cost advantage of shale extraction, which continues to improve at a rapid pace with faster cycle times, process enhancements and new technology deployment. More restrictive regulation would probably be an impediment for marginal shale E&P companies but would be beneficial for the industry overall in terms of defining and adhering to industry best practices.

Natural Gas Carbon Capture and Storage (CCS): A 2030 Solution?

Even though natural gas baseload generation produces on average 50-60% less CO₂ per MWh compared to coal generation, it still produces GHGs and is therefore problematic over the long term to keep the world on a sustainable 450 ppm emissions pathway. Therefore, the fuel switch alone in the long run is not a viable option from an emissions standpoint. Technically, we believe it will be easier and more economic to apply CCS technologies to natural gas power plants than to coal power plants. Moreover, discussion and analysis of CO₂ abatement for coal power plants has often focused on the \$/ton of CO₂ avoided rather than the \$/MWh of electricity production. Such analysis can be misleading given the almost 2x increase in carbon intensity of electricity production from coal-fired power versus natural gas.

Recent research supports this view. **A 2010 study by Element Energy evaluated the UK's power system and suitability for retrofitting the natural gas fleet to post combustion CCS technology and determined that it would be cheaper than coal-fired retrofits.** This is on back of The European Commission's Second Strategic Energy Review conducted in 2008 that examined the costs and emissions of various electricity generation technologies. The study was intended as an information resource in European Union decision making. The technical review determined that on a capacity equivalent basis, natural gas combined cycle power plants (NGCC) with post combustion monoethanolamine (MEA) scrubbing to capture CO₂ emissions were significantly more efficient for a 2015 plant-in-service date than the equivalent post combustion pulverized coal plant with post combustion MEA scrubbing and also more efficient than pre-combustion carbon capture from an integrated gasification combined cycle (IGCC) coal facility using the Selexol carbon capture process. The post combustion NGCC plant operated at a 49% efficiency rate, compared to 35% for both the coal plant designs.⁵³ Similarly, for post combustion retrofits, the latest technical data suggest that on a \$/kW basis, NGCC retrofits are likely to be at least 10-15% less expensive than coal retrofits.⁵⁴

Meanwhile, the most recent literature from the CCS Task Force in the US (August 2010) suggests that the incremental costs of new coal-fired CCS plants relative to conventional coal plants typically ranges from \$65-\$90/ per tonne of CO₂ avoided, with about 90% of that cost associated with the capital equipment for capture.⁵⁵ And this does not include the substantial pipeline infrastructure that would need to be added to transport the CO₂ to long term geologic sinks. The

⁵³ <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SEC:2008:2872:FIN:EN:PDF>, p. 14

⁵⁴ UK Electricity Generation Costs Update, Mott MacDonald, June 2010, p. 49

⁵⁵ Carbon Capture and Storage Interagency Task Force, August 2010, p. 9

Power Generation: Natural Gas – Fundamental View & Outlook

estimated length of pipelines needed for commercial deployment of CCS in coal-fired power stations ranges from 22,000 to 36,000 miles through 2030. By way of comparison, the natural gas pipeline industry built about 21,000 miles of pipeline between 1998 and 2007.⁵⁶ So while certainly technically feasible, there would be a large incremental cost.

In short, we believe CCS for gas will be a later measure in the 2020-2030 timeframe and beyond for deeper decarbonization. Over the next 10-15 years natural gas-fired power generation could lead to a step-change in CO₂ intensity and NGCC plants can be retrofitted later with CCS where technology development is advisable to lower the cost of capture and deliver flexibility of the CCS plant needed for power production intermittencies. Longer term, retrofitting CCS for gas is as cheap or likely cheaper than retrofitting CCS for coal per MWh of electricity generated. And there would need to be less than half the CCS storage space, because of the lower emissions.

Natural gas conclusions: flexible dispatch and environmental advantages favor gas over coal

Changing industry fundamentals and lower and more stable natural gas prices versus recent history are improving the outlook for natural gas power generation. We expect that natural gas power plants will replace a large share of the coal power plants that are retired as a result of forthcoming regulation. Consequently, we foresee the share of US electricity supply from natural gas-fired generation increasing from 23% in 2009 to 30% in 2020 and 35% in 2030. Consequently, we expect the annual power sector natural gas burn to increase from about 6.7 Tcf in 2009 to 9.7 Tcf per year in 2030. This share shift includes an additional ~27 GW of new natural gas power plants between 2010 and 2030 at an approximate incremental capex of ~\$33 billion.

Thermal power plants are most efficient when they are run continuously. Starting and stopping and cycling—ramping up and then down from idling capacity—causes plants to burn more fuel and therefore produce more emissions than they would if they were running at normal levels. Coal power plants are less efficient at cycling than gas power plants, which is why they are largely run as baseload and midmerit plants rather than to meet peak loads. A consequence of larger penetrations of wind energy into the power grid as we discuss in more detail later in this report is that the fossil fleets will need to become smarter, more flexible and will frankly be required to cycle more often as power grid operators become more comfortable with adjusting to the diurnal energy flows from renewables. In this regard, natural gas plants are a more logical pairing fuel with renewables than coal generation. Gas plants are highly dispatchable, have the flexibility to cycle up and down and can go from “turning gear” to “emissions compliant” in a matter of minutes. In addition, there are instrument and control improvements that can be made to older gas plants at relatively little capital cost to extend their lives and make them more agile. Such cycling flexibility simply would not be possible to achieve with a coal power plant.⁵⁷

⁵⁶ Carbon Capture and Storage Interagency Task Force, August 2010, p. 38

⁵⁷ Some coal plants are cycled on with a cold start, which requires start-up fuel (typically diesel or oil), auxiliary power and additional manpower. Others are cycled with a warm start, using a boiler or turbine temperature of 250-700 degrees F, with the plant off-line for 12-48 hours prior to start-up. Still others cycle on with a hot start, with a boiler or turbine temperature of 700-900 degrees F, with the plant off-line 8-12 hours prior to start-up. No coal plant can cycle and be “emissions compliant” on par with a natural gas plant.

Power Generation: Nuclear – Fundamental View & Outlook

Summary

- Nuclear energy will continue to be an important part of the low carbon generation portfolio mix given the stability of the entrenched capital stock.
- High capital costs, long lead times, financing barriers and political risk limit deployment between now and 2020 to just a few units.
- From 2020 to 2030 we expect new nuclear builds to displace some of the older coal plants for baseload generation and to complement natural gas generation for fuel diversity. The share of total nuclear supply increases only modestly to 23% in 2030 from 20% today. However, nuclear energy's contribution to lower GHG emissions through 2030 is notable because of the high capacity factor at which nuclear power plants run.

Economics

Today, nuclear-power plant new builds are more expensive than fossil fuel baseload generating technologies such as coal-fired power or natural gas. Lower long term natural gas prices—which determine wholesale power prices in most electricity markets—increased capital costs and lower power demand have made nuclear power plants challenging to build. Nuclear-power plants are more expensive to build than coal facilities, natural-gas plants and wind farms, costing around \$6,100 per kilowatt of capacity compared with \$2,890 for pulverized coal, \$4,750 for integrated gasification combined cycle (IGCC) coal, \$1,230 for natural gas combined cycle (NGCC) and \$1,970 for onshore wind, respectively. We estimate the LCOE of nuclear new builds to be \$0.12-to \$0.14/kWh, making nuclear generation among the least attractive options for new builds without subsidies. However, once in operation, nuclear plants have relatively low and predictable fuel, operating and maintenance costs compared with other power generating methods and typically operate at higher capacity factors in the 90% range. We estimate that old nuclear power plants can generate electricity in the \$0.07 to \$0.09/kWh range.

Industry backdrop and new build activity

The halcyon days for the nuclear power industry were in the late 1950s when expectations were that “learning by doing” would make nuclear power “too cheap to meter” and a technology that would displace coal. Reality tells a different story. Construction costs for nuclear power plants turned up sharply in the 1980s with inflation and longer construction times (due to non-standardized designs, an inefficient permitting process, and greater compliance following the Three Mile Island accident), leading to industry inactivity, contraction and cost overruns that plagued the sector in the 1990s. During this period new construction ground to a halt and a number of high profile projects folded, with rate payers absorbing the stranded costs.

Recently, concerns over CO₂ emissions from fossil-fuel-fired power plants, the need to create high paying permanent jobs and energy security and the desire to have less dependence on foreign oil and gas have recast nuclear power as a “green” industry capable of making a large contribution to reducing greenhouse gas (GHG) emissions and stimulating state economies. And so after more than 20 years of retrenchment, the nuclear industry is gearing up for growth once again, although for now most of the growth is coming from Asia, and it is unlikely that nuclear energy will make a large incremental contribution to US electricity supply by 2020⁵⁸. The great majority of nuclear plants in operation today are already over 20 years old, with many over 30 years old (IEA, 2010).

A number of nuclear-friendly state utility commissions in Southeast US—in particular—have riders in place that allow regulated utilities to minimize regulatory lag by earning their allowed return on equity (ROE) on their construction work in progress (CWIP) for early stage investments in developing nuclear projects. Such provisions substantially reduce the risk to investor owned utilities (IOUs) in the event that the project is not completed. Utilities such as Progress Energy (PGN), Duke Energy (DUK), Dominion (D), SCANA Corporation (SCG) and Southern Company (SO) have benefited from such favorable

⁵⁸ China has made the largest commitment to nuclear energy with 16 units under construction and 29 more planned. China's engineering skills and infrastructure along with its command-and-control political system have allowed it to complete projects on a scale that is simply not achievable elsewhere. In addition, Korea has developed a strong nuclear industry which is now taking the first steps beyond its home market, according to the IEA.

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regulatory treatment in their current nuclear development programs. Most of the proposed projects will be built adjacent to existing facilities that were originally designed to accommodate multiple units before the industry declined.

By contrast, nuclear development on the part of unregulated power generation companies is decidedly more complicated and necessitates bringing together a consortium of partners to de-risk the project economics. For these merchant players, the recent new proposals from the federal loan guarantee program (LGP) operated by the Department of Energy (DOE) is essential in bringing down the capital cost and financing the projects. In this respect the LGP is tantamount to a go/no go, or knockout, provision in terms of the project moving forward. Companies going down this route include NRG Energy (NRG), in collaboration with its Japanese Partner, Toshiba and Constellation Energy (CEG), in concert with its French partner, Areva, in the UniStar consortium.⁵⁹ Each is currently engaged in a due diligence phase with the DOE and expects to learn whether its project is approved by the end of 2010. NRG Energy has stated that without a loan guarantee it will abandon its nuclear development plans.

Government Support Essential

The complexity, risks, high-up front capital costs and long asset lives of nuclear-power plants mean that government incentives and guarantees are needed to drive investment to the industry. The 2005 Energy Policy Act (Public Law 109-58) contained a number of key elements to support nuclear energy development such as low-interest loans, risk insurance, indemnification, production tax credits and guarantees to safeguard spent fuel in long-term repositories. Of these support mechanisms, the most important is the loan guarantee program (LGP), administered by the DOE.

To date, however, the LGP has not lived up to its policy intent and has fallen short in catalyzing private sector investment. As an example, although the DOE was given authority to administer the program it was not until early 2010 that the Office of Budget and Management (OMB) appropriated the funds, leaving the DOE with only a skeleton staff. Consequently, of the initial 147 applications filed under the LGP, only 16 were asked to move to Phase II and from that cohort of projects only one actually received a term sheet.

2010 has been a key turning point for the LGP, which has moved into high gear and staffed up substantially thanks to greater support from the Administration and new leadership. Consequently, the agency's long delayed operations appear to be gathering momentum. As of June 2010, the DOE still has \$8.2 billion in remaining nuclear loan guarantee authority, after awarding \$8.3 billion in February for Southern Company's Georgia nuclear plant and \$2 billion in May for AREVA's Idaho uranium enrichment facility. In testimony before the Senate Appropriations Committee, Energy Secretary Chu said the DOE has said that the request of \$9 billion in additional loan volume would allow funding for three more nuclear projects before the end of Fiscal Year (FY) 2010.

Currently, the DOE has moved three nuclear applications to the "due diligence" stage: NRG/Toshiba (TX), UniStar's Calvert Cliffs (MD), and South Carolina Electric & Gas' Summer Station project. It is as yet unclear what the proposed \$9 billion would mean for the \$36 billion in nuclear loan guarantee authority that DOE requested for its FY 2011 budget.

Nuclear Energy Advantage

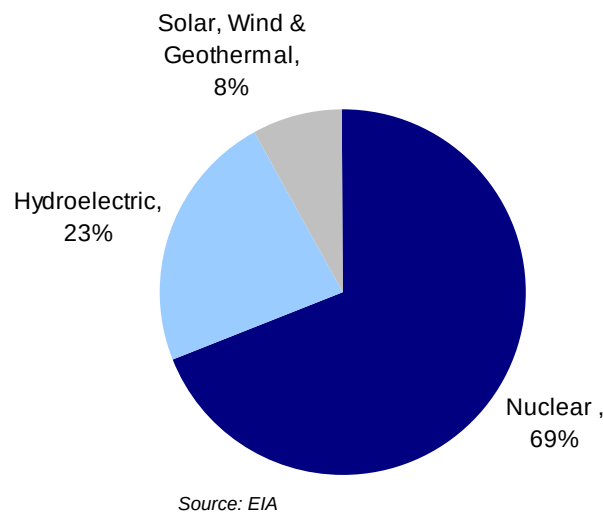
Nuclear energy has proven itself to be an important component of the global electricity supply mix, currently supplying 14% of global electricity (IEA, 2010). In the US, nuclear energy supplied 20% of total electricity in 2009. The principal advantages of nuclear energy are low variable fuel costs—since Uranium is an abundant element with most supplies in politically stable regions—and a favorable environmental profile relative to fossil-fuel generation. Accelerating the development of low-carbon technologies and promoting their global application is a key requirement for stabilizing GHG emissions.

⁵⁹ Note: As of October 2010, EDF agreed to pay ~\$250 million to buy out Constellation Energy's share in the Joint Venture. Additionally, EDF has announced a more measured approach to investing in the US.

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Consequently, nuclear and renewable power technologies are at the core of current energy policy discussions due to their low-carbon profiles. Nuclear power generation does not release CO₂ or other criteria pollutants such as sulfur dioxide and nitrous oxides, although some indirect emissions, mainly from fossil fuel use in the fuel cycle, can be attributed to nuclear power.⁶⁰ Nuclear and hydropower are the main low-carbon energy sources in the global mix at present, but of critical importance is that nuclear power is the only commercial **baseload** power source capable of delivering clean power today in scale and is therefore seen as being a key climate change mitigation technology in the long term once barriers and cost allocation issues are overcome. As an example, according to the EIA, nuclear power produced about 70% of GHG-free electricity production in the US in 2009 (Exhibit).

Exhibit 41: Nuclear power produced about 70% of GHG-free electricity production in the US in 2009



Finally, because it is a high fixed cost, capital intensive asset, the major appeal of nuclear energy from a community perspective is the economic boost. A typical nuclear plant will generate around 4,000 construction jobs and 300-500 permanent, high paying, positions once complete.⁶¹ In addition, the plants contribute permanently to the local tax base given their long asset lives.

Disadvantages

The main shortcoming of nuclear power generation is the high upfront costs. Other disadvantages include the technical complexity of nuclear plants and potential dangers of radioactive waste storage and handling, which are intractable problems that industry and government will have to address. Nuclear power is the most sensitive of all power generation types to changes in the cost of capital and inflation. Moreover, nuclear power new builds are characterized by public/private split incentives: the taxpayer and government bear much of the financing risk, cost and potential liabilities⁶² but do not share in the upside if the plant is eventually successful—e.g. power prices rise or CO₂ externalities are factored into the fully delivered price of power, leading to higher profitability for nuclear generators.

Estimates suggest that the cost of building a new nuclear plant in the US today range from \$6 to \$10 billion, which is in excess of the market capitalization of the median publicly traded utility. Financing is therefore a major challenge. With such

⁶⁰ On a lifecycle basis, there are GHG emissions associated with nuclear energy since uranium enrichment is among the most energy intensive industrial processes.

⁶¹ <http://www.unistarnuclear.com/>

⁶² Damages from accidents are capped via the Price-Anderson Act first passed in 1957; And with respect to long-lived radioactive wastes, the Federal government has guaranteed ultimate long term responsibility for management and storage in exchange for a small variable surcharge per kWh of production, although no such storage options currently exist and the Obama Administration announced that they would no longer fund Yucca Mountain

Power Generation: Nuclear – Fundamental View & Outlook

high upfront costs, the private sector is generally skeptical of funding such projects due to the long pay back periods required to recoup investments or repay loans and high perceived risks. During the construction phase of a nuclear plant, investors would be injecting substantial amounts of equity in to the project that would be tied up for a 4-5 year period without generating a return.

Historically, the high cost of capital for new builds stems from the industry's poor track record of delivering new reactors on time and budget and the inability to hedge forward the risk since power markets are illiquid beyond 5 years. Consequently, we expect that almost all of the next wave of reactor builds in the US will be constructed by regulated utilities that are able to put the asset into their rate base and earn a regulated return on the capital investment for their shareholders, including an allocation for construction work in progress.

Public sentiment is also a potential disadvantage. Nuclear energy has and to a certain extent always will be a divisive energy source in the public eye. Sentiment has shown a propensity to sway dramatically to extremes, largely in response to safety concerns—real or perceived. In this respect, nuclear power is perhaps the only electricity generation resource where a major global safety incident could potentially have an impact in derailing development plans elsewhere.

Finally, terrorism, nuclear proliferation and safe long term storage solutions for spent fuel are serious problems that still must be addressed. Safeguarding nuclear waste is critical for maintaining global security, particularly at facilities where spent uranium fuel is recycled or reprocessed (note: this is mostly only in Europe). Safe storage of nuclear waste is critical because spent fuel is highly radioactive, posing environmental and health risks, and it takes thousands of years to decay naturally. In the US, nuclear power plants do not recycle nuclear waste and have dry-cask on-site storage facilities, but operators frequently ship hazardous nuclear waste between plants for storage. Although we foresee relatively benign industry growth in the US through 2030, beyond that point if the nuclear generation eventually scales as a low carbon baseload source and doubles or triples in size, finding sufficient storage sites will become a formidable challenge. Reprocessing spent fuel significantly reduces the amount of waste that needs to be stored but is an energy intensive process and adds to the cost of nuclear power.

Other disadvantages and deployment barriers are listed below:

Deployment barriers 2010-2020

- Power sector fundamentals are cyclically and perhaps secularly weak
- Reluctance of private sector to provide financing and support
- Uncertainty about government's ability to commit incremental loan guarantees
- High capital costs to finance the large investments needed
- Decommissioning of the aging fleet, which ties up scarce engineering and construction resources
- Demographics and ageing workforce – there is a need to develop the necessary industrial capacities and skilled human resources to support sustained growth in capacity
- Expanding the supply of nuclear fuel in line with increased nuclear generating capacity and ensuring all users of nuclear energy have access to reliable supplies of fuel.

What about water? Potential Disadvantage Longer Term

Nuclear power systems require enormous quantities of water to produce electricity, requiring as much as 300,000 to 1,100,000 gallons *per minute*. About 45% of electricity produced from nuclear generation in the US relies on the intake water from lakes, rivers or oceans to absorb the heat transfer from the steam turbines. After the heat exchange the water is then recycled and discharged back to the source using a “once through” cooling process.

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Water use at power plants is subject to Federal regulation under Section 316 (b) of the Clean Water Act, which requires that plants use “the best available control for minimizing adverse environmental impact” (BACT). The permitting of water intake structures under the Clean Water Act is managed in partnership with state environmental agencies, and the EPA. New York and California, in particular, have issued regulations that are stronger than Federal guidelines. In sum, both states account for about 8% of total US power plant output and have issued regulations mandating a 93% reduction in water intake, effectively requiring steam turbine generators to replace their “once through” cooling water systems, which discharge water back into aquatic ecosystems, with “closed loop” systems that continuously re-circulate cooling water within the plant.

Nuclear plant operators could be required by federal or state regulations to install new cooling towers at all generating units currently using once-through systems. In a best case scenario from an investor perspective, these compliance costs could be capitalized in rate base, which would accelerate the earnings growth of regulated utilities. Unregulated generators, by contrast, would be forced to incur significant capital expenditures as well as a future drag on earnings in the form of higher depreciation expense and interest payments to fund the investment. Either way, the effect of potentially retrofitting about half of all US nuclear power plants with new cooling towers would raise the average price of electricity. To be clear, however, we view the cooling water intake issue as a longer term issue for the nuclear industry and it does not impact our 2010-2020 forecasts. Many nuclear power plants are vital to the stability of the grid. Consequently, reliability concerns on the part of system operators are likely to delay any swift legislative action and postpone cooling tower retrofits in to the 2020-2030 timeframe. But there is no doubt eventually water issues will layer additional costs to nuclear generation.

Nuclear Energy Conclusions: Share Stays the same in 2020, modest increase by 2030

While there is no doubt that industry fundamentals in the US for new nuclear development have become more constructive over the past two years with the Federal LGP gaining momentum and the potential for more government support in the 2011 budget appropriation, the barriers are still large. For the nuclear industry to meaningfully scale, much greater levels of government support will be required to de-risk the financing aspect and a national, long term storage solution for spent fuel must be put in place. Given the ballooning fiscal deficit in the US, we are skeptical that there will be the commitment on the part of government to fast start a new nuclear build program—ala France in the 1970s—on the order of what would be required to make a large impact from an emissions and energy security perspective over the next decade.

In the US, we estimate that about 70% of the 104 reactors will be eligible for 20-year life extensions; the rest will be decommissioned after they reach 40 years. The number of safety incidents and the particular technology used are the largest determinants of which reactors will be eligible for license renewals. Another factor weighing in on retirements which may accelerate the roll off of smaller, standalone units is the cooling water intake issue, which could require deploying costly new retrofits.

The 104 reactors in the US have an average age of 30 years and represented 106 GW of capacity in 2009. In our view, less than half of the 14 plants that have applied for a combined operating license (COL) from the Nuclear Regulatory Commission (NRC) and are currently in the approval queue will move ahead at a fast enough pace to have steel in the ground and deliver electrons by 2020. Therefore, we expect fairly modest additions to the nuclear supply mix with an incremental 6 to 8 plants operational by then. We have modeled 12 GW of new nuclear capacity between now and 2020 split between new builds and capacity upgrades at existing units. By 2030 we expect 126 GW of nuclear capacity, or an incremental 22 GW from today. We expect nuclear energy's contribution to US electricity supply to increase only modestly from 20% of supply in 2009 to 21% in 2020 and 23% in 2030.

Power Generation: Renewable Energy – Fundamental View & Outlook

Summary

- In our fuel mix pathway, renewables represent the fastest growth rate of electricity grid capacity additions between 2010 and 2020 and 2020 to 2030, driven in the short term by policy support and then achieve further uptake longer term as costs fall.
- Renewables share of electricity supply (including hydro) is expected to double from 10% today to 20% in 2030. Within renewables, wind and solar constitute 2% of supply today and increase to 14% of supply by 2030.
- For now, intermittency and operational barriers appear manageable given the still relatively modest penetration rates of wind and solar but are a constraint until the smart grid and utility scale storage are deployed.
- Section II of this paper looks at these issues in greater detail.

Economics: Coming Down the Learning Curve

Many renewable generation technologies represent the most expensive generation resources today, mostly because intermittent wind and solar generation technologies are still fairly immature and baseload hydro and geothermal resources have high upfront capital costs and are geographically constrained, which has limited scale-up. Within renewables, only onshore wind energy comes close to competing with traditional fossil generation, costing an estimated \$1,980 per kilowatt of capacity with an estimated LCOE of \$0.09 to \$0.11 kWh. Integration costs add another \$0.03 on average to the total “cash cost” of wind, making the fully loaded cost \$0.12 to \$0.14. Hydro and geothermal have capital costs of \$6,500 and \$4,500/kW, respectively, with LCOEs in the \$0.12 to \$0.14 and \$0.10 to \$0.12 range.

Solar energy is the most expensive by far and has only been deployed en masse in markets with accommodative energy policies and effective subsidies, such as in countries like Japan, Germany, Italy, Spain, France and more recently China. The US has large renewables potential but has seen less growth compared to other countries because of the stop/start and fragmented nature of policies and incentives. However, learning curve adoption and rapidly occurring industry maturity are driving down costs aggressively. We expect solar PV’s cost to decline from the current \$3,800 to \$4,500/kW range for commercial rooftop and LCOE of \$0.22 to \$0.30/kWh to an LCOE of \$0.12-\$0.15/kWh in the near term. We expect that certainly by 2020 solar energy should be competitive with fossil energy without subsidies, particularly in serving expensive on-peak demand where costs can typically be as high as \$0.20 to \$0.30 a kWh. Integration costs add another \$0.02/kWh to the LCOE cost, we estimate. Onshore wind, too, should be increasingly competitive without subsidies by that time. Solar CSP and offshore wind are likely to have longer learning curves given how immature they are to date. Therefore, we would expect these renewable technologies to be competitive without subsidies with conventional generation closer to the 2030 time frame. In general, we believe these assumptions are conservative even with a low gas price.

Industry backdrop

Right now, renewable energy deployment is highly sensitive to policy, government support, credit conditions and fossil fuel prices. Of these, the four most prominent levers for renewable energy projects to be deployed are:

- **Strong policy:** Policies that deliver Transparency, Certainty and Longevity (TLC) have been lacking in the US. Such programs have proven most effective since they lower the cost of capital and encourage large-scale financing;
- **Low cost of capital:** Returns are very sensitive to the cost of capital, which is a function of project risk and how the investment is being capitalized—e.g. debt/equity mix;
- **Lower gas prices a challenge short term:** Renewable energy has a higher upfront capacity cost than conventional power generation but no fuel costs; long term off take agreements such as power purchase agreements (PPAs)—particularly for wind energy—are sensitive to natural gas prices in particular.
- **Demand growth:** In areas/regions with strong power demand growth, renewable energy are an attractive option; however in the US we expect demand growth to be roughly flat through 2020; consequently aggressive renewable additions will have the impact on the margin of depressing power prices by increasing supply. While this may be

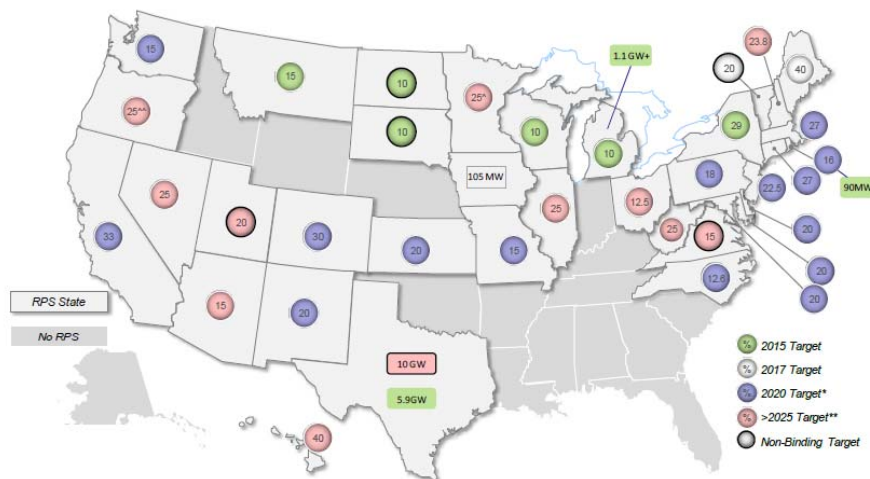
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positive in an overall economic context since it would temper the upward pressure on the cost of electricity, it does potentially put pressure on returns if the other three levers mentioned above are not being used.

The US has had a stop/start approach, subsidizing renewable energy through the tax code, which is generally considered to be an inefficient subsidy mechanism, due to higher transaction costs, compared to other policies such as feed-in tariffs. Consequently, in the US renewable adoption rates and capacity additions—particularly for wind energy—have waxed and waned primarily with the availability of tax credits and government stimulus programs and to a slightly lesser extent to the price of fossil fuels. The instability in capital flows and variability in demand for renewable energy based on changing risk assessments due to policy certainty have made the US renewables market volatile. There was strong growth from 2005 through the 2008 economic downturn, with the total installed base doubling from 30GW of renewables to 60 GW. The industry's growth trajectory, however, has been challenged by the economic downturn. Initially this was met by stimulus funding such as the cash grant but political pressure to reduce public sector deficits is stalling the extension of such incentive programs.

In the current market environment, renewable portfolio standards (RPSs), whether state or federal, will be one the industry's main drivers. Support for renewable energy is more uncertain today, however, because of the public sector budget crisis in particular. However, the general belief within industry is that there will likely be at some point within the next few years a comprehensive energy policy at a national scale that will support renewable energy and provide more legal enforceability or “teeth” than the state level RPS standards on their own, many of which are non binding in terms of enforceability. Across most states, RPS targets are set as a percentage applied to retail sales. Exceptions include Iowa and Texas, which have capacity based RPS targets. We are looking for a strong Renewable Energy Standard (RES) and longer term federal incentives such as a 1603 extension and a green bank.

Exhibit 42: Established US state RPS policies: May 2010



Source: Emerging Energy Research, "US RPS Markets and Utility Strategies: 2010–2025," May 2010.

Advantages

The main advantage for renewable energy is that there is for the most part limitless supply and much more modest environmental impact compared to fossil fuel-fired generation. In this respect, renewable energy is the only truly sustainable resource. And on this score, the resource potential is theoretically vast, exceeding total global electricity demand by an order of magnitude. Renewables also contribute to energy security, grid stability and provide an excellent hedge to fossil fuel prices. As an immature resource, there are still large improvements in technology and new innovation to be harnessed, particularly for solar energy.

