Paper #3-1

POWER GENERATION NATURAL GAS DEMAND

Prepared by the Power Subgroup
of the
Prepared for the Demand Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

Power Subgroup		
Chair		
Kurtis J. Haeger	Managing Director, Wholesale Planning	Xcel Energy
Assistant Chair		
Jeanette Pablo	Director of Federal Affairs and Senior Climate Advisor	PNM Resources, Inc.
Members		
Thomas M. Blake	Consultant, Chief Economist Office	ConocoPhillips
Susan C. Charlton	Managing Director, Intergovernmental Affairs	Dominion Resources, Inc.
Luciano Dalla-Longa	Group Lead, Natural Gas Economy, Business Development and Policy – Power Generation	Encana Corporation
Leo D. Eskin	Director, Advanced Energy Systems	Combustion Science & Engineering, Inc.
Thomas M. Grasso	Senior Advisor – Investment Appraisal, Global Business Development	ConocoPhillips
Jeffrey R. Grubb	Manager, Fuel Planning and Analysis	Southern Company Generation
Jack Ihle	Manager, Environmental Policy	Xcel Energy Inc.
Jim Jessee	Gas Supply Manager	Duke Energy Corporation
Marianne S. Kah	Chief Economist, Planning and Strategy	ConocoPhillips
Salud A. Layton	Policy Analyst	Dominion Virginia Power
Michael T. Leff	Industry Economist, Office of Electricity, Coal, Nuclear and Renewables Analysis, Energy Information Administration	U.S. Department of Energy
Bruce C. McKay	Managing Director, Federal Affairs	Dominion Resources, Inc.
James K. Martin	Senior Vice President, Regulation and Integrated Planning	Dominion Resources, Inc.
John N. Moura	Manager, Reliability Assessment	North American Electric Reliability Corporation
Bruce W. Rising	Strategic Business Management, Power System Sales	Siemens Energy, Inc.

Guodong Sun	Executive Director, New York Energy Policy Institute and Assistant Professor, Department of Technology and Society	Stony Brook University
Terence H. Thorn	President	JKM Consulting
Jeffrey L. Wallace	Vice President, Fuel Services	Southern Company Generation
Patrick H. Wood, III	Principal	Wood3 Resources

Table of Contents

Table of Contents 4

Introduction and Overview 6

Executive Summary 7

Chapter One - Power Generation and Demand Summary 8

A. Factors Driving the Outlook for Natural Gas Demand for Power Generation 8

B. Natural Gas Demand Outlook for Power Generation 10

C. Other Enablers of Increased Use of Natural Gas Demand for Power Generation 11

Chapter Two - The Outlook for Electricity Demand 13

Chapter Three - Implementation and Timing of Proposed EPA Regulations Affecting Power Generation 17

A. Proposed Regulations 17

B. Compliance Costs and Economics 18

C. Quantifying the Early Retirement Potential 23

Chapter Four - Costs for New Power Generation Capacity 26

A. Capital Costs for Generation Technologies 26

1. Levelized Cost of Electricity 26

2. Capital Cost Uncertainty 28

3. Impact of CO_2 Price on LCOE 33

4. What If All Coal Generation is Replaced by Gas Generation? 37

5. Options to Replace Coal Generation Capacity with Gas Generation Capacity 38

6. Carbon Capture and Storage 41

B. Short-term Economic Dispatch Costs Related to Existing Generation Facilities 43

1. Opportunity for Fuel Displacement without Additional New Generation 46

2. Size of Opportunity and Implications for Natural Gas Demand 49

C. Impact of Demand Side Management 51

D. Summary of Key U.S. Power Generation Studies 52

E. Electric Capacity Forecast Relating to Carbon Policy 53

1. Electricity Generation by Fuel 54

F. CO_2 Emissions and Prices 56

G. Barriers, Issues and Concerns Related to the Increased Role of Natural Gas Generation 58

1. Price Stability ... 58

2. Legislative and Regulatory Issues Related to Creating a Level Playing Field for Natural Gas Generation ... 59

H. Historic Subsidies ... 60

1. The Growth of Non-Fossil Subsidies ... 61

I. Regulations and Subsidies Affecting Gas Generation ... 61

1. State Mandates (Renewable Portfolio Standards) ... 61

2. Federal Programs ... 63

J. Policies Affecting Gas Generation ... 65

Chapter Five - Harmonization of Natural Gas and Power Markets ... 67

A. Firm Pipeline Transportation Capacity ... 68

B. Operating Day and Timeline for Scheduling ... 70

C. Firm Pipeline Service ... 72

D. Firming Up Intermittent Renewables ... 73

E. Curtailment Rules ... 75

F. Transparency ... 75

G. Transmission Issues ... 75

Chapter Six – Conclusions ... 76

Appendix A: Participating Individuals and Organizations ... 79

Appendix B: Reference Information ... 80

Introduction and Overview

A team of experts representing many different aspects of the power generation sector contributed to this report. The objective was to improve transparency related to our understanding of the future of natural gas as a primary fuel source for the power sector. The recent, and perhaps unprecedented, expansion of natural gas reserves in the United States has set the stage for a major shift in nearly every aspect of the energy conversion chain.

This positive change in our gas supply situation occurs at the same time as the United States is faced with an aging infrastructure of older, and often less efficient fossil (thermal) plants, many built at the time the interstate highway system was initially conceived and constructed. These facilities typically release more of the criteria pollutants than a modern gas-fired facility. They also face a gauntlet of regulations, perhaps so many that a large number of these facilities might be considered candidates for early closure rather than attempting to engineer solutions that permitted further operation.

Can the United States supply natural gas in the volumes needed, at competitive prices, for the power sector? The answer appears to be yes. More than sufficient natural gas reserves are available in the contiguous United States (and even more if those beyond the Lower-48 are considered). In addition, the most recent developments in power technology are designed primarily for gaseous fuel, the gas-turbine-powered Natural Gas Combined Cycle (NGCC) plants, are highly advanced and very efficient. Because they can be essentially factory produced, they also have the lowest capital costs ($/kW$_e$) available. NGCC also has the flexibility to operate efficiently over a wide range of utilization rates. In sum, given that we see no excessive economic or regulatory hurdles to overcome, the prospects for a substantial expansion of gas generation in the United States is a benefit as well as a practical solution to mesh with other power generation sources available.

Executive Summary

The expectation is that there will be a significant shift in the U.S. power generation sector over the coming years with natural gas increasing its market share. Some key highlights include:

1. The expectation of 30-80 GW of coal retirements mostly among older, smaller, and less efficient coal thermal units. These retirements will be accelerated by more stringent air, water, and hazardous materials environmental regulations.
2. Much of the additional (new) capacity will be based on natural gas fueled generation. Although natural gas expansion will be tempered by the 11,000 MW of new coal generation under construction, additional gas consumption could be in the range of 3 to as high as 10 bcf/day. The most likely forecasted range is 3-5 bcf/day, or about a 4% increase in today's consumption figures.
3. The lowest cost new generation that is the expected to supplant retirements in the coal fleet will be associated with gas-turbine based power generation equipment.
    a. Power generation technologies with the lowest cost uncertainty represent factory-built equipment, are usually quite large, and are based on a gas turbine core.
4. Addition of carbon capture controls to fossil fueled power generation is expected to substantially increase the cost of the power generation given the current state-of-the-art in gas separation technology.
    a. The cost for CO_2, at any level, raises the price of electricity for any power generation technology that uses a carbon bearing fuel. The increase in power cost is proportional to the cost of the CO_2. High CO_2 emitters are burdened with a substantially larger increase in terms of the percentage increase in electricity cost.
    b. A gas fired combined cycle power plant may have a lower cost of electricity than a fossil coal plant with carbon capture. However, it already has about one third the CO_2 emissions (tonne/MWh) as compared to a coal plant.
5. In the absence of any policy that specifically targets fossil fuel CO_2 emissions, coal is expected to continue to supply a substantial part of the U.S. power generation portfolio.

Chapter One - Power Generation and Demand Summary

The power generation sector is poised to have the largest impact on overall demand for natural gas over the next forty years. Key driving factors considered included an aging thermal cycle fleet, regulatory policy (including enforcement actions), and reduced uncertainty about the natural gas resource base and price volatility

Natural gas generation has significant advantages over other generation technologies including low up-front capital costs, reasonable energy production costs, a well established track record of performance and operational flexibility, and a minimal environmental emissions profile compared to other intermediate and base load fossil resources. The gas turbine is the core technology, used either singly (as a simple cycle combustion turbine) or combined with a steam heat recovery system in the combined cycle (the natural gas combined cycle, or NGCC). NGCCs have the flexibility to transition a range of positions in the dispatch order. They can fulfill the role of base-load or intermediate capacity, or if need be, the NGCC can also serve a role as a flexible generation component to support non-dispatchable renewable generation.

Increasing natural gas-fired generation is perhaps the fastest (and most cost effective) method of meeting near-term increases in electricity demand. To the extent it displaces existing coal-fired generation. It can also be an effective near term solution to reduce CO_2 emissions from the power sector, or to at least slow the growth of emissions until alternative technical innovations (e.g. CCS) might become available. Short-term changes in natural gas demand are strongly coupled to commodity price, while long-term power generation natural gas demand will be influenced by additional drivers, perhaps the most important of which are state and federal environmental regulations.

A. Factors Driving the Outlook for Natural Gas Demand for Power Generation

Even with the inherent advantages of natural gas described above, four major factors will determine the level of future natural gas generation demand:

- **The growth rate for electricity demand.** Natural gas-generation has generally the marginal source of generation although the percent to which it is the marginal source varies by region as well as by time of year and time of day. In some regions, gas may provide power during only relatively short peak demand intervals, in other parts of the country; natural gas is a substantial part of the energy supply base[1]. Growth in electricity demand should result in higher natural gas fired power generation demand. Almost all forecasts have electricity demand continuing to grow as new uses and applications of electricity continue to be introduced. This expansion will likely overwhelm energy efficiency improvement mechanisms that are currently underway, or are proposed.
- **Implementation and timing of proposed EPA regulations affecting power generation.** The EPA has proposed new or revised regulations covering sulfur

[1] In California, natural gas supplies 62% of capacity; in Ohio coal supplies 62% of capacity, and natural gas only 28%.

dioxide (SO_2), nitrogen oxides (NO_x), particulate ($PM_{2.5}$), mercury (Hg), ash disposal, once through cooling of power plants, hazardous pollutants, and CO_2 for new power plants. As recently as April 2011, EPA announced plans to lower the threshold for ambient ozone from 75 ppb to a range between 60 and 70 ppb[2] after having already reduced the standard only a few years earlier. The cost of complying with the proposed rules could accelerate the early retirement of a significant amount of coal-fired, oil and gas steam generation over the next few years. A reduction in these generation technologies due to more stringent environmental regulations might also result in a near-term increase in NGCC (or simple cycle peaking) generation to preserve reserve margins, an increase in gas-fired generation for existing and new NGCC capacity; and all of this would yield a reduction in CO_2 emissions from the power sector.

Most of the coal units that would be retired operate well below maximum capability due to higher heat rates (i.e. are less efficient at converting fuel to electricity), although many other factors are expected to play a role in determining the future of many facilities. Because of the higher efficiencies of the replacement generation, power generation gas demand will be a reduced fuel energy consumption. The efficiency (or heat rate) for natural gas fueled steam (Rankine) cycles is similar to that of the simple-cycle (Brayton) combustion turbine, there would likely be little change in gas generation or CO_2 emissions with this type of substitution[3].

As discussed below in Chapter 3, Section C, *Quantifying the Early Retirement Potential*, the studies reviewed suggested that the early retirement of coal-fired capacity could increase power generation gas demand from 3.3 to 10 Bcf/d, and with capacity retirements as high as 60 GW over the next decade (and possibly additional capacity retirements over the next 20 years). Increasing the dispatch capacity of the installed fleet (utilizing less coal generation, and more gas generation) reportedly could increase gas consumption from today's figure of 7.0 Bcf/d to 11.6 Bcf/d.[4] According to the CRS report, maximum demand for the gas fleet would be 12.7 bcf/d.

- **Fuel and Technology Available for New Power Generation Capacity.** Decisions on new power generation technologies will also be influenced by a combination of economic and other regulatory factors. Economic factors include expected life cycle costs that take into account capital costs, expectations for future fuel prices, dispatch role (utilization rate) and cost of emissions allowances if CO_2 emissions are regulated. Regulatory factors include **R**enewable **P**ortfolio **S**tandards (RPS) that mandate some level of renewable capacity by a certain date, availability of production tax credits (PTC), investment tax credits (ITC), loan guarantees and grants for competing technologies.

---

[2] Chemical and Engineering News, April 4, 2011 Volume 89, Number 14 p. 22 DOI:10.1021/CEN031511101925

[3] The CO_2 emission from a gas turbine (combustion turbine) cycle is approximately 0.40 – 0.45 tonne/MWh, similar to that of an oil fed thermal (Rankine) cycle unit.

[4] Subcommittee report, "Policy Options for accelerated deployment of natural gas end-use technologies for the purpose of reducing emissions of greenhouse gases", Draft report by the Emissions and Carbon Regulations Subgroup Policy Team.

- **Dispatch Economics and CO_2 Policy**. There is the risk of some measure of climate change legislation, although there is nothing yet on the horizon. However, EPA's recently finalized "tailoring rule" which would require large facilities, both new and existing (those that make modifications) emitting over 75,000 tons of greenhouse gases a year, to demonstrate that they are using the best practices and technologies to minimize GHG emissions. Generally power plants are dispatched based on variable generation costs with lower cost power plants being dispatched first. With low coal prices in most regions of the country, coal-fueled power plants will nearly always dispatch ahead of natural gas fuel power plants. Only where we find very efficient gas plants (NGCC) and low gas prices ($3-$5/MMBtu) does a gas-fired plant move ahead in the dispatch.

  A CO_2 allowance price would likely disadvantage a fossil coal plant more than a gas-fired plant, and produce a similar dispatch scenario. However, there will be regional differences related to power prices and energy supplies (coal, gas, etc.) that will impact how generation plants are dispatched. With a CO_2 emission allowance cost added to the variable production cost of electricity, the spread between delivered coal and gas prices is expected to be lower. However, a lower cost NGCC might not dispatch if there are transmission or other reliability constraints to displacing a more expensive coal plant.

B. Natural Gas Demand Outlook for Power Generation

With a wide range of potential policy decisions that could impact both electric natural gas demand, and the further complication that many states will pursue new environmental regulations regardless of federal action, it is not surprising that there is a wide range of outlooks for U.S. natural gas demand for generation as shown in Table 1.

Broadly speaking, the data here, and in the Demand Chapter (Figure 3-6) suggest a wide range of gas consumption (demand) for the power sector over the next 20 years. Some of this is clearly driven by policy (GHG regulation for example), some by technology (the widespread availability of natural gas from unconventional sources), and the economy (i.e., how much the U.S. economy will expand in the intervening years).

Table 1 Power Generation Gas Demand

	Natural Gas Demand (Bcf/d)						
Cases	2000	2010	2020	2030	2035	2030 CO_2 Price per Metric Ton	
AEO 2010 High Macro	14.1	17.9	15.5	21.0	21.3	Not applicable	
AEO 2010 High Shale	14.1	18.0	17.5	21.1	23.9	Not applicable	
AEO 2010 High Tech	14.1	17.2	13.9	15.4	16.2	Not applicable	
AEO 2010 Low Macro	14.1	18.0	14.7	17.1	18.2	Not applicable	
AEO 2010 Low Tech	14.1	17.9	15.9	21.0	22.2	Not applicable	
AEO 2010 No Shale	14.1	17.8	13.1	14.9	15.1	Not applicable	
AEO 2010 Reference	14.1	17.9	15.4	19.2	20.3	Not applicable	
AggOGMax		20.5	28.3	35.3		Unknown	
AggOGMedian		18.3	22.7	29.3		Unknown	
AggOGMin		17.1	15.5	19.3		Unknown	
EIA WM Basic	14.1	16.2	14.0	13.4		$64.80	2007$
EIA WM NoIntl_LtdAlt	14.1	15.0	26.1	31.5		$190.50	2007$
EIA KL Basic	14.1	17.2	17.1	17.7	18.6	$57.10	2008$
EIA KL NoIntl_LtdAlt	14.1	17.1	28.5	31.0	33.3	$144.83	2008$
Source: EIA and Argy Database							

In this table, the boundaries for the scenarios are, broadly speaking, a) fuel supply, b) technology, and c) regulations primarily addressing CO_2. The impact of different climate change proposals on U.S. power generation natural gas demand is shown in the power generation natural gas demand for the EIA *WM Basic and KL Basic* cases. For 2030, demand is 1.5 and 5.8 Bcf/d below the *AEO 2010 Reference Case* of 19.2 Bcf/d which does not include a cap and trade program. The *WM Basic* and *KL Basic CO_2* emission allowance prices for 2030 are $57.10 and $64.80 per tonne. However, power generation gas demand for the *WM No International Offsets/Limited Alternatives* and the *KL No International Offsets/Limited Alternatives* for 2030 are 31.5 and 31.0 Bcf/d, respectively, well above the *AEO 2010 Reference Case* of 20.3 Bcf/d.

In very general terms, the highest CO_2 prices are associated with the largest gas consumption increase. The increase in power generation gas demand under these two sensitivities comes from very high CO_2 emission allowances prices for 2030 of $190.50 and $144.83 per metric ton, respectively, which are necessary to achieve emissions reduction targets by the coal generation segment.

C. Other Enablers of Increased Use of Natural Gas Demand for Power Generation

Although many believe natural-gas-fired generation is positioned as the fuel of choice due to its economic and environmental advantages, there are key issues or concerns that must be addressed to enable more generators to use natural gas. These concerns relate to:

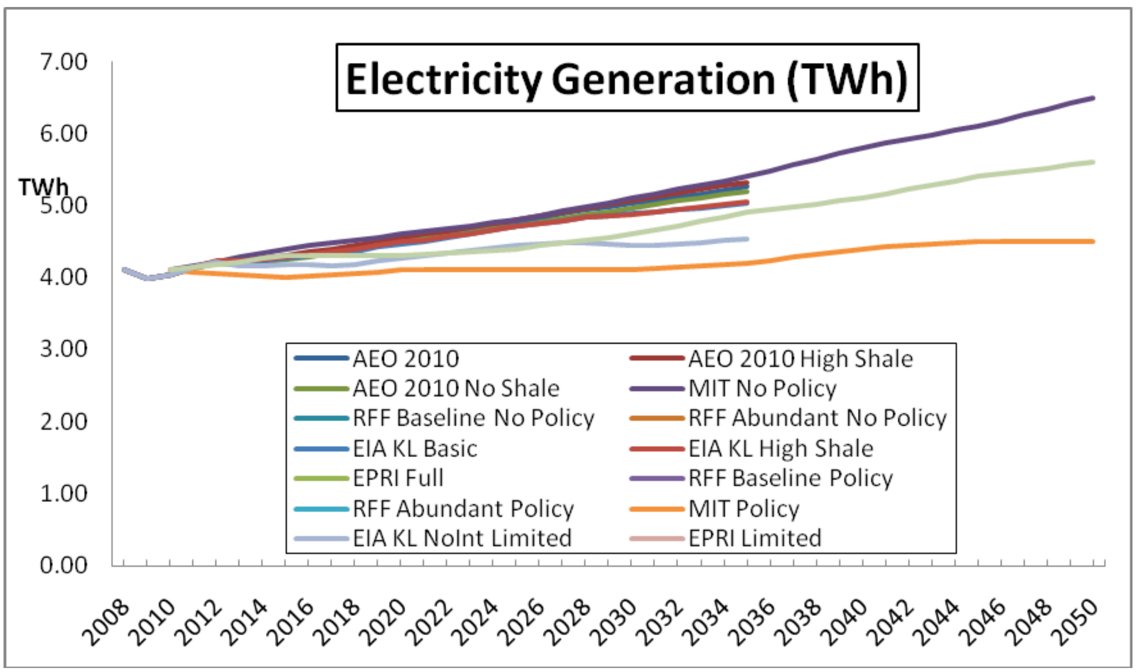
- The long-term fuel supply availability and the ability to adequately address and manage fuel price volatility.
- Adequate electric and natural gas infrastructure giving natural gas plants access to the grid and incremental gas supplies.
- The need to ensure that legislative and regulatory initiatives don't favor competing technologies over natural gas and disadvantage gas-fired generation.

- Operational issues related to the development and implementation of consistent and compatible scheduling, nominations, and supply delivery flexibility procedures need to be developed and implemented between the power generation sector and the natural gas supply and pipeline sectors. Another aspect of operational issues relates to increased use of intermittent renewable power sources and their impact on NGCC utilization rates, pipeline and storage operations and natural gas demand volatility.

Chapter Two - The Outlook for Electricity Demand

The drivers of electricity demand growth by sector are covered in the *Residential, and Commercial and Industrial Subgroup Reports*, respectively. Based on the studies considered, the demand for electricity generation is projected to increase, but the magnitude of the increase varies by each case in Figure 1 due to varying assumptions about gas supplies and CO_2 and other regulatory policies. Growth rates scale back fairly dramatically in the MIT[5] cases, depending upon what regulatory policy was assumed by the authors. For the non-climate change *EIA Cases,* the greatest impact on total electricity demand for 2035 are found in the *High and Low Macro Cases* (high or low GDP growth), followed by the *High and Low Integrated Technology* Cases with the *High or No Shale* appear to have only a minor impact (See Table 2). In the *Kerry Lieberman* cases where climate change policy is assumed, demand for electricity in 2035 increases above 2008 levels, but at a reduced rate. CO_2 costs are passed through to electricity customers, which are expected to reduce demand. This is particularly true for the *No International Offsets/Limited Alternative Case,* which has a very high CO_2 price as a result of not having international offsets, nuclear, or CCS to mitigate the cost of reducing CO_2 emissions.

Figure 1 Electricity Generation Forecasts under Various Scenarios



The forecasted growth for electricity in Canada is expected to follow a similar pattern to that of the United States (See Figure 2). However, Canada's grid is not tightly integrated into the U.S. grid, so there is little opportunity to transfer capacity North and South across the border. In the Eastern Interconnection, energy-only can be transferred to the United

[5] Massachusetts Institute of Technology,: "The Future of Natural Gas – Interim Report", July 2010, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf

States—Canadian resources supply little or no capacity through the Eastern interconnection. (See Figure 3)

Resources for the Future (RFF) studies show similar results in terms of impact of climate change on electricity demand and electricity prices.[6] A key difference from the *EIA Kerry Lieberman (KL)* cases can be found in the elimination of international offsets, which drives electricity prices up significantly compared to any of the other RFF cases. Another key difference in their analysis was that the *Kerry Lieberman* bill assumed that allowances would be allocated to local distribution companies who would be directed to rebate them to ratepayers. The transfer of revenue is phased out after 2025, but until then retail electricity prices are restrained by this mechanism. The RFF analysis does not assume such a provision, so electric prices rise more steadily reducing electricity demand.

An Electric Power Research Institute (EPRI) analysis also discusses how power technology availability impacts future demand for electricity over their projection period[7]. In their *Full Portfolio Case* (included in Figure 1) the price of electricity rises to 90% above 2007 levels in 2050, but the demand for electricity also continues to rise. In their *Limited Portfolio Case,* where new nuclear and CCS are not available, the price of electricity rises 210% and demand for electricity is essentially the same as in 2008. However, there is limited economic data to infer how a long-term, sustained increase in power prices will impact the ability or willingness to continue expansion or replacement of the power infrastructure.

Finding

Electricity demand is likely to grow under almost all outlooks driving a likely increase in power generation gas demand. But in cases with extraordinary increases in power prices, due to CO_2 controls, demand for electricity (or the rate of growth) is restrained

6 RFF: Abundant Shale Gas Resources: Long-Term Implications for U.S. Natural Gas Markets, Stephen P.A. Brown, and Alan J. Krupnick, August 2010, RFF Discussion Paper 10-41,http://www.rff.org/publications/pages/publicationdetails.aspx?publicationid=21286

7 Electric Power Research Institute : **The Power to Reduce CO_2 Emissions- The Full Portfolio**, 2009

Figure 2. Forecasted Electricity Demand-Canada

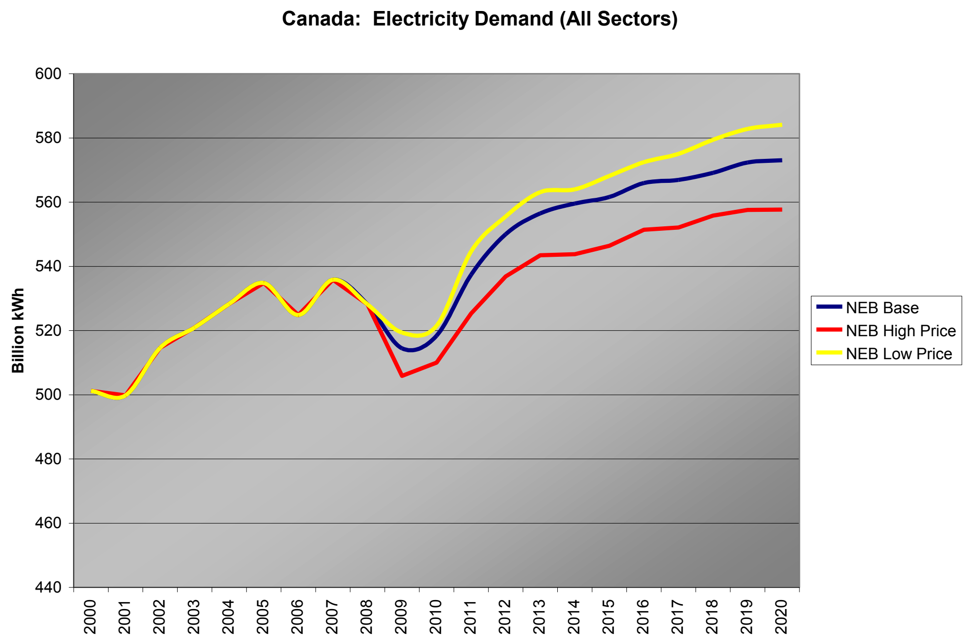


Figure 3. North American Grid Interconnection

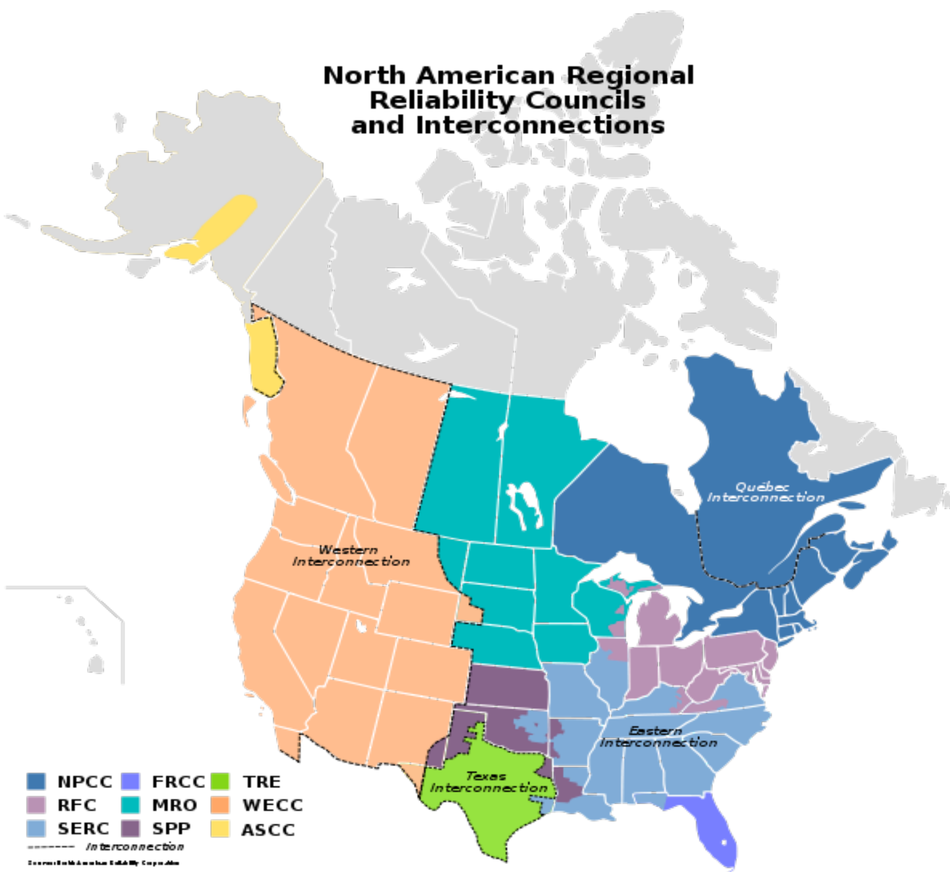


Table 2 Forecast for Electricity Demand-Various Scenarios[8]

U.S. Electricity Demand (Billion kWh)				
	2010	**2035**	**Increase (Decrease) from 2010**	**Delta from 2035 Reference**
AEO 2010 Low Macro	3,589	4,231	643	-429
AEO 2010 High Tech	3,574	4,236	662	-424
AEO 2010 No Shale	3,617	4,610	993	-50
AEO 2010 Reference	3,617	4,660	1,043	0
AEO 2010 High Shale	3,617	4,706	1,089	46
AEO 2010 Low Tech	3,618	4,857	1,239	196
AEO 2010 High Macro	3,618	5,095	1,477	435
EIA KL Basic	3,619	4,398	778	-263
EIA KL Noint_LtdAlt	3,620	3,894	273	-767
Source: EIA: 2010 Annual Energy Outlook, Energy Market and Economic Impacts of the American Power Act of 2010				

[8] EIA:2010 Annual Energy Outlook, **Energy Market and Economic Impacts of the American Power Act of 2010**.

Chapter Three - Implementation and Timing of Proposed EPA Regulations Affecting Power Generation

Long-delayed or shifting environmental rulemakings are creating tremendous regulatory uncertainty for many coal, oil, and gas-fired steam plants. Lacking specificity in the timing and extent of federal policies, can paralyze an industry facing daunting financial investments. In the near term, that inaction that is likely to be evident in severe underinvestment, or perhaps worse, investments that could be rendered worthless in the longer term.

A. Proposed Regulations

Proposed regulations include tightened ambient air quality standards, and increased regulation of pollutants under the *Clean Air Act*, and addition of new ones (CO_2). Further, proposed regulation of non-air media areas, such as disposal of coal combustion byproduct solids (ash), regulation of cooling water intake, and management of thermal and chemical discharges into water bodies, present a new regulatory challenge especially for the economic operation of coal plants. Environmental regulation for hazardous air pollutants through the Maximum Achievable Control Technology (*MACT*) requirement, are expected to produce a "go/no-go" response by the industry: Facilities that do not (or cannot) install controls are likely to become part of a yet-to-be-defined list of plants slated for closure[9]. Regulation of cooling water intake structures, *CWIS 316(B) Phase 2*, has the potential to impact a significant portion of the approximately 400,000 MW of thermal (coal, oil, gas, and nuclear) capacity, inducing some retirements, as well as spur upgrade/retrofits. Barring significant modifications or delays in implementing these environmental regulations, many of these requirements are likely to become binding between 2015 and 2020.

To continue operating under new or tightened regulations, coal plants are expected to require significant capital investments. But if the regulatory climate is sufficiently restrictive, even adding new environmental controls may not be able to bring some facilities into environmental compliance. EPA's new 1-hour SO_2 rule for ambient air could be a major challenge, especially for units using high sulfur coal. Reducing the averaging time (for the determination of ambient air quality) could make compliance with regional air quality issues nearly impossible. With such a narrow window of time averaging, the emissions during the start sequence of any fossil plant are likely to be released when the environmental controls are non-operable. Ironically, the 1-hour averaging time for NO_2 is expected to impact new gas fired generation negatively, even though all new generation types come equipped with the latest NO_x emission controls. The problem is exacerbated for smaller sources, an artifact of how predictive computer models forecast ambient air quality when siting a facility. Even with these limitations, there is likely to be more pressure to use gas fired plants to meet future demands.

[9] U.S. EPA issued a draft MACT regulation in March 2011, with most of its regulatory emphasis on large, electric generation units using either coal or oil as the energy source.

Table 3. Potential, New, or Tightened Regulations Racing Coal Plants within the Next Decade

Item	Pollutant or Issue	Policy	Description	Control Technology
Priority air pollutants and air toxics (non-CO_2)	Mercury	Maximum Achievable Control Technology Rule (MACT) Rule	Reducing emissions of mercury from coal plants	Fabric Filter and/or Activated Carbon Injection (ACI)
	Non-Mercury Hazardous Air Pollutants-Metals	MACT Rule	Reducing emissions of hazardous (non-mercury) emissions from coal plants	Fabric Filter and/or Activated Carbon Injection (ACI)
	Non-Mercury Hazardous Air Pollutants-Acid Gases	MACT Rule		Flue Gas Desulfurization (FGD) and possibly ACI
	Sulfur dioxide and nitrogen oxides	Clean Air Transport Rule (CATR)	Reduce the transmission of pollutants from upwind to downwind states	FGD, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR)
	Ground level Ozone	National Ambient Air Quality Standards (NAAQS)	EPA re-evaluation and likely reduction of ground-level ozone NAAQS	SCR, SNCR, low-NOx combustion technologies
	NO_2 / SO_2	NAAQS	Modeling for compliance using 1-hour averaging	Post combustion controls, fuel changes, faster starts, smaller and dispersed sources
	Visibility	Regional Haze	Reductions in emissions contributing to poor visibility in specified areas	FGD, SCR, SNCR, low-NO_x technologies and fuel switching
Water and Solids	Coal Combustion Byproducts	Resource Conservation and Recovery Act (RCRA) Subtitles C and D	Regulation storage and disposal of solid byproducts of coal combustion	Upgrades of ash disposals system
	Thermal Discharge	National Pollutant Discharge Elimination System (NPDES)	Water thermal loading regulation	Cooling towers
	Fish Impingements, Aquatic Species	Clean Water Act 316 (b)	Reducing impact on aquatic life	Cooling tower intake screens, air cooled condenser, closed loop cooling
Carbon	Carbon Dioxide	Clean Air Act (CAA) GHG regulation	Use of existing CAA authorities to reduce GHGs from new and existing power plants	Efficiency improvements, fuel switching, carbon capture and sequestration, biomass co-firing, increased renewables
	Carbon Dioxide	Potential Federal Climate Policy	Mandated carbon reductions through cap and trade or carbon tax or other mechanism	Efficiency improvements, fuel switching, carbon capture and sequestration, biomass co-firing, increased renewable
	Carbon Dioxide	Potential Regional or State Climate Policy	Mandated carbon reductions through cap and trade or carbon tax or other mechanism	Efficiency improvements, fuel switching, carbon capture and sequestration, biomass co-firing, increased renewable

B. Compliance Costs and Economics

The new set of regulatory drivers will likely require investments in one or more major environmental control retrofits for many coal plants, especially those coal plants built before the controls were mandated. For hazardous air toxics, few, if any, facilities were designed and built with the appropriate type of controls. However, where emission controls are installed (such as SCR or FGD), there is some reduction of specific air toxics. In some cases (such as mercury reduction), nearly 80% control has been observed (without the requirement of an additional control specific just to that pollutant).

A full complement of (non-carbon) environmental controls on a coal plant is likely to include flue gas desulfurization (FGD or "scrubber") system to reduce sulfur dioxide emissions, selective catalytic reduction (SCR) to reduce nitrogen oxides, activated carbon injection to reduce mercury, and a fabric filter to reduce particulates and non-mercury hazardous air pollutants. If the installed controls are insufficient, additional environmental equipment may be required to improve (or enhance) the performance (emissions reductions) to achieve the cleanliness requirements expected to be required for a carbon capture system. Such a plant may also need a separate cooling tower and upgrades to ash disposal systems.