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Disadvantages

Cost, performance characteristics and perception are the three main drawbacks to renewable energy. Renewable energy costs more than fossil fuel generation and has significantly lower capacity factors and operational flexibility. And since the 1980s, many utility companies have viewed renewable energy as being logistically and operationally challenging. Today's electric grid infrastructure was designed for central station fossil-fuel power stations. Integrating large fractions of renewable energy into the grid requires improved transmission, distribution and storage technology, more fully integrated and dynamic planning and dispatch process on the part of grid operators, and policies that put renewable energy on a more level playing field with conventional energy. In short, the electricity grid that has "gotten us here" won't "get us there" in a low carbon future without new infrastructure investment and substantial changes to energy policy. All of these factors layer on cost above and beyond the generation and LCOE costs of adding incremental renewable capacity to the system.

Deployment barriers for renewables are multifaceted (see section II of this report for a full discussion). From an operator perspective, the resources behave fundamentally different from fossil fuels and have thus far been a relatively inconsequential part of the energy mix so there is not a lot of operational history. However, there are operation fears—both real and perceived—about how to manage a grid that has 10%, 20% and 30% plus share of supply from renewable energy. However, there is no reason from a technical engineering perspective that these barriers can not be overcome. As we discuss in more detail later in this paper, aggregation and flexibility are really the key. On the financing side, incentives haven't traditionally been there for regulated utilities to invest in renewables and put the asset into the rate base.

Renewables Investment Conclusion

We expect the share of electricity supplied by renewable energy to increase from 10% in 2009 to 14% in 2020 and 20% in 2030. Most of this growth will come from wind and to a lesser extent solar. We expect the contribution from these two sources to increase from 2% in 2009 to 14% in 2030 due to large additions to meet state RPS programs. Wind energy has scaled and matured significantly over the past ten years and is now a "real" business in the context of annual capital spending in the power sector. Global spending on renewable energy in 2008 (most recent data) totaled about \$140 billion, exceeding investment in coal and natural gas by 27%.⁶³ We expect the combined capacity of solar PV, solar CSP, geothermal and wind energy to increase to 143 GW from 39 GW today, representing a 14% CAGR between 2010 and 2020. The secular driver is likely to be a transition from smaller scale developer led projects to larger scale utility projects, with utilities electing to put the investment on balance sheet and into their rate base rather than just purchase renewable energy electricity on behalf of their customers to meet an RPS target.⁶⁴

Wind energy will continue to dominate capacity additions for renewables because it has the most attractive relative generation costs even though solar PV economics have improved significantly over the past two years. Nevertheless, cyclical headwinds prevail over the next 12-18 months from low commodity prices and meager demand growth. In addition, continued investor uncertainty regarding federal climate change legislation and ambiguity over whether or not there might be a federal renewable portfolio standards (RPS), are also hampering growth relative to potential in the short-run.

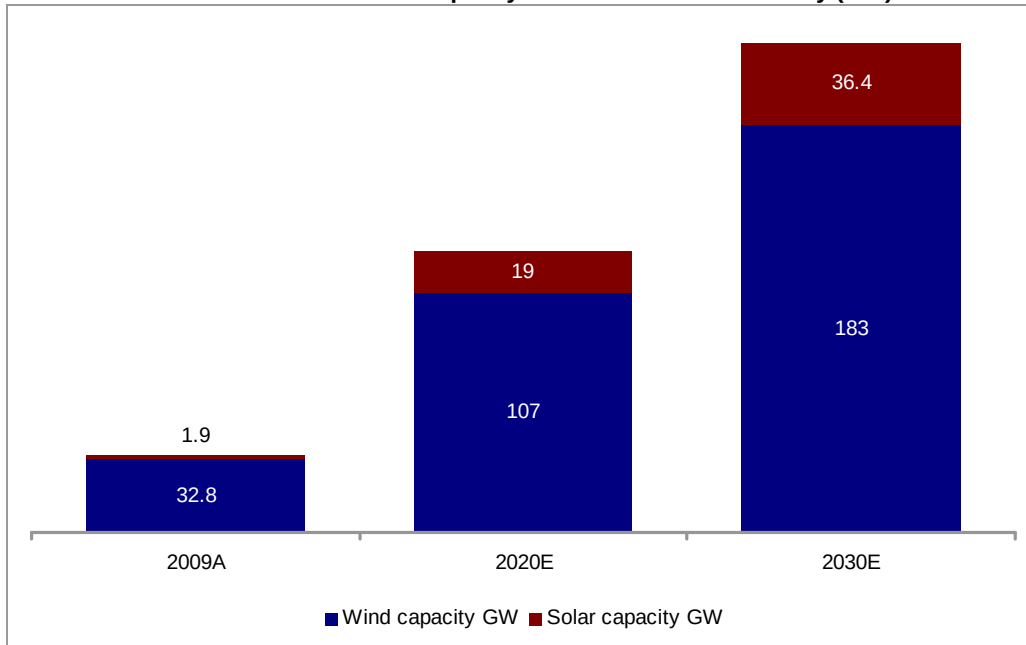
Nevertheless, we believe wind and solar have major growth ahead and will be the fastest growing capacity additions through 2030 with total installed capacity increasing from 34.7 GW in 2009 to 126 GW in 2020 and 219 GW in 2030. (See Section II)

⁶³ REN21, 2009

⁶⁴ Regulated firms respond to incentives, and this can be used to structure more effective regulation to stimulate investment in renewables. The productivity factor for regulated utilities is the authorized return on equity (ROE). Certain state regulators, such as the California Public Service Commission, have offered utilities a premium ROE for deploying renewables. For renewables to truly scale, utilities must get on board and incorporate renewables into their 3-5 year capital spending time horizons. This will only happen with the right regulatory incentive structures.

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Exhibit 43: Installed Solar and Wind Capacity Will Increase Substantially (GW)



Source: DBCCA analysis, 2010.

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Power System Analysis: Integrating Renewables

Summary

- Renewable energy is considered a significant contributor to any low carbon future energy system due to continued public policy support, improving cost competitiveness with fossil generation and large greenhouse gas abatement potential.
- In order to effect this growth in renewable energy capacity additions, it is important to understand the system integration issues in depth.
- We believe the system issues will cause renewables to scale at a more moderate pace than some forecast, at least through 2030.
- Ultimately, a smart grid with storage can allow a big scale up of renewables; indeed, we believe that over the long run, gas can back up renewables.

Executive Summary

- As wind and solar generation scale up, they will at a certain point fundamentally change the dynamics of standalone power grids, which were designed to support local and national markets and accommodate mostly fossil generation resources, which have low variability and have typically been located close to where the electricity is needed.
- Many states and national governments have set ambitious renewable mandates or targets by 2020, with California and Germany—among many others—calling for 30% of electricity to be supplied from renewable energy by then. Broadly speaking and as a practical matter, at these high levels of renewable energy penetration there is the potential for a significant gap between policy goals and the electricity system's ability to meet those goals without substantial infrastructure investment. This is due to the complexity of how electricity grids function and the fact that they have been designed and engineered to accommodate fossil fuels, which operate in a different manner from renewable energy.
- Renewable energy has two defining operating and performance characteristics. In the electrical engineering lexicon these features describe how the resources behave—e.g. their ramp rates, availability, dispatchability and impact on grid operations⁶⁵. They are:
 - **Baseload**—Hydro, geothermal, biogas and biomass generation resources operate at high capacity factors, have low resource variability and can be used reliably around-the-clock to satisfy minimum electricity load requirements. These highly dispatchable resources integrate with relative ease into most power grids.
 - **Intermittent**—solar and wind are variable generation resources with location constraints, low capacity factors and high variability. Their production depends on whether the wind is blowing and the sun is shining. As a consequence output from wind and solar can be negatively correlated with demand. Their principal benefits are low marginal energy cost and reduced greenhouse gas emissions.
- In order to scale up intermittent renewables substantially we see the following issues and processes playing out:
 - 1) How wide, diverse and interconnected are the fuel mix and generation resources available to the grid that is being asked to carry large amounts of intermittent power? This is a question of geography and fuel resources and interconnection, especially wind and solar. The wider and more diverse the grid, the more likely it can carry intermittent power.
 - 2) This immediately leads to the issue of transmission connectivity on the one hand and distributed power supply on the other. Larger amounts and seamless connectivity become more important as the network incorporates larger volumes of intermittent generation.
 - 3) Due to issues of reliability and stability, any power grid will need to become increasingly “smart” in terms of balancing the fuel mix as a 15% level of intermittency is reached. This suggests that smart grid technologies enabling two-way communication and see through along with improved load forecasting and resource optimization are the most essential at early stages.

⁶⁵ Please see Appendix for a complete description of these terms

Power System Analysis: Integrating Renewables

- 4) Finally, as the goal for ever increasing amounts of intermittent renewables, the ultimate solution rests on storage—essentially rolling away the intermittency issue completely. Options here range from newer technologies through to fossil fuel backup, particularly natural gas.
 - As examples, certain discrete power grids such as Denmark, Spain and Germany already have relatively high concentrations of solar and wind energy and have managed to integrate the supply into their electricity grids by utilizing transmission linkages with other grid systems (Denmark), excess fossil capacity (Spain), and improved radial distribution systems (Germany). However, as these grids move to even higher levels of intermittent penetration, balancing the costs of ancillary services, regulation services and storage required for reliability against the environmental benefits of low carbon generation will require significant incremental capital spending and operational process changes in managing the grid.
 - Thus, in evaluating renewable energy scale-up potential and limitations two large issues must be addressed:
 - i. An analysis of the existing resources, structure and limitations of the electricity grid that is adding incremental intermittent energy supply including congestion areas and interconnect capabilities;
 - ii. A study of how electricity grid systems integrate and manage high levels of variable and intermittent resources focusing on the advancements needed such as improved wind energy forecasting, power system visualization, transparency in grid operations and improved automation.

Key investment research conclusions: Renewable energy will become a much larger part of the global electricity mix over the next decade and a key contributor to low carbon energy growth plans due to strong policy support and improving economics that are coming from “learning curves” as the industry matures. Electricity grids of the future will be much more interconnected, flexible and dynamic and will embody:

- Implementation of the “smart grid” with greater resource planning and more robust scheduling on the part of grid operators;
- Vast expansion in transmission lines;
- Energy storage solutions;
- Larger volumes of natural gas generation as a flexible “firming” resource and;
- Supportive regulatory environments.

Power System Analysis: Integrating Renewables

As a framing exercise it is vital to look at intermittent scale up potential within the context of the overall system with a particular emphasis on:

- The geographic reach of the grid system and its interconnections;
- Load demand and supply requirements;
- Generation resources;
- Transmission capabilities;
- Enabling processes; and
- Deployment of enabling technologies

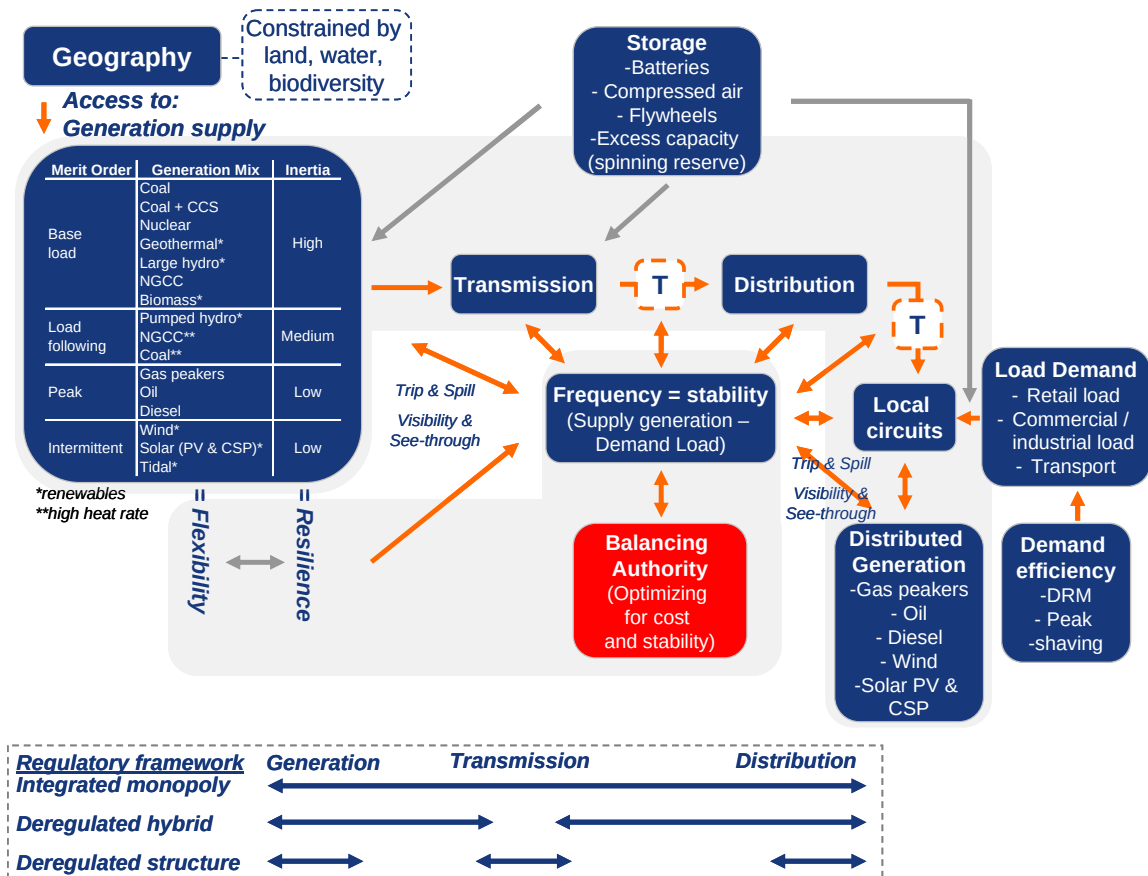
There will logically be a point at which a discrete power grid bumps up against the limits of renewable energy that the system can tolerate from a reliability perspective. At this point, the flexibility, storage, interconnection and contingency optimization protocols that are at the nerve center of the future “smart grid” become critical enablers. The conclusion from a wide range of credible grid integration studies is that penetrations above 20% and 30% of intermittent energy require significant changes in institutional power system procedures to meet the challenges of more rapid changes in operating conditions.

We analyze the system constraints that are imposed by large scale additions of renewable energy and the solutions to overcoming those barriers. We show how investors should think about what is required to transition to a lower carbon electric power system and the large market opportunities inherent in that shift. The urgency to combat climate change and create a sustainable power system will augur profound change over the next ten years to an industry that has been relatively static for the past 100 years. Large but feasible investments will green the grid and make the electricity system more flexible, reliable and secure. The technologies and processes that we predict will be deployed to meet these goals are either commercially available today or in the advanced stages of trial and testing. Moreover, the large market opportunity is driving innovation and creative thinking about problem solving, which will create both winners and losers.

On the next page, we map a hypothetical electricity grid, illustrating the wide range of system inputs and constraints that define how a grid operates. As is clear, it is a vast and highly complex infrastructure. The regulatory framework and incentive structure impacts resource allocation and investment and varies from integrated monopolies to deregulated structures.

Power System Analysis: Integrating Renewables

Power Markets for Investors: Understanding the System Interactions



Source: DBCCA analysis, 2010.

The Grid: The power system is an essential infrastructure resource and is said to be the world's most complex machine. Electricity is fundamental to economic growth. Energy use increases with wealth. The world is becoming increasingly wealthier and dependent on electricity as an energy carrier. **A power system must deliver secure, affordable, and most importantly reliable electricity as a fundamental building block to any developed economy. More recently, the power system has been constrained to be cleaner—e.g. releasing fewer criteria pollutants such as particulate matter, sulfur dioxide, nitrogen oxides and lead—and oriented toward lower CO₂ emissions.** In this next section we show how an electricity system works, emphasizing the important complementary role that natural gas generation plays with intermittent renewable energy such as wind and solar.

The National Academy of Engineering ranked the creation of the electricity grid as its profession's greatest achievement of the 20th century.⁶⁶ Electricity is the lifeblood of the economy and is fundamental to wealth creation and productivity gains. The nature and physical properties of electricity makes it distinct from other commodities and marketable goods. Buyers require electrons delivered at a specific voltage and frequency to meet their needs and enable **useful work** at any given time. The fundamental requirement is that the power is available when needed to serve a continuously varying customer load. Sellers, in turn, generate electricity and deliver the product to buyers as needed. But because production is capital intensive it is not practical to keep most plants running below their rated capacity factors. The electricity grid system is dynamic, subject to continuously changing conditions, only some of which can be anticipated. The complicating factor is

⁶⁶ <http://www.nationalacademies.org/greatachievements/Feb22Release.PDF>

Power System Analysis: Integrating Renewables

that the laws of physics require that load, or demand, be constantly balanced to match supply. In this respect, electricity differs materially from oil, natural gas, coal and every other bulk commodity in that there is no storage mechanism.

Moreover, the electromagnetic pulse that delivers energy does not follow a defined path from end point to end point, like a rail system delivering coal from point A—the mine mouth—to point B—a power plant—to fulfill a contract obligation. Instead, it is divided among parallel pathways according to Kirchhoff's⁶⁷ laws following all available delivery routes according to their resistances. Therefore, within the grid system it is **physically impossible** to match a specific batch of electricity from seller to buyer. This fact alone has made it more difficult to unbundle and reregulate the electricity market into a more competitive market structure compared to other critical infrastructure sectors like, say, telecommunications.

⁶⁷ Named after German physicist Gustav Robert Kirchhoff, the Kirchhoff circuit laws are ubiquitous in electrical engineering and state that at any given node, or junction, in an electrical circuit, the sum of currents flowing into that node is equal to the sum of currents flowing out of that node.

1. Electricity system key deliverables and defining characteristics

1.1 Resilience

Because electricity is vital to virtually every aspect of our personal and professional lives and to the economy at large, the electricity grid is engineered to be **resilient** to handle a wide spectrum of demand conditions and delivery pathways. The general international rule of thumb is for the system to have a 10-15% reserve margin⁶⁸ prior to the deployment of bulk storage. Today, this means that a typical electricity grid is in equilibrium and able to deliver power from a supply/demand and reliability perspective when it has a buffer of 10-15%⁶⁹ excess generation capacity compared to the forecast hour of peak demand—the typical August afternoon during a heat storm when electricity demand is at its maximum for the year. In simple terms, this can be considered to be the margin of safety required to reliably match supply with demand across all conceivable market conditions.

But adequate generation alone does not make an electricity system resilient. Transmission and distribution system architectures designed to interact with generation resources to deliver the electricity supply to the load are the key support structure of the network and more often the points of vulnerability. These parts of the network interact with generation through computerized energy management systems that are controlled by system operators and utilities. Properly functioning, these systems maintain stable voltage and frequency and have backup plans and risk management tools—such as real time contingency analysis and resource optimization protocols—to keep the grid resilient in the face of unexpected system failures such as a blown transformer or a downed power line.

Electricity is an essential infrastructure resource and the economic consequences of not being able to deliver reliable power are severe. Each year \$ billions of lost economic activity occurs due to power disruptions that run the gambit, ranging from a reduction in power quality at a distribution point that might foul sensitive electrical equipment to—in a worst case scenario—entire grid systems being compromised and disconnecting from the grid. An extreme example was the August 14, 2003 Blackout in the United States, which resulted in the loss of 61,800 MW of electric load and an economic loss estimated to be \$7-10 billion. The Blackout was a case when backup protocols and risk management procedures failed.⁷⁰ This event was caused by a confluence of events—the grid operator having trouble with its dispatch scheduling program, power lines being under loaded due to problems with an energy management system and electricity shorts from trees touching sagging power lines under heavy winds and grounding the power. The tipping point came when a major 345kV feeder transmission line in northeastern Ohio tripped offline and shut down a major path for power imports. This was the starting point of a cascading failure in which the system oscillations grew so large that the grid completely shut down and could not rebalance. When all was said and done 265 power plants were lost in the event and a large part of the US economy ground to a halt.⁷¹ Unfortunately, major reliability events occur with some frequency (Display).

Exhibit 44: There Have Been a Substantial Number of Major US Reliability Events

Date	Event
August 14, 2003	Eastern USA and Canada cascading outages
January-May 2001	California emergencies and outages
May-December 2000	California emergencies and outages
August 1999	Chicago Loop distribution failure
July 1999	Chicago distribution failure
July 1999	New York City distribution failure
December 1998	San Francisco blackout
June 1998	Mid-Continent Area Power Pool breaks up
January 1998	Northeast Power Coordinating Council outage
June 1997	Minnesota-Wisconsin separation

Source: EPRI

⁶⁸ Amount by which capacity resources exceed net peak customer demand as expressed as percent of net peak demand (NERC definition)

⁶⁹ 15% is the conventional international standard for adequate reserve; however, the proper generating reserve margin depends on the characteristics of the system, such as type of generation, load growth, and connectivity with adjacent power pools.

⁷⁰ <http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf>, p.1

⁷¹ [file:///nycinfo-vf12.svc.db.com/USERS23\\$/mellnil/Power%20System/February%202010/2003_blackout.ppt#10](file:///nycinfo-vf12.svc.db.com/USERS23$/mellnil/Power%20System/February%202010/2003_blackout.ppt#10)

1. Electricity system key deliverables and defining characteristics

1.2 Reliability: Adequate Tolerances a Must

Power quality is an essential component of reliability and refers to the set of boundaries that allow electrical systems to function seamlessly without compromising performance or compatibility. The concept cuts both ways. On the supply side, voltage stability is what drives power quality and is dependent on utilities providing standardized electricity with respect to amplitude and frequency. And on the demand side, electrical equipment must be tough enough and flexible enough to handle a standardized unit of electricity without incident. Although “**reliability**” broadly speaking means maintaining a high level of uninterrupted service without degradation in power quality, in reality the term encompasses a wider subset of nuances which include:

- **Short-term flexibility: Security Function**—the electric system must be able to respond and react quickly to unexpected events such as unplanned generator outages, transmission lines downed by storms and sudden fluctuations in the system due to congestion or circuit faults. System operators perform triage under such circumstances, shutting down certain power plants, starting up backup power plants, disconnecting certain loads or even whole sections of the network in order to avert cascading—uncontrollable feedback loops in which the problem compounds and potentially takes the whole system down as illustrated earlier in the 2003 Northeast blackout example;
- **Long-term planning: Ensuring Adequacy**—system planners must plan ahead and ensure that the grid is capable of meeting future needs. This would include defining the desired reliability parameters within the context of a depreciating capital stock and new load growth —e.g. assessing the impact that the completion of a new energy intensive steel plant, for example, might have in permanently altering the demand curve—and ensuring that the resources and protocols are in place to adequately meet these future requirements;
- **Economic Consequences: Marketplace Requirements**—electric customers depend on the network to enable their production and business transactions. When the network is interrupted, they miss the profits on the unconsummated transaction and, possibly, lose share to competitors connected to a more reliable network. Moreover, certain customers such as datacenters, financial trading desks and hospitals are considered mission critical, which means that they require—and are willing to pay for—higher levels of reliability and often have self-generating capabilities (backup) to ensure that business functions are uninterrupted under most any conceivable contingency.

In sum, the **notion of “reliability”** varies among market participants and is often measured by outage indices defined by the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366, which relates to customer satisfaction and length and frequency of service interruptions.⁷² Customer reliability and power quality requirements sometimes exceed the grid's performance capabilities. And while the assumption of uniform and highly reliable electricity is a cornerstone of developed market economies, the continued transition toward a more digital economy increases the strain on maintaining ever greater standards of reliability, including “seven 9s,” premium electricity engineered to deliver less than three seconds of down time per year across all conditions. But the process uptime of even a premium electricity grid with three seconds of downtime is about ten hours per year annualized, according to Lawrence Berkeley National Laboratory. Because the customer's synchronous machines must be rebooted, there is lost productivity. Increasingly, customer expectations and requirements often exceed an electric grid's ability to provide reliable power, which results in customers procuring back up power options or self-powering. This is deemed necessary because millisecond deviations in power quality can cause equipment to fail or automated processes to move out of synch.

⁷² <http://eetd.lbl.gov/ea/EMP/reports/47043.pdf>

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Exhibit 45: Disconnect Between Utility Reliability and Process Uptime: The Need to Self Power

	Service Reliability Events	Process Uptime 1 Hr Downtime per Event	Typical Applications
Standard Electric	25 events / year 22 @ 1/4 second 1 @ 2 seconds 1 @ 5 minutes 1 @ 30 minutes 2,107 seconds/yr. downtime 99.99% reliable 4-nines	25 hours total downtime per year 99% reliable 2-nines	- Plastics - Computers - Machinery - Textiles - Cell towers - Residential applications
Premium Electric	10 events / year 0.25 second each 2.5 seconds/yr. downtime 99.99999% reliable 7-nines	10 hours total downtime per year 99% reliable 2-nines	- Semiconductor manufacturing - Auto manufacturing - Fiber optic cables - Web farms - Continuous processes

Source: LBNL

1.3 Voltage and Frequency Maintains Stability: Key Control Variable (supply minus load)

Two cardinal rules for the power system are that uniform voltage and stable frequency must be maintained at all times in precise harmony. These two concepts are as fundamental to the electricity grid as inhalation and exhalation are to the human body. If either is strained beyond a very narrow tolerance, the system becomes unstable and begins to breakdown. The electricity network has built in tools and processes to keep voltage and frequency deviations in check.

1.4 Everything Synchronized; e.g. Clocks, Data Centers, Bank Vaults, etc.

Low voltage dims lights while high voltage ruins electric appliances. Higher than normal frequency speeds up the operation of electrical motors and pumps and can also damage the electric generating equipment. Frequency changes occur when generation doesn't match load. If there is not enough generation to support load, frequency dips. Conversely, if generation exceeds load, frequency rises. Lower than normal frequency slows the operation of electric motors and clocks and can interrupt and cause economic harm to end users who rely on the synchronized frequency from the grid to keep their equipment, bank vaults, security systems etc. running soundly. Frequency deviations beyond a tolerance can cause generators to protect themselves by disconnecting from the electric system, which in turn can lead to further mismatches, causing more generators and/or customer loads to disconnect from the system, resulting in uncontrolled cascading outages like what occurred during the northeast blackout in 2003.

In the US and Canada the standard is 60 Hertz (cycles per second). European and Asian power grids have a 50 Hertz standard. The system operator constantly balances supply to match demand and ensure consistent frequency; that is the harmonics between the generation sources and load must be in synch. Hertz is a measure of the rate at which an alternating current reverses direction. Each two consecutive reversals is called a cycle. Hertz and stable voltage are the key measures of the stability of the system and it is a constant high wire balancing act. Deviations of more than 0.5 Hertz in

1. Electricity system key deliverables and defining characteristics

either direction cause automatic stabilization measures to kick in to prevent a wide spreading cascading event from unfolding as a result of voltage variation from a change in frequency.

Frequency control is maintained by:

- **Throttle control:** Coal-fired steam plants can be adjusted by opening or closing the throttle to the steam turbine, thus increasing or dampening power output;
- **Disconnecting load:** In deregulated markets, energy intensive industries such as steel and aluminum can agree to be disconnected from the load when there is a frequency imbalance and are paid a contracted price for that service;
- **Spinning reserve:** Most fossil plants operate below their rated capacity and keep a portion of their supply available as spinning reserves that are able to come on line quickly to provide capacity and inertia to the power system to meet imbalances in frequency.

Properly balanced, all electricity generators spin at the same cycles per second throughout the system adjusting to increased and decreased demand in synchronous fashion. An analogy would be a peloton of bicycle riders maintaining the exact same cadence up and down hills adjusting their work to the changing requirements of the landscape. Tolerance variances for frequency are extremely narrow and typically have to be maintained within ± 0.5 Hertz by balancing power supply and demand. This is achieved by dampening output of generators using governors, or increasing output by tapping into spinning reserves, which is simply excess capacity not being utilized by a generation source—e.g. a 100 MW rated power plant running at 90 MW, implying 10 MW of spinning reserve which can be brought on quickly within minutes.

1.5 Automatic Voltage Regulators (AVRs); controls/governs generator

The volt (V) is the unit of electromotive force that measures the potential of electric currents and must be maintained relatively constant. Most load serving entities try to maintain a voltage range within $\pm 5\%$ of the nominal system mandated voltage level (e.g. 480V $\pm 5\%$ in the US at the distribution level). At the endpoint voltage standards are 120V $\pm 5\%$ in North America and 220-230V in Europe and Asia. Voltage control throughout the network is maintained by four principal methods:

- **Automatic Voltage Regulators (AVRs):** Devices intended to regulate voltage automatically—often called power conditioners or stabilizers. There is tremendous diversity in the size and type of AVRs and they run from the microscopic on printed circuit boards to the size of a large house at power plants;
- **Static VAR Compensators (SVCs):** perform a special function of high speed voltage response on transmission lines, providing fast-active reactive power. Reactive power (units are called VARs) is the engineering term that describes the background energy movement in an Alternating Current (AC) system arising from the production of electric and magnetic fields. These fields store energy which changes through each AC cycle. Reactive power flows can give rise to substantial voltage changes throughout the system, which is why power electronics controls are employed to maintain stable voltage configurations;
- **Transformers:** produce magnetic fields and therefore VARs and are used to step-up or step-down the electricity voltage;
- **Shunt Capacitor and Reactors:** placed in or out of service by the transmission operator generally via supervisory controls when circumstances require additional resources. Employed at the grid substation level to “shape” load, shunt capacitor banks also help reduce power losses by improving current flow through transmission lines. Moreover, since capacitors produce VARs, generators no longer need to produce as much power, enabling them to operate at higher power factors and produce more real power—e.g. watts.