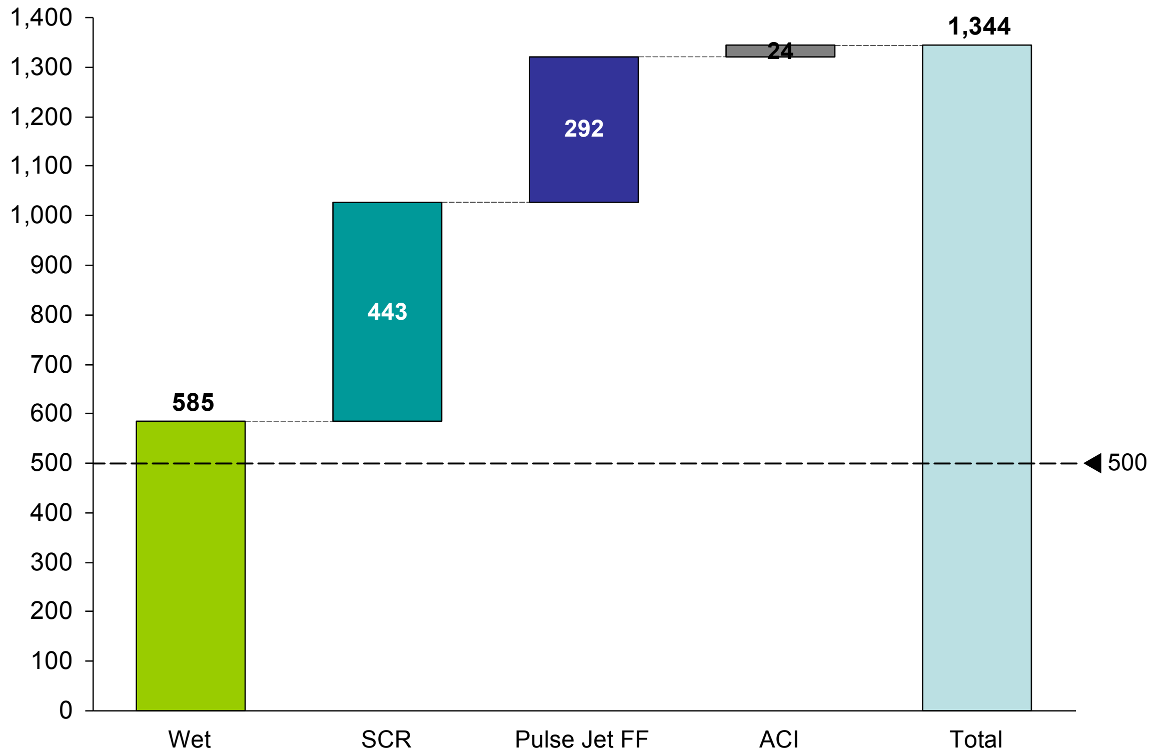
Some coal plants today lack all of these, and few if any have them all. For example, FGD is in place on only about half of U.S. coal-fired units today. The full retrofit cost (one that includes an FGD, SCR, fabric filter, activated carbon injection, as removal, and cooling upgrades), could run between $800-$1,400/kilowatt for relatively large 500 MW coal-fired units (Figure 4), depending on site-specific characteristics. These retrofit costs could exceed the capital cost of a brand-new, state-of-the-art natural gas-fired combined cycle plant. The 2009 decision to retrofit the Brayton Point (Massachusetts) coal units (1,134 MW) is estimated to be $500 million[10], $440/kW, about one-half the cost of replacing the entire plant with new gas generation.

These economic factors are underscored by the December 22, 2010 announcement by Basin Electric to forgo a carbon capture retrofit at a large pulverized coal plant in North Dakota[11]. The project Front End Engineering and Design (FEED) study cost alone was $6.2 million dollars, a portion of that paid for by the state. To support the economics of the process, CO_2 extracted from the facility would have been used for Enhanced Oil Recovery (EOR). But even with an income stream from CO_2, the approximately $500 million price tag was too high for the owners. And at this investment level, the installed technology would have processed only 25% of the CO_2 from the plant. Using 1 tonne-of CO_2/MWh as a benchmark for a typical fossil coal plant, a 25% reduction would yield net emissions of about 0.75 tonne-CO_2/MWh, which is still twice the level of a state-of-the-art NGCC. Expanding the comparison, the retrofit cost would be approximately $1,000 /kW, on par with currently available gas fired technology. The dilemma is that retrofitting the facility would be expensive and those costs (not offset by product sales) would have to be subsidized, probably by the rate payer (or some tax mechanism). And the GHG emissions would be no better than what might be currently available, at a lower price (although with a different fuel charge).

[10]Application for: BWP AQ 03, filed with Mass DEP, February 11, 2009, Transmittal No.: X224106, Application No.: 4B08052

[11] News report: Basin Electric Foregoes CO_2 Retrofit. http://www.basinelectric.com/News_Center/Publications/News_Releases/Basin_Electric_postpones_CO2_capture_project.html

Figure 4. Estimated Capital Cost for Environmental Upgrades ($/kW) to a 300 MW Coal Plant[12]



Together, the cost of upcoming environmental investments, the aging of the U.S. coal fleet, and increased competition from natural gas as new supplies of low cost natural gas become available portends a potential for a wave of coal plant retirements over the next several years. Plant owners are evaluating their entire portfolio with an emphasis on older (less efficient) power plants, primarily the coal fleet[13]and are looking at several scenarios. In those regions with excess capacity (reserve margins greater than 20%) older less efficient units may be retired wholesale, without replacement, or at least with no replacement that is coincident with the retirement. Under the lowest forecast rebound in economic growth and electricity demand, a significant number of plants that might retire could be supplanted with new gas-fired generation. Or if the costs justify, some of the units (most likely the larger units) would be upgraded with more effective environmental controls. Alternatively, the continued availability of a large fleet of low-cost fossil generation could be used to sustain an expanded renewables portfolio in other parts of the country. This idea was explored by ISO New England in a recently completed study suggesting that, with a substantial investment in transmission, an additional 12 GW of renewable (wind) generation is possible in the Northeast by tapping available reserve Midwestern capacity.[14] The study proposes that the lowest cost electricity would be achieved with transmission of 9,600 MW of coal power from the Midwest. Making this

---

[12] Edison Electric Institute, Potential Impacts of Environmental Regulation on the U.S. Generation Fleet, Washington DC, January 2011

[13] The inclusion of emission regulations on oil fired units potentially impacts 28,000 MW of generation, although these units could be shifted to cleaner, less polluting fuels.

[14]New England 2030 Power System Study, Report to the New England Governors, February 2010

power available for backing up renewable generation could absorb some of the excess capacity noted in the Midwest region.

While using Midwest coal capacity to back up renewable generation may offer one scenario to mitigate the growth of gas-fired generation, it may only be practical under a set of very narrow conditions. It requires the continued use of fossil coal as a source of generation and additional transmission capacity expansion. Also, it doesn't alleviate the requirement that those facilities would have to retrofit for environmental compliance. Finally, it would require that these older fossil plants adapt to a new role, one they were not designed for, a supporting role where they would function as peaking or intermediate generation supply instead of base load capacity.

The magnitude of environmentally-driven investments possibly required for coal plants in the next several years raises the question of whether the plants would run long enough to pay off the any retrofit (upgrade) investment. Major investments in power plants are usually financed for at least 15 to 20 years. This is likely due to a difference between merchant plants (which typically deliver electricity via a power purchase agreement) and regulated utilities (which could include the cost of controls into a rate base).

The owner of a coal power generation unit must evaluate whether the plant will operate and make enough profit for years into the future, weighing such factors as demand, competition from other fuels, and future environmental regulation including possible carbon regulation. For a typical coal plant, a $20/tonne carbon price would roughly double the effective fuel cost per MWh to operate the plant, creating a major new competitive challenge. Costs for compliance with the MACT rule are expected to vary by plant size (MW), fuel type (PRB, Lignite, or Bituminous), and currently installed environmental controls (for some facilities this would be none).

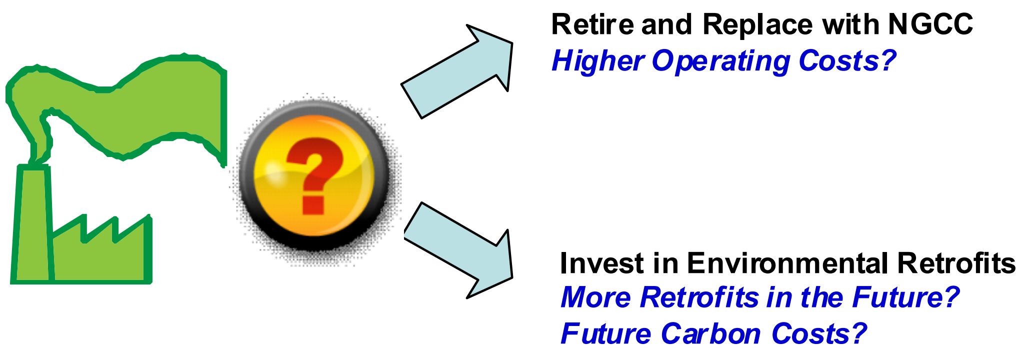
Many of the studies reviewed suggest using the age of a plant as an indicator (or proxy) for determining whether the facility is retired or upgraded (or re-powered). Older coal plants in the U.S. may be particularly vulnerable to retirement or substantial modification to continue operating. One-third of U.S. coal-fired capacity is more than forty years old today.[15] The risk exposure for these facilities can be expressed in several ways. First, these older plants are generally less efficient, so their operating costs tend to be higher, and future carbon regulation would adversely affect them more strongly. Second, due to their lower efficiency, these same facilities are expected to operate less (or dispatch less), offering reduced chance to pay back investments (although this also implies that their carbon footprint is not as significant compared to a base-loaded unit). Third, older plants are less likely to have environmental controls for priority pollutants today, as the controls were not required when the plants were built. Only 27% of the coal units over forty years old are currently fitted with FGD.[16] Fourth, older coal units are on average much smaller, and therefore more expensive on a per MW basis to retrofit with environmental controls. A recent Sanford C. Bernstein research shows that a 500 MW coal unit might cost $420/kW to fit with FGD, but a 50 MW coal unit could cost $1,137/kW.[17] The same

[15] M.J. Bradley and Associates and Analysis Group*, Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010.
[16] Ibid.
[17] Sanford C. Bernstein & Co., *Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for the Energy & Power Markets*, July 2010.

diseconomies for smaller units exist for SCR retrofits: the 500 MW unit might require \$116/kW, while the 50 MW unit might require \$203/kW to retrofit with NO_x emissions controls.[18] Fifth, older coal units tend to have higher maintenance costs, further reducing their competitiveness.

Because the retrofit cost for smaller plants is typically less cost effective, operators may default to one of several options: 1) retire the facility and purchase power from other suppliers if there are no transmission bottlenecks for doing so; 2) retire the facility and replace it with new capacity, most likely an NGCC or 3) operate the facility on natural gas instead of coal. In this last case, even though the heat rate may not be ideal, it provides a short-term relief while still preserving some of the operational features (e.g. turndown) found in many of these thermal plants. Table 4 below shows the relative advantages and disadvantages for two conversion options. The cost of various capacity options is discussed below under Costs of New Power Capacity. The subject is discussed in more detail in Chapter 4, Section A.5, *Options to Replace Coal Generation Capacity with Gas Generation Capacity*

Table 4. Coal to Gas Conversion Options



	Advantages	**Disadvantages**
A) Repower Burn natural gas in existing coal boilers	Use of existing transmission access Potentially wider turn-down ratio than coal-only option. Quick compliance with possible upcoming SO_2 and MACT requirements	Less efficient than NGCC plants May lack gas pipeline access Natural gas is typically more expensive than coal.
B) Repower existing coal plants to burn natural gas by replacing the boiler with a CT	In most cases, this is less expensive than building a new NGCC Use of existing transmission access	Much less efficient than a new NGCC Limited if plant is considered to be critical to grid reliability and would be unable to go off-line for the 4-6 months needed to convert to NGCC

[18] Sanford C. Bernstein & Co., *The Long View: Forthcoming EPA Emissions Regulations Will Force Power & Capacity Prices Higher -- Who Will Benefit?*, July 2010.

Natural gas-fired generation provides the most obvious replacement for retired coal plants, as natural gas can provide reliable capacity and dispatch, and also because many NGCC facilities are underutilized today. NGCC plants can also significantly reduce exposure to the long list of new environmental regulations facing coal plants. NGCCs have low emissions of nitrogen oxides, virtually no sulfur dioxide, mercury and hazardous air pollutant emissions, and less than half the carbon dioxide emissions of older existing coal plants.

C. Quantifying the Early Retirement Potential

During the period when this report was compiled, additional market assessments continued to be developed. In early April of 2011, nearly 104 fossil plants had announced retirements according to various press releases and public statements. Two weeks later, that number had increased to 124. Clearly the tempo in the industry is increasing, and quantifying the impact of regulatory rules on retirements has moved to the realm of speculation. **The Demand Chapter** has included even more studies than those reviewed here, and reports an even wider range of retirement potential (12 to 101 GW, with an average of 58 GW). With critical factors (regulations, fleet age, low cost gas, etc.) changing almost weekly, one would expect that the direction of flow is much easier to predict (more retirements) than the quantity (how many retirements). Such a fluid process does not lend itself open to even detailed methods of quantification, as there are many other factors that are likely to come into play, such as gas pipeline capacity, transmission constraints, and possibly local workforce issues.

A number of recent studies attempt to quantify fossil coal unit retirements under the new set of environmental regulations. The exact set of environmental regulatory drivers under examination varies across studies, but there is some consensus that the "Maximum Achievable Control Technology" (MACT) rule for mercury and other hazardous air pollutants, and the "Clean Air Transport Rule" (CATR) focusing on interstate transportation of sulfur dioxide and nitrogen oxides, are the main drivers for retrofit-or-retire decisions on coal plants. Both MACT and CATR implement existing regulations that have been under development for several years, and both are scheduled to require compliance by 2015. The studies examined here estimate between 30 and 80 GW of retirements out of today's total 337 GW[19] of existing coal-fired power plants in the near-to-mid term. Not all of the retired capacity will need to be immediately replaced as in many regions reserve margins are in excess of what is required. Further, how much generation needs to be replaced may be quite a bit less than suggested by the quantity of capacity being retired as many of the candidates for retirement operate at low utilization rates reflecting their high heat rates.

[19] 337 GW is the current nameplate rating of units installed, including those that are announced for retirements. Figures of installed capacity range from 314 GW (Charles River Associates) to 337 GW. Some authors use the summer net rating, which allows comparison between peak demand and available capacity. However, equipment orders (or sales) are almost exclusively reported as nameplate rating. This distinction is not trivial, and has been a cause for some confusion.

Table 5. Potential Coal Plant Retirements Lead to Increased Market Share for Natural Gas

Data Source	Potential Coal Plant Retirements by 2015-2020 GW	Increase in Natural Gas Consumption Bcf/d
Bernstein Research[20]	60	3.3
Credit Suisse[21]	60	5-10
INGAA/ICG[22]	50	5.5
Brattle Group[23]	40-55 (SO_2/NO_x based) +10 GW for cooling issues	5.8 (by 2020)
Charles River Associates[24]	39 GW (by 2015)	
NERC[25]	39 to 69 (by 2018) All thermal plants	Not stated
Deutsche Bank[26]	60 (by 2020) 92 (by 2030)	3.8

Notes: At 50% capacity factor, and 50% average thermal efficiency, 60 GW of retired thermal plants could be replaced with 37 GW of NGCC, simply on an energy basis. However this does not address needs for peak demand, backup power for renewables, or system reliability requirements.

If the near-to-midterm losses in coal generation (capacity) are replaced by natural gas-fired generation, the analyses have found increases in natural gas consumption of between 1-2 Tcf per year (using the 3-5 Bcf/d range noted in Table 5). This represents an increase in overall U.S. natural gas demand of 4-9%. Notably this increase is specifically due to coal plant retirement. The retirement-driven demand increase is expected to be additive to increases in natural gas demand to meet growing demand for electricity. Longer term, a retirement potential of 60 GW could result in increased gas consumption of 5-10 Bcf/d. (58 GW is the average noted in the Demand Chapter.)

The potential increase in power generation gas demand from early retirement of coal plants is in sharp contrast to flat or declining natural gas demand for other sectors. The replacement of coal generation with gas-fired generation would also reduce carbon

[20] Sanford C. Bernstein & Co., Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for the Energy & Power Markets, July 2010
[21] Credit Suisse, Growth From Subtraction: Impact of EPA Rules, September 2010
[22] Interstate Natural Gas Association of America/ICF International, Coal-Fired Electric Generation Unit Retirement Analysis, May 2010.
[23] Brattle Group Study "Prospects for Natural Gas Under Climate Policy Legislation", 8 December 2010
[24] Charles Rivers Associates, "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT—Executive Summary", (http://crai.com/uploadedFiles/Publications/CRA-Executive-Summary-Reliability-Assessment-of-EPA's-Proposed-Transport-Rule.pdf)
[25] NERC 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, October 2010
[26] Deutsche-Bank, "Natural Gas and Renewables-A Secure Low Carbon Future Energy Plan for the United States", November 2010

dioxide emissions by 80-170 million metric tons/year, or 3-7% of 2005 power sector emissions levels.

The vast majority of vulnerable coal plants are located in the Midwest and Southeast according to an assessment conducted by ICF International for the Interstate Natural Gas Association of America. Their study classified vulnerable coal plants as having no FGD scrubbers or SCRs and no plans to add them, as being over the age of 40, and having heat rates of greater than 10,000 Btu/kWh. Of the 50 GW that fit these criteria, 36 GW of the plants were located in either the East North Central census region or the East South Central census region.[27] The replacement of coal plants lacking environmental controls with cleaner NGCC plants has the potential to significantly reduce emissions of NO_x, SO_x, and CO_2 in these regions of the country.

A National Electric Reliability Council (NERC) study listed in Table 5 reveals a more stark picture than most others in the industry have discussed to date.[2] Their analysis of four key environmental proposals (*Clean Water Act-Section 316*(b), *Title I of Clean Air Act-NESHAP, Clean Air Transport Rule*, and *Coal Combustion Residuals-CCR*) suggest that under the most strict interpretation of the rules, as much as 75 GW of thermal (coal, oil/gas steam, and nuclear) plants in the U.S. could either be forced to shut-down (retire) or experience some degradation in performance. NERC's assessment was based primarily on the capacity (GW) of the facilities, not their total energy generation (GWh). Both capacity and energy demands need to be factored into the final analysis of how the regulatory impacts will affect the fleet portfolio. NERC's study suggests that new regulations on cooling water intakes would become the deciding factor in retirement or retrofit of many plants. NERC's analysis did not consider the impact of greenhouse gas regulations. EPA's announcement in late March to move toward a less restrictive federal standard doesn't clearly define the issue for the end user. If each state enacts its own standards for cooling water restrictions, this could create an equally complex, and costly set of barriers for the thermal fleet.

Finding

Implementation of various proposed EPA regulations affecting power generation will likely lead to an increase in gas-fired generation capacity and power generation gas demand. The range of potential increase in power generation gas demand ranges from 3 to 5 Bcf/d.

[27] States include Michigan, Illinois, Wisconsin, Ohio, Kentucky, Tennessee, Mississippi, and Alabama.

Chapter Four - Costs for New Power Generation Capacity

The technology choice to meet new capacity requirement from a combination of growth in electricity demand and replacement of existing capacity being retired includes substantial economic assessment. A key evaluation of the "economic choice" is the levelized cost of electricity (or LCOE) over the expected life of the new capacity. Included into the LCOE evaluation is the capital cost of the equipment. Although this is not the only factor; the total capital requirement affects the capacity of the market to finance a specific technology.

A. Capital Costs for Generation Technologies

The following discussion identifies the range of expected costs for a number of generation technologies and the impact these assumptions have on the ultimate economic competitiveness of these technologies. The economic competitiveness of natural gas generation will depend on the cost to construct and operate natural gas-fired generation in comparison to the expected cost to construct and operate other competing generation technologies. For natural gas, the capital cost has typically been the lowest threshold—it is the fuel costs that primarily drive the cost of electricity. In the studies reviewed, the range of expected construction costs for various generation technologies vary greatly based on a number of underlying assumptions associated with those technologies. But we find consistency that technologies using a gas turbine as the core component are among the lowest in capital costs.

1. Levelized Cost of Electricity

Advanced technology power generation system costs are summarized in Table 6. The more detailed breakdown is provided at the end of this document in Table A-1. Data was extracted from the *AEO 2010 Reference Case , AEO 2011 Reference Case, Edison Electric Institute (EEI)*, and two versions from EPA (the most recent being *EPA 4.10*). Table 6 has key summaries and cost comparisons for each technology. More recent cost estimates are, in some cases, noticeably greater than earlier reports. System costs are estimated in $/kW, but for some technologies there are very few units of comparable or similar technology in operation to compare with. Where there are few units in operation, there is greater the uncertainty of the cost data.

The plant capacity in MW is assumed to represent the nameplate capacity. Total capital costs (CAPEX) assumes that $/kW was derived from a nameplate value. A constant capital recovery factor of 12% is assumed in each case. In addition, a NGCC was selected as the benchmark for this tabular summary revealing a theme throughout this report that this particular technology choice has one of the lowest levelized cost of electricity (LCOE). In Figure 5 we find that examining the forecasted CAPEX costs ($/kW on the left axis), the bulk of U.S. installed current capacity (in GW) comprises nearly 90% of the installed capacity with a CAPEX below $3,000/kWe.

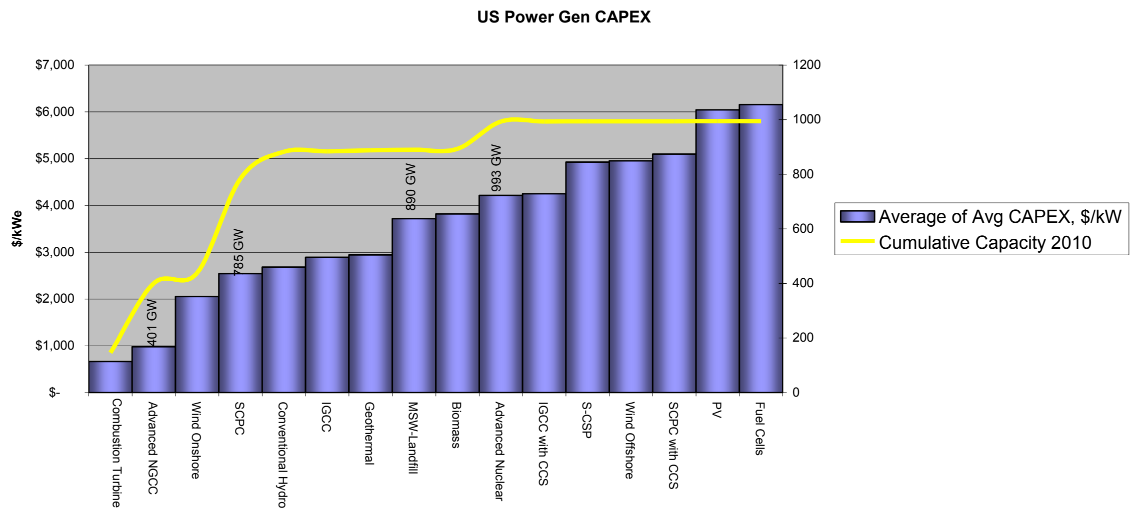
Table 6. Cost Comparison of Primary Power Generation Systems

Case	Technology	$/kW	LCOE, $/MWh		LCOE Relative to NGCC
		Avg CAPEX	Average	Maximum	
1	*SCPC*	$ 2,543	$ 69.52	$ 79.65	114%
1a	*SCPC with CCS*	$ 5,099	$126.38	$126.38	207%
2	*IGCC*	$ 2,894	$ 81.18	$ 98.08	133%
2a	*IGCC with CCS*	$ 4,251	$111.84	$136.10	183%
3	***Advanced NGCC***	**$ 982**	**$ 61.20**	**$ 62.53**	**100%**
3a	*NGCC with CCS*	$ 1,996	$ 90.93	$ 94.45	149%
4	*Combustion Turbine*	$ 665	$165.33	$173.54	270%
5	*Fuel Cells*	$ 6,157	$207.59	$219.27	339%
6	*Advanced Nuclear*	$ 4,214	$104.81	$126.96	171%
7	*Biomass*	$ 3,821	$ 83.80	$ 85.44	137%
8	*Geothermal*	$ 2,945	$ 65.66	$ 83.36	107%
9	*MSW-Landfill*	$ 3,720	$ 89.36	$202.60	146%
10	*Conventional Hydro*	$ 2,684	$ 49.15	$ 54.59	80%
11	*Wind Onshore*	$ 2,053	$105.30	$122.01	172%
12	*Wind Offshore*	$ 4,956	$252.98	$293.12	413%
13	*S-CSP*	$ 4,928	$212.19	$219.80	347%
14	*PV*	$ 6,044	$280.89	$288.70	459%

Levelized cost represents the present value of the total cost of the operation and construction of an electric power plant over an assumed economic life, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation. It is a key input to long-term projection models, as well as a useful metric in comparing the costs of different technologies on an equal basis. In addition, for a merchant generation project to be profitable, the future price of electricity needs to be equal to or greater than the LCOE. The major components of LCOE are capital costs, operation and maintenance (O&M), fuel costs, and the cost of capital (interest rate). The characteristics of different technologies affect the overall LCOE. For nuclear power and coal plants, overnight capital costs are the most dominant component of their LCOE, while for natural gas plants overnight capital costs are lower, but fuel costs are higher.

The LCOE is calculated for each of class of power generation, but included is a cost assumption for CO_2. To try and make this analysis relevant in light of concern over CO_2/GHG emissions, a cost burden of $20/tonne is assigned as a cost for each tonne of CO_2 emitted. Later, we expand on this to consider the impact of a range of CO_2 cost burdens on the generation, and its impact on LCOE. Despite the addition of a cost loading for CO_2, the more familiar combustion generation systems appear to offer the lowest overall cost of electricity. MSW-Landfill and Geothermal LCOE costs are among the lowest (in this study). However, the nominal size of these plants is typically 50 MW or less, and there is no expectation that these technologies could displace a significant amount of large fossil generation[28]. And there are no operating geothermal plants in the United States east of 118° West Longitude, placing all of the geothermal units in the more geologically active part of the United States (and within a single reliability council, WECC, boundaries).

Figure 5. Average CAPEX costs for key power generation technologies[29]



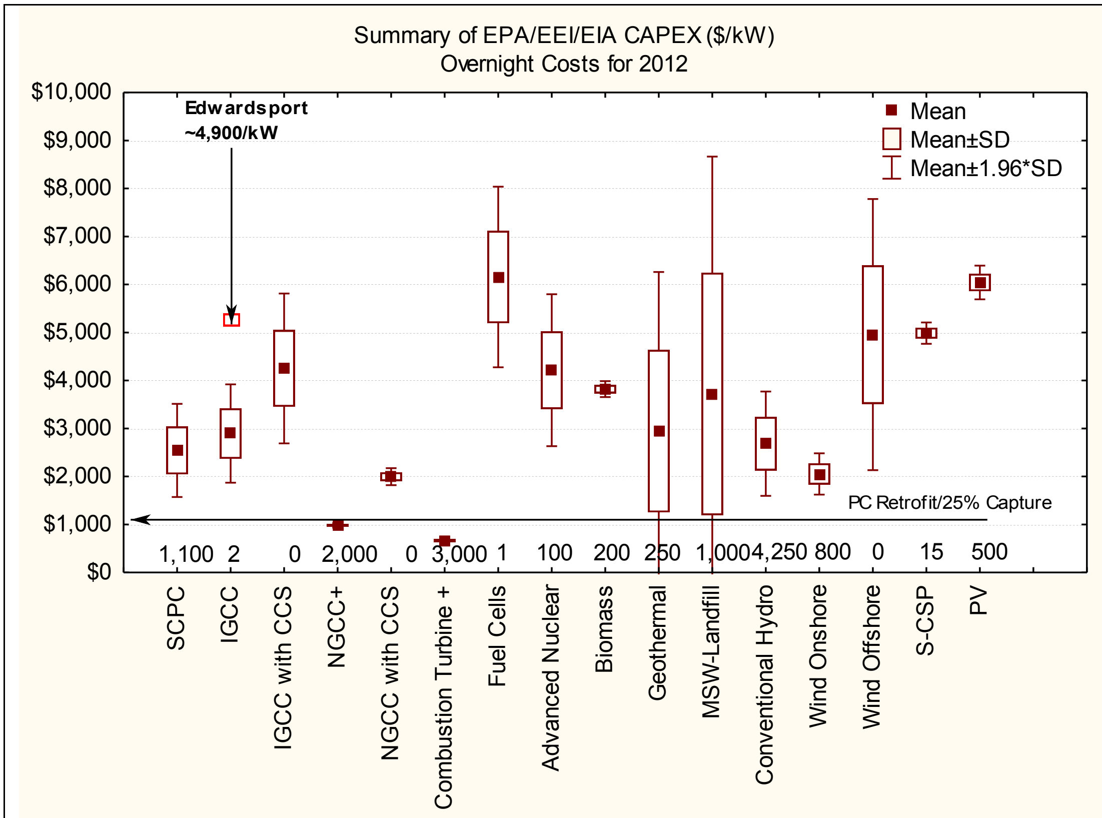
2. Capital Cost Uncertainty

Table 6 (and data from Table A-1) is also summarized visually in Figure 6. In addition, some recent cost data from projects under construction are highlighted. Also, included in the estimates of CAPEX costs are the estimates of the current installed capacity of similar, comparable generation technologies. The figures are not intended to represent the installed capacity of each technology, but provide some benchmark of the status of a specific technology today. For example, there are approximately 3,000 combustion turbines (simple cycle gas turbines) installed in the United States. Some of these, but not all, are representative of the latest and highest efficiency gas turbine designs. However, technologies across a range of performance spectrums (and unit age) are included in this estimate.

[28] In the U.S., current geothermal power generation is approximately 3.4 GW of installed capacity; 238 separate units with an average nameplate rating of 14 MW. The vast majority of this capacity, 99% of it, is no farther east than California/Nevada

[29] Forecasted CAPEX costs are extracted from Table A-1. Capacity is nameplate capacity from SNL.com, obtained from open source FERC filings.

Figure 6 Summary of CAPEX costs for various generation technologies[30]



The greatest number of installed individual units are hydroelectric units (these comprise less than 100,000 MW of installed capacity). For comparison, in the U.S., thermal (steam) generation makes up approximately half of the installed capacity; nearly 462,000 MW including about 337,000 MW of coal capacity. While the LCOE for hydropower is the lowest (See Table 6), the fact is that most of the hydropower within U.S. borders is already fully utilized, and there is little possibility for any significant expansion of this capacity (or energy), except possibly through additional imports (with the vast majority of that coming from Canada).

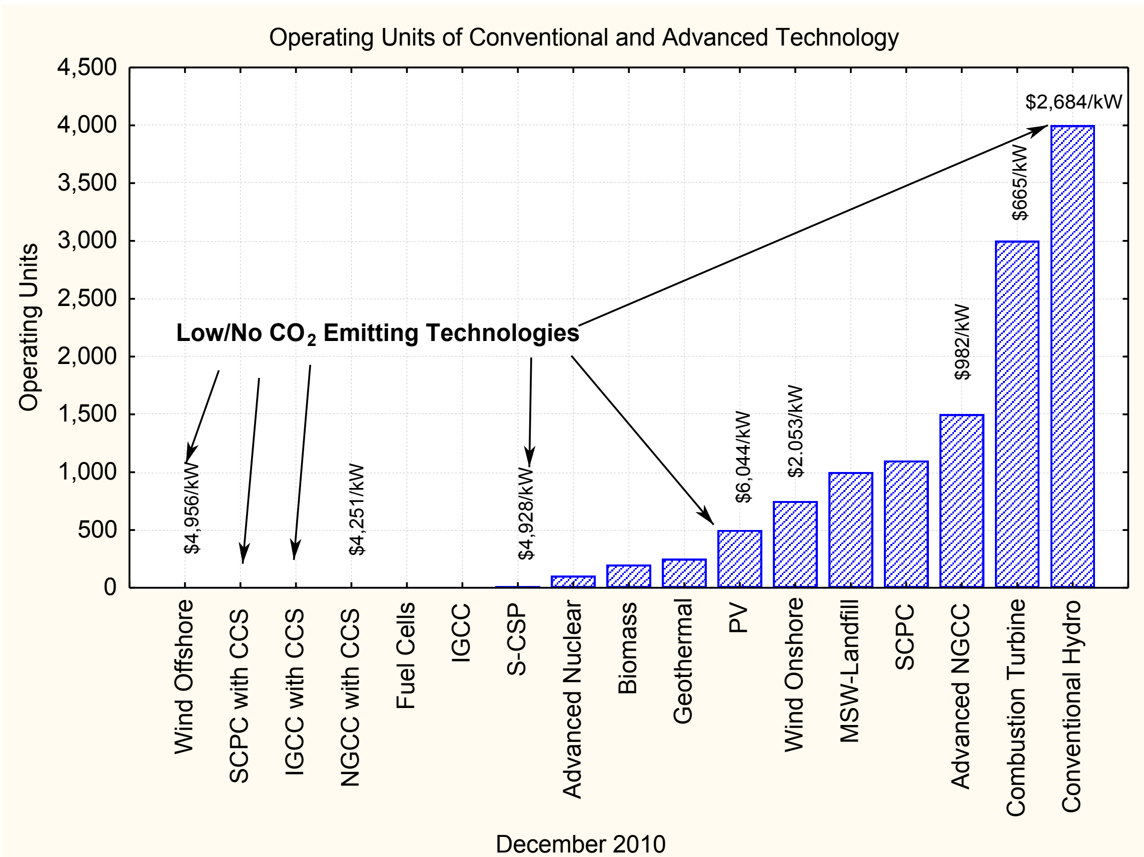
At a high level, one observes that there a correlation between equipment capital costs and their numbers in the market place (in Figure 5 the operating units represent all equipment in place, not necessarily what might be considered the latest innovation, thus while there are several thousand gas turbines in operation, only those reaching commercial operation in the last five years might meet the standard of "advanced" gas turbine). Generation equipment with costs that exceed $4,000/kW represent only about 10% of the installed capacity. The high variability associated with the MSW-Landfill costs is due entirely to a 200% increased noted in the AEO 2011 data.

Estimating overnight capital costs becomes more difficult when there is a lack of substantive empirical cost data. For instance, none of the proposed new-design nuclear

[30] This number of units operating on landfill gas is dominated by reciprocating units (>1,000), with several hundred gas turbine units in place.

plants proposed has been completed (at least four are under construction), and neither has a large scale coal plant with CCS. Therefore estimates of capital costs for these projects cannot be verified in terms of their actual cost performance (i.e. how closely the actual costs achieved the targeted as-sold costs). This leads to disagreement on expected costs across studies. Table A-1 later in the document shows the assumed capital costs for different technologies each of the studies evaluated. The *AEO 2011 Reference Case* estimates for nuclear, coal with and without CCS, and several renewables are higher than what have previously been assumed. A recent study by Rice University compared the results from their survey of industry estimates and found that AEO 2010 was consistently lower.[31]

Figure 7 Number of operating units for each technology class[32]



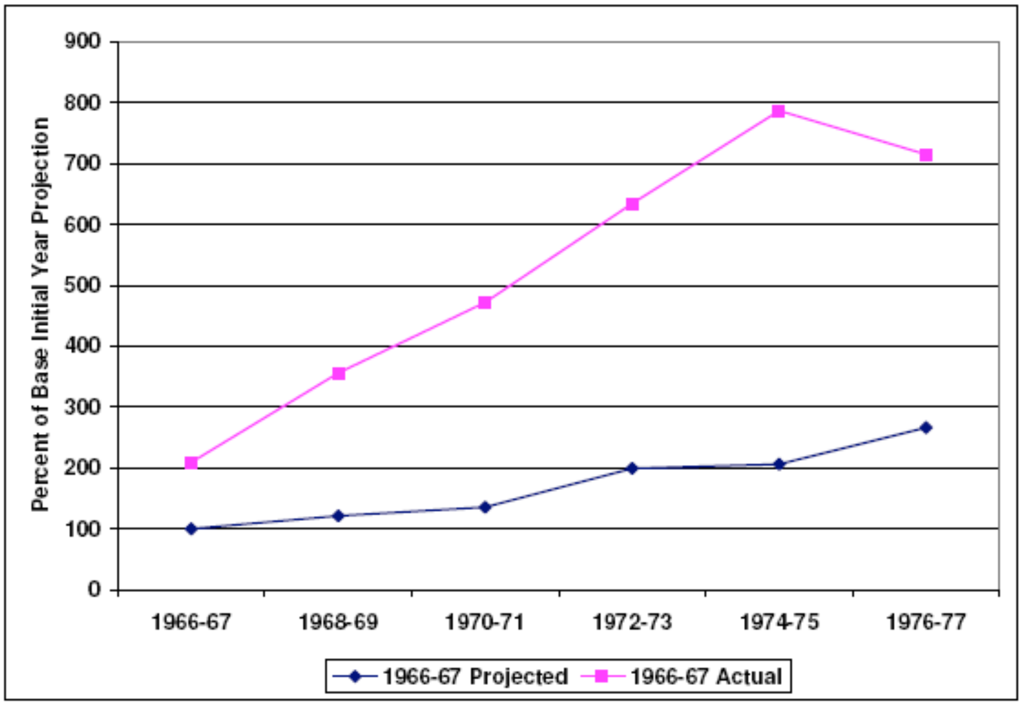
In Figure 5, the NGCC units represent the sum of individual gas turbines and steam turbines installed (the components that comprise what is referred to as a combined cycle). The total number of NGCC installations (combinations of both Rankine and Brayton cycle) is slightly less than 600.