1.6 Rotating mass/inertia: Determined by the sum of the spinning masses (NERC definition)

Rotating mass and inertia are important concepts in grid stability. Baseload generators are critical to the physics of the system in this regard. According to the North American Reliability Corporation (NERC)—the self-regulatory organization

1. Electricity system key deliverables and defining characteristics

responsible for ensuring the reliability of the bulk power system in the US and Canada--, rotating mass in a power system is defined as the sum of the spinning masses—e.g. the generators. The rotational kinetic energy of the connected synchronous generators help balance production and consumption by providing enough energy storage—in the form of inertia—to sustain the grid for cycles to seconds (depending on the amount of imbalance). Recall from our earlier discussion, too much generation and the system frequency increases, too little and the system frequency decreases. And since it is a dynamic system there is constant variation in load.

It is not physically possible to maintain a perfect generation versus load balance although active digital control systems attempt to do this by constantly adjusting the generators' power input to adjust to voltage sag and frequency dips. Nuclear and coal power plants are relatively insensitive to such variations and are able to “power through” minor drops in frequency in ways that a natural gas power plant or wind farm (as currently deployed) generally can't. Wind manufacturers such as GE, Vestas and Siemens, however, are now designing generation units with standardized Low Voltage Ride Through capabilities that deploy reactive power onto the electricity grid so they don't trip offline in response to voltage drops from the transmission lines.⁷³ Nevertheless, for grid stability purposes, baseload generation capable of providing large scale rotating mass is extremely important for load balancing through major system disturbances based on current centralized grid configurations.

1.7 Energy Security

Thus far, we have talked about reliability, voltage and frequency as being key variables for a stable and secure electricity grid. Energy security and safety are two additional operating concerns of paramount importance given the grid's critical economic function and the perilous nature of its product and byproducts if not handled appropriately. In November 2007, BP CEO Tony Hayward defined energy security as “access to reliable sources of energy, at an affordable price, produced in an environmentally responsible and safe manner.”⁷⁴ Security and safety protocols run across the entire value chain from production to consumption and are monitored by a combination of overlapping regulatory bodies and industry best practices. A few of the basic security issues are listed below:

- **Security of supply:** The four dominant resources used for power production worldwide are coal, enriched uranium (nuclear power), water (hydro power), and natural gas. Ideally, a power grid would have a balance of these resources supplying electricity to reduce the risk of a supply disruption from any one resource. Grid systems that do not have a diverse supply of generation resources are potentially more vulnerable to supply interruptions.
- **Contingency plans:** The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies is a must. Regulatory authorities and system operators have detailed protocols and contingency plans to accommodate every conceivable event from a blown circuit to hydro dams specifically allocated to provide “black start” power to restart the grid in the event of a total system shutdown—e.g. blackout.
- **Waste disposal:** Coal and nuclear power plants—in particular—produce toxic and potentially lethal byproducts which must be carefully monitored and stored. Employing best practices in handling these waste products is essential given the possible health and environmental consequences. Storage facility design, maintenance and operation for these hazardous materials are often highly regulated.
- **System complexity:** Electricity systems are evolving from being characterized as “dumb” one-way communication systems to “smart” two-way “self-healing” systems, the so-called smart grid. Layering two-way information technology capabilities onto the grid has many benefits and may potentially redefine the grid's efficiency and productivity. However, it also substantially adds to system complexity and raises the bar for security.

⁷³ http://www.gepower.com/businesses/ge_wind_energy/en/downloads/ge_lvrt_brochure.pdf

⁷⁴ Energy security and America, BP CEO Tony Hayward details commitment to US energy security in the new era, *The Houston Forum*, November 8, 2007.

1. Electricity system key deliverables and defining characteristics

1.8 Vulnerability to Cyber-Intrusions with Increased Layering of Two-way IT Technology

- **Cyber security:** Protecting software and safeguarding system algorithms from outside intruders is a growing concern for electricity grid operators. Case in point: In 2000, a discontented employee rigged a computerized control system at a water-treatment plant in Australia, releasing more than 200,000 gallons of sewage into parks, rivers and the grounds of a Hyatt hotel. And while nothing like this has yet happened to the electricity grid, system operators have adopted robust compliance procedures to ensure that grid participants are using IT security best practices. This is increasingly important, particularly in the wake of the Stuxnet computer worm which was discovered in June 2010 and has been targeted to infiltrate and reprogram industrial systems.
- **Automated dispatch:** In developed markets with competitive wholesale prices, the electricity infrastructure is highly automated. Utilities and regional grid operators use sophisticated energy management systems that are supplied by supervisory control and data acquisition (SCADA) systems accessed through phone lines or over the internet to manage generation dispatch based on price signals while keeping the system in balance. SCADA systems are inherently insecure according to security experts because they use software running on standard operating systems on standard server hardware, making them subject to the vulnerabilities of those systems. Grid security is a growing concern. In the last year, authorities from the US Department of Homeland Security (DHS) have detected an up tick in cyber intrusions and have found software tools left behind that could be used to destroy infrastructure components of the US power grid.⁷⁵ The reason cyber-terrorism is so worrisome is that the electricity grid is highly interconnected and an isolated problem can quickly amplify and be difficult to contain.
- **New operating challenge:** In North America, NERC requires that grid operators under its control area sign off to cyber-security guidelines and principles.⁷⁶ However, as recently as April 2009 NERC's Chief Security officer warned members that he was concerned that only about a third of the facilities required to adhere to NERC's guidelines had signed off about the identification of Critical Assets (CA) and the associated Critical Cyber Assets (CCA) which could be used to manipulate them.⁷⁷ NERC defines CA as those "facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."
- **Market opportunity:** Cyber security is a task that electricity system engineers may be ill- equipped to deal with, since it is largely outside of their core competency in managing the grid. And as we discuss later in this report, the Smart Grid is likely to become a key energy efficiency and intermittent energy generation enabler. As the architecture of the grid becomes more complex there may be a growing third party services opportunity for vendors and consultants specializing in IT security in order to ensure that the grid remains hardened and able to withstand potential software issues.

⁷⁵ <http://online.wsj.com/article/SB123914805204099085.html>

⁷⁶ <http://www.nerc.com/files/CIP-002-1.pdf>

⁷⁷ <http://online.wsj.com/public/resources/documents/CIP-002-Identification-Letter-040609.pdf>

2. Regulatory structure: Impacts operations, strategic planning and customer incentives

Operating certain indispensable and essential basic services such as electricity has historically been seen as needing strong regulation. The industry structure has been monopolistic in nature with customers better served by imperfect competition. And while this long held paradigm has been undone somewhat over the past fifteen years or so, the model of “allowable” regulated prices for providing an open access public service continues to be the model of choice in most world power markets.

There are three prevailing global electricity regulatory structures, which define the incentive and operational protocols of how the system functions:

2.1 Vertically integrated

The classic utility structure is the vertically integrated regulated natural monopoly model, in which a utility controls the entire value chain from generation, to transmission to distribution to balancing supply and demand. Vertically integrated utilities typically deploy Integrated Resource Plans (IRPs) to manage their operations in both the short term and long term through business cycles and regulatory cycles. These essential services are governed by the “regulatory compact”⁷⁸ that is designed to strike a fair balance between consistent returns to shareholders and predictably priced and reliable power to rate payers. The utility typically has the capital structure and reasonable return formula imposed on it by the regulator based on competitive industry benchmarks. The role of regulation in theoretical terms is to provide a correcting mechanism for market failure due to the monopoly structure, which exists because it is less costly to have a single electricity service provider rather than competing service providers. In exchange for a natural monopoly in a service territory, the integrated electric utility must operate within the constraints imposed on it by a regulator. In most markets, the electric utility is legally obligated to serve all customers at reasonable rates on a non-discriminatory basis. Electricity rates are not set by the market but rather based on the “cost of service” which seeks to be a closely imitative substitute for competition. Regulatory commissions act as substitutes for the market place. Rates are periodic and are settled in a rate case or tariff proceeding between the integrated utility and the regulator. System planning and resource adequacy are managed in an integrated process and are influenced by regulatory forces rather than competitive market forces. Incentive structures are aligned toward deploying large amounts of capital—e.g. growing the rate base—and earning an allowed return on that capital investment rather than on margin optimization. More recently, energy efficiency incentives have become a focus for regulators in order to avoid building new generation, one of the benefits of which is reduced power plant emissions. The vertically integrated grid remains the dominant structure today in most world electricity markets.

2.2 Hybrid structure

Starting in the 1990s, electric grid systems began to disaggregate across the globe following the restructuring and de-regulation trends seen in other sectors such as telecommunications and banking. Utilities in Argentina, Brazil, the UK and parts of the US were reregulated. As this process unfolded the integrated utilities in certain jurisdictions were broken into pieces: generation, transmission and distribution functions were moved into separate entities and subject to greater market competition. The idea was that market competition would challenge the economy of scale benefits of the vertically integrated utility and provide customers with better service and prices that more accurately reflected the cost of the marginal producer. For a host of reasons, unbundling the electric industry has been more complicated compared to other capital intensive essential infrastructure industries. For one, the system complexity and interconnected infrastructure—much of which has very long asset lives—is hard to unwind efficiently without compromising reliability. Other issues include overlapping layers of local, state and national regulation—sometimes in conflict—and the challenge of establishing fair compensation schemes for unbundling stranded assets previously funded by rate payers. The success of unbundling has been mixed. In general, introducing retail competition and establishing new market rules and protocols has proven harder

⁷⁸ “Utilities agree to invest funds to serve customers, in expectation of a reasonable return, commensurate with the protection of risk assured through regulation.”--- *The Regulatory Compact as defined by Leonard S., Andrew S. and Robert C. Hyman, America's Electric Utilities: Past, Present and Future, 8th Edition, pp. 181-182, Public Utilities Reports, Inc.*

2. Regulatory structure: Impacts operations, strategic planning and customer incentives

and more complex than expected and has not universally led to lower consumer rates, better reliability and a more efficient market. As a consequence, very few systems have been completely disaggregated, with the notable exception of the UK. However, even the UK is reexamining its regulatory structure because it is perceived to be a barrier for the country to achieve its climate goals. Nevertheless, the hybrid structure prevails in most competitive electricity markets with distribution and transmission still by and large regulated functions, while generation in certain markets is bid competitively.

2.3 Fully Deregulated

The objective of competitive markets is to provide adequate supplies of electric generation with lower costs to society, lower risks to consumers, and greater diversity than would otherwise be expected under a centralized monopoly model. Where it has been possible to establish competitive de-regulated markets, power generators earn returns based on their cost structure and the tenor of the supply/demand dynamics of power markets across a wide spectrum of market products and services such as the day-ahead market, capacity market, full requirements market, ancillary services market and spot market. In the latter, power prices that are determined by the marginal cost of production each hour based on the ever-changing balance of supply and demand. In these markets electricity is valued as a commodity just like gold, oil or pork bellies. Variable production costs are low compared to the high capital costs of generation capacity additions. During periods of surplus capacity, competition among suppliers drives prices down to the variable cost. When capacity is scarce, prices theoretically can rise until they reach the replacement cost, the level at which a producer would be encouraged to add new units of capacity. Practically speaking, supply is fairly inelastic given the long lead times to build new plants in response to price signals. Therefore, from a fundamental perspective, wholesale power markets never reach replacement cost for a sustainable period of time.

In competitive markets the supply curve determines profitability. In these markets, power is dispatched to meet demand based on “merit order” bids starting with the lowest marginal cost fuel source: usually hydro, coal, nuclear or renewables without fuel costs (e.g. wind or solar if available) and then natural gas, fuel oil and diesel generation. The plant with the highest marginal cost is dispatched last and satisfies demand requirements. Gross margins⁷⁹ in competitive power markets fundamentally boil down to fossil fuel arbitrage. In any given hour the marginal generating unit sets the energy price for all producers. Spot and forward power prices track the commodity prices of the price setting fuel that is on the margin the greatest number of hours in a year. In most markets, natural gas is the marginal fuel; although in coal dominated markets it is coal. Within each class of generator there are units that have either a higher or lower “heat rate”—which is defined as the thermal efficiency of the unit, or how many British Thermal Units (Btus) of fuel, required to produce a kilowatt hour (kWh) of electricity. It would not be a very profitable endeavor to own a high heat rate—e.g. inefficient—natural gas power plant in a market where coal is on the margin. Conversely, it could be very profitable to own a low heat rate—e.g. efficient—coal plant in a market where natural gas is on the margin.

A challenge for fully deregulated markets is the high risk premium for new investment in a competitive market structure. The long asset lives and high cost for replacement capital stock benefits regulated incumbents who bear less financing risk. Forward electricity markets beyond several years are fairly illiquid making it difficult to hedge the financial risk of building expensive nuclear power plants or large intermittent wind or solar farms without regulatory support or tax subsidies. Given the volatility in deregulated electricity prices and significant fixed maintenance capex required to run generation equipment safely and reliably, most competitive power producers engage in active physical and financial hedging programs selling power forward on a ratable basis to ensure reasonably stable cash flows and achieve a targeted gross margin. Notably, since 2008 as a result of the economic contraction, forward power prices have been below the cost of new construction for both renewables and non-renewable generation, which makes new investment in a competitive market context unattractive without subsidies.

⁷⁹ In power, a producer's gross margin is generally defined as revenues less the cost of fuel. As an example, if sales were 100 and the cost of fuel were 60, the gross margin would be 40, or 40% of sales.

2. Regulatory structure: Impacts operations, strategic planning and customer incentives

2.4 Conclusion

On the whole, it seems that governments believe the hybrid regulatory structure makes the most sense for stimulating investment in lower carbon generation including intermittent resources. The hybrid model appears to provide the best odds for ensuring reliability and electricity system adequacy while introducing the benefits of competitive market structures. Clearly, open access to transmission lines and competitive wholesale and retail procurement options is beneficial to customers in the long run as it introduces more competition and market pricing dynamics.

Nevertheless, many electricity markets are now at a critical juncture from a regulatory standpoint with respect to the challenges imposed by a lower carbon energy system pathway and the issue of cost allocation. In particular, it is not altogether clear that the old regulatory models are suitable for meeting the challenges that lie ahead and the potential disruptive impacts that come with more dynamic electricity delivery systems characterized by greater variable supply and customer choice. Scale deployment of lower emitting generation requires a fresh look at regulation and incentives, in our view, since the competitive market on its own in the absence of a high (\$40+) carbon price is not equipped to deploy the necessary capital at this stage. Furthermore, the issue of “who pays” looms large since it is politically infeasible to expect ratepayers to assume the whole burden of the incremental cost. As it stands today, regulation tends to favor incumbent electricity service providers. And here we would point out that in many electricity markets energy efficiency measures do not have adequate regulatory support, even though the economic returns are often higher than building new generation because of its low capital intensity and rapid paybacks. In part this is because the incentives are skewed toward “spinning the meter” and selling more volumes of electricity. Consequently, some European countries such as the UK are reevaluating their regulatory structures in order to increase the odds of success in meeting 2020 climate targets.

3. Geographic reach: Defines system resources

An electricity grid is defined by its legacy design architecture and limited by its geographic reach. Most grids were developed without centralized planning and have evolved from small generation units sized and located to meet urban and industrial load requirements to larger networked systems benefiting from economies of scale that reach to customers far from the generation source. In the early days, the decision of where to locate power plants within a geographic constraint was based in large part on leveraging transportation infrastructure such as canals and railroads to ensure cost effective delivery of bulk feedstock (mostly coal). Broadly defined, a grid's geography encompasses its physical features, population, resources, economy and climate. Access to natural resources—such as different sources of electricity supply including fossil, nuclear and renewable energy—and interconnection and transportation linkage capabilities are fundamental system inputs since they define supply limitations and contingencies. Transmission and distribution infrastructure are also critical system components because as the grid network has evolved generation resources have increasingly been sited farther from the load. In general, diversity of generation technologies gives the system greater **flexibility** in planning for resource adequacy, contingency and hedging options to react to changing market conditions, mechanical failure and hard-to-predict natural phenomenon such as extreme weather events while maintaining stable voltage and frequency.

3.1 Climate/Weather Affects Energy Use, Grid Reliability and Planning

Another related factor to geography that defines the grid is the **local climate** and seasonal and diurnal weather patterns, which **affect usage patterns**, generation dispatchability, grid reliability and planning. Hot humid climates have larger cooling systems needs compared to milder climates and load patterns tend to be “peakier” with usage patterns spiking in response to weather extremes. The grid in these climates must be designed to withstand large usage fluctuations and loss-of-load probabilities stemming from customer behaviors and weather patterns. When extreme events happen to grid systems not designed to handle such variations, the outcomes are almost always universally bad.

A case in point was the 2003 European heat wave—one of the hottest on record—which was particularly detrimental to France. France relies on nuclear energy to supply about 75% of its electricity. 14 of the country's 19 nuclear generating stations are inland and rely on river water for cooling. When water temperatures rise, EDF (the state-run electricity monopoly) is forced to curtail power production at its nuclear facilities in order to comply with strict environmental regulations designed to protect aquatic ecosystems. During the worst of the heat storm in July 2003 about 20 GW of France's 63 GW of nuclear capacity were out of service. Consequently, EDF had to import expensive power from the UK. Fortunately, the transmission lines from the UK were adequate and there was no need to curtail power. But the harsher impact of the heat wave—by far—was the human health impact. In France air conditioning is relatively rare. Tragically, the death toll from the extreme heat reached 15,000 people.⁸⁰ Most of the victims were elderly. They expired in their homes at night with temperatures in the triple digits since stone homes retain heat and air conditioning systems in France are a rarity.

In contrast to France, Florida has limited abilities to import power, which makes the southern part of the state especially vulnerable to weather and climate change. Florida's grid system conforms to NERC reliability standards and is designed to withstand gale force winds which occur every year with the hurricane season. Although a peninsula, Florida has a power grid constructed like an island system. Island systems are not as resilient to generator or transmission outages because of their isolated configuration. Thus, when disruptions occur they are often localized and, if not properly contained, detrimental to the state's economy since there are limited interconnection links. Therefore, the balancing authority and utility operators must perennially prepare for hurricane season and have developed strategies to harden the grid and enhance **reliability**, such as building transmission lines capable of withstanding extreme winds along major corridors, burying about 40% of distribution lines to homes and businesses along key pathways, and employing aggressive line clearing and vegetation management to prevent downed trees and shorts from disrupting service.

Similarly, grid systems with expected large penetrations of **variable** renewable energy—such as wind and solar—must plan around the diurnal and intermittent behaviors of the resources and have adequate backup storage and interconnection

⁸⁰ http://www.usatoday.com/weather/news/2003-09-25-france-heat_x.htm

3. Geographic reach: Defines system resources

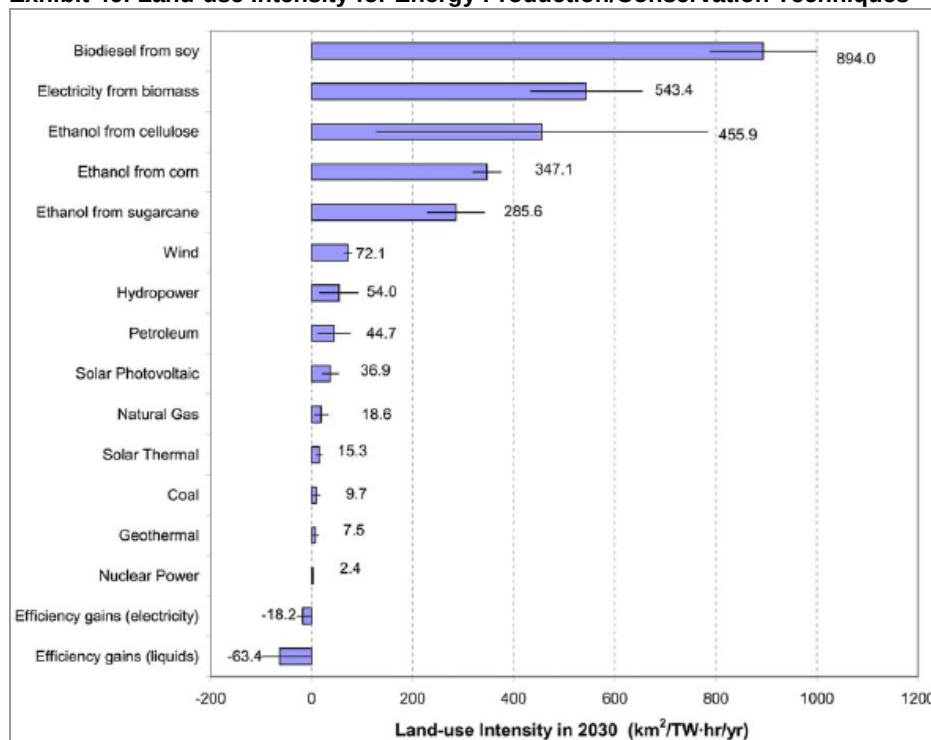
options to manage around the resource limitations. Wind often blows hardest at night when energy demand is low. Sunlight, too, is an inherently variable resource due to day/night cycles and changes in cloud cover and provides its maximum output during the day typically within a few hours of peak demand, but generally misses the late afternoon peak in most regions. This is the motivation for solar thermal to scale with energy storage to increase the solar operating window. In order to understand the systems reliability impact of high levels of wind and solar energy integrated into the electric power system, data sets and the corresponding response of various-sized systems to changes including ramp rates need to be characterized. The variability and nondispatchability of today's wind and PV systems affect not only the stability of the utility grid but also the economics of both the generator and the energy distribution system. In scale the two resources could prove complementary. But because they are variable and their output varies significantly over timescales, balancing authorities and load serving entities must rely on forecast accuracy and contingencies to ensure that these resources interact fluidly with other power supplies.

3.2 Land, water and biodiversity limitations

Island systems such as the United Kingdom and Ireland have especially limited interconnections to other power systems. Thus, balancing authorities have to be particularly resourceful in managing and planning the grid infrastructure using indigenous resources, since finite resources from other power pools are available.

Moreover, such systems are by definition **land constrained**, which means that incremental generation must either be built adjacent to or over existing generation on so called “brown field sites”. In meeting new regulatory mandates for low carbon power, there are few economically attractive alternatives given the geographic limitations of island systems. Options are essentially limited to rebuilding/retrofitting existing facilities, enhancing the transmission interconnects, or adding new capacity offshore—e.g. wind or tidal power. Biogas generation with methane from landfills is also an attractive option.

Exhibit 46: Land-use Intensity for Energy Production/Conservation Techniques



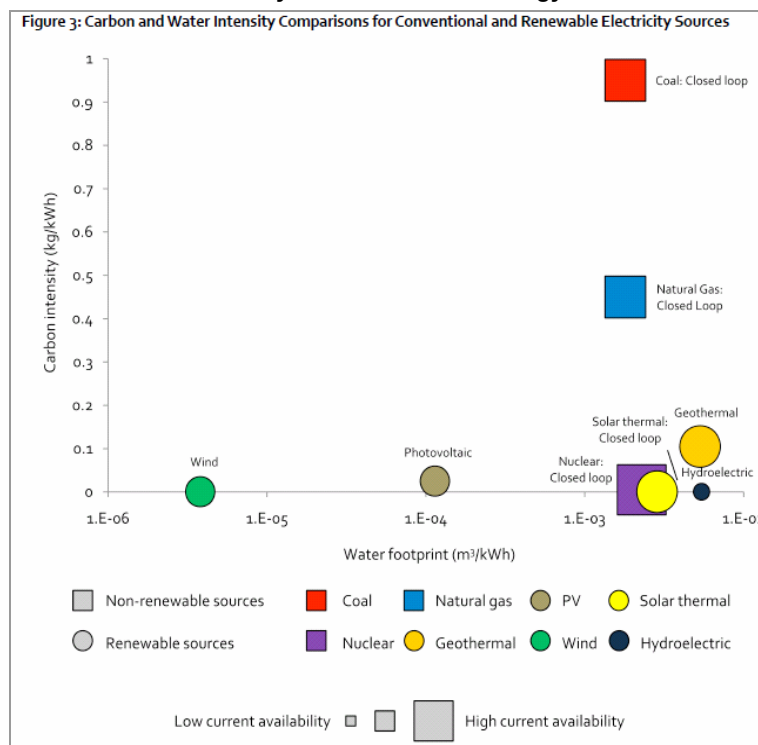
Source: The Nature Conservancy. Land-use intensity for energy production/conservation techniques. Value shown is for 2030, as measured in km² of impacted area in 2030 per terawatt-hour produced/conserved in that year. Error bars show the most-compact and least-compact estimates of plausible current and future levels of land-use intensity. Numbers provided are the midpoint between the high and low estimates for different techniques. For liquid fuels, energy loss from internal combustion engines is not included in this calculation. doi:10.1371/journal.pone.0006802.g003

3. Geographic reach: Defines system resources

By contrast, regions such as the United States and Australia with ample land and abundant natural resources are limited principally by transmission and environmental regulation and policies. Generally speaking, the **greater** the **diversity of power generation technologies** and the broader the transmission reach available to a system, the **more flexible** the grid is in adapting to changing load requirements and integrating intermittent resources. One potential side effect of adding intermittent energy sources, though, is the so called “sprawl” impact due to lower energy density generation resources which can impact specific habitat types and the ecosystem processes they support (Exhibit 47). In particular, according to a study by Robert I. McDonald et al funded by the Nature Conservancy, temperate deciduous forests and temperate grasslands will be most impacted.⁸¹ Wind generation deployment in most jurisdictions is subject to environmental impact studies to access the impact on species such as bats and condors.

A final consideration related to geography is the availability of water and the impact such use has on biodiversity, particularly marine life and ecosystems. Power generation requires vast amounts of water. Thermoelectric use accounts for approximately 38% of all water withdrawals in the US—coal, gas, and nuclear plants combined use about 136 billion gallons of fresh water per day. While withdrawals are high, actual water consumption by the US electric sector represents about 3% of total use.

Exhibit 47: Water Use by Generation Technology



Source: Lux Research

In addition, about half the power plants in the US are located close to rivers and bays and use **water** to condense the steam produced by the large boilers in a process known as “once-through cooling” whereby water is withdrawn directly from the source, diverted through a condenser where it absorbs heat from boiler steam and then discharged back at elevated temperatures. Because once-through cooling systems do not re-circulate the cooling water, they can require as much as a billion gallons of water per day. Rules limiting temperature differences between inlet and outlet water are designed to avoid biological impacts in the receiving water body. In areas with limited water supply or where temperature effects could occur,

⁸¹ Robert I. McDonald et al, *Energy Sprawl or Energy Efficiency: Climate Policy Impacts on Natural Habitat for the United States of America*, www.plosone.org

3. Geographic reach: Defines system resources

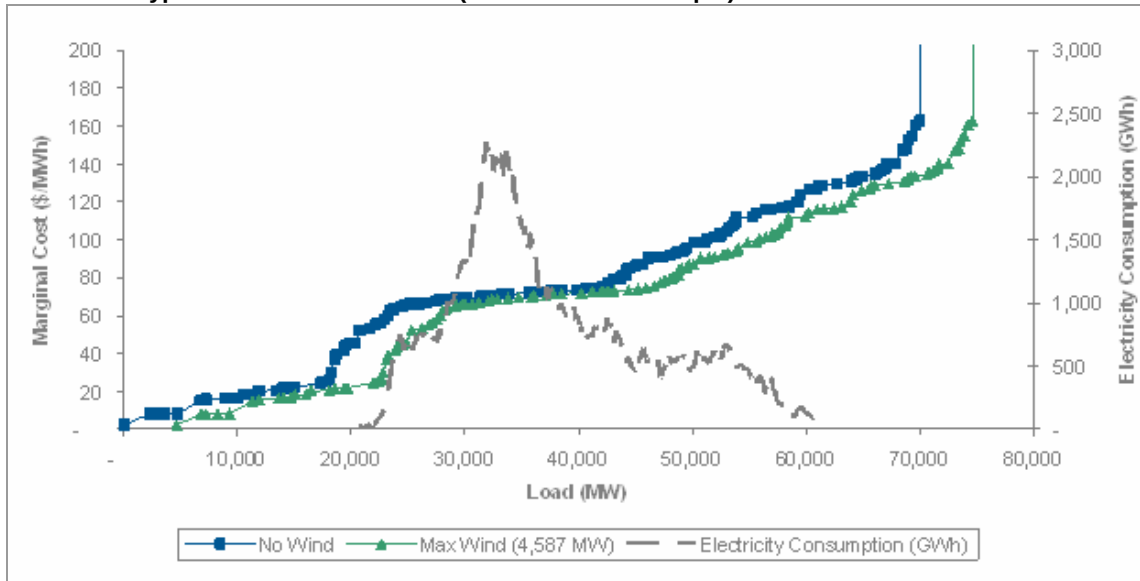
power plants are equipped with recirculating cooling tower systems. The impact on **biodiversity** varies widely from plant to plant and is impacted by changing weather and climate conditions. In the US, some of these facilities will require the addition of cooling towers mandated by the Environmental Protection Agency (EPA). Other regions may face similar regulatory constraints and environmental mandates imposed on power plants using these cooling systems. New construction and permitting for Solar CSP and coal and natural gas plants often employ dry cooling techniques which use convective heat transfer rather than water to cool the heat. In the case of CSP, such techniques can reduce water consumption closer to that of a solar PV plant, albeit with some performance penalty owing to the parasitic load from the heat exchangers.