Understanding the equipment costs, both the proposed costs and the final delivered costs, is crucial to quantifying the longer range technology forecast. The nuclear industry in particular has had a history of cost overruns. Figure 8 highlights the projected costs of

[31] James A. Baker III Institute for Public Policy, Rice University. *Energy Market Consequences of Emerging Renewable and Carbon Dioxide Abatement Policies in the U.S*, Peter R. Hartley, Ph.D. and Kenneth B. Medlock III, Ph.D.
[32] Data from SNL.COM, obtained from FERC form filings; cost data from Table A-1.

reactors built in the United States to their actual costs on the date of completion (for the first wave of early nuclear power plants). Clearly the overruns of this first-of-a-kind technology were significant, sometimes pushing 800% of the initial costs.[33] The implication here is that delivering a new, advanced technology (and doing so on a very large scale) can yield unpredictable results relative to capital costs, especially if there is a significant time lag between conception and commercial operation.

Figure 8 Early Estimates of U.S. Power Reactor CAPEX

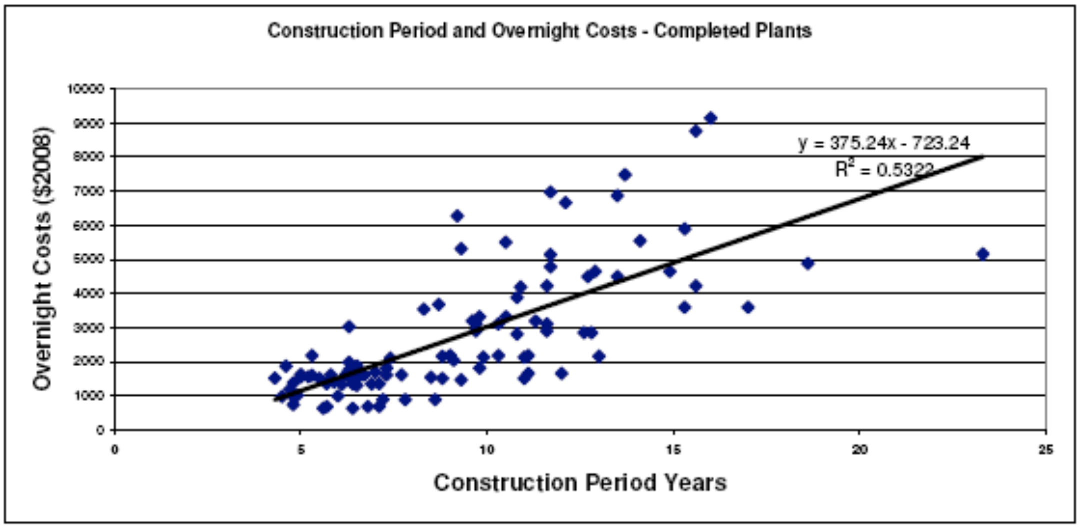


Source: Energy Information Administration, January 1, 1986.

Introducing another significant factor impacting the final cost estimate is the estimation of the length of the build schedule. Building nuclear power (or most likely, any large and complex energy facility) was historically a time-sensitive proposition. As plant construction times dragged on, costs escalated (See Figure 9). The same sort of delay (and sensitivity to cost escalation) is typically not found with construction related to natural gas power plants in general.

[33] Mark Cooper, Senior Fellow, Vermont School of Law; *THE ECONOMICS OF NUCLEAR REACTORS: RENAISSANCE OR RELAPSE; http://www.vermontlaw.edu/Documents/IEE/20100909_cooperStudy.pdf*

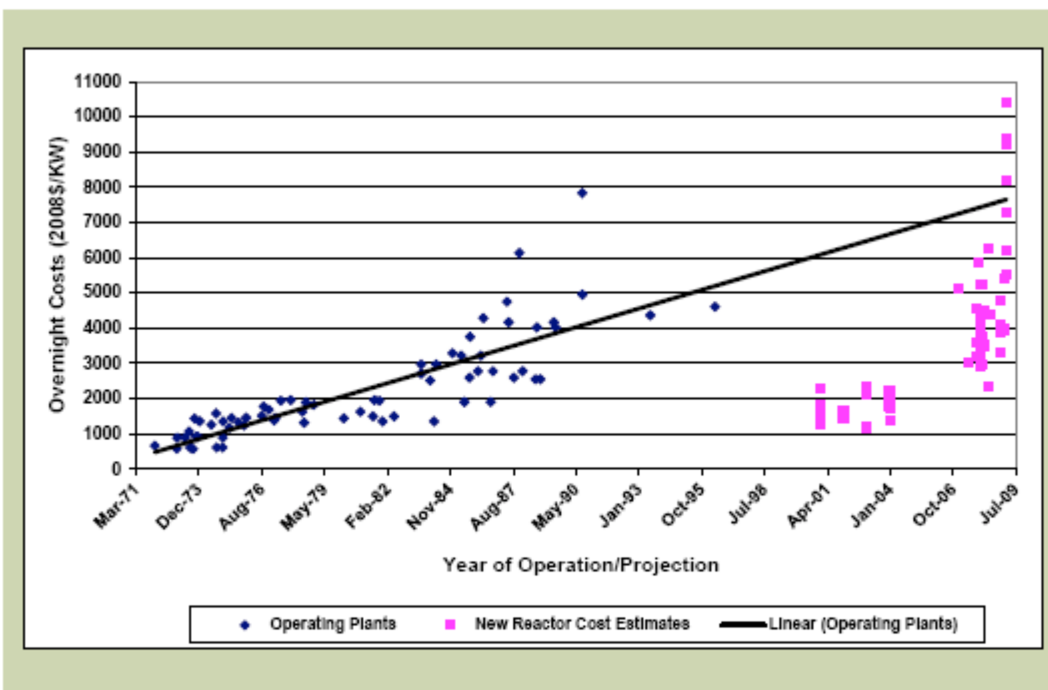
Figure 9. U.S. Nuclear CAPEX cost sensitivity to construction period.



Source: Koomey and Hultman, 2007.

Despite the increase in technical knowledge, and with millions of operating hours, it appears the forecasts for new reactor construction are not faring much better than their previous counterparts (See Figure 10). By default, the financial undertow associated with this increase, may, in the end, encourage the expansion of even more gas-fired generation.

Figure 10. Overnight CAPEX costs for power reactors



Finding

Capital cost uncertainties are significant for some technologies; especially those where the production volume is low (less than 100) or where there has been a significant time lapse since the most recent wave of construction. Capital costs uncertainties for conventional technologies using a gas turbine core (CT and NGCC) are among the lowest.

3. Impact of CO_2 Price on LCOE

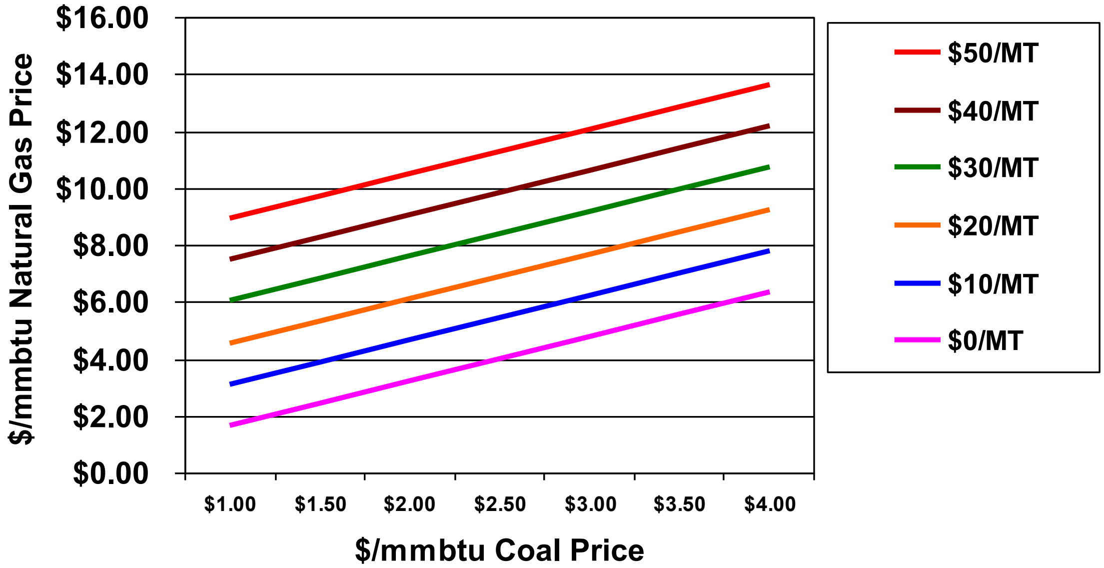
Longer term, carbon costs may become another environmental driver challenging all generation, but coal generation will be especially impacted. Numerous forecasts of recent Federal climate proposals show that climate regulation could reduce coal-fired generation significantly. While Federal climate legislation currently appears stalled, it could regain momentum in the future. Meanwhile, state and regional GHG regulations may expand beyond the Northeast, as proposed under the *Western Climate Initiative* and the *Midwest Greenhouse Gas Reduction Accord*. Furthermore, EPA is in the process of developing regulations for GHGs from stationary sources like coal plants under the *Clean Air Act*. Under EPA's recently-finalized "tailoring rule,"[34] starting on January 2, 2011, new or major modified power plants must receive a permit under the *New Source Review Program* and install BACT for emissions of GHGs. Regulation of existing coal plants could follow under other authorities of the *Clean Air Act.* The definition of BACT for GHG was clarified somewhat by EPA in November 2010, which stated that BACT's applicability for GHGs would focus on plant efficiency.[35] As the first BACT decision (an air permit) was issued for a natural gas combined-cycle, it could be a precedent setting occasion. As of now, carbon capture and CCS is not a BACT requirement, although EPA leaves open the possibility that it might be in the future if it becomes commercially applicable to power plants.

Of course, economics of generation will be a major driver in determining how much fuel displacement switching (or substitution) takes place. Displacement occurs when one plant shifts another from the dispatch stack e.g. when a gas-fired plant displaces a coal-fired plant that is more than likely not co-located. Switching or substitution occurs when there is a change in fuel used for a particular plant. Such plants are considered dual-fueled. The following graphics provide some visual guidance as to the role of charge (or price) for CO_2 and its impact on gas to coal displacement.

[34] A regulation of GHG gases, but at a scale (higher emissions level) that avoids the restrictive 100 tpy and 250 tpy limits noted in PSD.

[35] PSD and Title V Permitting Guidance For Greenhouse Gaseshttp://www.eenews.net/assets/2010/11/10/document_gw_04.pdf

Figure 11. CO_2 Price Impact on Coal to Natural Gas Switching in Currently Operating Power Plants



Source: EIA AEO 2011 Power Cost Assumptions
Assumes 11,000 Btu/kWh heat rate for coal-fired plants and 7,050 Btu/kWh for NGCC plants
Includes only variable O&M costs

Figure 11 shows the impact of CO_2 price on the coal-to-natural gas fuel switching in currently operating power plants. This chart only considers the variable operating costs associated with currently operating NGCC plants with a heat rate of 7,050 Btu/kWh versus currently operating coal-fired plants with a heat rate of 11,000 Btu/kWh. With coal prices between $2.00 and $2.50/MMBtu and no CO_2 price, natural gas prices would need to be between $3.50 and $4.00/MMBtu for a NGCC to dispatch ahead of a coal plant. In the past year, we have seen up to 4 Bcf/d of additional natural gas demand due to coal-to-natural gas displacement. As natural gas prices increase relative to the coal price, higher CO_2 prices would be needed to induce displacement of coal-fired generation by gas-fired generation. At $6 to $7/MMBtu natural gas prices, the CO_2 price would need to be $20 to $30 per tonne to induce fuel displacement.

As noted earlier, Levelized Cost of Electricity (LCOE) is substantially determined by the equipment capital costs (CAPEX), variable production costs (operating costs that are substantially impacted by fuel price), and under the scenarios just considered, a cost (or price) for CO_2. Depending upon the likelihood of a market for CO_2 emission credits, a CO_2 price is expected to be a key role, possibly a dominant role in the power pricing. Table 6 summarizes the LCOE for new power generation technologies assuming a constant CO_2 price of $20/tonne, with hydropower yielding the lowest LCOE price (and least sensitivity to any CO_2 cost burden). Figure 12, using a range of CO_2 costs, shows the impact of a CO_2 charge (or a tax). Here the values shown are the cost increase above the case for that technology with no charge (or burden) for emission of CO_2. Those cases where the emissions are zero initially exhibit no increase in the LCOE as the CO_2 charge changes. Of interest, even those technologies that invest in CO_2 capture are not immune to additional price increases (in electricity) associated with a CO_2 charge. Those technologies cited with "CCS" already carry a cost burden 50-80% higher than the benchmark case (which is the natural gas combined cycle, with no capture).

Figure 12. Impact of CO_2 Cost on Increase in LCOE above the Baseline[36].

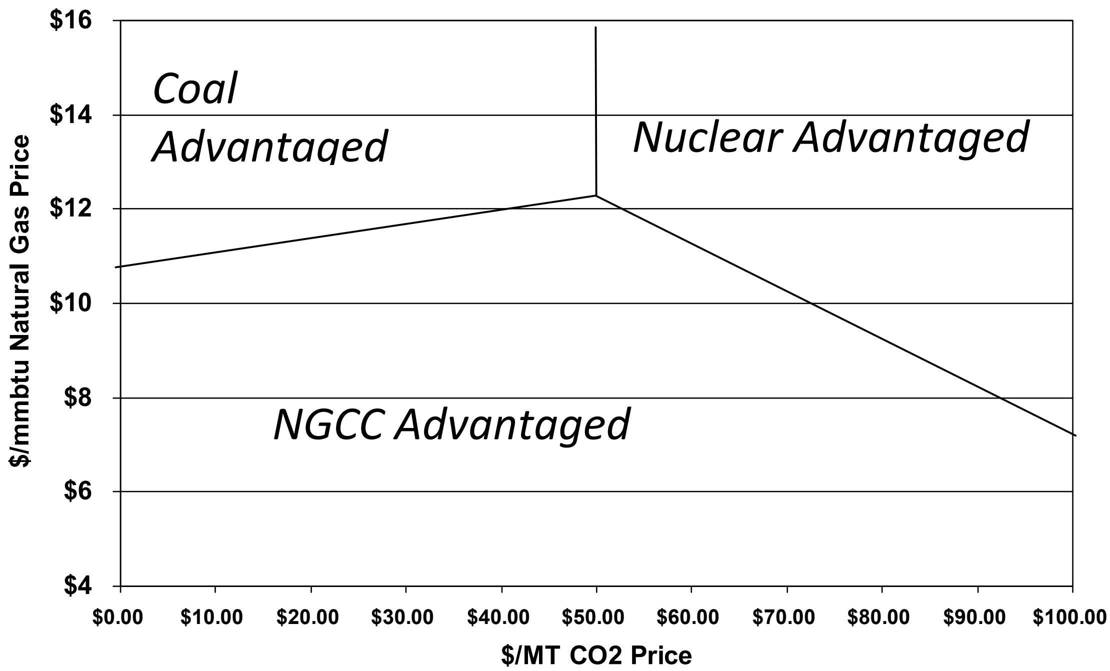
It is the fossil coal based units (Super Critical Pulverized Coal (SCPC) and Integrated Gasification Combined-cycle (IGCC)) which are expected to bear the brunt of the increase in LCOE with a cost burden for the CO_2. However, as shown in Figure 5 (extracted from Table 6) on page 25, those technologies most sensitive to a CO_2 burden (gas turbine and fossil coal technologies) are among the least capital intensive (the five bars on the left side of the figure). Inclusion of carbon capture may reduce the sensitivity of a CO_2 charge on the fossil technologies; but as shown earlier in Figure 5, this moves them to the higher CAPEX technologies on the right. The markets seem to reflect this relationship between capital cost sensitivity, and the amount (and type) of energy conversion devices deployed. Figure 5 depicts that the low CAPEX cost technology has historically been the source of the bulk of the installed generation capacity. More expensive technologies provide very little capacity and generation (there are no operating plants utilizing carbon capture that make up any significant capacity to the U.S. power system). Only the nuclear, with over 100 GW of capacity appears to deviate from this

[36] Data extracted from LCOE values shown in Table A-1, with progressive CO_2 burdens added to the cost figures

observation. But its high capital cost still presents major challenges in terms of providing cost competitive generation not reliant upon fossil fuels

Figure 13 introduces a new dimension by including the CO_2 price and natural gas price combination that would favor building a new NGCC plant, a new coal-fired plant or a new nuclear plant. With CO_2 prices propagating through the cost structure, new coal-fired power plants are preferable only when natural gas prices are greater than $10/MMBtu. At gas prices up to $11/MMBtu, gas-fired power plants are preferred over nuclear plants until the CO_2 price rises to $30/tonne. With gas prices of $6-$8/MMBtu, the CO_2 price would have to be $100/tonne to make the economic choice (to build) nuclear. Whether the markets would accept this is a separate issue. The challenge—and opportunity—is that U.S. reserves of natural gas are growing, and costs are expected to remain below a $6.00/MMBtu threshold for many years.

Figure 13. Window of Opportunity for New Natural Gas Combined Cycle Plants



Source: EIA AEO 2011 Power Cost Assumptions
Assumes 11.5% IRR for all new power plants
Coal cost $2.50/mmbtu

Building new NGCC plants has the advantage over boiler repowering by being able to use the latest, most efficient technology. By replacing an older gas thermal plant with a more efficient combined cycle, the energy production (in MWh) will be reached with perhaps as little as 50% of the gas originally consumed.

Finding

Using LCOE as a metric, new NGCC capacity has a lower cost than all other power generation classes, with the exception of geothermal and conventional hydro. The CAPEX for new NGCC is relatively precise compared to other generation technologies. At gas prices below \$10/MMBtu NGCC is favored over coal at zero CO_2 price. At gas prices between \$6 and \$8/MMBtu, NGCC is favored over coal even with CO_2 prices up to \$100/tonne.

4. What If All Coal Generation is Replaced by Gas Generation?

Almost every case considered expects natural gas generation to continue to expand. New NGCC capacity will be needed if the desire to move away from coal goes beyond the potential coal generation that can be replaced by using existing NGCC plants. The American Public Power Authority (APPA) study "*Implications of Greater Reliance on Natural Gas for Electricity Generation*" estimates that replacing all 337 GW of coal plant capacity with natural gas generation would increase natural gas demand by 14.1 Tcf/year (38.6 Bcf/d). Such an increase in gas demand over even a few years is unrealistic given that total U.S. natural gas demand for 2010 is estimated at 61.7 Bcf/d.[37], although making this substitution would yield a net reduction of CO_2 emissions of about 550 million tonnes annually. In 2007, coal plants produced over 2,000 TWh of energy. Even if one assumes maximum use of existing NGCCs, over 1,300 TWh of coal generation would need to be replaced by new combined cycles plants. To meet this need, about 175 GW of new NGCC capacity would need to be built assuming an 85% utilization rate. This seems an extreme case, although equipment suppliers were able to deliver 150 GW of gas turbine equipment between 2000 and September 2010 (these figures represent gas turbines ordered, and do not include the steam turbine cycle for combined-cycle power plants). And during the period 2000-2010, 278 GW of gas turbine nameplate capacity reached commercial operation (238 GW of summer net capacity).[38]

Notwithstanding the prevalence of natural gas supplies, and the regulatory factors aligned against coal-fired generation, about 11,000 MW of new coal-fired capacity is currently under construction (See Table 7)[39]. These facilities are expected to be in operation prior to 2015. This volume of non-gas fired capacity has the potential to mitigate the increase of gas consumption, at least in the short term.

[37] AEO 2010 Reference Case
[38] www.snl.com
[39] www.snl.com, Nov 2010

Table 7. U.S. Fossil Coal Construction (2010)

Unit	Nameplate Capacity (MW)	Generation Technology	State	NERC Region
Edwardsport IGCC	618	Combined Cycle	IN	RFC
Virginia City Hybrid Energy Center	668	Fluidized Bed	VA	SERC
Formosa Point Comfort	155	Fluidized Bed	TX	ERCOT
Formosa Point Comfort	155	Fluidized Bed	TX	ERCOT
Spiritwood Energy Cogen Plant	99	Fluidized Bed	ND	MRO
Oak Grove Project	944	Steam Turbine: Boiler	TX	ERCOT
Iatan 2	914	Steam Turbine: Boiler	MO	SPP
Sandy Creek	900	Steam Turbine: Boiler	TX	ERCOT
Cliffside	825	Steam Turbine: Boiler	NC	SERC
J.K. Spruce	820	Steam Turbine: Boiler	TX	ERCOT
Trimble County	760	Steam Turbine: Boiler	KY	SERC
Prairie State Energy Campus	750	Steam Turbine: Boiler	IL	SERC
Prairie State Energy Campus	750	Steam Turbine: Boiler	IL	SERC
Longview Power	700	Steam Turbine: Boiler	WV	RFC
Elm Road Generating Station (Oak Creek)	615	Steam Turbine: Boiler	WI	RFC
John W. Turk, Jr. UPC	600	Steam Turbine: Boiler	AR	SPP
Dry Fork Station	422	Steam Turbine: Boiler	WY	WECC
Two Elk One	320	Steam Turbine: Boiler	WY	WECC
Southwest Power Station	300	Steam Turbine: Boiler	MO	SPP
Whelan Energy Center	220	Steam Turbine: Boiler	NE	MRO
Total	11,535			

Note that the bulk of these facilities are based on what might be considered a more conventional power generation: steam turbine boiler, relying on thermal coal to generate electricity. Nominally, these facilities will operate with efficiencies ranging between 35 to 41% cycle efficiency. This is certainly better than those in the current fossil coal fleet today which averages between 33-34%. This improvement in efficiency alone will yield an incremental improvement in the CO_2 tonnes/MWh.

5. Options to Replace Coal Generation Capacity with Gas Generation Capacity

There are potentially five options to replace coal-fired generation capacity with gas-fired generation capacity (options to replace the equipment, but not including options to fully retire, and import electricity from other regions, or expanding regional interconnections):

- Refuel (fuel switch) existing coal plants to burn natural gas by site and equipment modification.
- Repower by adding a gas turbine/combustion turbine to produce thermal energy for the steam cycle.
- Repower by replacing the entire coal facility with a new NGCC plants on the same site
- Convert existing simple cycle gas turbines to NGCCs by adding steam recovery boilers and steam turbines.
- Develop NGCC generation at new sites (greenfield site development).

Table 8 highlights some of the advantages and disadvantages for each option. All of these options could require the build out of new natural gas pipeline capacity to the plant site. The last option could require new transmission capacity to the plant.

Table 8. Comparison of Near Term Fuel Switching Opportunities

	Advantages	**Disadvantages**
A) Refueling existing coal plants to burn natural gas in existing coal boilers	Use of existing transmission access Potentially wider turn-down ratio than coal-only option. Quick compliance with many proposed regulations (clean fuel exemption)	Less efficient than NGCC plants May lack gas pipeline access Reduced output when operating on off-design fuel
B) Repower existing coal plants to burn natural gas by replacing the boiler; addition of a gas turbine, but retention of the available steam turbine and generator.	In most cases, this is less expensive than building a new NGCC Use of existing transmission access	Much less efficient than a new NGCC Limited if plant is considered to be critical to grid reliability and would be unable to go off-line for the 4-6 months needed to convert to NGCC May lack gas pipeline access
C) Replace the entire existing coal facility with a new NGCC on the same site	Similar efficiencies as new NGCC plant Use of existing transmission access and infrastructure	Higher capital cost than the boiler replacement option Limited if plant is considered to be critical to grid reliability and would be unable to go off-line for the 4-6 months needed to convert to NGCC May lack gas pipeline access
D) Convert existing simple cycle gas turbines to combined cycles by adding steam recovery boilers and steam turbine.	Low capital cost to improve efficiency and competitiveness with coal plants Use of existing pipeline capacity and transmission access Could support cycling needs of increased renewables	Many units less efficient than new NGCC plants Pre-existing permit restrictions on operating hours Typically dispatched later in order because of higher variable operating costs
E) Build NGCCs (or CTs) at a new sites	Higher efficiencies than other options Less expensive alternative than nuclear or wind on a \$/MT of CO_2 avoided	Higher capital costs than other options Need for new site permitting May need new transmission and/or pipeline capacity

Burning natural gas in boilers designed for coal is an opportunity to switch fuels without significant added capital cost. These plants already have access to the local grid and sufficient transmission capacity as they are in use today. Using natural gas in these boilers is a quick way to reduce CO_2 emissions. However, burning natural gas in these types of boilers is less efficient than using gas in NGCC plants and consequently will have higher CO_2 emissions.

Repowering coal plants to use natural gas is another way to reduce CO_2 emissions. The potential for repowering existing coal plants across the nation is largely unknown. Decisions on which plants could be targets will depend on:

- Location
- Whether the plant is needed for grid reliability
- Whether the economics justify the switch, boiler replacement or site repowering based on local power prices
- Need for new infrastructure (gas supply pipeline or electric transmission).

Beyond fuel-switching, the options remaining to repower a coal-fired power plants become limited to a) replace the boiler (but keep everything else, including the steam turbine), or b) replace all of the generation components. Boiler replacement consists of replacing the boiler with a combustion turbine and a heat recovery steam generator, but maintaining the basic infrastructure (the existing steam turbine and its generation). It increases the unit's net generating capacity by 150-200%, while reducing the heat rate required by 30-40%.

The more extensive repowering (replace all rotating equipment) may require demolition of most of the existing coal plant, replacing this with a new (and more efficient) combined-cycle plant on that site. The benefits of this approach are the potential for faster permitting since an existing site is being used, transmission access already in place, and no increase in social and economic impacts on the local area. Rebuilding of the entire plant has the advantage over repowering just the boiler because the net result is a much more efficient facility.

There are several references to repowering in the studies reviewed, such as the APPA study's section on repowering. However, most studies indicate that further assessment of the viability and desirability of repowering is needed.

If all coal generation were to be replaced with gas generation, could it be done? The answer is partially yes. In 2010 the coal fleet generated some 2,000 Billion kWh of energy with over 326 GW of capacity (burning that much fuel also released about 2 billion tonnes of CO_2). Using a capacity factor of 80% for gas-fired generation, it would require approximately 285,000 MW of new gas generation construction. The U.S. can deploy well over 150,000 MW of gas fired generation per decade (not including the additional generation from the thermal cycle). So, yes, it appears that over several intervening decades, the U.S. could—hypothetically—offset or replace most of the coal generation. And operating with a gas-fired system (based on a fleet of NGCCs) would yield a CO_2 production of approximately 700 million tonnes/year, or a 60% reduction. The natural gas requirements to feed this replacement capacity would be large (approximately 13 Tcf/year, using a 52.5% cycle efficiency and 80% capacity factor[40]), but given the size of the developing reserve basins, the U.S. could accommodate this gas demand. Expansions of other infrastructure elements (pipelines, compressor stations, transmission, etc.) would also be required. It might represent the largest industrial undertaking in decades. On the negative, if CCS becomes a prerequisite for new power plants, it could actually increase the consumption of gas further. CCS, as we understand it today, adds greatly to the parasitic losses at a facility. Requiring all new NGCCs to incorporate CCS would reduce their net generation substantially, forcing an even larger number of units to be built, and consuming additional natural gas (or any fossil fuel used to operate the facilities). Requiring *existing* NGCCs to retrofit would likely cause even greater performance losses, as virtually none of the installed fleet has been optimized to accommodate such an energy intensive post-combustion process. And as highlighted several times, this comes with a higher LCOE. Since much of the coal capacity is sited in areas of the U.S. with low electricity prices, the percent increase in electricity in the critical manufacturing regions of the U.S. would increase, and increase even more significantly if every facility were required to capture CO_2.

6. Carbon Capture and Storage

If the U.S. adopts as a goal an 80% reduction in CO_2 emissions by 2050 from 2005 levels, studies suggest that for natural gas or coal-fired generation to be viable in 2050, then carbon capture and storage (CCS) is needed for both technologies[41].

CCS is perhaps one of the more challenging technological innovations coming to power generation. CO_2 control represents a significant departure from experience with environmental controls. Regulated pollutants (such as SO_2 or NO_x) are essentially trace components, byproducts from the combustion of fossil fuels. CO_2 on the other hand is a bulk gas constituent, one that could comprise as much as 12% of an exhaust gas. And its relatively inert state makes extraction and recovery a very energy intensive process.

The operating carbon capture systems today typically fall into one of two categories: 1) collection of CO_2 from a relatively clean exhaust stream for the use as a food or beverage additive or 2) a research or demonstration project to evaluate the economics and technical issues associated with large scale carbon capture from power generation.

There are no large scale operating carbon capture plants connected to a power station currently operating (large scale implying that 50% or more of the exhaust CO_2 is recovered of a facility 25 MW or larger). In those operating units where CO_2 is recovered, typically only 1 or 2 % of the exhaust volume is treated in the CO_2 recovery cycle. This may result in a few tons to a several hundred tons per day of production, but this is nowhere near the level that one might consider commercial (in terms of commercial for reducing CO_2 emissions from a power plant).

[40] The often quoted "60%" efficiency figure is usually an ISO sea-level rating (no losses). A relatively modest cycle efficiency is used because facilities are expected to cycle up and down throughout the year, and to account for performance degradation. Also, the increasing presence of renewables on the system will most likely lower the efficiency of existing generation by forcing the units to operate at partial loads much of the time.

[41] Massachusetts Institute of Technology,: "The Future of Natural Gas – Interim Report", July 2010, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf

Forecasting the cost of CCS is perhaps more art than science given the uncertainty around process and costs. While there are an abundance of references to extract from, for brevity we will use data from the AEO 2011 *Updated Capital Cost Estimate for Electricity Generation Plants (December 2010)*. Below is an extract from that report's Table 2-5 – Technology Performance Specifications that has been extended to include an estimate of LCOE and emissions per MWh.

Table 9. Cost of Coal and Gas Technologies (with and without CCS)

	Technology	*Advanced Pulverized Coal*	*Advanced Pulverized Coal with CCS*	*IGCC with CCS*	*Advanced NGCC*	*Advanced NGCC with CCS*
	Size, MW	650	650	380	400	400
	Capacity Factor	80%	80%	80%	80%	80%
SO_2	**Lb/MMBtu**	0.100	0.020	0.015	0.001	0.001
NO_x	**Lb/MMBtu**	0.0600	0.0600	0.0075	0.0075	0.0075
CO_2	**Lb/MMBtu**	206.0	20.6	20.6	117.0	12.0
CAPEX	**$/kW**	$ 3,167	$ 5,099	$ 5,348	$ 1,003	$ 2,060
Heatrate	**Btu/kWh**	8,800	12,000	10,700	6,430	7,525
Variable O&M	**$/MWh**	$ 4.25	$ 9.05	$ 8.04	$ 3.11	$ 6.45
Fixed O&M	**$/kW-yr**	$ 35.97	$ 76.62	$ 69.30	$ 14.62	$ 30.25
Generation	**MWh/yr**	4,555,200	4,555,200	2,663,040	2,803,200	2,803,200
Fixed Cost	**$/MWh**	$ 5.13	$ 10.93	$ 9.89	$ 2.09	$ 4.32
Total Capital	**$ Million**	$ 2,058.6	$ 3,314.4	$ 2,032.2	$ 401.2	$ 824.0
Capital Recovery Factor	**%**	12.0%	12.0%	12.0%	12.0%	12.0%
Fuel Cost	**$/MMBtu**	$ 2.50	$ 2.50	$ 2.50	$ 6.00	$ 6.00
Fuel Cost	**$/MWh**	$ 22.00	$ 30.00	$ 26.75	$ 38.58	$ 45.15
LCOE	**$/MWh**	$ 85.61	$ 137.29	$ 136.25	$ 60.95	$ 91.19
Emissions						
SO_2	**Lb/MWh**	0.880	0.240	0.161	0.006	0.008
NO_x	**Lb/MWh**	0.528	0.720	0.080	0.048	0.056
CO_2 Emissions	**Lb/MWh**	1,813	247	220	752	90
CO_2 Storage	**Lb/MWh**	-	2,225	1,984	-	790
Emissions Relative to NGCC with CCS						
SO_2		116.94	31.89	21.33	0.85	1.00
NO_x		9.36	12.76	1.42	0.85	1.00
CO_2 Emissions		20.08	2.74	2.44	8.33	1.00
CO_2 Storage			2.82	2.51		1.00
Source: AEO 2011 Reference Case						

Of interest is the conclusion that *Advanced NGCC with CCS* exhibits an LCOE of $91 per MWh compared to *Advanced Pulverized Coal with CCS* (post combustion capture) of $137 per MWh and *IGCC with CCS* (pre-combustion capture) of $136 per MWh. This analysis assumes a delivered coal and gas prices of $2.50 and $6.00/MMBtu, respectively. It appears that an NGGC with CCS can be competitive with an IGCC with CCS unless the delivered gas price exceeds $12.00/MMBtu.

Just as importantly an *Advanced NGCC with CCS* has substantially lower emissions of SO_2, NO_x and CO_2. Emissions of CO_2 for *Advanced Pulverized Coal with CCS* is 2.74 times greater than an *Advanced NGCC with CCS*, but more importantly the quantity of CO_2 that needs to be stored is 2.82 times greater. Emissions of CO_2 for *IGCC with CCS* is 2.44 times greater than an *Advanced NGCC with CCS,* but more importantly the quantity of CO_2 that needs to be stored is 2.51 times greater. In addition, the gas option does not emit any mercury or generate ash. Furthermore, the coal options with CCS have a significantly higher heat rate than coal without CCS suggesting the emissions of mercury and the generation of ash will be much greater than without CCS.

Finding

Natural gas with CCS may have a lower LCOE per MWh than coal with CCS, but should also have significantly lower emissions of SO_2, NO_x, CO_2, mercury and ash and significantly lower CO_2 transportation and storage requirements. However both these assessments are based on models, not actual operating experience. And the price of natural gas (or its availability) will strongly impact the competitiveness of power generation by natural gas. Federal research and development and pilot project dollars for carbon capture should be at least equally focused on natural gas and coal.

B. Short-term Economic Dispatch Costs Related to Existing Generation Facilities

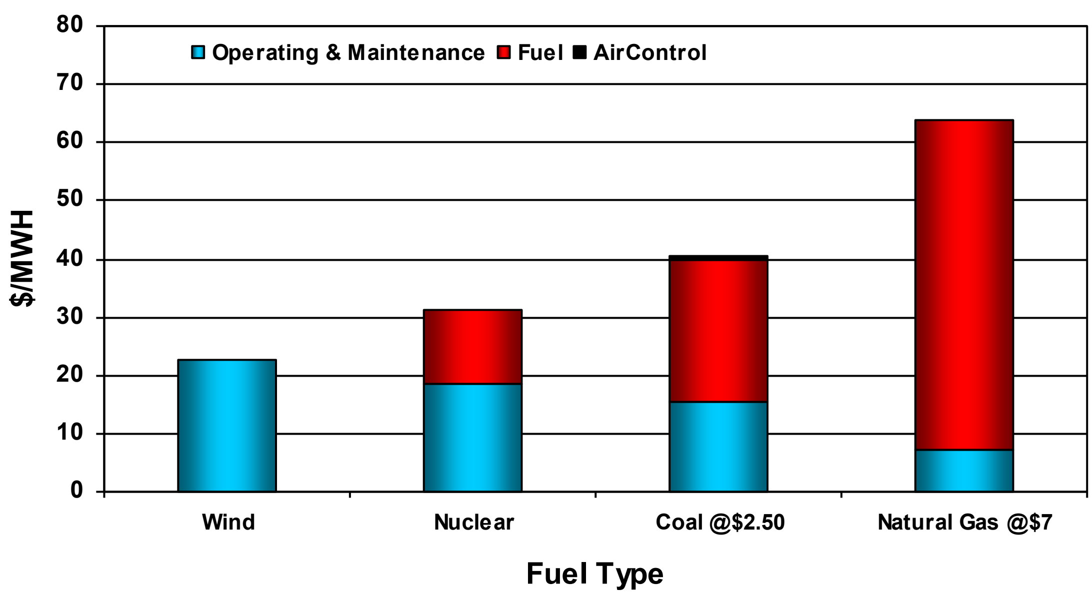
The order in which power units are dispatched is determined primarily by the variable production costs for electricity. Wind generation has no fuel costs and very low variable costs and thus is expected to be dispatched first, if it is available for dispatch. Nuclear generation has low fuel and variable costs and is generally dispatched ahead of coal and natural gas plants. Coal-fired and natural gas-fired power plants then compete on the margin for the ability to dispatch. Figure 14 highlights the variable costs associated with several different types of power plants and are indicative of the order in which they would likely be dispatched to meet the load demands within a specific ISO region. As noted already, even though the dispatch cost for wind is the lowest, it cannot be dispatched if wind power is not available on the system (or a set of unique meteorological conditions results in no wind production). To some extent this creates a quandary: policy makers and regulators would prefer to see the wind used as much as possible, but the reality is that it is not always available.

Renewable energy generation (which primarily provides energy, MWh, not capacity), carries with it additional hidden costs beyond generation CAPEX. For wind, most of the resource base is concentrated in regions where there is minimal load. In fact, a large amount of wind resource straddles the Eastern and Western Interconnections. Currently there is little power transmission capability between these two regions. Tapping these resources requires construction of new transmission capabilities, which can be expensive. And in those parts of the country that have undergone substantial deregulation, the generation owner is likely to be a separate entity from the transmission owner. We have yet to develop fair and effective regulatory mechanisms for assigning the cost of transmission to the generator or the end-user. Various mechanisms are being explored (everyone pays a flat rate, like the postal service is one example). But it is clear that if the cost of the transmission must be added to the generation cost for remotely sited renewables, the final cost is likely to be substantially greater than the wholesale costs (LCOE) described in previous sections.