And, as we saw in the earlier example in France, electricity systems that are heavily dependent on a generation technology that uses vast quantities of water—such as nuclear energy—are less flexible when natural resource availability becomes a constraint. Quite obviously, such systems are vulnerable to the impact of extreme droughts, weather variations and changes in regulation that might limit water use or require plants to adopt recirculating cooling technologies.

4. Load demand defines supply requirements

Electricity use—load demand—is influenced by many factors but tends in the aggregate to correlate primarily to cyclical and structural elements of the underlying economy served by the electric grid. Global demand for electricity has grown 3.6% a year on average since 1971, more than double the 1.7% demand growth for all energy uses combined. Seasonal and daily variations in load reflect usage patterns over the shorter term. Since electricity can't yet be stored economically, load defines the supply requirements on a periodic basis, expressed as a load curve (Exhibit 48).

Exhibit 48: Typical 24 Hour Load Curve (Texas ERCOT example)



Source: Sanford Bernstein

4.1 Key Demand Drivers: Residential; Commercial & Industrial; Plug-in Hybrid Vehicles—Eventually

Developing countries ramping up their infrastructure and manufacturing capabilities generally have electric growth rates modestly exceeding trend economic growth. Developed countries, by contrast, typically have a larger services component in their economies and have electric growth rates that are half to two-thirds of economic growth. Factors such as building standards and codes, climate, the penetration of energy intensive industries—e.g. uranium enrichment, steel blast furnaces and aluminum smelting—and geography play into the mix.

Each grid system will have a balance between residential and commercial and industrial (C&I) load; the split in the US and most of Europe is approximately 60% residential and 40% C&I, in developing countries and countries with a large industrial base such as China and Germany the ratio is typically reversed. Grid operators and generators especially like C&I load because it “firms” the load. It is more stable and consistent than residential demand patterns since it supplies factories running around-the-clock. On the other hand, C&I load is more cyclically sensitive and swings more dramatically during inflection points in the business cycle.

Changes in usage patterns from new technologies and processes also have a large impact. For example, the introduction of air conditioning in the 1960s permanently raised demand in developed countries with warm climates. Another, less obvious demand driver for increased electricity use in the economy more broadly is the substitution in many industries from mechanical systems—such as diesel motors, gears, belts, and pulleys—to electrical systems, including motors, actuators, automation and robotics.

And this trend toward electrification continues. Today, a relatively small data center with about 3,000 servers consumes enough electricity in one month to power about 500,000 homes for a year. In the future, it is expected that plug-in electric

4. Load demand defines supply requirements

vehicles will be a new source of overnight electricity demand as they scale, requiring significant investment in the electricity grid to ensure reliability.

4.2 Climate and Weather Impact Demand

Residential demand is driven by seasonal usage patterns, weather and geography—as we discussed earlier in the paper. Peak demand comes in the summer and winter months to run cooling and heating systems. The spring and fall are called the “shoulder months” and it is not unusual for there to be excess generation that must be “spilled” or sold at negative prices since demand is seasonally weak during those periods due to low heating and cooling requirements. Balancing load in power systems that are adding substantial amounts of intermittent generation—such as Texas—is particularly tricky during shoulder months, when there is often excess wind energy, for example, at night. Major maintenance at large generating plants—such as a steam generator replacement or scrubber installation—is often scheduled during these shoulder months.

4.3 Energy Intensity of Economy Varies

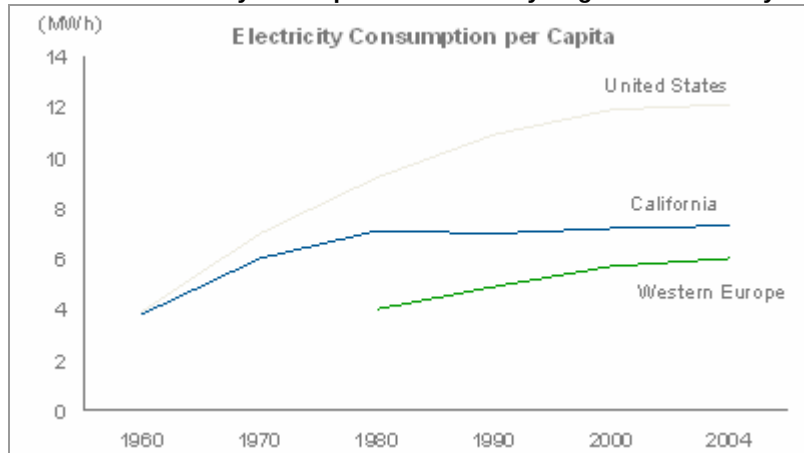
Economies vary widely in their energy intensity and electricity usage per capita depending where they are on the development curve, the rural versus urban population mix and the structural nature and organization of the economy. Rich OECD countries such as the US, Canada and Europe have high per capita electricity consumption. Not surprisingly, geography affects usage. Canada uses the most electricity per capita among developed countries because its population is relatively small—about 34 million people—but its geographic footprint is vast, whereas European countries use less electricity per capita because their populations are squeezed into smaller footprints. On the other hand, developing countries such as Brazil and India have relatively low usage patterns per capita since they are still industrializing and have large populations. However, since energy is the lifeblood of economic growth, its use accelerates dramatically as countries industrialize but then levels off as economies mature and their growth rates slow.

4.4 Energy Efficiency: Varies Widely Across Geographies and Regions

Like energy use more broadly, electricity usage around the world has become more efficient but still has significant room for greater improvement. Most developed countries have become more services oriented and, indeed, electricity output per unit of GDP output has fallen at a compound average rate of 0.5% over the past decade, according to the World Bank. Not surprisingly, electricity demand elasticity is highly price sensitive. Countries with expensive electricity have higher electrical efficiency and often more stringent building codes. According to the IEA and the Collaborative Labeling and Appliance Standards Program (CLASP), 77 countries representing more than 80% of the world's population and 90% of global GDP now have efficiency standards and/or labeling for electric devices. However, there are still wide variations in the pricing and subsidization of electricity.

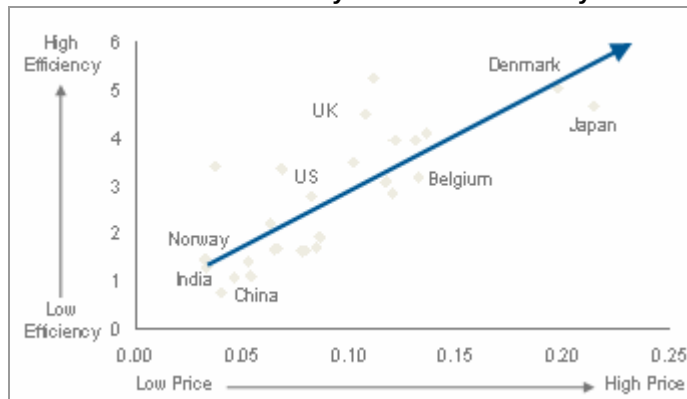
4. Load demand defines supply requirements

Exhibit 49: Electricity Per Capita Use Varies by Region and Country



Source: CEC, EU, DOE, DBCCA

Exhibit 50: Price of Electricity Influences Efficiency



Source: EIA, WorldBank, AllianceBernstein, DBCCA

4.5 Energy Efficiency and Conservation Are Not the Same

Electric efficiency should not be confused with conservation. Efficiency results from better technologies and processes—e.g. using less energy to produce the same amount of useful work; it is conservation without sacrifice. Conservation literally means planned protection of a scarce resource or guarding against waste, without specifying how the resource is conserved. To many people, it implies sacrifice: loss of comfort or convenience, or making do with less. It means using less energy because you're driving less and car pooling; turning the thermostat down in winter (as US President Carter requested in 1979) or the air conditioner off in summer (as Japanese Prime Minister Koizumi asked in 2005). In other words, conservation could mean warm beer and cold showers depending on society's utility function and life style tolerance.

Interestingly, research has shown that conservation within limits does not reduce consumer utility and satisfaction. In some electricity markets, for instance, customers agree to let their service provider adjust air conditioning cooling by several degrees in response to tight power market conditions and in most cases the customer does not notice the difference what so ever.

Efficiency measures are likely to increase in importance over the next five years both by push and pull. Regulators are requiring increasingly more stringent efficiency standards for new appliances and electronics. The IEA estimates that 5-15% of residential electricity is wasted by appliances and electronics in standby mode. And a 2009 study from The Electric Research Power Institute (EPRI) found that utility energy efficiency and demand response can realistically lower the growth

4. Load demand defines supply requirements

rate for electricity consumption by 22% and the growth rate for peak demand by 46% compared to EIA projections.⁸² Going forward, EPRI estimates that energy efficiency programs have the potential to realistically decouple electricity usage growth from economic growth. To date, residential customers have had very few tools available to optimize their electricity use. Utilities are in the process of installing two-way smart meters in many service territories, which will increase transparency and—as we discuss later in the smart meter section of the report—open the door for new business models to enable greater end use efficiency.

4.6 Efficiency: A Chain of Processes

Harnessing energy to do work involves a chain of processes, each with its own efficiency profile. The overall efficiency rate is the result of multiplying together the efficiency rates of each link in the chain.

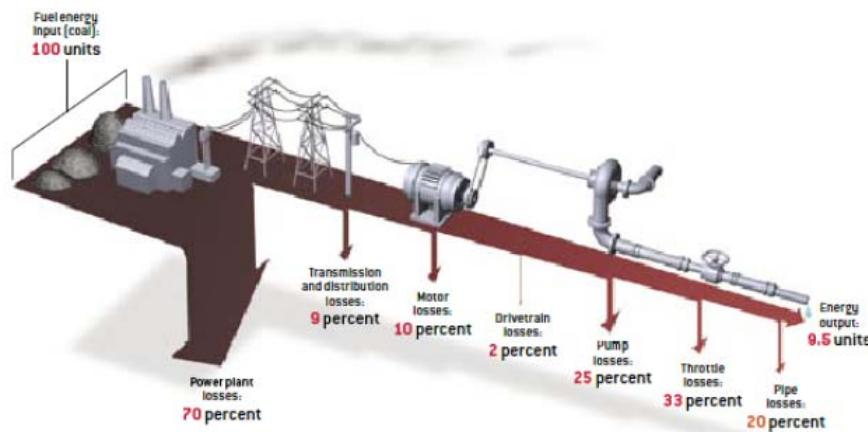
- **The extraction efficiency** of a raw fuel such as coal measures the total amount of energy contained in a given quantity of coal after extraction, processing, and transport relative to the total energy the coal when it was still in the ground (before extraction, processing, and transport). The typical extraction efficiency of coal (average of surface and deep mining) is roughly 70%. The efficiency of refining it and transporting it to a power plant for electric generation is about 90%. Thus, complete efficiency for extracting, readying, and delivering coal to power plants is about 63% (70% x 90%).
- **The conversion efficiency** of a fuel is amount of useable energy produced from the raw fuel relative to the energy content of raw fuel synonymous with the thermodynamic concept of First Law efficiency. The conversion efficiency of burning coal to produce electricity is about 30 to 45%, depending on the type of coal, steam temperature and pressure and other factors.
- **Distribution and/or transmission efficiency** is the amount of energy delivered for use to a desired location relative to the amount of energy released for delivery. The efficiency of transmission and distribution efficiency of delivering electricity from a generating plant to a home or building is about 90 to 95%.
- **End-use efficiency** is the amount of work an application (such as an air conditioner, automobile or computer) produces relative to its energy input and has the most near term leverage an electricity system perspective since the capital stock turns over much more rapidly than generation and transmission. Our research bolsters the commonly held belief that end-use efficiency represents the “low hanging fruit” in terms of generating positive returns on incremental capex. Since many electrical applications operate on DC power and electric current is delivered as AC power, the end-use efficiency includes the efficiency of converting AC to DC, which is typically 65%. End-use efficiency varies widely by application. Internal combustion engines used for transport are about 15% efficient in converting energy in gasoline into propulsion, and electric motors are internally 80% efficient in conversion of electricity into work, although electrical systems may be only 30% efficient.⁸³

⁸² Robert I. McDonald et al, *Energy Sprawl or Energy Efficiency: Climate Policy Impacts on Natural Habit*

⁸³ <https://www.alliancebernstein.com/institutional/Registered/ArticleDetail.aspx?nid=6848&cid=50515>

4. Load demand defines supply requirements

Exhibit 51: Succession of Energy Conversion Losses from Source to Use



Source: RMI

4.7 Energy Efficiency Barriers and Solutions

For energy efficiency measures to take foot they need to be seamless and provide the desired results without compromising performance. Energy efficiency barriers are numerous but include: 1) poor performance of past measurement/engineering benefits—in some instances claims of high energy savings are never proven or substantiated; 2) high capital costs of new technologies—the focus is often on upfront cost versus lifecycle costs; 3) increasing complexity of operations (more complex systems)—e.g. cooling component of buildings interacting with a water component that now has to be maintained and, perhaps most importantly 4) the principal/agent problem of who pays for the efficiency improvements and who benefits—e.g. landlords are less likely to pay for efficiency improvements to building systems if the benefits only accrue to the lessee.

As analysts and investors, we believe the global trend of greater economy-wide energy efficiency measures will intensify and indeed likely roll up non-linearly as utility incentive structures become more aligned to harness the often more favorable risk adjusted returns associated with investments in energy services and conservation benchmarked against new generation projects. Wide bodies of literature support this view, including work from McKinsey and Company that shows the negative cost—and hence positive internal rate of return (IRR)—that can be achieved by investments in a wide range of efficiency measures. Since energy efficiency savings have such a compelling long run payoff, it has always been somewhat puzzling why such measures have not taken off more forcefully over the past thirty years. We believe much of this is the result of institutional barriers, particularly regulatory rate making and efficiency mandates that often have minimum standards that are easily achieved with no penalty for non-compliance.

We expect to see more stringent global policies directed toward energy efficiency over the next several years, which could decouple electricity growth from economic growth in economies able to deploy efficiency measures. In many instances the IRR on capital spending for efficiency investments are superior to larger capital projects. In particular, research by McKinsey & Company points to large opportunities for new HVAC, controls, lighting, reduced standby losses, combined heat and power (CHP), more efficient appliances, power electronics, and better building materials and processes, among others.⁸⁴

⁸⁴ Unlocking Energy Efficiency in the US Economy, July 2009

5. Generation: Supply to the system; centralized more common than distributed today

The modern electric grid is centralized and benefits from the economies of scale of an interconnected system that has evolved from distributed systems which were common at the industry's outset over a hundred years ago. Today, large, stationary power plants dispatch their product into the complex networked grid system for use over a large geographic area. By contrast, distributed electric grids are self powered and contained—e.g. off the grid—and are connected to a home, small community, factory or campus and are self-managed. Although each configuration has its own pros and cons (See Exhibit 5.1), centralized grid systems in OECD countries are unlikely to be displaced by micro-grids, which show greater potential in developing countries that have not yet installed expensive capital stock. Cost is the largest barrier, particularly because there is a demonstrative scale advantage to central station power. To put this into perspective, about 1 MW of central station power supply can accommodate up to 5 MW of load demand. This is because the shape of the load varies from user to user and a centralized generation unit within a network is more efficient. By contrast, distributed generation has to be sized to accommodate the maximum specific requirements of an individual building's power needs. Distributed systems represent a small portion of electricity volume globally; no more than about 5-8% of the total in most OECD countries. Nevertheless, the growth rate of such systems is quite high due to favorable incentives. The DOE estimates that there are about 12 million distributed grid units in the US representing a total capacity of about 200 GW.⁸⁵ Most of these are backup power units. In the future, there is likely to be an increase in distributed intermittent sources with deployment of smart grid technology, better storage, and more competitive equipment pricing as the wind and solar equipment supply chains become more developed.

5.1 Pros and Cons of Centralized Versus Distributed Electricity Systems

Centralized Pros	Centralized Cons	Distributed Pros	Distributed Cons
Economies of scale; lower (\$/kWh) production cost vs distributed generation	Diseconomies of scale if link between economic growth and electricity consumption decouples	Sized for specific application	Must self fund backup; no economies of scale
Provides rotating mass	Outages affect many users	Outages have limited impact	Lack of system inertia
Benefits from network for reliability	Vulnerable to network issues	Less dependent on large transmission projects	Lower energy density
Delivers power across large footprint	Dependent on transmission	Enables rural economic growth	Asset property rights
Once built, asset lives are long	Hard to displace; retrofits costly	Better process efficiency	Hard to scale
Logistics for large fuel supply	Process efficiency loss	Lessens fuel price risk*	Higher (\$/kWh) production cost vs central station generation
Enables nuclear, geothermal and large scale hydro	Inflexible	Flexible	Higher environmental compliance cost
Easier to implement environmental control		Serves niche applications	

Source: DBCCA analysis, 2010. * Note: This will depend on the fuel used in the generation and the underlying supply/demand fundamentals of the fuel. Natural gas supplies in North America, for instance, appear to have become more abundant than previously thought in recent years and forward price curves have fallen to reflect the more immediate supply response enabled by horizontal drilling in shale plays.

Generation is the foundation of the centralized electricity grid system. It is the place where mechanical energy is converted to electrical energy. In all electricity supply systems, the power demand varies over the course of a day; there is a rise and fall every 24 hours, with usually a nighttime minimum and daily maximum as we discussed previously regarding load

⁸⁵ <http://www.ferc.gov/legal/fed-sta/exp-study.pdf>, p 2

5. Generation: Supply to the system; centralized more common than distributed today

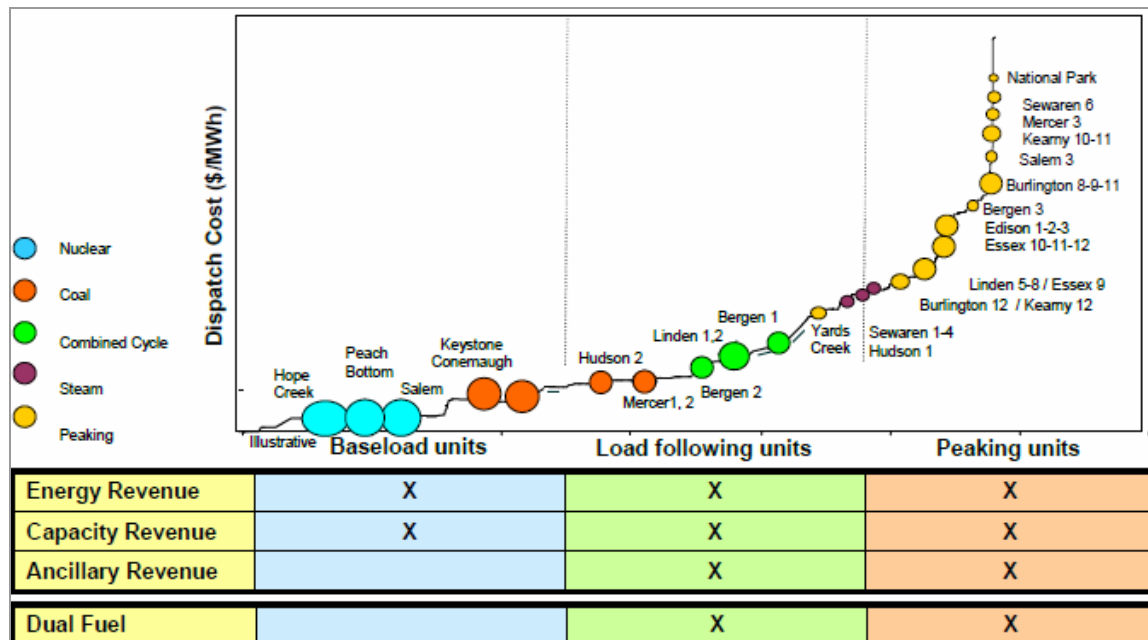
duration. To meet the continuously changing power demands, a mixture of different types of generation plants with varying degrees of responsiveness, or ramp rates, is needed. Ramp is the time that it takes a generator to change its output, generally expressed in megawatts per minute. There are three traditional categories of generation—baseload, load following and peak—and we introduce a fourth, intermittent. We discuss each in turn:

Exhibit 52: Characteristics of Baseload Generation (New Jersey Example in Dispatch Curve)

Merit Order	Electricity Resource Commercial Now	Central / Distributed	Ramp Rate (Hi / Med / Low)	Flexibility (Hi / Med / Low)	Inertia (Hi / Med / Low)	R&D Stage
Base Load	Coal	C	Med	Low	Hi	+ CCS
	Nuclear	C	N/A	Low	Hi	Modular scale
	Geothermal*	C/D	N/A	Low	Med	
	Large Hydro	C	Hi	Hi	Med	
	NGCC	C	Hi	Hi	Low	+ CCS
	Biomass (co-fire)*	C	N/A	Med	Low	

*Renewable energy; includes co-firing with coal; large hydro not considered renewable in most regions

Source: DBCCA



Source: Public Service Enterprise Group

5.2 Baseload

Baseload is the lowest variable cost generation resource but generally has the highest fixed cost. Baseload plants include: large-scale hydro, geothermal, nuclear, coal, lower heat rate natural gas combined cycle (NGCC) and biomass. The heat rate is a measure of the thermal efficiency of the plant—specifically how many British Thermal Units (BTUs) of fuel are required to generate a Kilowatt hour (kWh) of power. Higher heat rate plants are less efficient, since they require more energy to produce a kWh of power. Baseload plants are designed to operate at high capacity factors and run all the time since they have a low ramp rate from a cold start; that is it takes a long time for the plants to cycle on and off—anyway from several hours to an entire day. Therefore, the only fast ramp available from baseload plants comes from spinning reserves—unloaded generation that is synchronized and ready to serve additional demand—once the plant is already

5. Generation: Supply to the system; centralized more common than distributed today

operating. In a load duration curve, the baseload requirement is the minimum amount of power that a grid requires at all time.

5.3 Load following

Exhibit 53: Characteristics of Load Following Generation

Merit Order	Electricity Resource Commercial Now	Central / Distributed	Ramp Rate (Hi / Med / Low)	Flexibility (Hi / Med / Low)	Inertia (Hi / Med / Low)	R&D Stage
Load Following	Pumped hydro*	C/D	Low	Hi	Med	
	Small hydro (sub 30MW)*	C/D	Med	Med	Low	
	NGCC (high heat rate)	C	Hi	Low	Med	
	Coal (high heat rate)	C	Med	Low	Hi	

*Renewable energy. Source: DBCCA

The load shape changes throughout the day, ramping to adjust for changes in demand. Load following generation resources are designed to cycle with the changes in load. These generation resources include pumped hydro, higher heat rate natural gas combined cycle plants and higher heat rate coal plants that cycle on and off but stay constantly active. Load following ramp up time varies from instantaneous to several hours.

5.4 Peak

Exhibit 54: Characteristics of Peak Generation

Merit Order	Electricity Resource Commercial Now	Central / Distributed	Ramp Rate (Hi / Med / Low)	Flexibility (Hi / Med / Low)	Inertia (Hi / Med / Low)	R&D Stage
Peak	Gas peakers	C/D	Hi	Hi	Low	
	Oil	C/D	Hi	Hi	Low	
	Diesel	C/D	Hi	Hi	Low	

Source: DBCCA

Peak generation is generation in standby mode, ready to be called into service during short periods of peak demand when not being utilized (average capacity factor in the range of 5-10%). This generation generally has high variable costs and is primarily comprised of simple cycle natural gas power plants and diesel generators.

5. Generation: Supply to the system; centralized more common than distributed today

5.5 Intermittent generation resources

Exhibit 55: Characteristics of Intermittent Generation

Merit Order	Electricity Resource Commercial Now	Central / Distributed	Ramp Rate (Hi / Med / Low)	Flexibility (Hi / Med / Low)	Inertia (Hi / Med / Low)	R&D Stage
Intermittent	Wind*	C/D	N/A	Low	Low	
	Solar PV*	C/D	N/A	Low	Low	
	Solar CSP*	C/D	N/A	Med	Low	Scaling now
	Tidal*	C/D	N/A	Low	Low	

*Renewable energy. Source: DBCCA

Many renewable electricity sources have variable power output, which raises substantial integration challenges if, as widely anticipated, renewable energy sources rise to substantial levels in grid power systems. Among the challenges of intermittent generation are forecasting availability, lack of dispatchability, lower energy density, uncontrolled ramp rates and inertia. An exception is that some solar thermal plants supply thermal inertia if they are large enough. Solar PV, too, is often described as having high ramp rates. There are times when the wind does not blow and the sun does not shine. Overcoming these limitations is technically feasible, but requires substantial transmission and infrastructure investment. These issues raise concerns about the impact of intermittent resources on maintaining reliability and the balance between load and generation.

In simplified terms, electricity is the energy carrier converted by the mechanical power of the generator turbine spinning a magnet surrounded by three coils of wire (3 phase Alternating Current power). As the magnet spins, its lines of force cut the wire and induce an electric current into the wire. Once the mechanical energy is transformed by magnetism into an electric current it travels along the path of least resistance at the speed of light to where it is needed for useful work.

6. Transmission

6.1 High Voltage AC and DC Used for Long Haul Transmission

From the generation source, electricity must be delivered to the load. Electric power transmission is the bulk transfer of electricity to consumers from the generating station. For efficiency, electricity is stepped up to a higher voltage (up to 765kV) to reduce resistance as it flows across great distances to substations closer to load. Transmission lines are much like water pipes. Just like a wider water pipe can carry more water, a higher voltage transmission line can carry more electricity. There are two primary high voltage technologies: alternating current (AC), which is the most common and flexible; and direct current (DC) which has a lower capital cost and line loss than AC but requires expensive conversion equipment for transferring the power back to AC. DC transmission is used primarily for long haul electricity transmission from large generating sources located far from the demand centers—e.g. hydro dams, nuclear generation facilities, coal plants, aggregated wind farms or CSP solar plants—to the load areas. In the future, high voltage direct current (HVDC) could be a good systems strategy for moving large volumes of intermittent energy from the source to the load area.

Once electricity has made the journey along the high voltage lines to the end point it must be stepped down to a lower voltage at distribution feeder substations to be useful for homes and businesses. If you tried to plug a toaster or blender directly into an overhead power line it would explode instantly, since household appliances are designed to run on 110 to 220 volts, thousands of times less than the voltage in power lines. Again referring to the water analogy, it would be like trying to swim through Niagara Falls. Transmission is generally a limitation to renewable energy scale-up but the market is beginning to respond to the constraint.

An innovative proposal in New Mexico from the startup firm Tres Amigas (www.tresamigasllc.com) aims to create a “super station” of underground high voltage DC lines which would be among the more innovative and audacious utility industry projects ever proposed. The project would allow producers to move bulk quantities of electricity among the country’s three asynchronous transmission grids: ERCOT (Texas) and the Eastern and Western Interconnections. In theory, wind power from Texas could be shipped to California and solar power from California and Nevada could be transported east. In the application filing to the Federal Energy Regulatory Council (FERC), the lead FERC counsel stated: “This configuration and particular set of capabilities does not exist anywhere in the world. No one has ever built a facility like it.”⁸⁶ Although this is a potentially transformational project, we would caution that because of regulatory and legal complexity of the Tres Amigas proposal and the potential for price arbitrage between the three power grids, its future viability on legal and regulatory grounds is highly uncertain even though it appears technically sound and has attracted strategic corporate partners such as American Superconductor.

6.2 Transformers

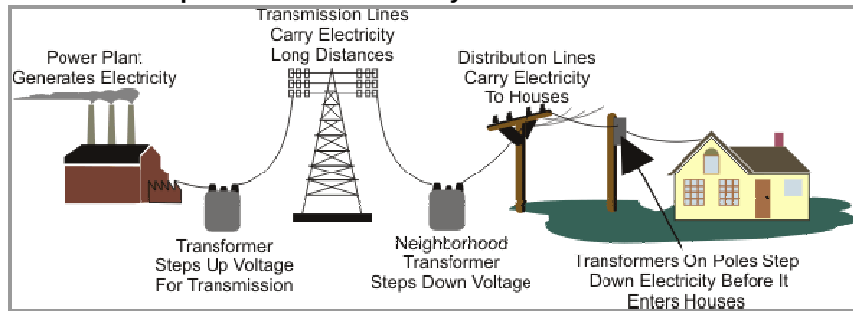
Transformer equipment reduces the voltage of the electric current using the principle of induction to transfer power from one circuit to another taking advantage of the magnetic flux properties of electricity. When a fluctuating electric current—e.g. AC power—flows through a wire it generates a magnetic field all around it. The strength of the magnetic field is directly proportional to the size of the electric current. One of the properties of electricity is that when the magnetic field fluctuates around a piece of wire, it creates a current in the wire. And if a second wire is placed close to the first wire, the current in the first wire induces current in the second wire, creating a secondary current.

If the two wires are the same length and dimension, then the voltage will be the same. If the looping or “turns” of the second wire is larger (either due to a wider wire or series of coils from a longer wire of equal width) then the secondary current will be stronger. Therefore, the size of the transformer is proportional to the step-change in voltage—the larger the required change in voltage, the larger the transformer. Transformers hum with electromagnetic energy as they convert the voltage of the electricity at the various substations and distribution feeders in the grid.

⁸⁶ *Public Utilities Fortnightly*, February 2010, p. 18

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Exhibit 56: Simplified View of Electricity Grid



Source: EIA

The electric distribution system is the connectivity infrastructure from the transmission system to the load. These are the poles, wires, high-voltage switch gear, step-down transformers, voltage dividers and related equipment necessary for converting high voltage electricity to lower voltages at the load. The equipment and processes employed to direct the power flow through the distribution system depends on the end use customer requirements and in this respect the grid is truly “spaghetti” since no two distribution systems are precisely alike and each is a tangle of wires and transformers.

The subtransmission voltage is usually between 34.5 and 138 kV depending on the architecture of the grid. The distribution substation, which is made up of power transformers together with the necessary voltage-regulating apparatus reduces the subtransmission voltage to a lower primary system voltage for local distribution. The three-phase primary feeder is the worldwide industry standard for AC systems; so called because three circuit conductors carry three alternating currents of the same frequency cycling at different intervals of a third each which provides constant power throughout the cycle. Three-phase feeders usually operate at voltages from 4.16 to 34.5 kV and distribute electric power from the lower-voltage bus of the substation to its load center, where it branches into three-phase subfeeders and three-phase and occasionally single-phase laterals for delivery to end user.

6.3 Local Circuit Distribution: Architecture Defined by Application and End Use Requirements

No two distribution systems are alike because load requirements vary substantially and distribution architectures are generally not standardized. The configuration of the system and how it interacts with the transmission and generation grid resources defines end use flexibility and affects the time required to restore power after a failure event. At its most basic, a distribution system is configured as a Simple Radial—meaning that a single incoming power flow is received and delivered to its endpoint; e.g. one way power flow from generation to transmission to distribution to circuit to use. Radial systems have very little spare capacity or duplication of equipment, which means that there are little to no contingencies for equipment failure or line loss. Therefore, failure in any one component or path will interrupt the load. No surprisingly, most reliability issues occur at the distribution part of the grid where the utility has the least see through. Sadly, even in this day and age of instant communications most utilities only know that there is a service problem when a customer calls to report that the power is out.

A Primary Selective Distribution System is a more resilient distribution configuration than a Radial system in that the power is fed to the load by two different power sources running through multiple transformers and circuits. When one primary circuit is out of service, the remaining circuit in the distribution system has sufficient capacity to deliver power to the load. Finally, there are Secondary Selective Distribution Systems, which are the most resilient.

Facilities requiring uninterruptible power—e.g. hospitals, factories and datacenters etc.—are typically designed around the Secondary Selective Distribution System construct. Facilities tied to these grid designs have half the load connected to one incoming power source and the other half of the load connected to another. Both power flows are energized through a piece of equipment called a tiebreaker. If load is interrupted from one source, the main circuit breaker to the faulted source is

6. Transmission

opened and the tiebreaker is closed, allowing power to flow from a single source. In addition, Secondary Selective Distribution Systems often have a distributed backup power source, such as a diesel generator or banks of batteries, which can run for a period of time in the event that both incoming power sources are compromised.

7. Renewable and intermittent generation: Overcoming the barriers to scale

Renewable energy is energy generated from natural resources—sunlight, wind, tides, water, biomass, and geothermal heat—which are naturally replenished and not subject to depletion rates like fossil fuel energy sources. Wind and solar are intermittent renewable energy sources; that is there is diurnal and seasonal variation that is not always constant.

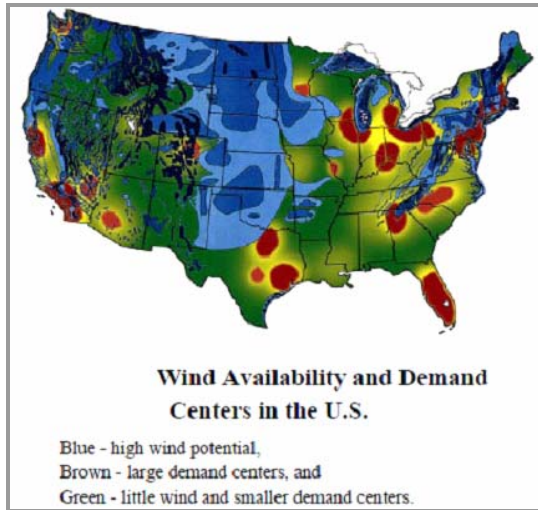
Up to now in this report, we have tackled the issues regarding integrating intermittent renewable energy in scale into the bulk power system from a balancing authority and system planning perspective. To summarize, wind and solar generation present the following challenges and limitations to electricity grid systems:

- **“See Through”:** Distributed resources, particularly solar photovoltaic rooftop, currently often lack two-way interaction with the grid system and, in many instances, are not included as a resource for long term planning and system adequacy assessment. From a grid operator’s perspective, they don’t exist or are just considered to be negative load;
- **Rotating Mass:** Wind and solar energy resources do not provide a comparable level of inertia and synchronous generation spin relative to large fossil, geothermal and nuclear generator turbines; hence, even in scale, variable energy supplies would not be able to absorb minor frequency blips without additional equipment and processes, making the grid potentially less stable;
- **Dispatchability:** Solar and wind are variable resources; in the absence of storage or aggregation across geographies the ability to ramp up quickly to meet demand reliably requires a backup generation source;
- **Transmission:** The best variable generation resources are seldom close to the load areas; in the US about 7% of the population lives in the ten states with the most wind potential and the best solar resources are in the desert, far from load demand (Exhibit 57);
- **Land use:** Due to their low energy density compared to fossil fuels and nuclear energy, intermittent energy generation requires a larger geographic footprint per MW; as a reference point, supplying the US with 20% wind generation would require about 50,000 square kilometers of land on shore (roughly the land equivalent of the state of Rhode Island) and 11,000 square kilometers dedicated for off shore projects;⁸⁷
- **System complexity:** Higher levels of intermittent generation may affect the mix and dispatch of other generation on the system over time, since non-variable and dispatchable generation is needed to maintain system reliability when resource dispatchability is low; thus additional contingencies and incremental system adequacy analysis are required to ensure reliability;
- **Greenhouse gas emissions:** Since intermittent resources require fossil-fueled backup resources on standby, the reduction in greenhouse gas emissions is less than the kilowatt hours displaced, although there is clearly a significant net benefit.

⁸⁷ http://www1.eere.energy.gov/windandhydro/pdfs/20percent_summary_chap5.pdf

7. Renewable and intermittent generation: Overcoming the barriers to scale

Exhibit 57: The Best US Wind Resources are Far From Demand



Source: NERC

So what is a grid operator to do? Develop a robust planning process. Intermittent generation supply has been the fastest growing source of new generation in the US and Europe over the past five years driven by strong public policy and incentives. In 2008, wind energy accounted for 42% of all new electricity capacity additions in the US.⁸⁸ We see no signs of these trends abating. Based on our research, we believe most power systems can handle 10-15% intermittent generation supply of total load without retooling the systems architecture, depending of course on the particular generation mix, interconnection ties and peakiness of the load. However, in the future when intermittent penetrations increase to 15-20% and 20-30% as they are likely to in certain electricity markets such as California, Spain and Germany, new enabling processes will be required to ensure adequate grid reliability. Intermittent generation supplies require a “dance partner”. It could be ancillary services or spinning reserves, excess fossil generation repurposed as backstop power, storage, incremental fossil generation—e.g. natural gas peaking plants—or more responsive demand side management programs. The precise theoretical penetration level limits of intermittent resources and enabling technologies and processes “depends” from market to market on the specific characteristics, resources and flexibility of a given system. There is no optimally efficient mix. But with the right lead times and policy support engineers can accommodate renewable limitations.

The limitations must be addressed head on and include:

7.1 Variable Power Generation

A barrier to scale deployment for intermittent energy is variability. The ability of a system to integrate large penetrations of variable resources depends heavily on the mix of other generation resources. From a balancing authority’s perspective, the fundamental *raison d’être* is to balance the load reliably and dispatch energy efficiently. All intermittent resources have a certain amount of unpredictability that defies statistical probabilities. In wind, for instance, although there are diurnal and seasonal patterns that are fairly constant, over multiple decade long time periods there have been years when wind speed has been as much as one half that of good years; moreover low wind speed years are typically clustered.⁸⁹ Normalized wind variability is reduced with aggregation. This principle applies to small scale-scale and large-scale geographical aggregation and to all timescales of grid operation.⁹⁰ As wind scales and becomes a larger part of total generation in grid systems, new analytic tools will be required to model the variability of wind over long time periods in a given geography to help the balancing authority prepare for reliability in 2015, 2020 and 2025 and schedule ample backup resource capacity. Already,

⁸⁸ <http://www.pnas.org/content/106/27/10933.full.pdf>

⁸⁹ *Renewable Electricity and the Grid—The Challenge of Variability*, Edited by Godfrey Boyle, Earthscan, 2007, p 7

⁹⁰ *IEEE power & energy magazine*, November/December 2009, p. 91

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system operators in Germany, Spain, Denmark and Texas have become much more adept at integrating wind and improving scheduling. Ultimately, the amount of renewable energy scale-up possible in a given power system comes down to economic costs and benefits—e.g. how much is the rate payer or government willing to pay (via taxation) to deploy renewable energy, along with the flexibility and limitations of the current grid system.

7.2 Backup Capacity

In a power system, a continuous balance between electricity production and consumption must be maintained. Because of its variability, intermittent generation can't displace conventional fossil generation on a one-to-one capacity factor adjusted megawatt basis without compromising grid reliability. For all practical purposes, a certain amount of backup fossil capacity is needed. From an economic optimization perspective this is best achieved by leveraging the existing generation capital stock rather than building “backup” fossil generating plants since this would be an exceptionally costly use of power generation resources.

In the US, as an example, there are ample gas-fired power plants that are underutilized and could be used to backstop wind with the right economic incentives and transmission interconnections. The reason the average capacity factor for natural gas has been just ~37% since 2003 is that natural gas generation has been less economic than coal-fired power.

Just how much fossil capacity is required to support intermittent energy generation depends on the specific system dynamics of the power grid and the mix of generation resources available at a given time. The risk of loss of load or dispatch can be calculated and factored into grid planning. Capacity payments for generation available to run as needed—such as gas peakers—on the supply side and payments for reducing consumption on the demand side are common in many deregulated power markets and will increase in importance for stabilizing the grid as more intermittent generation is added.

Generally, at wind penetrations of up to 20% by energy, the incremental balancing costs caused by wind are 10% or less of the wholesale value of the wind power.⁹¹ However, from an emissions perspective even though a kWh provided by intermittent renewables displaces an otherwise CO₂ emitting kWh from coal or gas, the incremental reserves (spinning or non-spinning) required to reliably backstop intermittent generation consume fuel so the net emission reductions are somewhat reduced. In some instances, the load following fossil plants may be forced to operate at a reduced level of efficiency, resulting in increased fuel consumption and increased emissions per unit of output.⁹² Again as intermittent load scales, there will be new market opportunities for highly efficient fast start gas turbines that have a better emissions footprint than the current fleet.

⁹¹ *IEEE power & energy magazine*, November/December 2009, p. 93

⁹² *IEEE power & energy magazine*, November/December 2009, p. 94

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Special Focus: The Pairing Opportunity of Natural Gas Generation and Renewables

The interaction between natural gas and renewable energy is of particular interest within the context of a lower carbon energy system, since natural gas is very much a “bridge” generation technology given its flexibility to run as base load or peaking capacity and favorable emission profile compared to coal. However, the relationship between natural gas and renewables is not necessarily intuitively obvious. Depending on the specific fundamentals of a given power market, natural gas could be complementary to renewables or a competitive threat. On the one hand, natural gas is a logical pairing option or “dance partner” for intermittent wind and solar generation. Underutilized gas plants can provide backup power to stabilize the electricity grid when intermittent renewables do not dispatch, provided there are the right transmission linkages and ability to receive energy capacity payments. On the other hand, natural gas sets the marginal wholesale power price in most competitive electricity markets and therefore directly affects long term renewable power purchase agreements (PPAs) for solar and wind farms that do not have feed-in tariffs, significantly impacting the internal rate of return (IRRs) of these projects. This has recently caused the growth rate of wind energy in particular to slow because the forward electricity curves do not support marginal projects that are not able to maximize incentive capture.

The fundamental backdrop supporting natural gas generation on the supply side comes from its abundance and recent technology and manufacturing process breakthroughs in non-conventional shale resource plays that allow extraction at relatively low marginal cost. Over the longer term, we expect renewables and natural gas to become more complementary resources. Already we are seeing signs of companies beginning to think in these terms. One solution may be to build hybrid natural gas and solar power plants, such as the 110 MW solar thermal generation plant that is being built by Next Era Energy in Florida and grafted on to the back of a large 3,800 MW natural gas combined cycle power plant. Solar electricity—when available—will reduce the output from the natural gas power plant and the stored energy from the solar thermal part of the plant will also help improve the overall efficiency of the natural gas unit so that it reduces its overall CO₂ emissions.

7.3 Managing Uncertainty

Aggregation helps balancing authorities manage risk as part of their core competency. No generation is available 100% of the time. Plants have downtime for both scheduled and unscheduled maintenance and repairs. And demand sometimes changes briskly beyond expected norms. The risk of a “scheduling error” one hour ahead is typically about 1%. To mitigate the risk of not being able to match supply, the grid dispatcher schedules reserve capacity such as spinning reserves or pumped hydro. The precise ratio beyond the forecast scheduling error probability varies from system to system depending on its flexibility. Managing this uncertainty becomes potentially more complicated with larger shares of intermittent resources bidding into the system. The correlations of wind speeds decreases with distance, which makes a strong case for transmission lines interconnecting wind generation over large geographies to reduce supply fluctuations and balance the load.

The question of whether intermittent renewables require dedicated storage backup ultimately comes down to weighing the costs versus the benefits. Storage and transmission are extremely expensive but not necessarily required in the short run. Many studies analyzing the implications of large scale solar and wind additions to the grid conclude that integration costs for penetrations of up to 20% of delivered load are modest, and implementation can be achieved by improved forecasting and advancements in scheduling existing resources.

7.4 Comprehensive Planning

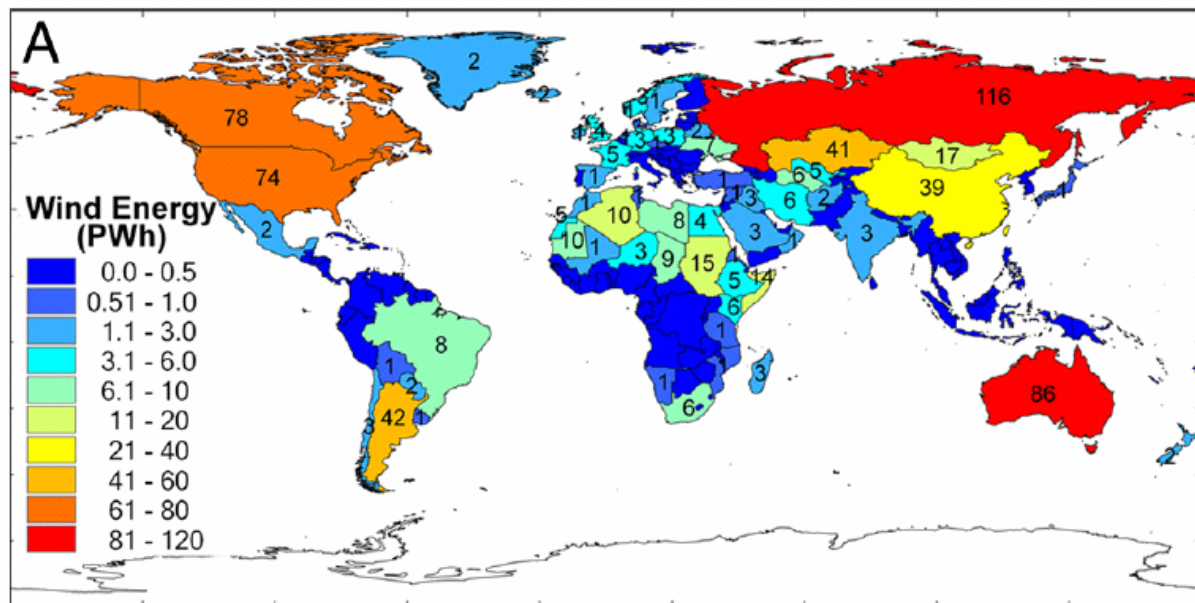
The electrical power system was never designed for two-way power flow at the distribution level. With many larger PV installations coming online soon or being announced, they are expected to be interconnected with legacy distribution circuits encompassing different characteristics like circuit designs, load and generation mixes. As a general rule of thumb, their penetration effects will likely need to be dealt with differently depending on the specific last mile circuit characteristics.

7. Renewable and intermittent generation: Overcoming the barriers to scale

Large additions of distributed systems such as rooftop solar and local wind plants can impact the bulk power system. In many instances a developer is responsible for financing a system integration study and paying for the upgrade costs to the distribution system. Small-scale units typically fly beneath the regulatory radar relative to larger power plants and do not always show up as resources in grid planning. As these systems are aggregated into the system, it will be important for standards to develop and for the balancing authority to have “see through” in order to accommodate issues such as forecasting availability, voltage ride-through, safety, reactive power, and controllability.⁹³ As the shift toward variable generation intensifies, power system planners and operators will need to develop improved operational and planning guidelines and practices to reliably accommodate the resources in the bulk power system.

There is no technical natural long term supply limit to the theoretical potential of renewable energy to supply the world's electricity needs (Exhibit 58). However, the barriers are not trivial and require overcoming the systems engineering, land use and, most importantly, cost, challenges, for instance. Nevertheless, in theory a network of land-based 2.5 MW turbines restricted to non-forested, ice-free, nonurban areas operating at as little as 20% of their rated capacity could supply >40 times current worldwide consumption of electricity and >5 times total global use of energy in all forms. Resources in the contiguous United States, specifically in the central plain states, could accommodate as much as 16 times total current demand for electricity in the United States.⁹⁴

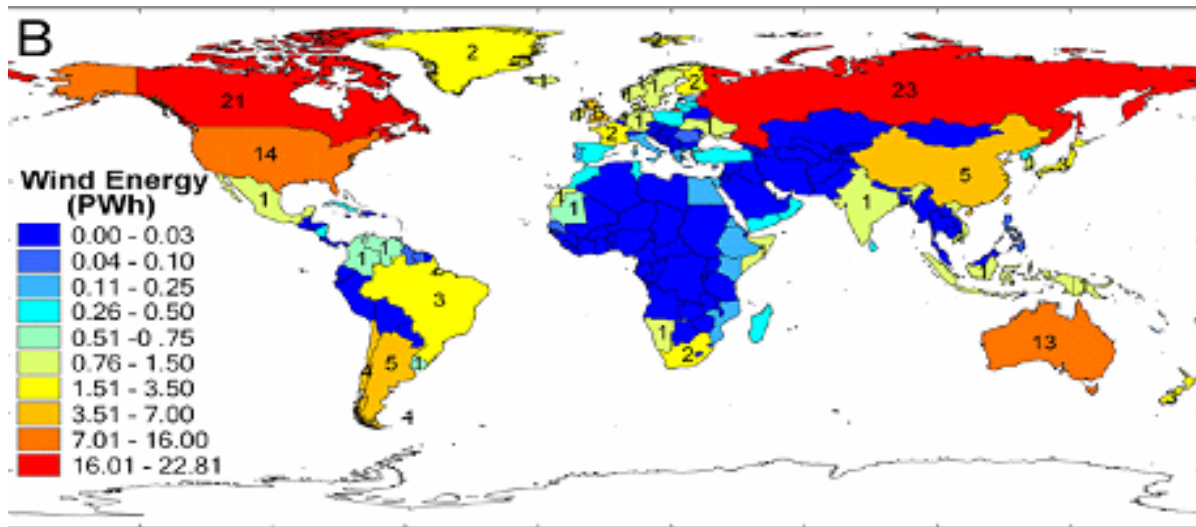
Exhibit 58: There is Ample Global On Shore (A) and Off Shore (B) Wind Capacity



⁹³ http://www.nerc.com/files/IVGTF_Report_041609.pdf, o. ii

⁹⁴ <http://www.pnas.org/content/early/2009/06/19/0904101106.abstract>

7. Renewable and intermittent generation: Overcoming the barriers to scale



Source: NASA

Our research shows an intense focus right now among all the key stakeholders to overcome these barriers and find solutions to enable the scale-up. Talking to industry players, there is a general feeling that these limitations must be taken care of and can be addressed from a systems engineering planning perspective with the right lead times and an adequate time scale. With planning foresight, scale and enabling processes limits can be addressed: for instance solar and wind are complements diurnally with wind blowing hardest at night—in North America, at least—and solar can potentially shave peak load during the day. Over the course of the next 12-18 months we expect a number of influential technical studies to be released from industry and government research labs outlining pathways solutions. And based on our interviews, it is clear the balancing authorities are working on complicated system algorithms with the best math minds in the world at institutions like the Massachusetts Institute of Technology and the California Institute of Technology to develop systems and protocols that simply do not yet exist.

To recap, there are solutions.

- **Expensive fossil fuel backup:** A simple way to achieve a 100% renewable energy supply would be to add expensive fossil fuel backup. But that of course is not economically feasible. And indeed there are research studies underway that show that there would be more emissions from natural gas turbines operating as backup for a wind power plant than from a coal integrated gasification combined cycle (IGCC) power plant because cycling gas plants off and on is not thermally efficient.
- **More storage:** Storage, too, would make a large impact, but no one has yet developed a storage option that could scale at reasonable cost. Better technology and asset optimization, enabled by a “smart grid” will help.
- **Smart grid:** Better smart grid tools could enable real time demand response to manage some aspects of variability. Also, load shifting to flatten the onpeak duration curve, including ice storage could help.
- **Transmission:** And then there is of course transmission, which can, and will, in our opinion, be among the most important levers.
- **Micro-grids:** Finally, the “last mile” distribution infrastructure in most grid systems was designed for centrally distributed one-way power flow and must be hardened to accommodate two-way power flow from distributed resources, such as solar PV. The good news from an investor perspective is that each of these obstacles is an unmet market opportunity.

8. Enabling processes: Allow the system to meet its deliverables

8.1 Balancing Authority Ensures System Functions Reliably

In order to keep the grid functioning, there needs to be an entity responsible for controlling all the inputs. Organizational infrastructure, protocols and processes play a vital role in making the system work to meet its deliverables. As we discussed previously, electricity follows the “path of least resistance” so it generally cannot be routed in a specific direction or stored for anything but a very short time. This means generation and transmission operations must be monitored and controlled in real-time, 8,760 hours a year, to ensure a consistent and ample flow of electricity. This requires the cooperation and coordination of hundreds of electricity industry participants. Imagine a single air traffic control tower routing airplanes for ten metropolitan airports and you get a sense for the scope and responsibility of a grid operator.

The conducting function of “orchestrating” the tight match of supply with demand falls squarely into the hands of a balancing authority, or system operator. In the classic vertically integrated utility model this control function is housed within a single utility or shared among a few utilities working collaboratively in a shared or adjacent service territory. In the US hybrid and competitive wholesale power markets, the balancing authority is either an Independent System Operator (ISO) or Regional Transmission Operator (RTO), whose function is to act neutrally and independently and create rules and procedures that ensure markets operate fairly, efficiently and reliably. The UK, France and Spain have independent National Grid operators responsible for balancing supply and demand; in Germany the balancing authority responsibilities are shared amongst independent entities set up by electric utilities—including Vattenfall, E.ON, RWE and EnBW—but recently there has been pressure from the country's Environmental Ministry to create a national power grid.⁹⁵

As more complexity is added to the electricity grid, the role of the balancing authority will increase in importance—transforming it from a conductor to a nerve center. Variable resources differ from traditional fossil-fuel resources in a fundamental way: their fuel source (wind, sunlight and moving water) cannot presently be controlled or stored.⁹⁶ Operational changes from the balancing authority are inevitable with higher penetrations of wind and solar and include:

- **Advanced technology control:** Measurement tools for two-way power flow will have to be developed to provide better “see through” into the edge of the distribution system. Today, performance measurement at the generation and transmission part of the system is extremely precise. However, there is very little intelligence at the last mile, or edge. Smart meters and improvements in control technologies will be increasingly important.
- **Comprehensive Planning:** Distributed generation and micro-grid arrays will need to be incorporated into integrated resource plans as firm capacity. Today, these resources are “noise” and in many cases are undetected by the balancing authority. Going forward, these resources will need to be considered on par with larger transmission connected variable generation such as wind farms.
- **Enhanced measurement and forecasting:** Day ahead and real time planning competencies will need to incorporate greater variation in supply from intermittent resources. The issues of note include more precise weather and load demand forecasting and a greater availability of resource contingencies.
- **Flexible resources:** The steep ramps inherent in quick changes in intermittent supply from a sharp drop off in wind or cloudy weather that may limit solar generation will be backfilled by flexible resources such as demand response, plug-in electric vehicles and storage capacity.
- **Bulk storage:** To maximize the value and production of intermittent generation bulk grid storage options will be deployed throughout the electricity grid.
- **Greater access:** Aggregation helps limit the variability of wind and solar. Balancing authorities will become more interconnected with neighboring grid systems for greater stability.

⁹⁵ <http://www.reuters.com/article/rbssIndustryMaterialsUtilitiesNews/idUSLR62562920090827>

⁹⁶ *Accommodating High Levels of Variable Generation*, North American Electric Reliability Council, April 2009, p. 1

8. Enabling processes: Allow the system to meet its deliverables

8.2 Optimizing Dispatch: From Least Cost to Highest Marginal Cost

- **Energy Market:** The balancing authority coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market—which includes the spot (e.g. real-time 10 minute market); day-ahead market; ancillary services, spinning reserve and full-requirements market; forward calendar year and year ahead strip; and capacity markets. The balancing authority optimizes generation dispatch in merit order to match demand—from least cost to highest marginal cost—sending real time dispatch signals to generating units;
- **Planning System Adequacy:** As part of the long-term planning to ensure system adequacy, the ISO/RTO's in the US PJM and MISO service territories have implemented a Reliability Pricing Model (RPM), which provides a long-term price signal for required generation capacity (3-years forward) in regular auctions to incent new investment in generation and ensure the grid has sufficient resources to preserve system reliability;
- **Locational Marginal Pricing (LMP):** In the US the LMP concept—which is sometimes also called nodal pricing—was created by the Federal Energy Regulatory Commission (FERC) to create a market-pricing approach to price electricity based on the cost to deliver the last unit of electricity at a specific end point taking into consideration generation and transmission limits. Most of the world electricity systems use zonal prices, which reflect the cost to deliver electricity at a sub-regional rather than specific end point;
- **Auctioning Firm Transmission Rights (FTRs):** The grid is limited by transmission bottlenecks and at periods of peak demand congestion along certain pathways limit the amount of wholesale power that can be delivered. FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on hourly congestion price differences across a transmission path in the day-ahead energy market, thus allowing producers to hedge price risk when delivering power onto the grid;
- **Maintaining Best Practices:** In North America, ISO/RTOs adhere to the NERC compliance standards. NERC is responsible for the bulk power system and provides the planning and operating rules that electric utilities follow to ensure the most reliable system possible;
- **Enforcing Penalties:** NERC and the ISOs/RTOs have the legal authority to enforce compliance with NERC Reliability Standards and have developed a rigorous program of monitoring, audits and investigations. Financial penalties and other enforcement actions are imposed on market participants for non-compliance.

8.3 Balancing Authority Dependent on “See Through”

The balancing authority relies on two-way control systems to manage disparate generation resources for its operations, adjusting ramp rates of facilities as necessary, “spilling” power when needed, and generally keeping tabs on the operability, availability and contingencies of a wide range of generation resources and transmission pathways. In markets where incentives are in place for Demand Response programs, the balancing authority will implement planned reductions in electricity use during times of high demand. In order for this to happen, the balancing authority depends on “see through” to the resource from two-way communications to ensure reliability and safety.

Notably, such frequency control works most fluidly with large, centrally generated resources. Anything less than 20 MW in size is “noise” for a large balancing authority. Thus far, this has diminished the potentially positive impacts of distributed generation resources—such as PV and plug-in hybrid vehicles—in firming the load at a systems level because of their size and, more importantly, lack of dispatch visibility or “see through” to the operator. Moreover, in the event that the operator needs to isolate a portion of the grid and de-energize it for safety reasons, there is no guarantee that this will have happened with distributed resources.

To underscore the value of “see through,” the two-way communication maintains grid stability by reducing the stress on the system and reducing the need for new generation resources. In competitive markets, the balancing authority can use frequency controls to reduce, limit or curtail power demand from end-use customers who agree to reduce their electricity use in response to power grid needs, economic signals from wholesale energy markets, or special retail rates. This could

8. Enabling processes: Allow the system to meet its deliverables

be reducing power to irrigation pumps, heavy industry or cycling residential air conditioners on and off in fifteen minute intervals to conserve energy.

8.4 Permitting, Fast Tracking and Eminent Domain: Overcoming NIMBY and BANANA Forces of Resistance

Regulatory and governance constraints that restrict electricity system investment—particularly for transmission projects—are barriers to scale for renewable energy projects. Over the past several decades, Not In My Back Yard (NIMBY) public sentiment inhibiting development has been augmented by Build Absolutely Nothing Anywhere Near Anything (BANANA) activism. The bottom line is that it has become increasingly difficult to get approval to build new electricity infrastructure given the formidable bureaucratic obstacles that impede progress. These forces of resistance are well known and the play book is relatively constant: absent any perceived benefit—e.g. job creation, rent, subsidized energy, tax breaks etc.—local community members frequently balk at transmission and generation projects. Ironically, the fact that such investment is likely to improve reliability and hence increase the odds that the lights stay on is often completely overlooked. Consequently, a well-crafted permitting strategy for new projects including grid-tie provisions, contingencies, and flexible financing is absolutely essential for any infrastructure project.