And renewable generation is not expected to be dispatchable, like much of the installed base of fossil and nuclear. Wind generation tends to be more available during off-peak months and off-peak hours, periods when coal and nuclear are expected to be operating at base load (typically in the overnight hours). Adding new wind generation may require increased cycling of the installed coal and nuclear capacity, capacity that is generally not designed for cycling. Increased cycling costs should raise the O&M costs and increase electric prices. Increased cycling of coal generation will likely lead to an increase in emissions as the effective heat rate increases and environmental controls operate less effectively.

A storage solution that allows intermittent renewable generation to be dispatched as needed may solve part of the scheduling problem. But it further adds to the cost of intermittent renewable generation. Not only must the CAPEX of the renewable generation be included in the LCOE, but that CAPEX will now include a storage component that is expected to be roughly the same magnitude. The CAPEX of transmission needed to move renewable generation to load centers would further increase the LCOE of renewable generation. This adds to the dilemma—the fuel is free (wind or sunshine), but the costs continually increase as a technical solution is sought to eliminate or reduce the vagaries of its availability.

Figure 14. Variable Costs for Power Generation by Fuel Type[42]



For natural gas-fired plants to compete with existing coal plants, natural gas prices would need to be near $4/MMBtu. Recent history has shown that natural gas can displace coal in the power generation dispatch stack when gas prices are sufficiently low. In 2009, when natural gas prices were below $5/MMBtu for much of the year and even fell below $3/MMBtu during August and September, estimates for incremental gas demand from coal-to-gas switching were between 2-4 Bcf/d. A Bentek Energy paper[43] noted that the

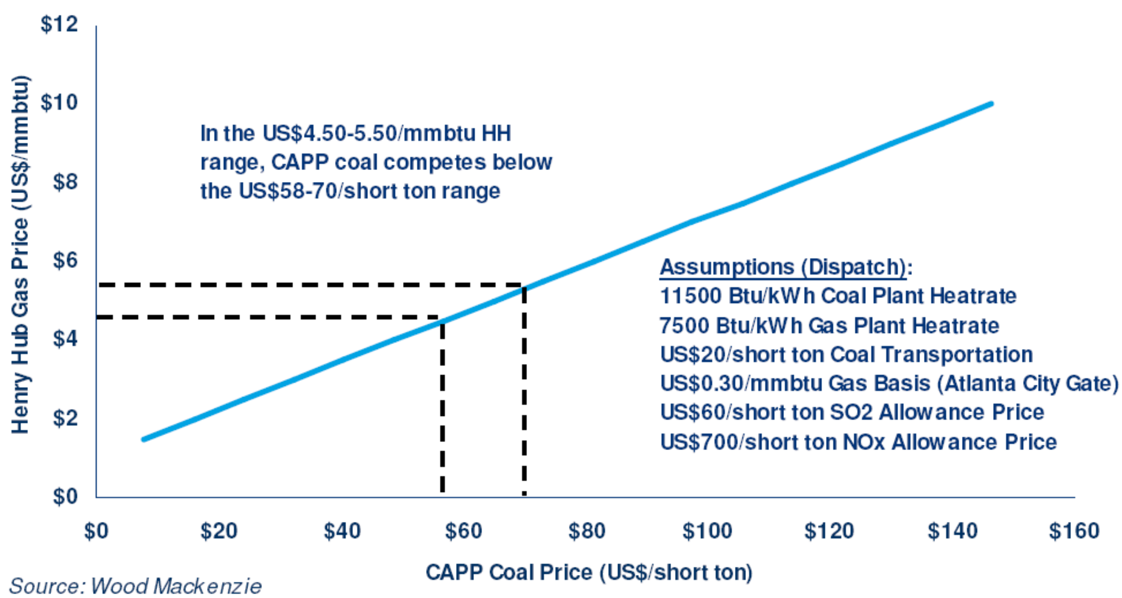
[42] Reference: Wood Mackenzie
[43] Bentek Energy – Market Alert, August 3, 2010, page 22

coal-to-natural gas displacement seen in 2009 was temporary due to the unusually low natural gas prices in that year. Economic incentives will likely be required to continue this fuel-displacement beyond a period of very low gas prices. In 2010, as natural gas prices rebounded, some reverse displacement occurred, as Bentek Energy predicted. However, this reverse displacement was limited by an increase in coal prices.

The impact of the price of carbon is expected to affect the dispatch order of generation; but how the order shifts is likely to be dependent upon load (overnight, off-peak load is expected to be only about 60% of peak demand, depending upon the season). Using a price of $35/tonne for CO_2, the price elasticity for electricity demand is expected to be about -0.10, on average (this yields a 10% reduction in coal generation and a 12% reduction in gas use as these are on the margin) for the Midwest ISO.[44]

In Figure 15 below, the blue line represents the indifference point for dispatching either a coal-fired or natural gas-fired power plant in the regions that use Central Appalachia coal (CAPP). When the combination of coal prices and natural gas prices are above the line, coal-fired power is preferred. When the price combination is below the blue line, natural gas-fired plants are dispatched ahead of coal plants. As shown in the chart, if coal prices are between $570/short ton, Henry Hub prices would need to be between $4.50-5.50/MMBtu to be competitive. The example in the chart is based on assumed heat rates of 11,500 Btu/KWh for the coal-fired plant and 7,500 Btu/KWh for the natural gas-fired plant. A more efficient natural gas-fired plant (current natural gas combined cycle plants have rates below 7,000 Btu/kWh) would be competitive at either lower coal prices or higher natural gas prices than shown.

Figure 15 Central Appalachia Coal Prices versus Natural Gas on Dispatch Decisions



[44] A. Newcomer, et al. "Short Run Effects of a Price on Carbon Dioxide Emissions from U.S. Electric Generators",. *Environment Science & Technology*, v 42, No. 9, **2008** pp 3139-3143

1. Opportunity for Fuel Displacement without Additional New Generation

Coal-fired power plants account for about 80% of the CO_2 emissions in the power sector and 33% of all U.S. CO_2 emissions. Reducing CO_2 emissions from coal plants is the focus of many proposals that look to reduce overall U.S. emissions. The quickest way to reduce emissions is to displace existing coal-fired plants from the dispatch stack by using existing natural gas-fired power plants since NGCC plants produce 60% less CO_2 emissions than coal plants, and a NGCC is far more likely to be nearer to the dispatch slot for a coal thermal plant than a simple cycle combustion turbine.

The age and inefficiency of a significant portion of the coal generation capacity in the U.S. increases the desirability of coal to gas displacement to lower CO_2 emissions. Currently, the U.S. coal fleet has over 90 GW of capacity that is over 50 years old and nearly 160 GW of capacity that is over 40 years old. Of this 160 GW of capacity, nearly 60% do not have scrubbers (FGD's for SO_2 mitigation). These plants may be retired in the next 5-7 years due to the more stringent Clean Air Act regulations. In addition to the lack of scrubbers, the older coal capacity has significantly higher heat rates than NGCC plants. The differences in heat rates allow for economically driven coal-to-natural gas fuel displacement when natural gas prices are low or when coal prices are high.

There are several ways to immediately displace coal generation with natural gas generation:

- Operate the existing NGCC plants at higher and coal plants at lower utilization rates. NGCC plants exhibit capacity factors somewhat less than 40% (the overall industry utilization for all gas when combustion turbines are included is less than 20%) versus an optimal rate of 85%.
- Convert some fossil coal (or possibly oil) units to natural gas. This type of fuel substitution may be necessitated in the short run just to meet some specific environment requirements such as SO_2 emissions. But because gas-fired thermal (steam) systems are likely to have excellent turn-down, this type of fuel substitution may also be needed because of the expected influx of energy associated with intermittent renewable generation. It is also non-dispatched, and when the capacity is lost due to changes in meteorological conditions, a rapid ramp in dispatched generation that is based on gas may be the alternative.

However the potential impact of renewable capacity additions, the total energy may offset fossil fuel generation, Thus, substituting generation (kWh) is not the same as substituting available capacity (kW). For example, if all the capacity in the WECC were replaced with wind, it would not meet the peak load requirements (which typically occur during the day), nor would it generate sufficient energy (the capacity factor for wind is only about 30%).

Table 10. 2009 Emission and Performance Data for U.S. Generation (source: www.snl.com)

	Fuel Type Natural Gas			
	Nameplate MW	Avg Capacity Factor	Net Gen MWh	CO2, tpy
Generation Technology				
Combined Cycle	232,473	39.11	753,499,285	321,661,250
Steam Turbine: Boiler	76,012	17.57	74,268,454	49,092,153
Grand Total	**308,484**	**32.48**	**827,767,739**	**370,753,403**
	Fuel Type Coal			
	Nameplate MW	**Avg Capacity Factor**	**Net Gen MWh**	**CO2, tpy**
Generation Technology				
Steam Turbine: Boiler	332,646	54.50	1,754,784,209	1,867,826,731
Grand Total	**332,646**	**54.50**	**1,754,784,209**	**1,867,826,731**

In 2009, some 2,769 TWh of generation was produced by all fossil fuels, generating about 2.3 gigatonnes of CO_2. The breakdown between technologies and fuel sources is summarized on Table 10[45]. For the fossil systems reported operating in 2009 CO_2 emissions were roughly 0.83 tonnes/MWh. Given that an optimized NGCC can achieve a CO_2 emissions level of 0.35 tonne/MWh, there is an opportunity for substantial improvement (reduction) in CO_2 emissions through a combination of fuel and technology substitution or displacement, if reduction in CO_2 emissions from industry-specific sources is the objective.

As is evident from Table 10, natural gas generation operates at a substantially lower capacity factor compared to the coal fleet (which is primarily a thermal/steam fleet). Not all the thermal (or steam) fleet operates on coal; there is substantial (84 GW) capacity of thermal (or steam) plants operating on natural gas or oil, and at much lower efficiencies than their combined-cycle counterparts.

For the past decade there is clear evidence of an on-going shift between the generation of electricity by natural gas and that by coal (See Figure 16), with the recent economic pullback affecting coal generation more than from gas generation. According to EIA's Electric Power Annual, the decline in generation from 2008 to 2009 was about 4.1%, the largest decline in 60 years[46]. Despite this, there was strength in the utilization of natural gas for power production.

The downturn in consumption shown in Figure 16 was driven substantially by the tremendous impact of the economy on the industrial sector. The prognosis for recovery, both in terms of electricity consumption and production (capacity utilization) within the industrial sector appears to be good, but with clear room for additional growth. As shown in Figure 17[47], current U.S. industrial production levels are below normal, and a recovery could easily generate additional demand for electricity.

[45] Information obtained from SNL.COM are excerpts of DOE FERC form data.
[46] U.S. Department of Energy, "Electric Power Annual 2009", http://www.eia.gov/cneaf/electricity/epa/epa_sum.html?src=email
[47] St. Louis Federal Reserve, http://research.stlouisfed.org/fred2/graph/?chart_type=bar&s[1][id]=CUMFN , accessed 24 Nov 2010

Figure 16. Comparison of Generation by Fuel Type Since 1996

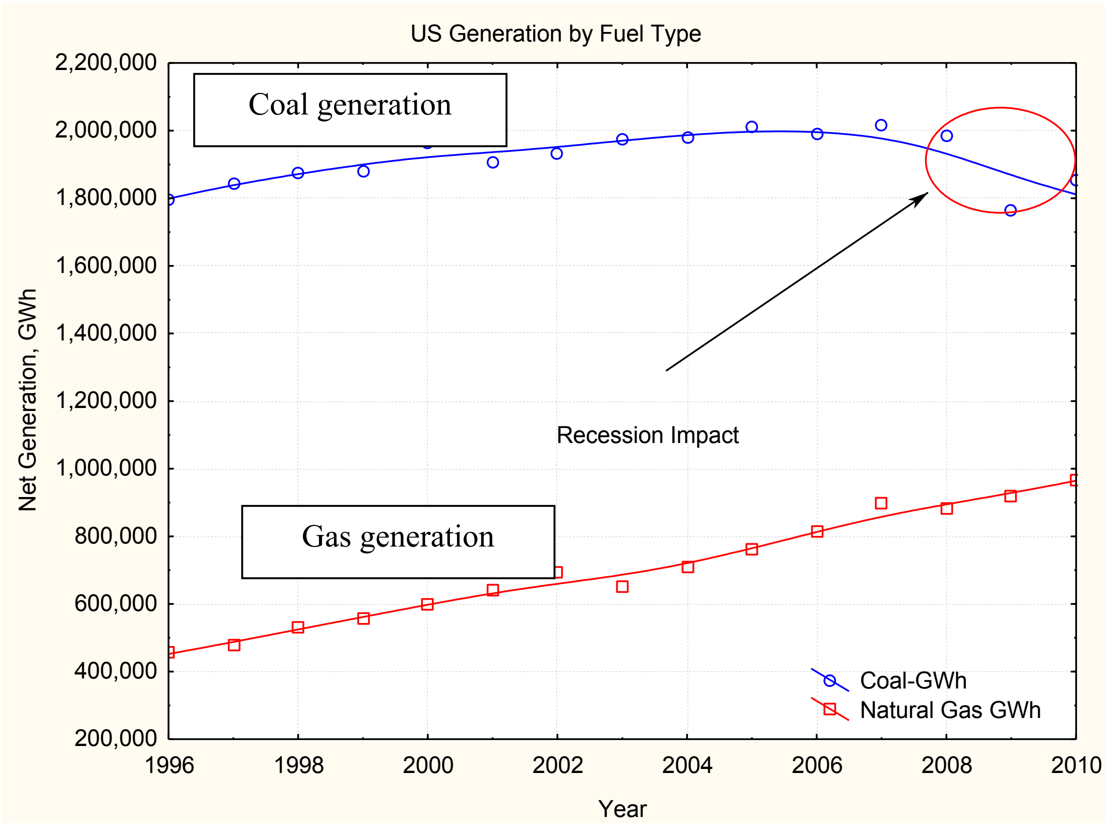
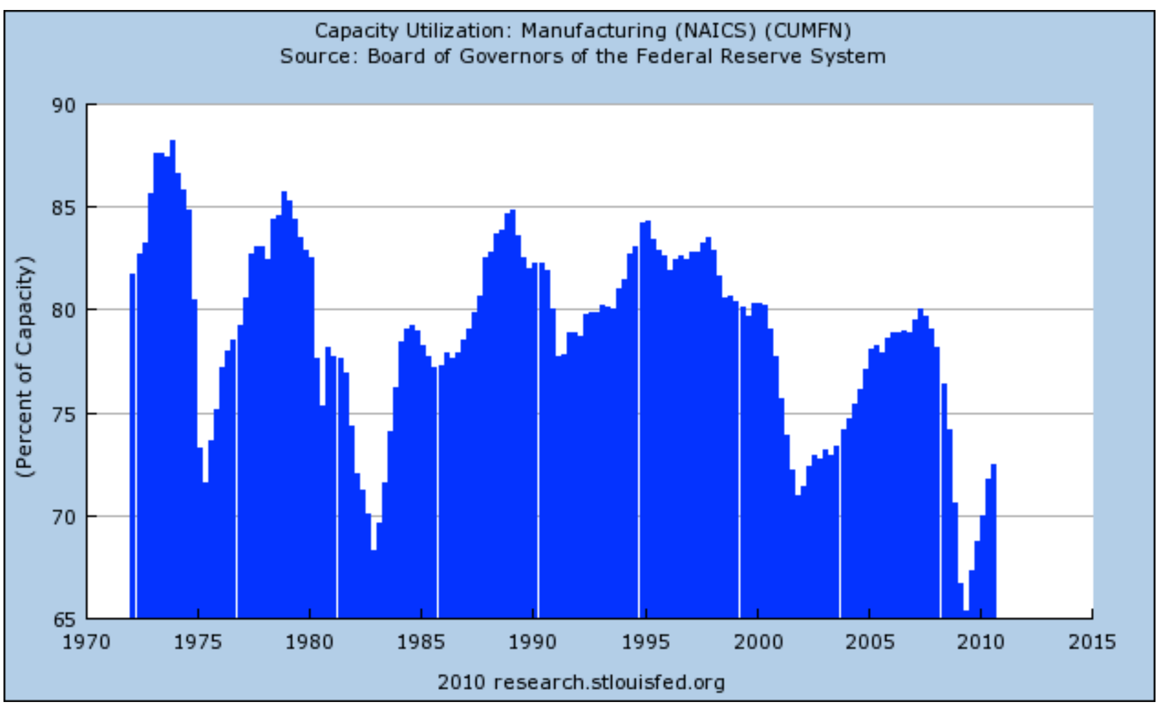


Figure 17. U.S. Industrial Capacity Utilization 1972-2010



Using existing NGCC capacity represents a quick and low (capital) cost way to reduce CO_2 emissions. There would be no additional capital costs needed as the plants are already on-line – just incremental fuel and operating expenses would be incurred. The current NGCC fleet operates at about 40% capacity utilization[48]. The reason for the low utilization of the fleet comes from the boom in NGCC construction in the 1990's when natural gas prices were at historic lows and NGCC capacity increased 43%. A rapid rise in natural gas prices and a forecasted electricity demand that did not materialize as expected, led to NGCC capacity being under-utilized. If the utilization of NGCC was increased to 85%, the CO_2 emissions from the power sector could be reduced by 15%. However, there are numerous constraints that will limit the potential for fuel-switching in existing NGCC plants, which will be covered in the section on *Barriers to Fuel Displacement* below.

Burning natural gas in boilers designed for coal is another opportunity for fuel displacement without significant added capital cost. These plants already have access to the local grid and sufficient transmission capacity as they are in use today. Like higher utilization of existing NGCC plants, using natural gas in these boilers is a quick way to reduce CO_2 emissions. However, burning natural gas in these types of boilers is less efficient than using gas in NGCC plants.

2. Size of Opportunity and Implications for Natural Gas Demand

The Congressional Research Staff (CRS)[49]study presented a theoretical maximum amount of fuel displacement that is possible by more fully utilizing the existing fleet of NGCC plants in the U.S. The study showed that running NGCC plants at an 85% utilization rate would permit approximately 640 TWh of coal-to-natural gas fuel displacement. The reduction in coal generation would decrease CO_2 emissions by 636 million tonnes, while increasing CO_2 from the NGCC plants by 254 million tonnes for a net CO_2 emissions reduction of 382 million tonnes. The incremental natural gas demand from this fuel displacement would be 12.7 Bcf/d (the total consumption would be approximately 15 Bcf/d). The CRS study was essentially an energy-only study, replacing coal MWh with gas generation MWh, and did not consider that some of this gas generation might also be servicing the intermediate and peaking power (MW) markets. The CRS study also indicates numerous barriers that could preclude the U.S. from reaching this maximum potential displacement. These barriers are discussed in the *Barriers* section below.