8.5 Fast Tracking Transmission: China for a Day

Fast track planning for transmission, including eminent domain oversight for key pathways and trunk lines, is a vital **enabling process** and will only grow in importance as larger volumes of low carbon intermittent sources of electricity such as wind and solar are planned to be added to the grid. And while transmission lines are an essential infrastructure for making the grid more resilient and flexible, making large transmission capacity additions is an arduous process. Ten years from the initial planning phase to completion is a normal timeline when lines traverse urban oasis and national forests in the US and Europe. As a result, the value of existing pathways that could potentially be repurposed to either carry more energy or become more flexible may indeed increase because of the high barriers to entry for capacity additions.

Americans aren't alone in their skittishness. In the U.K., which aspires to generate about 15% of its electricity from renewable sources by 2020, local opposition is holding up proposed wind projects. Resistance in Ontario led the Canadian province to pass legislation in May 2009 establishing a framework for locating renewable-energy sites; local opponents will be able to challenge projects on environmental or safety grounds, but not for aesthetic reasons.⁹⁷

In 2008, the IEA cited “not in my backyard” sentiment as among the top five threats to the growth of renewable energy world-wide. “Only a limited set of countries have implemented effective support policies for renewables and there is a large potential for improvement,” the report said, advocating for the removal of “non-economic barriers, such as administrative hurdles, obstacles to grid access, poor electricity market design, lack of information and training, and the tackling of social acceptance issues (“not in my backyard” - NIMBY), with a view to overcome them - in order to improve market and policy functioning.”⁹⁸

Success stories include Spain⁹⁹, Germany and China. In 2005, the Spanish government approved a Renewable Energy Plan (Plan de Energías Renovables, PER) by Royal Decree 661/2007, which guaranteed a high feed-in tariff for solar electricity and priority interconnection right for all renewable generation sources. Germany has pursued a feed-in tariff for solar, which has been highly successful in increasing supply. China, too, has been successful in scaling up wind and solar over the past two years. When it comes to building transmission lines and enabling variable generation lower carbon technologies strong government policy is an effective tool; whether it be royal decree, subsidized tariffs or command and control governance with eminent domain.

⁹⁷ <http://online.wsj.com/article/SB125201834987684787.html>

⁹⁸ http://www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=271

⁹⁹ Note: Spain's feed-in tariff was subsequently found to be too generous and has been a significant contributor to the country's “energy tariff deficit.”

8. Enabling processes: Allow the system to meet its deliverables

8.6 Supply Chain: Scale and Process Vital for Driving Down Cost

A large share of the cost premium of wind and solar over traditional fossil fuel generation is due to supply chain inefficiencies and a wide variation in standards and practices. Wind generators, for example, were completely sold out of turbines in 2007 and did not have the manufacturing capacity to add more supply. To be fair, the same conditions have happened in the past with a scarcity of gas turbines relative to demand; however gas turbines have higher availability since they are not an intermittent resource and can therefore potentially overcome a higher capital cost due to supply shortages with greater energy revenue and are typically not subsidy dependent. And offshore wind developers were limited by the availability of shipping capacity to haul and install the large turbines. Solar photovoltaic shipments from 2006-2008 were limited by tight capacity supplies of the raw material, silicon, a constraint that corrected but is now again becoming a near-term barrier for accelerating cost declines. But other parts of the solar value chain, such as installation, still have room for cost improvement.

There are many opportunities for improvement in renewable energy generation, including the use of lighter weight and more efficient conversion materials, lower cost materials, and increasing the manufacturing scale to improve yields. Improved and more flexible distribution and installation systems will also help. As the economics of renewable energy improve, traditional utilities may build more renewable energy facilities and put them in rate base rather than sign purchase power agreements (PPAs) with project developers to comply with renewable energy procurement imposed on them by regulators. In turn, this could potentially drive down the costs even further given the potential for a more stable and large scale customer base. Regulated utilities now qualify for renewable power tax incentives in the US and regulators in states like Michigan and California have begun to experiment with allowing utilities to build some renewable generation as part of their General Rate Case.

9. Enabling technologies: How to make a more complex grid stable and resilient

Today's electricity systems are based on old technologies and processes that have been battle tested for over a hundred years. Compared to other sectors like Information Technology and Financial Services there has been much less innovation in the way the product—electricity—is produced and distributed to customers. This is primarily because of the unique characteristics of electricity—the physical properties of it traveling at the speed of light, the need to constantly balance supply to meet demand, and the significant operational and economic consequences that result from interrupted power delivery. If a cell phone call is dropped because of a fault point in the network, a user simply reconnects and the worst that happens is a few minutes of lost productivity. Moreover, there is a perfect albeit less convenient substitute in the form of a landline. If a bank erroneously deposits a money transfer to the wrong account, the wire transfer can be reversed with no harm to the customer. Electricity systems, by contrast, are vastly more complex and there is quite simply less room for error given the potential consequences. But electricity has to become cleaner and produce fewer emissions without sacrificing reliability. A series of enabling processes can make a difference.

9.1 Storage

Storage is tremendously valuable to the grid because it increases system flexibility. However, this benefit must be weighted against the cost. Cost effective dispatchable energy storage was considered one of the Holy Grail technologies for the electricity grid even before intermittent energy became a focus. In fact, the early research around compressed air storage was based on the belief that spilled generation from nuclear generation could be stored and then dispatched to the grid when it was more valuable. Electricity energy storage broadly defined is simply any means of siphoning power directly from power plants or the electric grid and storing it for later use. If scalable, storage could potentially revolutionize electricity markets and enable significant process changes. But to date storage penetration has been extremely limited mostly due to the high costs and limitations of technologies. However, the expected introduction of high levels of electricity supply from intermittent sources such as wind and solar puts storage front and center as a vital technology for stabilizing the more complex grid of the future.

A breakthrough in the cost and performance of electricity storage would significantly improve the flexibility of the grid and potentially improve the efficiency of electricity delivery. Vendors are now in the process of building the capacity to supply products in volume to the market, as well as to build market awareness of the technology and to continue to drive down the cost of manufacturing the energy storage systems. Once universally implemented into grid planning, storage systems will enable larger supplies of variable resources while also optimizing and improving the **flexibility** of the existing infrastructure and reducing the need for new transmission and distribution. Storage will make better use of excess capacity, including spinning reserves and gas peaking plants, dispatching them when it is economically efficient relative to the storage alternatives. Over time, this should improve the overall stability of the grid while providing cleaner electricity with less price volatility for consumers. Just as with renewable energy, bringing down storage cost is essential for widespread adoption.

The performance of storage options varies and affects their applicability to grid operations. We group storage technologies with their grid application in the supply stack below (Exhibit 59).

Exhibit 59: Energy Storage Applicability to Grid System

Baseload	Intermediate (load following)	Peak	Intermittent
CAES (compressed air)	CAES	Battery (Lithium Ion)	CAES
Pumped hydro	Pumped Hydro	Flywheel	Battery (Flow, NAS & Lithium Ion)
Battery (Flow or NAS)	Battery (flow or NAS)	Excess fossil generation	Excess fossil generation
	Excess fossil generation		

Source: EPRI, CAISO, DBCCA

9. Enabling technologies: How to make a more complex grid stable and resilient

We review the current state of storage solutions below and evaluate their commercial status and scale potential:

- **Batteries:** Large-scale battery storage systems (2-10MW) are in the early implementation phase. To put this in perspective, all the batteries in the world today would be able to provide only about 10 minutes of the world's electricity needs. Thus far, they have not entered scale production so the form factors and cost parameters are far from commercially optimal. Grid operators envision using these batteries for reducing peak load, "islanding" power for strategic deployment when needed to circumvent cascading system losses, intermittent storage to backstop wind and solar and sub-transmission support to balance reactive power flows.
- **NAS Batteries:** Sodium sulfur (NAS) batteries are currently produced by NGK Insulators Ltd of Japan (among others) in 1 MW units the size of a double-decker bus at a cost of about \$4.5 million per MW. Tokyo Electric Power (TEPCO) has deployed the batteries in 1-10MW configurations providing 4-8 hours of storage. NAS strengths are compactness, modularity and ability to be relocated. But because of the reactivity of the chemicals involved and the ceramic separator required to keep the chemicals apart, the batteries are expensive to manufacture—e.g. more than three times the capital cost of a gas peaker power plant. Moreover, to play a significant role in balancing the load and receive capacity credits for regulation in the day-ahead market, NAS battery form factors would need to increase by an order of magnitude larger—e.g. 3-30 MW per installation. From a dispatchability perspective, the physical properties of NAS batteries are such that they need to be slowly cycled in charging and discharging. Thus, NAS batteries are not suitable for load balancing signals from a system operator to react to peak load conditions and work better with the baseload and load following part of the supply stack. In addition, a further limitation is the energy penalty. NAS batteries typically discharge 80-85% of the electricity put into them. However, they can potentially enhance reliability and provide support for weak links in the sub-transmission system, helping to avoid equipment overload.
- **Lithium Ion Batteries:** In contrast to NAS batteries, Lithium Ion technologies have superior dispatchability and performance characteristics for grid operations that require rapid power delivery. Several California utilities are now performance testing scalable modular batteries from A123 Systems, which are designed to discharge instantaneously from a frequency signal from the balancing authority. In addition, lithium ion batteries have better round trip efficiency, with a 10% energy penalty which place them best-in-class on this metric relative to other storage options at the present time. Lithium batteries are particularly well suited for power quality and reliability applications such as Frequency Regulation and Synchronous Reserve (Spinning Reserve). The technology also shows great promise in providing Uninterruptible Power Supply (UPS) for customers who require a high level of reliability and for enabling renewable energy management. The downside is that they need to be recharged frequently.
- **Pumped Storage:** Pumped hydro storage systems are the most effective bulk storage options for effective grid balancing at the present time. During periods of low electricity demand (often at night) when power is cheap water is pumped from a lower reservoir to a higher reservoir for storage; it is then released to run turbines during periods when demand is high. From a thermodynamic perspective pumped storage is a net user of energy and is about 70-85% efficient. High capital costs, long construction and permitting processes and the requirements for adequate geography are limitations. Also, the relatively low energy density of pumped storage systems requires either a very large body of water or a large variation in height.
- **Thermal Storage:** Thermal storage is one of the oldest energy storage processes. Before electricity, ice was harvested in the winter and stored for use in the summer to preserve food. Today, thermal storage systems are making a comeback as a strategy for reducing peak load demand. State-of-the-art energy efficient buildings—those designated Platinum by the U.S. Green Building Council's Leadership in Energy & Environmental Design (LEED)—such as the new Bank of America headquarters building in midtown Manhattan, employ combined heat and power (CHP) systems that recycle gray water and make ice at night when electricity is cheap and load requirements are low. The ice is then used during the day with the air conditioning systems to reduce peak electricity needs. Early stage capital is being deployed to unlock this potential. Start-up Ice Energy backed by EnergyCapital Partners is focused on shifting commercial electricity usage from peak to off-peak, when energy generation is cleaner, less expensive and more abundant¹⁰⁰.

¹⁰⁰ <http://www.ecpartners.com/>

9. Enabling technologies: How to make a more complex grid stable and resilient

- **Molten Salt:** Fluids are used for energy storage in concert with concentrated solar power (CSP) energy systems. Molten Salt (60% sodium nitrate and 40% potassium-nitrate; e.g. salt-peter) has proven to be the most cost effective and safe option compared to other liquid storage options such as oil, air, sodium and pure salt. Molten salt melts at 430°F and is kept liquid at 550°F in an insulated cold storage tank. The salt is then pumped to the top of the solar tower, where concentrated sunlight heats it in a receiver to 1050°F. The heated salt then flows back down to a second insulated hot storage tank. When electricity is needed from the plant, the hot salt is pumped to a conventional steam-generating system to produce superheated steam for a turbine/generator. Depending on the size of the storage tank, the system can be configured to store solar energy from anywhere from two to twelve hours with a roundtrip efficiency of 99%. CSP systems are typically 50-500 MW and constructed either in a parabolic-trough, dish engine, or tower system. Since the salt stores heat efficiently, CSP systems can be used in concert with natural gas power plants. In these hybrid systems, heat from the sun is used to preheat water that exhaust gases from the gas turbine will boil. Such a configuration could get significantly more work out of a natural gas plant, operating at an efficiency of about 70-75% compared to 50-60% of a standard natural gas power plant.
- **Compressed Air (CAES):** Salt dome caverns and dry oil wells can work as effective storage options for compressed air storage. The process involves taking excess energy from a power plant or renewable energy source such as a wind farm, using it to run air compressors, which pump air into an underground cave where it's stored under pressure. When the air is released, it powers a turbine, creating electricity. The round trip energy efficiency is about 85%. There are only a handful of compressed air storage projects in the world with only two in operation in Alabama and Germany. Compressed Air is likely to be an important enabling technology for wind energy; although to scale depends on geography and ease of permitting.
- **Flywheels:** Flywheel energy storage systems have been employed for thousands of years and can be seen in potter's wheels or internal combustion engines. A flywheel is a simple form of mechanical energy storage: energy is stored by causing a disk or rotor to spin on its axis. Stored energy is proportional to the flywheel's mass and the square of its rotational speed. Flywheels work very successfully for short term gaps in electricity and can provide full power within 10 seconds but are typically sized to provide uninterruptible power supply (UPS) for no more than fifteen minutes. Historically, there have been safety issues with very large flywheels, which may limit their application to balancing frequency response and minor grid disturbances. Roundtrip energy efficiency is about 85%.
- **Spinning Reserve:** Fossil and nuclear generating plants seldom operate at their maximum rated capacity. Operators typically keep a portion of the nameplate capacity offline as synchronous (spinning) reserves, rotational mass energy available to be brought on instantaneously to meet a change in load. Spinning reserves and other so called ancillary services typically receive a higher energy revenue price than the rest of the capacity given their scarcity value and available must run status based on their ramp rates.
- **Excess Fossil Capacity:** A less obvious storage resource is excess fossil capacity. Europe and the US had a "dash to gas" power generation boom in the late 1990s, which left an overcapacity of gas power plants. Consequently, the capacity utilization of these gas fleets has been consistently under 50%. Therefore, these excess capacity reserves can serve as storage and—with the right lead times and incentives—function as a backstop for intermittent energy. A major constraint, though, is location since the plants were not initially designed and sited to function as storage for backstopping the load and intermittent resources. In other words, the plants are unlikely to be configured into the grid in an ideal fashion. A second constraint is that generation cannot absorb excess energy that may result when there is more night-time renewable production than customer load. Another issue has been cost; variable operating and maintenance costs for gas peakers are relatively high compared to other storage options. But if natural gas prices were to stay structurally low for a long time due to a fundamental supply overhang from shale resources, the economic viability of excess fossil capacity as a storage mechanism would increase.
- **Demand Response:** As the Smart Grid is implemented, control over customer loads may be used to provide some of the benefits of fossil capacity. Cycling loads can be monitored and controlled via the Smart Grid so that non-essential loads can be turned on or off when there is a need for certain ancillary services. As an example, "regulation up" service can be provided by limiting air conditioner run times, ice makers, clothes dryers, refrigerator defrost cycles, and other loads that do not need to operate immediately.

9. Enabling technologies: How to make a more complex grid stable and resilient

- **Electric Vehicle Storage:** While still very nascent, the distributed electric vehicle storage (EVS)—the so-called vehicle-to-grid (V2G)—concept has the potential to significantly reconfigure the electricity grid architecture requirements. The V2G concept describes a system whereby power would be sold to the electricity grid from the electric drive motor of a hybrid or electric plug-in vehicle. The idea is that since most vehicles are parked for about 95% of the time, they could be used in scale as mobile distributed power plants. A large limitation is that the grid in its current configuration was not designed for major two-way power flow and local circuits would easily be overwhelmed by plug-ins. Moreover, balancing authorities and electric utilities have no “see through” into distributed V2G systems. Therefore, a host of information technology tools and processes and electronic circuitry would need to be installed if V2G is to become a realistic storage opportunity. Denmark appears to be an early adopter of this concept. Dong Energy, a Danish utility, has teamed up with the start-up electric vehicle company, A Better Place, to build an electric-car charging and battery-swapping stations that rely on wind energy.¹⁰¹ One of the other hurdles with V2G that may keep it from developing is vehicle warranties. Automakers will have to warrantee that their batteries will last a minimum number of miles. Discharging the system while parked would likely void the vehicles warranty. This is why V2G may become a disruptive leapfrogging technology in developing countries with less restrictive regulation for product performance, such as China.

9.2 Information Technology/Smart Grid: Key Enabler

Integrating multiple sources of energy supply into the distribution system requires precise coordination and an inter-operable common infrastructure and control system which is still lacking. Eventually, the deployment of information technology and two-way communications capabilities to the processes and protocols of the electricity grid will allow variable renewable energy sources, demand response, plug-in hybrids, and energy markets to function harmoniously. Scaling these resources has the potential to redefine the parameters of how the grid functions. In effect, the system is transitioning from a radial network to one that is interconnected and networked. Of note, regulatory barriers remain formidable and the proper incentives are still often lacking even though some of the immediate benefits have long been recognized. In particular, automated meter reading and the ability to pinpoint service outages have reduced costs and improved reliability. In this respect the old adage that you can’t manage what you can’t measure certainly applies. On the other hand, new technology also increases the complexity of the electric grid, making the system potentially more vulnerable. System operators will need to carefully evaluate contingency measures and become more comfortable integrating new packet—e.g. data bit—driven architectures into their planning.

We consistently hear from smart meter companies and utilities alike that the regulatory compact is perhaps the single largest barrier. For utility commissions the regulatory process requires measuring the benefits of smart meters to justify the expenditure. Because it is an infrastructure investment the benefits accrue over time. At this juncture the benefits are largely supposition and there have been a number of cases where customers have seen higher bills soon after receiving smart meters and have had strong negative reactions. In these instances, the upfront capital cost for the meters is socialized into electricity bills but the actual savings potential are not yet realized since there is a behavioral learning and adoption curve.

So while there has been a lot of excitement around the technology, it is an education process. The broader benefits of smart grid have been difficult to quantify since the full potential in most instances has not yet been realized. Moreover, simply requiring that utilities install smart meters does not necessarily ensure that the theoretical benefits will ever be fully realized. In this respect, smart meters should be seen as a **key enabler** that can open new ways of improving how electricity is provided and used while also driving new energy services business models. But in order for the full potential of the smart grid to be harnessed, behavioral changes and clearly defined economic benefits and incentives will have to be put to the test under a variety of market and grid conditions. In addition, the grid must be able to properly carry out the operation instructions from the system operator either through pre-installed automatic protocol or manual action.

¹⁰¹ <http://www.greentechmedia.com/articles/read/better-place-grabs-103m-names-new-danish-ceo-5589/>

9. Enabling technologies: How to make a more complex grid stable and resilient

A precise definition of the Smart Grid is illusive. We contrast the legacy electricity grid with the future smart electricity grid in Exhibit 60 below.

Exhibit 60: Smart Grid versus Traditional Grid

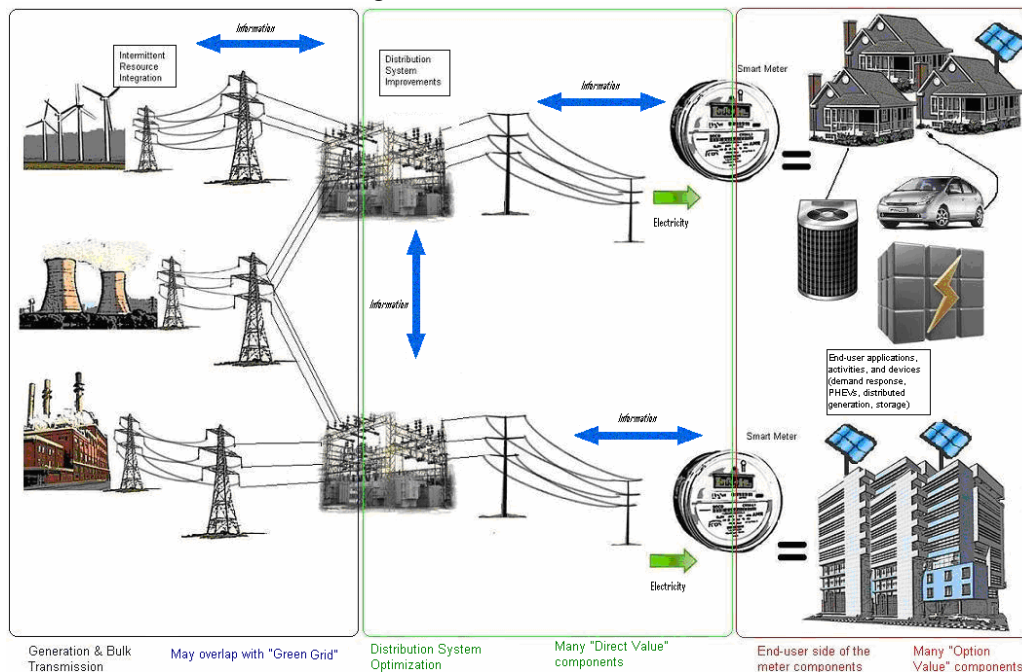
Legacy Electricity Grid	Smart Electricity Grid
One way communication (centrally planned)	Two way communication (central & distributed)
Mechanical system; often proprietary	Digital system; focus on open standard architectures
Long lived assets (30-70 years)	More frequent replacement cycle
Fundamentally dumb; mechanical switches	Self healing; algorithms
Average service; customer calls inform utility of outages	Service enhancement; better information about outages
One bill each month	New products and services; various pricing plans
Inflexible	Flexible; customers can adjust usage to price signals
Archaic billing practices	Dynamic billing; feedback on usage patterns and benchmarking versus other customers

Source: DBCCA

Based on our research, we expect the following five fundamental technologies to drive the smart grid:

1. **Integrated communications:** connecting components to open architecture for real-time information and control, allowing every part of the grid to both “talk,” “listen and act;
2. **Sensing and measurement technologies:** supporting faster and more accurate response such as remote monitoring, time-of-use pricing and demand-side management;
3. **Advanced components:** applying the latest research in superconductivity, storage, power electronics and diagnostics;
4. **Advanced control methods:** monitoring essential components, enabling rapid diagnosis and precise solutions appropriate to any event; such control systems are super important for reliability;
5. **Enhances interface and decision support:** making human decision-making better with technology and artificial intelligence.

Exhibit 61: Smart Grid Technologies



9. Enabling technologies: How to make a more complex grid stable and resilient

9.3 Balancing a System and Efficiency

The role of the Balancing Authority will increase as the electricity grid become more dynamic and incorporates new technologies and processes such as Advanced Metering Infrastructure (AMI) which will enable a larger penetration of intermittent and distributed energy sources. AMI is a key building block and the highest priority in achieving the smart grid. It is the fundamental link required by the other key technologies in the value chain.

Over the past several years, utilities in Europe and the US have begun to install a new generation of electric meters featuring two-way communication capabilities and the ability to calculate energy use in real time. Software is an absolutely critical enabler to manage and process large data volumes and there is a greater need for increased grid intelligence for real-time management, control, diagnostic/analysis and response capabilities. Our research shows that such software applications are still very nascent and that there is a large market opportunity for the vendors that get it right. Once the infrastructure is in place, we would expect to see a paradigm shift 5-10 years down the road with new business models proliferating, just like 3G networks enabled the iPhone and the internet enabled Facebook.

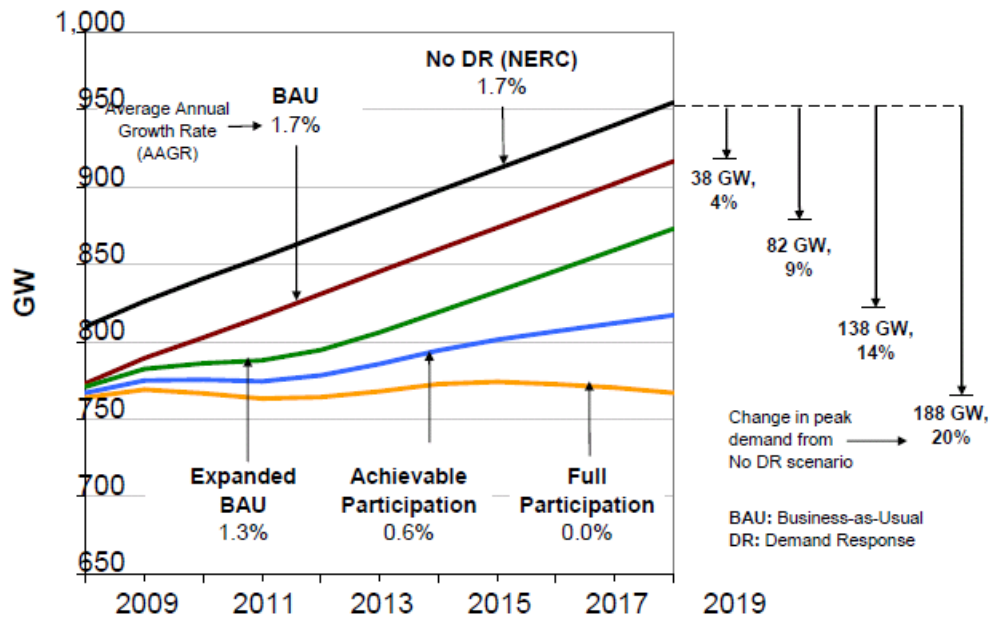
9.4 Demand Side Management (DSM) and Real Time Pricing

AMI is expected to enable a whole new set of grid process improvements, including Demand Side Management (DSM) voluntary curtailment of load in response to price signals or congestion. Under such programs, electricity users receive an economic incentive for curtailing electricity use when supply is tight and agree to let the Balancing Authority, utility or other program coordinator use frequency controls to interrupt load. DSM reduces the need for expensive peaking generation capacity. Taken to the extreme, AMI also enables real time pricing in competitive power markets where spot electricity prices reflect the cost of the marginal generating unit dispatching power at the nodal level. Because of diseconomies of scale, most utilities believe that hourly price signals would be sufficient for residential use. However, commercial and industrial customers may alter their processes or adjust the timing of work in response to real time price signals from the grid. For instance, depending on market conditions, a steel producer might get a larger financial margin by not using power and reducing blast furnace capacity.

Residential customers could substantially change their usage patterns over the next five years as smart meters are implemented in major geographic footprints and a wider choice of products and services become available. Perhaps most importantly, the network effect will foster innovation and greater connectivity and could substantially reduce the need for additional generation capacity as shown in the Exhibit below. Although electric plug-in vehicles are in their infancy, lessons learned in new markets, such as Denmark, will be hugely beneficial in evaluating the electric grid's resilience in the face greater complexity. Real time pricing has worked well in other formerly regulated industries, so there is no reason why with the right planning it can't also transform the electricity market. And in scale DSM reduces the need for new generation as shown in Exhibit 62 below.

9. Enabling technologies: How to make a more complex grid stable and resilient

Exhibit 62: US Peak Demand Forecast Reduces With DSM Implementation



Source: FERC, DBCCA

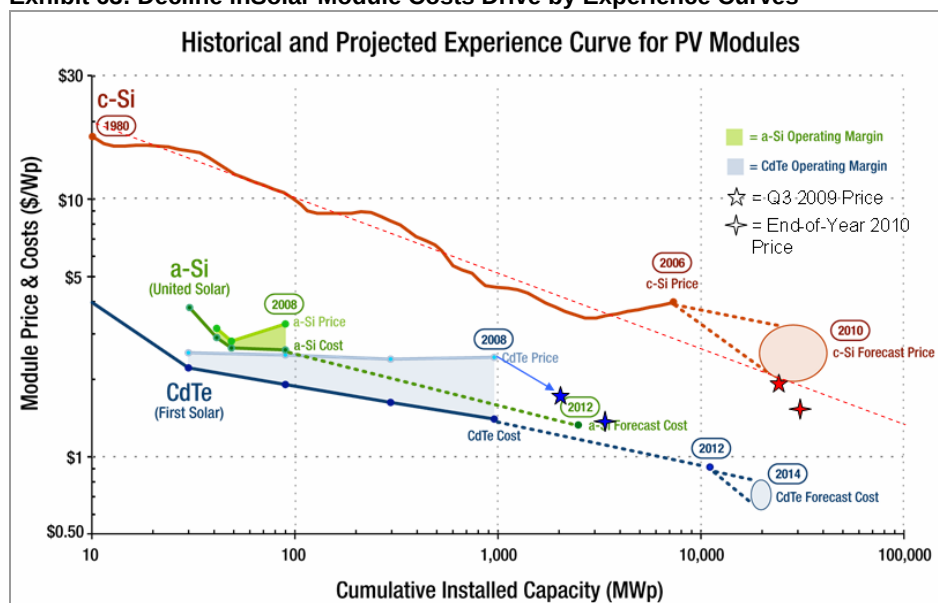
10. Capex cycle: Withstanding a major transformation

The electricity grid is capital intensive. Barriers to entry are high compared to other industries given the formidable regulatory and permitting constraints and large capital requirements to build, operate and maintain assets. Replacement cycles occur over multiple-decade timescales, given the long asset lives of power plants. The increasing urgency to reduce CO₂ emissions complicates the next generation capex cycle.

Even though the focus of this paper has been on natural gas and renewable energy, it is important to look at renewable energy within a broader context to other types of generation. Today, we estimate that renewable energy—including hydro—comprises 19% of worldwide electricity supply. Over the next two decades, a large portion of the legacy coal infrastructure in the OECD will either be retrofitted for carbon capture and storage (CCS) or mothballed. The degree to which renewable energy displaces coal and gains share depends in large part on the success of the enabling processes we have discussed throughout this report. The most recent scientific evidence points to a median increase of 5.2 degrees Celsius by 2100¹⁰². Governments are responding to mitigate the potential impacts of this business-as-usual pathway, which we believe will likely result in a shift of generation capacity from mostly traditional fossil fuels to a greater share of lower-carbon alternatives.

Scaling renewable energy promises to be an expensive proposition, although costs are expected to decline as illustrated in the Exhibit below. Indeed the IEA's 450 ppm pathway forecasts an incremental \$527 billion being spent on renewable energy globally from 2010 to 2020, rising to \$2.3 trillion between 2010 and 2020.¹⁰³ And this is without factoring in the incremental cost for new infrastructure required to bring on renewables in size.

Exhibit 63: Decline in Solar Module Costs Drive by Experience Curves



Source: NREL

Both OECD and non-OECD generation capital stock are aging; hence there is such a large technology and policy focus on lower carbon emitting power plants since, once built, these plants typically last for 30-50 years before retirement. Therefore, from a climate change perspective the investment decisions made over the next 10-15 years will impact the emissions profile well into mid-century. It is therefore incumbent from a climate change perspective to match the capital stock runoff to lower carbon emitting generation, including intermittent energy generation sources.

¹⁰² See: Probabilistic forecast for 21st century climate based on uncertainties in emissions (without policy) and climate parameters, available at http://www.dbcca.com/dbcca/EN/carbon-counter/mit_probabilistic_scenarios.jsp courtesy of the American Meteorological Society.)

¹⁰³ http://www.iea.org/weo/docs/weo2009/climate_change_excerpt.pdf

10. Capex cycle: Withstanding a major transformation

The societal challenge today is bridging the gap between an aging electricity generation infrastructure with a heavy carbon emissions profile dominated by coal generation and a future generation fleet that is more environmentally benign. The economic barriers are not trivial since there are several trillion dollars worth of electricity infrastructure already in place around the world. A key likely strategy is to extend the lives of low carbon emitting plants, such as nuclear power, while also retrofitting efficient coal plants with carbon capture equipment and natural gas plants with CCS post 2030. Current industry research is focused on these issues and there is reason to believe that a significant portion of the current capital stock will be repurposed with carbon capture equipment and/or engineered to extend its life-cycle.

10.1 Capital Intensive Industry

Spending in the electricity sector generally falls into three categories: maintenance, environmental and growth. In mature economies, maintenance and environmental capital spending dominate. Developing countries—most notably China—are in growth mode and are rapidly adding new baseload generation and transmission. In the US, capital spending in the electricity industry is forecast to be about \$230 billion (cumulatively) for the 2008-2010 time period and could be as much as \$2 trillion (cumulatively) through 2018 net of the impact of demand response and energy efficiency programs.¹⁰⁴ Note that most of this capital spending is on maintenance programs to keep the grid functioning reliably.

Building new generation is expensive while most equipment costs have not decreased with the recent economic downturn because demand for power equipment globally is still reasonably strong, particularly in the Middle East and Asia. Nevertheless, the cost of generation for all renewable energy technologies will fall in the future for two reasons. First, today's premium prices act as an R&D subsidy for renewable energy. Over time these higher upfront costs will bear fruit as the industry experiences "learning curves" through simple learning by doing. Second, there will be economies of scale benefits. As a rule of thumb, costs fall by 15-20% for every doubling of capacity. By comparison, conventional electricity generation technologies have typical learning rates of ~5% and nuclear energy has negative learning rates with costs becoming more expensive over time.¹⁰⁵

10.2 Long Investment Cycles

Investment cycles in the electricity sector are long given the complexity and scale of the facilities and the web of intervening stakeholders that can impede the process. Even once everything is set, it can still take up to five years to build a nuclear or coal CCS plant. Considering that the average business cycle is about seven years, this adds significantly to the financing risk since the economic conditions at the outset are seldom the same when the project gets underway and completed. And the history of large power plants being built on-time and on-budget is not a good one. Where this has occurred—such as in Japan with the Westinghouse nuclear reactors built by Toshiba in the 1990s—it has been because there was a conscious decision to use standardized processes and a limited number of vendors in the supply chain.

10.3 Flexibility Limited by Legacy Capital Stock

The electric grid's flexibility is hindered by the longevity of its capital stock and long lead times for new investment. In this regard, intermittent generation has an advantage because the form factors are smaller and more modular, resulting in faster time to market. Also, developers can procure equipment such as wind turbines and nacelles and choose which wind sites offer the best economic returns as business conditions change. Therefore, an advantage is greater flexibility compared to large scale fossil and nuclear builds, which can easily span a decade from the initial planning phase to delivering power. On the flip side, the overnight capital cost and levelized cost of electricity for intermittent energy is substantially higher than traditional fossil fuel generation. Consequently, since intermittent energy represents the fastest growing source of new generation and is the marginal supply, average cost for the electricity grid in the aggregate is unavoidably trending higher.

¹⁰⁴ http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/Financial_Review_full.pdf, p.10

¹⁰⁵ PricewaterhouseCoopers LLP, *100% Renewable Electricity: A Roadmap for Europe and North Africa*, April 2010

10. Capex cycle: Withstanding a major transformation

Since the cost is ultimately passed on to the consumer and reflected in higher wholesale and electricity rates, the enabling processes we reviewed previously will only grow in importance.

Exhibit 64: CO₂ Abatement and Capital Expenditures in the IEA's 450 – Scenario

	Abatement Gigatons CO ₂		Incremental Capex (\$ 2008 bn)	
	2020E	2030E	2010-2020E	2020-2030E
Efficiency	2.5	7.9	\$1,999	\$5,586
Renewables	0.7	2.7	\$527	\$2,260
Biofuels	0.1	0.4	\$27	\$378
Nuclear	0.5	1.4	\$125	\$491
CCS	0.1	1.4	\$56	\$646
Total	3.85	13.84	\$2,734	\$9,361

Source: *How the Energy Sector Can Deliver on a Climate Agreement in Copenhagen: Special early excerpt of the World Energy Outlook 2009 for the Bangkok UNFCCC meeting*; © OECD/IEA, 2009.

Appendix

US Renewable Energy Policy Framework

Demand-Pull policies

(1) Renewable Portfolio Standards (RPS): Establishes Demand for Renewables

RPS programs are state-specific quotas that require that electric load servicing entities supply a certain percentage of their electricity from renewable energy sources by a given date, and are typically backed by compliance enforcement mechanisms including the trading of Renewable Energy Certificates (RECs) or an alternative compliance payment (ACP), which sets the ceiling for REC pricing. RECs are generated when a qualifying renewable energy source contributing towards the RPS delivers power to a grid operator. Such exchanges are typically contracted in a long term power purchase agreement (PPA) with bundled environmental attributes—e.g. the RECs—delivered along with the power. Enforceability and the potential for shortfalls in meeting RPS targets due to state budget pressures and transmission constraints is a risk for RPS targets being achieved. However, this risk is somewhat offset by state Public Utility Commissions (PUCs), which recognize the positive economic stimulus and jobs benefits that can accrue from renewable energy deployment.

State / Local Level: US states have favored either voluntary or mandated RPS systems, as a policy mechanism for achieving renewable energy volumes over short and medium term timeframes — e.g. up to 15 years. RPS policies have been in existence at the state-level since the late 1990s, and there are currently 29 US states that have mandatory RPS systems, while six more have non-binding RPS goals. Many RPS programs include requirements for specific technology mixes, or “carve outs” to support higher cost generation, such as solar PV; however, RPS policy designs vary widely among states and uniform design elements have not yet emerged.

Variations that exist include targets and timeframes, eligibility of various clean technologies, compliance flexibility, enforcement policies, eligibility rules for geographic location and electricity delivery, and allowance of unbundled RECs and REC trading. As an investment theme, RPS mechanisms currently in place represent a sizeable growth opportunity. It is estimated that approximately 71 GW of cumulative new capacity is needed to fully meet these RPS policies by 2025. DBCCA expects wind and solar to deliver about 517 Terawatt hours (TWh) of electricity supply in the US in 2025, representing about 12% of total electricity supply.

Federal Level: Although there is no federal RPS at the moment, various pieces of proposed climate and energy legislation have included a federal RPS. The American Clean Energy Leadership Act proposes a 15% RPS by 2021 through 2039. The American Clean Energy and Security Act calls for a 20% RPS by 2020. A federal RPS remains a key theme for boosting the amount of clean energy produced in the US, and could have a significant impact on project development since a Federal RPS would likely have more legal certainty and enforceability than state RPS programs.

(2) Production Tax Credit (PTC) / Investment Tax Credit (ITC) Induce Renewable Energy Supply

Federal Level: To date, the US federal approach towards boosting and subsidizing renewable energy and energy efficiency has been primarily through the tax code under the theory that lowering marginal tax rates stimulates a supply side response. Since 1992, Internal Revenue Service (IRS) Section 45 Production Tax Credits (PTC) has been the subsidy mechanism of choice by Congress, followed by the addition of the Investment Tax Credit (ITC) since 2005. The ITC allows for a 30% subsidy of solar, fuel cells and small wind systems, and 10% for geothermal, micro-turbines and Combined Heat and Power systems. The PTC provides a 10-year 2.1¢/kWh (2010 \$) credit (indexed to inflation) for wind, geothermal, closed-loop biomass and a 1.1¢/kWh for other eligible technologies and is most useful for developers who pay taxes and are seeking to lower their effective tax rate to boost returns. Non-tax paying entities can monetize the PTC value of their projects via “partnership flip” equity financing structures in which the majority ownership of the asset is transferred to a

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partnership controlled by an investor with passive tax appetite for the life of the PTC, after which point the controlling interest reverts to the project developer. However, the PTC and ITC are set to expire by 2013 and 2017, respectively.

Currently, renewable project developers can elect to receive the ITC in lieu of the PTC, as a result of the American Recovery and Reinvestment Act of 2009 (ARRA), so for a short while through the end of 2010 wind projects can benefit from subsidized capital costs, a tax shield and accelerated depreciation—modified accelerated cost recovery system (MACRS), which writes down the capital cost of renewable projects over five years, providing substantial front-loaded cash flows and rapid equity payback for projects that utilize leverage. The ITC reduces federal income taxes for qualified tax-paying owners based on capital investment in renewable energy projects. Both the PTC and the ITC can be applied to Federal tax liabilities from the prior year and carried forward up to 20 years.

(3) Section 1603 Treasury Grant Program: A Big Success

Federal Level: The Section 1603 Treasury Grant Program (“cash grant”), as created by ARRA, provides grants of up to 30% of the cost of building new renewable energy facilities in the case of wind, biomass, geothermal, solar, landfill gas, trash, hydro, marine, and qualified fuel cells. The Section 1603 program has been especially successful in deploying capital. Applicants elect a cash grant in lieu of federal tax credits, such as the PTC/ITC. The program was created to address the reduction in private sector credit capacity and the increase in the cost of tax equity financing stepping from the economic downturn. The cash grant is for projects that commence construction in 2009 and 2010 and are placed into service prior to 2013 for wind and prior to 2017 for solar.¹⁰⁶ The cash grant is paid when the capital investment is deployed and reduces the required equity contribution from project developers. The value of the cash grant is substantial and can add as much as 400 basis points to the internal rate of return (IRR) of a wind project with a 70%/30% debt to equity ratio. As of August 2010, the grant program had provided an estimated \$5 billion in grants, with more than 87% allocated to wind farms.

The investment and project development community is now focused on seeing an extension of the cash grant program beyond 2011. There have been some legislative proposals that have included the extension of the cash grant program, including the House Ways & Means proposed bill, “The Domestic Manufacturing and Energy Jobs Act of 2010,” which would extend Section 1603 by another two years through 2012. If extended, the program would have a significant impact on the scale-up of renewable energy capacity in the US, as well as job creation and advancement towards a low-carbon economy.¹⁰⁷ However, with the change of control in Congress and heightened focus on fiscal restraint we believe odds of the Section 1603 cash grant program being extended are more muted.

(4) Department of Energy Loan Guarantees

Federal Level: ARRA amended the Department of Energy’s (DOE) Section 1703 loan guarantees of the Energy Policy Act of 2005 by creating \$40 billion worth of new loan guarantees, known as Section 1705. The program’s mission has been to provide guarantee-based financing for high-potential projects intended to decrease greenhouse gases; create new jobs; employ new or significantly improved technologies; and have a reasonable prospect of repayment. These loan guarantees are provided to commercially proven technologies in the renewable energy, transmission, and “leading edge” biofuels sectors that have the ability to be scaled up. Alternative fuel vehicles, hydrogen & fuel cells, efficient buildings technologies (originally covered under Section 1703) were added in July 2009 to the approved list of 1705 projects and an additional \$8.5 billion of available guarantees were made available. Approximately \$4 billion is appropriated by Congress to cover the application costs or credit subsidy funds of the 1705 loan guarantees. All in, \$48.5 billion of loan guarantees and \$4 billion of credit subsidy costs bring this program to a whopping \$52.5 billion “clean energy” program. The DOE has been

¹⁰⁶ Mark Bolinger and Ryan Wiser, Lawrence Berkeley National Laboratory, “PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States,” March 2009

¹⁰⁷ Please see: <http://www.uspref.org/white-papers/> “US PREF jobs analysis”

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streamlining its loan guarantee review process and is approving ~\$700mn to ~\$1 billion in loans per month, making the government the largest project financier in the market today.

The DOE has established two forms of solicitations thus far under the Section 1705 program – the Financial Institution Partnership Program (FIPP) and a direct DOE application process. The latter is for projects to submit applications directly to the DOE for funding consideration. The FIPP program is an evolving partnership with various global financiers to provide products that meet the needs of the aforementioned projects. One of the latest unofficial products is to create an “OPIC-style” fund that uses mezzanine debt to invest as equity capital into projects.

PROPOSAL: Clean Energy Deployment Agency (CEDA)

Federal Level: Various pieces of proposed legislation in both the Senate and the House of Representatives would create a Clean Energy Deployment Administration (CEDA). The CEDA concept has appeared in a broad spectrum of proposed bills such as: the American Clean Energy and Leadership Act, American Clean Energy and Security Act and the Green Bank Act.

CEDA would combine its own mandated programs with those of the existing DOE Loan Guarantee Program. CEDA is expected to be funded with \$10 billion of base capital, and would administer various types of credit instruments (such as loan guarantees, insurance products, and secondary market supports) with the aim of accelerating private sector investment in the clean energy sector for both early stage and conventional renewables technologies. Assuming that these funds are leveraged 20:1, it would expand the low interest rate-funding base to \$200 billion to encourage the private sector to invest in low-carbon technologies. CEDA’s goal is to decarbonize the US economy as much as possible and at the lowest possible cost, while catalyzing as much private sector financing for this purpose as possible. CEDA’s focus on aiding debt markets would help build depth to the renewable energy project finance market. At this time, the creation of CEDA is highly uncertain.

(5) Section 48C Advanced Energy Manufacturing Tax Credit program

Federal Level: Established by ARRA, Section 48C provides a 30% investment credit for qualified property used in a qualified advanced energy manufacturing project, such as facilities that manufacture components for the production of renewable energy, advanced battery technology and other innovative next-generation green technologies. The program was initially funded with \$2.3 billion of tax credits, and is expected to support total capital investments of \$7.7 billion in new renewable and advanced energy manufacturing projects. This remains a critical program to help improve the competitiveness of US renewable energy manufacturers, with the ability to spur additional demand and create additional US jobs. Due to its popularity, various pieces of pending federal legislation include provisions to expand this program, including the proposed American Power Act which would add an additional \$5 billion to this program, as well as The Domestic Manufacturing and Energy Jobs Act of 2010 which would add an additional \$3 billion to the program.

Supply Push Policies: Mandates and Standards

(1) US Feed-in Tariffs

State / Local Level: There is active interest from policy makers, industry groups and advocacy organizations across the US to adopt European-style feed-in tariff (FiT) policies at the state level. DBCCA believes that there is strong evidence that Advanced Feed-in Tariff (FiT) programs that exhibit Transparency, Longevity and Certainty (TLC) can clearly reduce project risk, allow renewable energy developers to obtain a lower cost of capital, and create new jobs. Core elements of successful FiT policies are: guaranteed payments, must take rules, differentiated payments by resource based on generation cost, long

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term payment tenures, and periodic degression toward grid parity based on changes in industry fundamentals. Such policies have proven effective in ensuring a volume response to support energy and climate targets. Nowhere has this been more apparent than in Germany, which is currently the world's largest solar market.

Since 2006, sixteen states have formally considered FiT legislation, and eight states have some form of a FiT in existence. In 2009, Oregon, Maine, California and Vermont each passed legislation to establish policies described as FiTs, with Vermont's system being the most notable. Several municipal utilities also implemented FiTs in 2009-2010, including Gainesville, Florida, Sacramento Municipal Utility District and San Antonio, Texas. Significantly, the total capacity that will be supported by these municipal programs is projected to exceed the capacity supported by current state programs. Utilities in several states have also implemented 'voluntary' FiT programs.

(2) Clean Energy Renewable Bond (CREB)

Non taxable entities such as municipalities may not be able to directly benefit from tax incentives, but may instead reap differentially higher cash incentives at the state level, and also may have access to attractive tax-exempt municipal debt or even “zero interest” Clean Renewable Energy Bond (CREB) financing at the federal level. With the passage of the Energy Policy Act of 2005, certain tax-exempt entities now also have access to CREBs, which provide the bondholder with a tax credit in lieu of an interest payment. As such, CREBs offer the promise of a 0% interest rate to the borrower over a 10- to 15-year term; in practice, however, transaction costs have reportedly eroded much of this promise (Cory et al., 2008). As with municipal bonds, CREBs are not available to (non-governmental) non-profit entities; only projects sponsored by governmental entities, electric cooperatives, and public power providers are eligible for CREB financing. Furthermore, the typical maturity of a CREB – 10 to 15 years – is shorter than the 20- to 30-year maturity often seen for municipal bonds.¹⁰⁸

(3) Rate-based Renewable Energy Growth: An Emerging Theme

To meet an RPS target, regulated utilities have begun to increase their investment in wind and solar generation putting the assets on balance sheet as opposed to signing PPAs with renewable energy developers. Until recently, most utilities in regulated states were restricted from taking advantage of federal tax incentives such as the PTC or ITC or were prohibited from building renewable generation and putting it into rate base because of statutes that expressly limit incremental capacity additions to least cost resources. This is, however, beginning to change and rate based renewable generation is becoming a larger share of the mix and a targeted exit opportunity for late stage pipeline development. We expect that Public Utility Commissions will increasingly come to recognize that rate-based renewable additions may be in the rate payers' best interest given utilities' lower cost of capital versus independent project developers and core competency in managing construction projects.

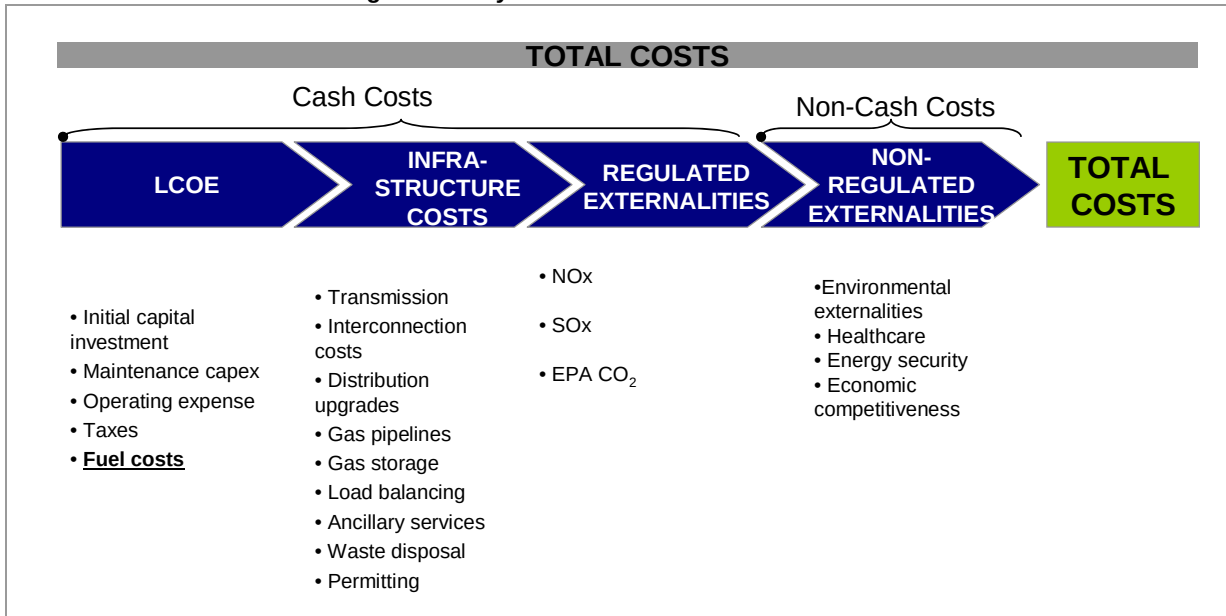
How We Calculated Total “Cash Costs”

In this report we applied a “total cost” framework to evaluate the economic consequences of transitioning to a lower carbon fuel mix in the US electricity sector. As illustrated in the exhibit below, total cash costs, consist of the levelized cost of electricity (LCOE)—and the subcomponents that go into the LCOE calculation—plus the infrastructure costs and the environmental compliance costs that will be required to make coal-fired power generation EPA compliant.

¹⁰⁸ Mark Bolinger, Lawrence Berkeley National Laboratory, “Financing Non-Residential Photovoltaic Projects: Options and Implications,” January 2009

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Exhibit 65: A Framework for Looking at Total System Costs¹⁰⁹



Source: DBCCA analysis, 2010.

LCOE

We started our total cash cost analysis by calculating the new build LCOE for a wide range of generation resources, adapting an algorithm from the National Renewable Energy Laboratory (NREL). We then applied input assumptions based on our fundamental assessment of technology costs and performance for each generation source. The inputs in the algorithm are illustrated below.

¹⁰⁹ Depreciation, a non-cash accounting cost, is not included in this graphic but would also impact true cost economics

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Exhibit 66: DBCCA LCOE Analysis

$$LCOE_{nom} = \frac{OC * CT * S + \sum \frac{[FC * (1 + FE) + FOM * S + VOM * MWh * (1 - DF)]^n}{(1 + DR_{nominal})^n}}{\sum \frac{[MWh * (1 - DF)]^n}{(1 + DR_{nominal})^n}}$$

$$LCOE_{real} = \frac{OC * CT * S + \sum \frac{[FC * (1 + FE) + FOM * S + VOM * MWh * (1 - DF)]^n}{(1 + DR_{nominal})^n}}{\sum \frac{[MWh * (1 - DF)]^n}{(1 + DR_{real})^n}}$$

Where
 OC = Overnight Capital Costs
 CT = Construction/Finance cost multiplier
 FC = Fuel Cost → $FC_j = \text{Fuel Price}_{j-1} * MWh_j * (1+e)$ (where j is the particular year and e is the inflation rate)
 FE = Fuel Escalation factor
 FOM = Fixed O&M costs (\$/MW) → $FOM_j = FOM_{j-1} * (1+e)$ (where j is the particular year and e is the inflation rate)
 S = Size of Plant
 VOM = Variable O&M costs (\$/MWh) → $VOM_j = VOM_{j-1} * (1+e)$ (where j is the particular year and e is the inflation rate)
 DF = Degradation Factor
 MWh = electricity production = $MWh = S * 8760 * CF$
 CF = Capacity Factor
 n = number of years
 $DR_{nominal} = \text{Nominal Discount Rate} = (1 + DR_{real})(1 + e) - 1$
 e = inflation rate

Source: NREL, DBCCA

The assumptions we used in our modeling for new builds and the point estimate of the \$/kWh LCOE outputs (far right column) are displayed in the Exhibit below. We then applied a range to these outputs based on the fact that there are likely to be variations that extend beyond a single “reference” plant. We also calculated the implied LCOE of current—rather than new build—coal, gas and nuclear generation as well as the implied LCOE of a depreciated coal plant retrofitted to be EPA compliant. Our capital cost assumptions used in the inputs reflect our best estimate of the current market valuation for secondary transactions of generation assets. Retrofitting an old coal plant adds \$0.02 to \$0.03/kWh to the LCOE of an old coal plant.

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Exhibit 67: DBCCA LCOE Input Assumptions

Technology	2010 Capital Costs (\$/kW)	Heat Rate (Btu/kWh)	Plant Life (Years)	Variable O&M (\$/MWh)	Fixed O&M (\$/yr/kW)	Fuel Cost (\$/mmBtu)	Real Discount Rate (%)	Plant Size (MW)	LCOE (\$/kWh)
New Builds									
Scrubbed Coal Plant	\$2,890	8,979	30	3.67	22.8	\$3.00	10.50%	1	\$0.09
IGCC Coal Plant	\$4,750	9,000	30	4.00	28	\$3.00	10.50%	1	\$0.12
NGCC Plant	\$1,230	6,700	30	2.85	6.25	\$6.00	10.50%	1	\$0.07
Nuclear	\$6,100	9,720	40	0.00	126	\$0.85	10.50%	1	\$0.12
Wind	\$900	N/A	20	0.00	99	\$0.00	10.50%	1	\$0.09
Solar PV	\$4,790	N/A	20	0.00	34.7	\$0.00	10.50%	1	\$0.35
Used Assets									
Coal	\$700	11,000	10	3.80	24.8	\$3.00	10.50%	1	.04-.06
NGCC	\$500	7,900	10	2.95	6.5	\$6.00	10.50%	1	.05-.07
Nuclear	\$1,200	9,900	20	0.00	130	\$0.85	10.50%	1	.07-.09
Wind	\$900	N/A	10	0.00	100	\$0.00	10.50%	1	.08-.09
Coal retrofit (EPA)	\$700	11,000	10	1.25	5	\$3.00	10.50%	1	.02-.03

Source: DBCCA analysis, 2010.

In Exhibit 68 below, we show the components that are layered into the \$700/kW estimated cost for an EPA retrofit for a coal power plant. We then looked at what the environmental compliance retrofit costs would do to the economics of coal-fired generation, comparing the incremental capital cost (\$/kWh) to the LCOE of older, fully depreciated coal plants. As described below, the \$/kW capital cost of adding control technology can be upwards of \$700/kW. Running the capital cost for control technology through the LCOE model results in an incremental \$0.02 to \$0.03 to the cost of old coal generation.

Exhibit 68: Control Technologies Add Significantly to Coal Generation Cost

	CATR				Mercury MACT	
	Sulfur Oxide (SOx)		Nitrogen Oxide (NOx)		Mercury (Hg)	
	Dry Sorbent					
	Scrubber	Injection	SCR	SNCR	Scrubber / SCR	Baghouse w/ ACI
Removal Rate	95%+	<70%	70-95%	30-75%	>90%	80-90%
Capex	\$300 - 500 / kW	\$50 / kW	\$200-300 / kW	\$30 - 75 / kW	\$450 - 700 / kW	\$150 /kW
Reagent	Limestone	TrONA	Ammonia	Ammonia or urea	Activated Carbon	Activated Carbon
Reagent Cost	-	-	0.47	0.47	0.94	0.94
Parasitic Load	3-5%	0%	0	0	3-5%	0.50%
Coal Efficiency	Eastern / Western	Western	Eastern / Western	Eastern / Western	Eastern / Western	Eastern / Western ⁽¹⁾

(1) Brominated Activated Carbon for Western Coal

Source: Credit Suisse, EPA

In the Economics section of this report we presented the table below. Details of how we derived the “other cash costs” are discussed below.

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Other Cash Costs

Exhibit 69: Fully Loaded Cash Costs: It's not just about LCOE, There Are Other Costs Too (No Carbon Price Assumed)

	<u>LCOE</u> (\$/kWh)	<u>Other Cash</u> <u>Costs</u> (\$/kWh)	<u>Fully</u> <u>Loaded</u> <u>Cash Cost</u> (\$/kWh)	<u>DBCCA Comment</u>
Old coal (\$3/mmBtu)	.04-.06	.02-.03	.06-.09	Retrofit costs required to be EPA compliant; only newer and more efficient coal plants are likely to be upgraded; no carbon price assumed. See Exhibit 19, pg 29.
New coal (\$3/mmBtu)	.07-.09	.03-.05	.10-.14	EPA regulation on multiple pollutants pending; compliance costs uncertain; almost impossible to get air permit because of unknown Best Available Control Technology (BACT) for CO ₂ ; retrofit for CO ₂ could add incremental 30-50% to the capital cost; no carbon price assumed. See Exhibit 19, pg 29.
Old gas (\$6/mmBtu)	.05-.07	.01	.06-.08	Older gas plants were designed to run as baseload and often lack digital instrumentation; to pair with renewables new instrumentation and fast start optimization controls may be required; economics improve substantially with \$4-\$5mmBtu gas. See Exhibit 19, pg 29.
New gas (\$6/mmBtu)	.06-.08	.00-.02	.06-.10	An estimated 50 GW of gas assets are co-located next to inefficient coal plants; replacing additional coal with gas could require substantial gas pipeline additions. See Exhibit 19, pg 29.
Old nuclear	.07-.09	.04	.11-.13	Cooling water retrofits and steam turbine replacements may be necessary for lifecycle extensions.
New nuclear	.12-.14	??	??	New nuclear requires loan guarantees; massive scale-up from 2020-2030 would require substantial government support and a long term storage option for spent fuel. Fully loaded costs hard to measure.
Wind	.09-.11	.03	.12-.14	The best on-shore wind resources are far from the major cities that constitute demand and therefore require substantial transmission and fossil backup because wind often blows at night when demand is low; revitalization of under utilized gas plants may diminish the need for as much transmission capacity additions.
Solar	.22-.30	.02	.24-.32	The best solar CSP sites are in the desert, far from load centers, requiring incremental transmission; however, solar is peak coincident and therefore in scale can displace expensive and inefficient fossil generation, particularly if located close to the load, so there is a merit order effect that could be beneficial for rate payers in that large solar additions would diminish the need for dispatching expensive high variable cost fossil peaking generation.

Source: DBCCA analysis, 2010.

Below we describe other cash costs that are added to LCOE to reach a fully loaded cash cost. As mentioned above, the capital costs of environmental control technology adds about \$0.02-\$0.03 to the cost of coal-fired generation. And we think this is conservative because there could easily be an equal incremental cost for waste handling and cooling water retrofits as we discuss next.

New coal generation faces potentially as much as \$0.03 to \$0.05 in incremental costs. About \$0.01 to \$0.02 comes from the potential phase out of Wet Ash Handling and Storage. The EPA's Regulatory Impact Analysis (RIA) estimates the potential compliance cost. Over 50 years at a 7% discount rate, the EPA calculates the present value of the compliance costs at \$20.3 billion under Subtitle C, which would allow the government to set requirements for the issuance of waste management permits. Dividing this cost by the 1,788 TWh of 2009 coal generation, results in a \$/kWh cost of \$0.01. A further \$0.01 to \$0.02/kWh of incremental costs could accrue to new coal-fired (and potentially nuclear, too) power plants if once through cooling systems, as regulated under Section 316 (b) of the Clean Water Act, are no longer permitted. The

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National Energy Technology Laboratory (NETL), estimates that water usage in coal power plants may increase at 3x the rate of water usage overall in the US from 2005-2030, which could add substantial costs.¹¹⁰

As a point of reference, Dominion Resources is currently in the process of building closed loop cooling towers at its ~1,000 MW Brayton Point coal plant at a capital cost of \$744 million, or \$679/kW.¹¹¹ Running this through our LCOE model implies \$0.02 to \$0.03 per kWh of incremental cost. The EPA has calculated the projected cost of installing cooling towers, which derives dry cooling cost based on the generating unit's water intake.¹¹² The equation the EPA uses is $(\text{Capital cost} = 2 \times 10^3 X^3 + 0.00002 X^2 + 337.56 X + 973608)$ where X is the water intake flow in gallons per minute (GPM). Bernstein Research has estimated that these cooling water costs could add between \$2-3 billion in added environmental costs for affected utilities.¹¹³

We expect only a 13% increase in the current natural gas pipeline infrastructure to be required to accommodate our coal to gas fuel mix shift because about two-thirds of the shift comes from the improvement in the utilization rate of current gas-fired generation. We estimate that the \$/kWh cost will be about \$0.01 as illustrated below.

Exhibit 70: Incremental Gas Infrastructure Requirements of Coal to Gas Fuel Switch

Incremental Electricity Sector			Miles Required	% increase vs 2009 Pipeline	Cumulative Cost (%bn)	2009-2030 Average NGCC Supply (TWh)	Incremental \$/kWh cost
2030 Gas Demand	bcf/day	tcf/year					
0.5	21	7.7	28,900	10%	108		
3.8	25	9.1	37,700	13%	129	1,241	.00-.01
6.6	37	13.5	61,600	21%	163		
14.1	70	25.6	116,000	39%	348		

Source: EIA, Aspen Environmental, DBCCA analysis, 2010.

Older nuclear plants also may be subject to costly cooling water tower retrofits. We have examined the estimates made in state regulatory filings in New York, California and New Jersey. Estimates of the costs of installing cooling towers at nuclear power plants are illustrated below. The average \$/kW cost is \$879. Running this through our LCOE model, results in an incremental \$0.03-\$0.04/kWh.

Exhibit 71: Cooling Water Retrofits Could be a Substantial Cost to Nuclear Units

Owner	Plant	Owned Capacity	Upgrade Cost (\$m)	Upgrade Cost (\$/kW)
Constellation	Ginna	581	189	325
Exelon	Salem	981	500	510
Exelon	Oyster Creek	615	750	1220
Entergy	James Fitzpatrick	852	240	282
Entergy	Indian Point	2,045	1,079	528
Edison International	San Onofre	2,250	3,000	1,333
PG&E	Diablo Canyon	2,300	4,500	1,957
Average				879

Source: EPA, Regulatory Filings, Bernstein, DBCCA

Wind and solar energy face an incremental \$0.02 and \$0.03/kWh, respectively, in cash costs based on the need for backup power, load firming and ancillary services because they are intermittent load. These estimates are consistent with a wide range of credible studies.

¹¹⁰ National Energy Technology Laboratory NETL, Water Vulnerabilities for Existing Coal-fired Power Plants, August 2010

¹¹¹ <http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9Mzg3MTUzZfENoaWxkSUQ9Mzg5NTQ1fFR5cGU9MQ==&t=1>, p. 60

¹¹² http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/devdoc_index.cfm

¹¹³ Bernstein Research, US Utilities: Coal Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?, October 2010

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Modeling Details and Coal Retirement Schedule

Modeling Details: Bottoms Up Capital Stock Model

The bottoms up model captures asset stock turnover of the US power sector. Each year in the model, megawatts (MWs) of capacity by generation type are either added or retired based on our fundamental input assumptions. We then assume a utilization rate for each generation type that is within the broad parameters of what would be expected based on typical performance and operating metrics. Finally, we multiply MW x capacity factor x 8760 (# of hours in a year) to calculate total kWh of production. The aggregate supply from all generation resources are then totaled and conform to our demand forecast, which assumes 0.5% y/y CAGR in load growth. A constraint in this modeling process is to adjust utilization rates of the capital stock so that the output is roughly inline with our demand forecast.

Coal and gas are the two big changes in the fuel mix shift. We build in an aggressive retirement of the coal fleet starting in 2015 spreading the retirements of the oldest and most inefficient coal units in equal portions through the forecast period. In total, we forecast that 69,000 MW of coal generation is retired between 2009 and 2020. Natural gas capacity additions are much more modest at just 26,000 MW over the same time period. This is because we assume that the utilization rate of the natural gas power plant fleet increase from 23% in 2009 to 35% in 2030 as illustrated below.

Exhibit 72: Aging Coal Infrastructure is Likely to be Retired and Replaced with Natural Gas

Future Coal Retirements	Total GW	Average Unit Age	Average Unit Heat Rate
2010-2020 Period	60	62	16,990
2020-2030 Period	92	47	12,654

	Coal		Gas		Contribution to Share Gain
	2009A	2030E	2009A	2030E	
Capacity (GW)	337.3	185.6	454.6	480.6	4%
Capacity Utilization (%)	60%	54%	23%	35%	8%
Energy generation (TWh)	1,778	878	770	1,463	
% US Supply	47%	22%	23%	35%	12%

Source: EIA, DBCCA

As far as capacity additions in the model, wind and solar are the large additions to comply with state renewable portfolio standard (RPS) portfolio standards. We used the forecast compiled by IHS Emerging Energy Research for renewable energy market sizing to reach RPS targets. Geothermal grows modestly while the capacity additions to hydro are assumed to be roughly flat. And nuclear grows gradually, too, consistent with the announced projects. Natural gas supply also increases to make up for the large number of MWs of coal that are retired. A summary of the capacity forecast is illustrated below.

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Exhibit 73: DBCCA Power Generation Capacity Forecast (MW)

Capacity MW	2009A	2020E	2030E	2009-2030 CAGR
Coal traditional	337,300	277,600	185,600	-2.9%
Coal CCS	-	1,500	2,000	
Natural gas	454,611	467,811	480,511	0.3%
Natural gas CCS	-	-	-	
Petroleum	63,655	63,655	63,655	0.0%
Nuclear	106,147	119,947	125,947	0.9%
Hydro	77,882	78,832	79,332	0.1%
Onshore wind	38,500	101,500	172,500	7.8%
Offshore wind	100	5,500	10,500	26.2%
Solar PV	2,209	14,459	30,459	14.0%
Solar CSP	514	4,514	5,904	13.0%
Geothermal	3,281	6,981	9,331	5.4%
Total	1,084,199	1,142,299	1,165,739	

Source: EIA, DBCCA analysis, 2010.

Many caveats to this analysis are needed. Calculating the total capital stock turnover on a national level over long time scales dramatically oversimplifies an incredibly complex system. The moving parts that affect the generation retirement/new build decision include: generation source, age and efficiency of plant, regional market constraints, geographic limitations, risks of change in regulatory policy and the potential for technical innovations. However, we believe this modeling approach is a reasonable if perhaps somewhat simplistic approximation at what the future electricity system might look like based on what we know today.

Modeling Details: Tops Down Supply Share and Emissions Model

Our tops down electricity sector model fixes the share of electricity supply from fossil, nuclear and renewable generation resources based on our bottoms up model for 2020 and 2030. We set the level of aggregate demand for those years based on an assumed 0.5% CAGR for 2009 and 2030. We then calculate the associated CO₂ emissions of the generation forecast mix for 2020 and 2030. Finally, there is an input assumption for utilization rate of each generation resources, which then backwardly calculates the required amount of MWs of capacity that would be need to satisfy electricity demand based on the generation resource mix. This is a cross check for our bottoms up model.

Exhibit 74: DBCCA Forecast Change in Power Sector Supply and CO₂ Emissions

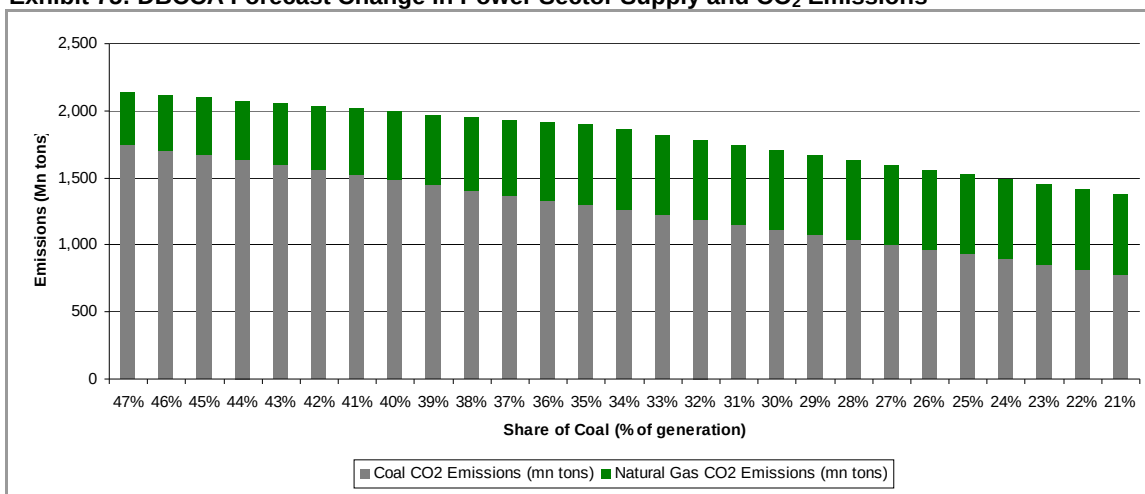
US Electricity Supply (% total kWh)	2005A	2009A	2020E	2030E	Comment
Coal traditional	50%	47%	34%	21%	Reduced to meet emissions target and comply with EPA regulation
Coal CCS	0%	0%	0%	1%	Limited deployment 2020-2030 with government R&D support
Natural gas	19%	23%	30%	35%	Coal to gas fuel switch, underutilized assets, strong new build
Natural gas CCS	0%	0%	0%	0%	No deployment, assume that gas CCS is viable post 2030
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 stream generation 'uprates' and 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
Total	100%	100%	100%	100%	
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
CO ₂ emissions (mn metric tons)	2,397	2,200	1,691	1,347	Emissions reduced substantially due to the coal to gas fuel switch
%CO₂ emissions reduction versus 2005		-8%	-29%	-44%	

Source: DBCCA analysis, 2010.

Appendix

Finally, taking a more detailed look at the absolute coal to gas fuel switch impact on CO₂ emissions from a sensitivity perspective we illustrate in Exhibit 3 how the share shift of emissions progresses as natural gas goes from 23% to 35% between 2009 and 2030 and coal's share declines from 47% to 22%.

Exhibit 75: DBCCA Forecast Change in Power Sector Supply and CO₂ Emissions



Source: DBCCA analysis, 2010.

We then unpack the emissions reduction even further to examine the contribution to the emissions reduction from each of the generation resources in aggregate from 2005 to 2030. As is clear, there is a portfolio effect with renewables, natural gas and nuclear energy the largest levers.

A few details on our contribution calculation:

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.

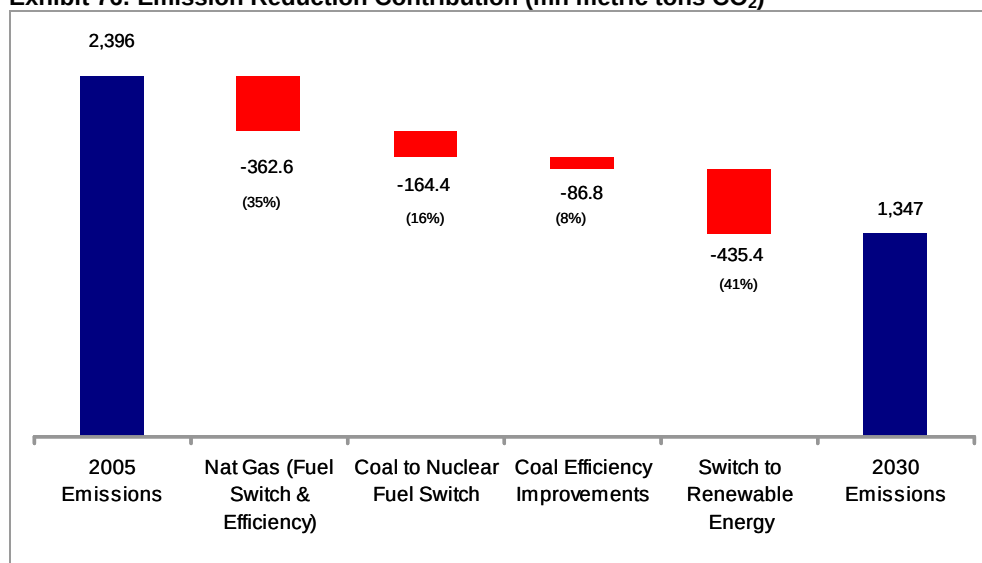
Coal efficiency improvements: For legacy coal assets, emissions intensity improvements drive a quantifiable value.

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.

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Exhibit 76: Emission Reduction Contribution (mn metric tons CO₂)



Source: EIA, DBCCA

Economics and Structure of the Electricity Sector: Regulated Rates and Marginal Cost Dispatch

Most of the US operates under an archaic bundled cost of service, regulated utility model. Under this model capital expenditure decisions, capital structure and electricity rates are negotiated between a vertically integrated utility and the state Public Utility Commission (PUC) and set for a prescribed period of time, generally 2-3 years. The bundled structure is designed to allow the utility and its shareholders a fair and reasonable rate of return—generally about a 10% return on equity (ROE)—and full cost recovery for prudently incurred expenses required to deliver reliable power. In a regulated context, this so called “base rate” is designed to cover the general costs of doing business, as well as the capital costs associated with these assets. Such costs might typically account for about a third of a customer’s bill with the balance constituting fuel cost—where there are in many instances pass through mechanisms in place in which the utility makes no money on procuring fuel to run the power plant but simply passes that cost on to the customer. In this respect, customers feel the cost impact of high or low commodity prices which are reflected in the electricity bill. Other “adders” to the electricity bill might include items such as municipal taxes, gross receipt taxes and environmental and conservation programs, which the utility collects and passes on to state government. Consequently, electricity rates tend to be the lowest in regions where there are largely depreciated generating assets that require very little maintenance and environmental capital expenditures and that burn an inexpensive fuel—generally coal. In the US, the Southeast and Midwest generally have the lowest electricity rates. States such as California, New York and Hawaii typically have higher rates.

There are two major differences between a regulated utility and an unregulated model from a return on capital standpoint. A regulated utility earns a fixed return whereas a purely deregulated or merchant regulated can earn whatever the market is willing to pay for electricity less its fixed operating and variable costs. Regulated utilities have higher certainty of capital recovery, whereas an unregulated generator might never recover its invested capital. Under regulation, the utility dispatches power according to need but charges its all-in bundled cost of generation, which includes all non-cash costs (mainly depreciation). Regulated utilities still dispatch electricity according to the cheapest variable cost (mostly driven by fuel cost), but they charge fixed costs, too, including the cost of equity. The full cost recovery model does not apply to unregulated generators.

Like regulated markets, unregulated markets dispatch the lowest variable cost power first—e.g. hydro, wind, coal and nuclear based on signals from the independent system operator (ISO). These low variable cost resources are dispatched frequently into the real time market to satisfy demand. As demand rises on any given day in the real time energy market,

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higher marginal cost resources such as natural gas peaking plants are dispatched. On an hourly basis, the \$/MWh price set by the marginal plant required to satisfy demand determines the revenue received for all merchant plants selling power into the wholesale market at that time. This means that low cost merchant generators with uncontracted or “open” hydro, nuclear and coal capacity can realize expanded profit margins when higher marginal cost plants dispatch power into the grid. Wholesale electricity prices might increase for any number of reasons including: a heat wave, reduction in transmission capacity or unplanned forced outage from a major generating station, which leaves the market short supply.

Basics of Regulated Utilities: How Rates Are Calculated

In Exhibit 77 below, we show the drivers for how electricity rates are calculated in a regulated context aggregated to a national level. 2008 is the test year in this hypothetical example. The starting point for calculating the “revenue requirement” is the net property plant and equipment (PP&E) held on balance sheet. Each year this balance sheet item changes to reflect changes in capital expenditures less depreciation. From the PP&E line item, an imputed revenue requirement is calculated multiplying PP&E by the prescribed allowed returns of the equity, debt and preferred equity capital structure. Layered on top of this are cash and non cash operating expenses. Adding all of these items together resulted in \$249 billion in regulated electricity revenues. Dividing this total by total aggregate electricity demand of 2,573,619 GWh resulted in national electricity rates of \$0.10.

Exhibit 77: Anatomy of Regulated Utility Rates

2008 Earnings for US Regulated Investor Owned Utilities (IOUs) (\$mn)				
	Balance Sheet	Authorized Returns	Income Statement	Sales/Rates
Total Rate Base	533,055	[property, plant & equipment]		
Average Capital Structure				
Equity	43.9%	10.33%	24,173	
Debt	55.9%	6.47%	12,536	
Preferred Stock	0.1%	5.00%	27	
Operating Costs				
Fuel			96,400	
Non-fuel Operating & Maintenance (O&M)			56,664	
Depreciation and Amortization (D&A)			22,457	
taxes (Income & Property)			19,919	
Other Operating Expenses			17,044	
Revenues (\$mn) and Sales (GWh)			249,250	2,573,619
Average Rates (\$/kWh)				\$0.10

Source: Edison Electric Institute, Barclays Capital, DBCCA

Electricity Rates: How Are They Determined?

Electricity rates are determined based on the average and marginal cost of supply. One of the larger factors that influences electricity prices is the regional supply/demand balance, or reserve margin. Most US states are regulated, which means that electricity rates are set based on the regulated cost of service model. However, there are 14 states that are partially or fully deregulated.¹¹⁴ In these states electricity prices are influenced by a host of other factors that filter into the price a utility without generation would have to pay to strike a power purchase agreements (PPAs) with independent generators to procure supply to fulfill its supply obligation.

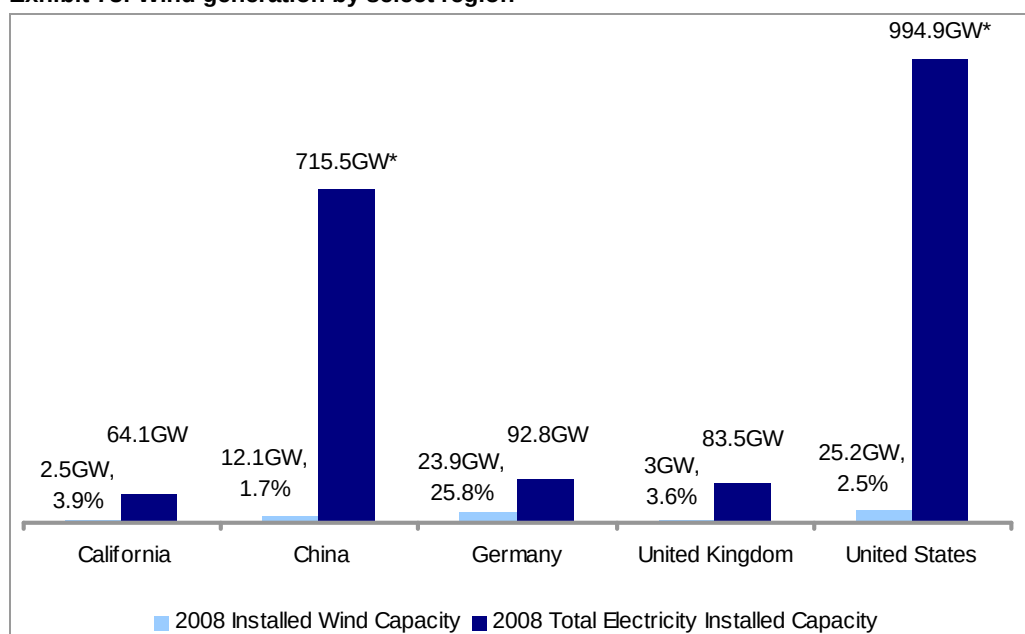
¹¹⁴ http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

Appendix

When a regulated utility faces significant changes in its cost structure, such as looming environmental decisions of whether or not to retire coal power plants and replace those assets with natural-gas fired generation or the runoff of contracted power contracts with independent suppliers, it must strike a formal agreement with the PUC to approve the implementation and cost allocation of the investment and power procurement plan. The most common mechanism for determining future earnings is a general rate case (GRC), which may occur any where from annually to very infrequently and often involves a “test case” based on a certain year. We expect that the fundamental changes the electric utility sector faces over the next 5-10 years will necessitate more frequent rate increases. A typical rate case plays out over the course of a year and starts with a company filing to the PUC and ends with a final commission order. Along the way, the rate process is subject to hearings, reply briefs and administrative law judge decisions.

Renewables: Still a Long Way to Go...

Exhibit 78: Wind generation by select region



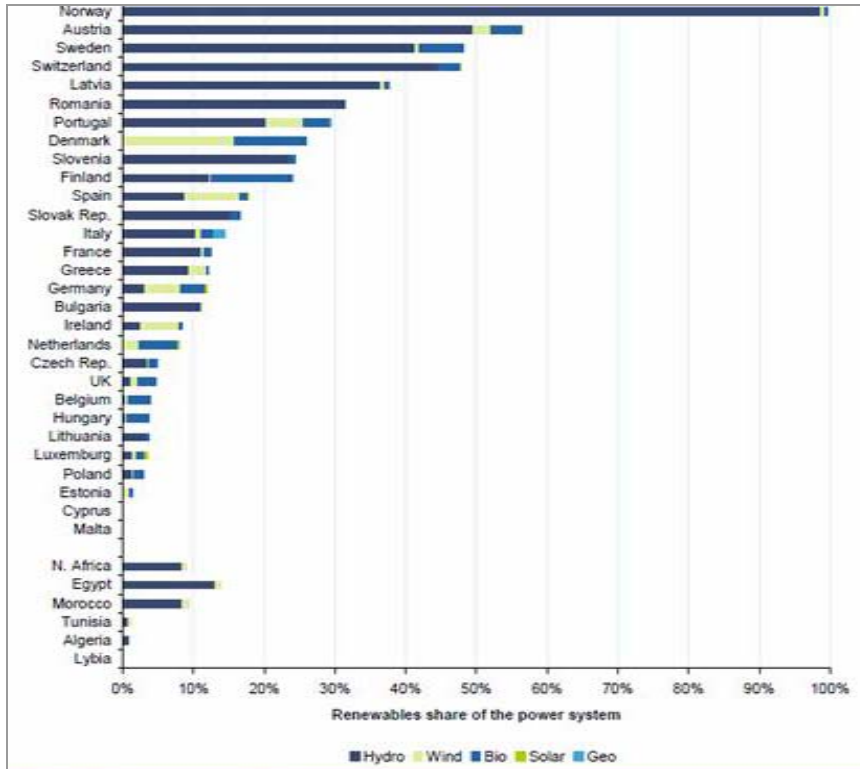
Source: American Wind Energy Association, Global Wind Energy Council, US Energy Information Administration, UK Department of Energy and Climate Change, DBCCA analysis 2010. * Data for 2007. (Note: Data represent installed capacity and not electricity generation. As an example, because of its low capacity factor wind generation represents ~25% of Germany's total nameplate electricity capacity but supplies less than 10% of net energy)¹¹⁵

¹¹⁵ About a quarter of the total electric generation capacity in Germany comes from wind turbines. However, in 2009 wind energy provided about xx% of Germany's total electricity supply. This is because wind energy has an average capacity factor of xx compared to high xx and xx capacity factors for coal and nuclear energy respectively in 2009.

Appendix

...But Europe Taking the Lead

Exhibit 79: 2009 % European and North African electricity (MWh) supplied by renewable energy as % of total electricity supply



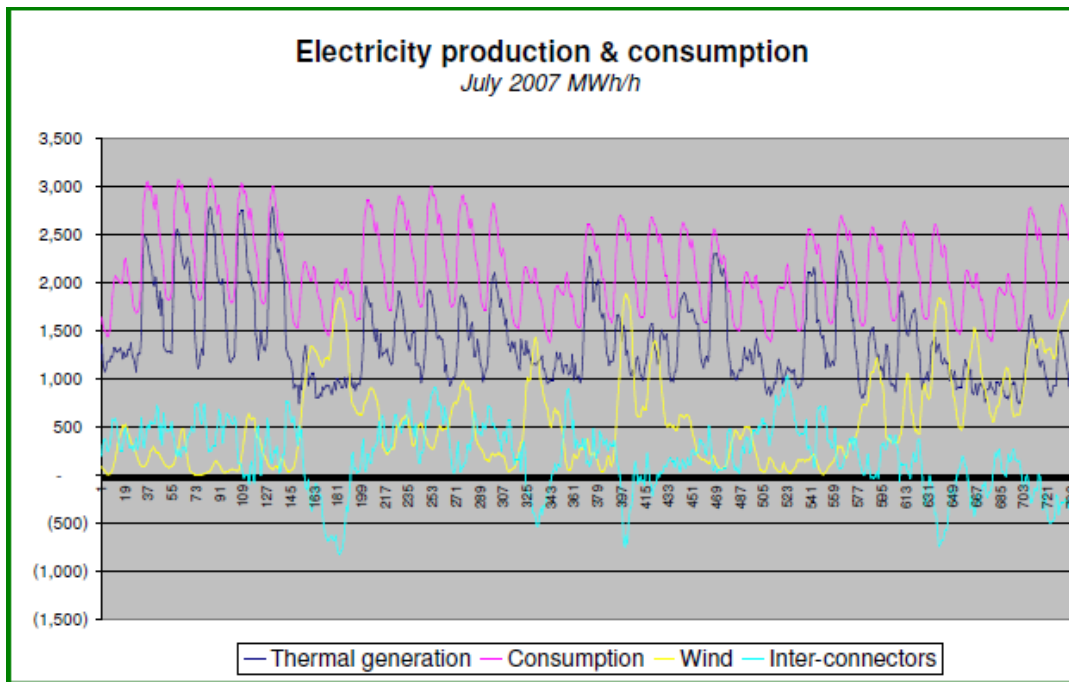
Source: IEA

Appendix

Denmark Case Study: Integrating Large Volumes of Wind Energy: It can be done

Denmark was the world's first large-scale user of wind power. In the early 1980s, an industry association called Danske Vindkraftverk (Danish Wind Craft Maker) persuaded the Danish Parliament's Green Party majority to establish a “feed-in” rate for wind generation. Since 1984, wind generators have been able to sell electricity to the grid on preferential terms that provide an attractive return on investment. Consequently, wind energy now represents about 20% of total electricity production in Denmark. However, although it is true that Denmark generates ~20% of its electricity demand from wind on an annualized basis, wind power contributes substantially less to the country's actual electricity use in any given hour because of wind energy's high variability. As shown in the yellow line in the chart below, wind supplied as much as substantially all of Denmark's electricity (hour 181 on the X axis) to as little as none over the course of July 2007.

Note: the X axis in this chart shows the hours in the month—there are 744 in all—and the Y axis shows consumption in megawatt hours on an hour by hour basis over the course of the month. As is clear, there were multiple hours during the month when wind supplied none of the electric supply in Denmark and electricity supply came entirely from imports and domestic fossil generation. The take home message is unequivocal: even with large amounts of electricity supplied by intermittent renewable supply, it is incumbent for an electricity grid to have fossil backup generation and interconnect capabilities with neighboring grid systems to reliably support the demand needs in the face of rapid changes in intermittent generation which can vary substantially hour by hour.



Electricity systems must continuously balance supply to meet demand. To keep its electricity grid stable Denmark is continuously importing and exporting wind energy. Denmark is able to do this because its grid synchronizes with neighboring and much larger electricity grids that serve as the “storage batteries” for the Danish system to help with congestion. The Scandinavian system (NORDEL) to the north, the German grid to the east and the vast UCTE European grid support the Danish grid fulfill this role. Operational evidence in Denmark shows that wind energy is stochastic—e.g. indeterminate and random—in the very short term which means that its grid must be extremely flexible in terms of importing and exporting electricity. Wind exports and electricity imports that are large as a percentage of Denmark's electricity needs are relatively small compared to the larger neighboring systems that stabilize its grid.

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I-019748-1.0