According to the studies reviewed, achieving higher utilization in existing NGCC plants by shutting down or limiting the run time of existing coal plants could replace a range of 102-423 TWh of coal generation. Replacing this coal generation could reduce CO_2 emissions in the power sector by a net of 58-252 million tones. This reduction represents between 4-10% of total power sector CO_2 emissions and would increase natural gas demand by 1.9 – 8.4 Bcf/d.

---

[48] EIA Electric Power Annual 2009, Table 5-2

[49] Congressional Research Service, **Displacing Coal with Generation from Existing Natural Gas Fired Power Plants,** January 19, 2010 R41027 (http://assets.opencrs.com/rpts/R41027_20100119.pdf)

Table 12 shows a summary of the studies' views on fuel displacement, emission reduction, and incremental natural gas demand.

Table 12. Summary of Potential Coal-to-Natural Gas Displacement in the United States

	Amount of Coal Generation Replaced (TWh)	Net reduction in Power Sector CO_2 Emissions (million tonnes)	% Power Sector CO_2 Emissions Avoided	Incremental Natural Gas Demand (Bcf/d)
MIT[50]	423	252	10%	8.4*
INGAA[51]	257	173	7%	5.5
The Brattle Group[52]	283	182	7%	4.6
ClearView[53]	164	118	5%	3.3
CRS[54] Theoretical Maximum	640	382	15%	12.7
CRS[55] 25 Mile Proximity Case	182	105	4%	3.5

* Estimated

The CRS study concentrates on replacing coal generation with nearby NGCC regardless of efficiency of the coal plants. The CRS study assesses the impacts on CO_2 emissions reduction of fully utilizing existing NGCC plants. This represents a theoretical maximum of CO_2 emissions reduction. This amount is calculated based on the excess capacity available at existing NGCC plants if the plants were run at 85% utilization instead of the 42% utilization that was observed. The CRS then analyzes how much of the theoretical displacement is obtainable given transmission and other infrastructure limits. In their analysis, CRS looked at two different limitation cases: coal-to-natural gas displacement for NGCC plants within 25 miles of targeted coal plants and NGCC plants within 10

[50] Massachusetts Institute of Technology,: "The Future of Natural Gas – Interim Report", July 2010, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf
[51] "Natural Gas Pipeline and Storage Infrastructure Projections Through 2030", October 2009, The INGAA Foundation, Inc. 10 G Street NE Suite 700, Washington, DC 2002
[52] The Brattle Group's "Prospects for Natural Gas Under Climate Policy Legislation"; INGAA's "Coal-Fired Electric Generation Unit Retirement Analysis
[53] ClearView Energy Partners, LLC., "Of GHG Bridges and Demand Opportunities: Natural Gas Policy Options", April 12, 2010, pp. 14-15.
[54] Congressional Research Service, **Displacing Coal with Generation from Existing Natural Gas Fired Power Plants,** January 19, 2010 R41027 (http://assets.opencrs.com/rpts/R41027_20100119.pdf)
[55] *Ibid*

miles of the targeted coal plants. These limitations reduced the amount of fuel displacement that the CRS study believed would actually occur with existing NGCC plants.

Both the INGAA study and the ClearView study concentrate on retiring coal-fired capacity that is considered to be the least efficient generation. With this approach from INGAA and ClearView, one is likely to get "more bang for your buck", with the retirements netting more CO_2 emission reductions with less incremental natural gas demand than seen in the CRS analysis. INGAA estimated that nearly 49 GW of coal generation capacity could be shut down due to stricter EPA regulations with a net CO_2 emissions saving of 173 million tonnes and with 5.5 Bcf/d of incremental natural gas demand. The ClearView study estimated that 32 GW of coal capacity could be shut down through incentives, creating a net CO_2 emissions savings of 118 million tonnes with 3.3 Bcf/d of incremental natural gas demand.

The MIT study also assessed the potential for coal-to-natural gas fuel displacement with existing NGCC plants. Their detailed analysis concentrated on the Electric Reliability Council of Texas (ERCOT) region and did not cover the entire U.S. From their extrapolation of the ERCOT results, they estimated that 423 TWh of coal generation could be replaced with NGCC generation with a net CO_2 savings of 252 million tonnes. That savings should create about 8.4 Bcf/d of incremental natural gas demand. The study also indicated that the potential for savings will vary from region to region in the U.S. In the Southeast region there are relatively large opportunities for displacement of inefficient coal plants, while in the Midwest region the opportunities are not as great.

The Brattle Group's study estimated the volume of fuel displacement that would occur for a given natural gas and CO_2 price ($5/MMBtu and $30/million tonnes, respectively). One conclusion to draw from this study is that low natural gas or high carbon prices would be needed to achieve the desired level of fuel displacement in the market place. For more discussion, please see the *Economic Barriers* section below.

When considering all of the many policy initiatives, technical challenges, and regulatory hurdles, the range of gas consumption scenarios is quite significant. The least impact on gas consumption (essentially no change) assumes limited or no impact from shale gas (or alternative unconventional natural gas sources). This leads to approximately a flat consumption of 15 Bcf/d (or about 5.5 Tcf/year, roughly 25% of all gas consumed in the U.S.). In the other extreme, one finds the potential for up to 35 Bcf/d (or about 12.8 Tcf/year) of consumption. In the latter case, clearly a substantial shift in the gas supply infrastructure must take place to accommodate such an uptake. However, our capacity to construct pipeline expansion is also significant, and should not present a hindrance.

C. Impact of Demand Side Management

Demand side management has taken a variety of forms in the past. For some large industrial users, demand side management may mean permitting the utility to interrupt service under certain conditions. It has also taken less obvious forms when individual customers are incentivized to replace inefficient appliances with newer models, or to replace incandescent lights with fluorescent fixtures.

Looking forward, there may be even more opportunities with new technologies being developed. Smart Grid may represent one of these unique demand side management tools. Rather than relying upon slow response market tools to requests to change behavior, the Smart Grid potentially could allow users to alter their power consumption in real-time. It may also allow the service provider the ability to make wholesale adjustments to the consumption of power, without relying upon geographical demand curtailments of power to balance load with demand.

D. Summary of Key U.S. Power Generation Studies

Several long term forecasts of the electric power sector fuel supply mix were examined in order to identify long term drivers that could potentially have a significant impact on the power industry and the role of natural gas in it. The studies featured are the U.S. Energy Information Administration's (EIA) *2010 Annual Energy Outlook (AEO)*, EIA's analysis of the *Kerry Lieberman American Power Act,* Massachusetts Institute of Technology's (MIT) *Future of Natural Gas Study*, and the Electric Power Research Institute's (EPRI's) study titled "The Power to Reduce CO_2 Emissions"[56]. Within these studies, several specific scenarios were highlighted because they included assumptions that could significantly impact future natural gas use in the power sector.

The key policy variable in long range electric power sector forecasts is climate change policy. A price on CO_2 raises the cost of generating electricity from all fossil fuels, especially coal, making electricity generated from lower carbon sources more competitive. This dynamic significantly changes the economic incentives guiding the construction of new power plants, the retirement of older ones, and how plants in-service are dispatched. Ultimately these decisions are reflected in the price of electricity, which is a driver for overall demand for electricity. (See *The Outlook for Electricity Demand* for a more detailed discussion of drivers of electricity demand).

When comparing studies, it is important to keep in mind that each one may have different underlying assumptions and models. Assumptions about technology cost and availability, emissions reduction trajectories, fuel prices, and macro-economic growth may vary across studies and all play a role in the results. The key assumptions underlying each analysis are shown in the appendix Table A-2.

A study by NETL suggests that the LCOE for a fossil coal plant (550 MW) would increase by 73%.[57] When the technology is assumed to be available at competitive prices, they make up an increased share of the generation mix, while the share for natural gas remains roughly the same. However, when nuclear and CCS use is limited (due to cost or policy), natural gas becomes the dominant fuel for power generation since there are few other fuel choices that have as minimal a CO_2 emission profile.

The availability of shale gas resources is an important driver for future natural gas use in the power sector with and without a carbon policy assumed. When larger amounts of shale gas resources are assumed, the amount of electricity generated from natural gas increases relative to baseline scenarios. Other long-term key drivers in the electric sector power sector explored are the availability of domestic shale gas, possible retirement of a large amount of coal plants, and costs and availabilities of various electric power technologies.

[56] Electric Power Research Institute : **The Power to Reduce CO_2 Emissions- The Full Portfolio**, 2009
[57] DOE/NETL-403-110609, **Life Cycle Analysis: Supercritical Pulverized Coal Plant,** Sep 30, 2010.

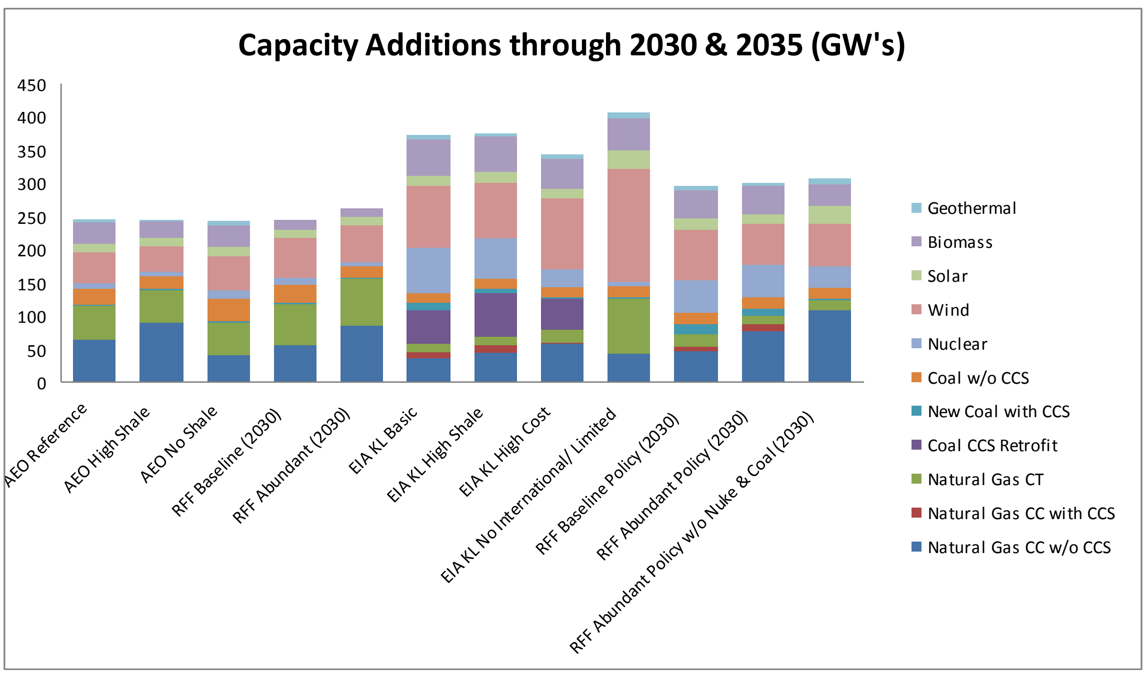
Finding

When a carbon policy is assumed, abundant natural gas supplies, nuclear power and CCS availability become key drivers for makeup of the future power generation portfolio. However, they also come with the risk of substantially higher electricity prices.

E. Electric Capacity Forecast Relating to Carbon Policy

The following forecasts are based on energy (MWh) substitution for each technology and policy considered. In the *AEO 2010 Reference Case*, 115 GW of new natural gas capacity is added through 2035, which is roughly split between NGCC and combustion turbines. In the *AEO 2010 High Gas* Shale Case, where natural gas prices in 2035 are 12% lower than in the reference case, 140 GW of natural gas plants are added, 63% of which are NGCC, as lower gas prices make it a more attractive option for base load generation. (See Figure 18)

Figure 18. EIA & RFF Capacity Additions through 2035 for EIA & 2030 for RFF[58] [slightly revised chart]



With a climate policy in place, total non coal capacity additions increase relative to no climate policy, as coal capacity is retired and replaced with alternatives. The amount of gas capacity added is largely determined by the availability and costs of other low carbon technologies. In the *EIA KL (Kerry Lieberman) Basic Case* where nuclear power and CCS are available, only 58 GW of new gas capacity is built. However, when nuclear and

[58] Source: EIA: 2010 Annual Energy Outlook, EIA: Energy Market and Economic Impacts of the American Power Act of 2010, MIT: Future of Natural Gas, RFF: Abundant Shale Gas Resources: Long-Term Implications for U.S. Natural Gas Markets

CCS are 50% more expensive, the gas capacity increases to 68 GW. In *the EIA KL No International Offsets-Limited Alternatives Case* new capacity climbs to 127 GW. 66% of new gas capacity is made up of combustion turbines, much of which are needed to serve as backup generation to the 198 GW of intermittent wind and solar in this scenario. The application of post combustion carbon capture in any of these scenarios is highly dependent both upon policy and critical technology breakthroughs. As noted previously, (See Table 9) the relative cost of a CCS retrofit is about equal to that of a NGCC.

RFF analysis shows similar results but there are a couple of important differences in the assumptions. The *Kerry Lieberman* bill assumed bonus allowances would be available to coal with CCS plants, and not for gas plants. RFF did not assume this subsidy exists, therefore allowing coal and gas with CCS to compete directly. Table 14 indicates that with bonus allowances, more coal with CCS gets built than natural gas with CCS. However, in the RFF case when abundant gas shale is assumed (the last row Table 14); the amount of natural gas with CCS built is equivalent to that of coal.

Table 14. CCS Capacity Additions Forecast (Various Scenarios)

CCS Capacity at the End of Forecast (GW)		
	Coal	Gas
EIA KL Basic (2035)	11.19	8.75
EIA KL High Gas shale (2035)	22.67	9.10
EIA KL High Cost (2035)	2.00	0.77
RFF Baseline (2030)	13.99	6.12
RFF Abundant (2030)	10.06	10.24

The Electric Power Research Institute (EPRI) *PRISM* analysis states that there is technical potential for 64 GW of new nuclear through 2030, 128 GW of new renewables, and 60 GW of CCS retrofits on coal plants. However, in their limited portfolio scenario where they assume that nuclear and CCS are not available, gas capacity is likely to become a more attractive option.

1. Electricity Generation by Fuel

In the absence of a climate policy, most studies show coal continuing to remain the dominant fuel for electricity through 2050. In the *AEO 2010* reference case, coal makes up 43% of the generation mix in 2035 (Figure 18). Generation from gas grows 24% above 2008, but still makes up the same 21% share of the electricity generation mix as it did in 2008. In the *High Gas Shale* case, this share increases to 25% and in the *No Gas Shale* case it decreases to 17%. MIT's *No Policy Scenario* shows a 33% increase in generation from gas through 2035 which increases to 66% through 2050, but coal continues to retain the larger share of the mix.

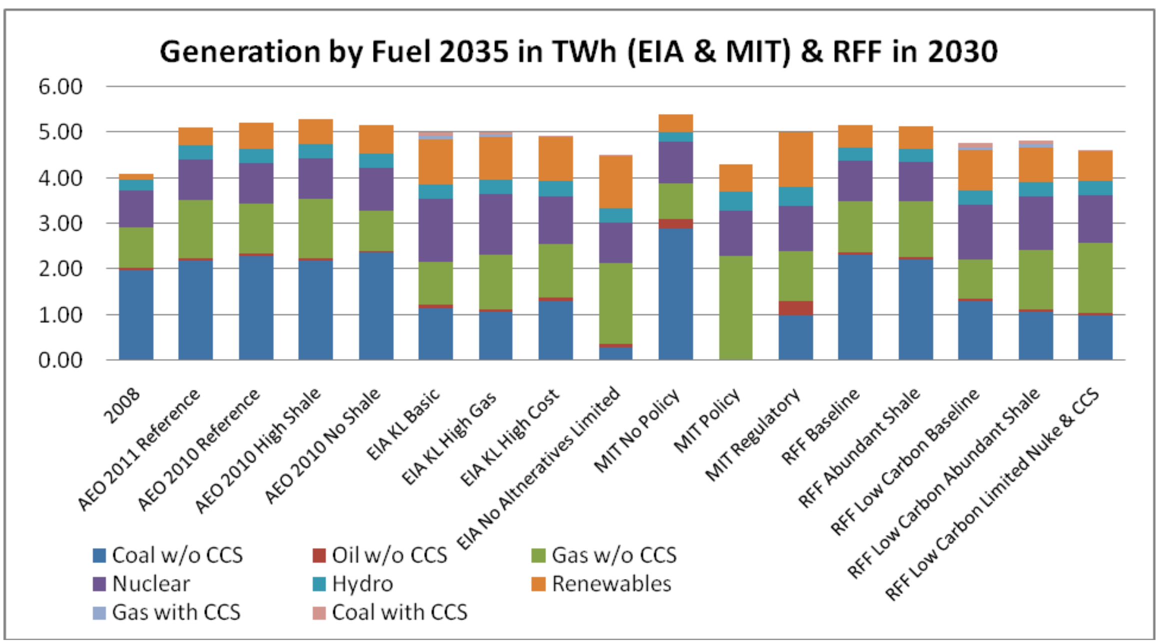
Under a climate policy, the amount of electricity generation from gas is determined by the availability of other low carbon alternatives. In *the EIA KL Basic* Case, where new nuclear and CCS are available, gas generation in 2035 actually decreases 13% relative to the *AEO 2010 Reference Case.* But this change is highly sensitive to the LCOE of the power. When the cost of nuclear power and CCS are 50% higher, gas generation increases 7% above the *EIA KL Basic* Case, and in the *EIA KL No International*

Offsets/Limited Alternatives scenario, gas generation increases 62% above 2008 levels, making up over 40% of electricity generated in the U.S.[59]

The other studies examined show similar results. In RFF's *Baseline Gas Shale Availability Case*, gas is expected to make up 18% of generation in 2030, while in the abundant gas shale case it makes up 27%, and in the *Restricted CCS and Nuclear Case* this share climbs to 33% (See Figure 17). In the EPRI scenarios, when new nuclear and CCS are available, generation from natural gas makes up approximately 20% of the generation mix in 2030, but when they are not available it makes up over 50%. This share declines to approximately 30% in 2050, as the more stringent CO_2 cap drives up cost of generating electricity from gas, to the point where it is displaced by a significant amount of renewables.

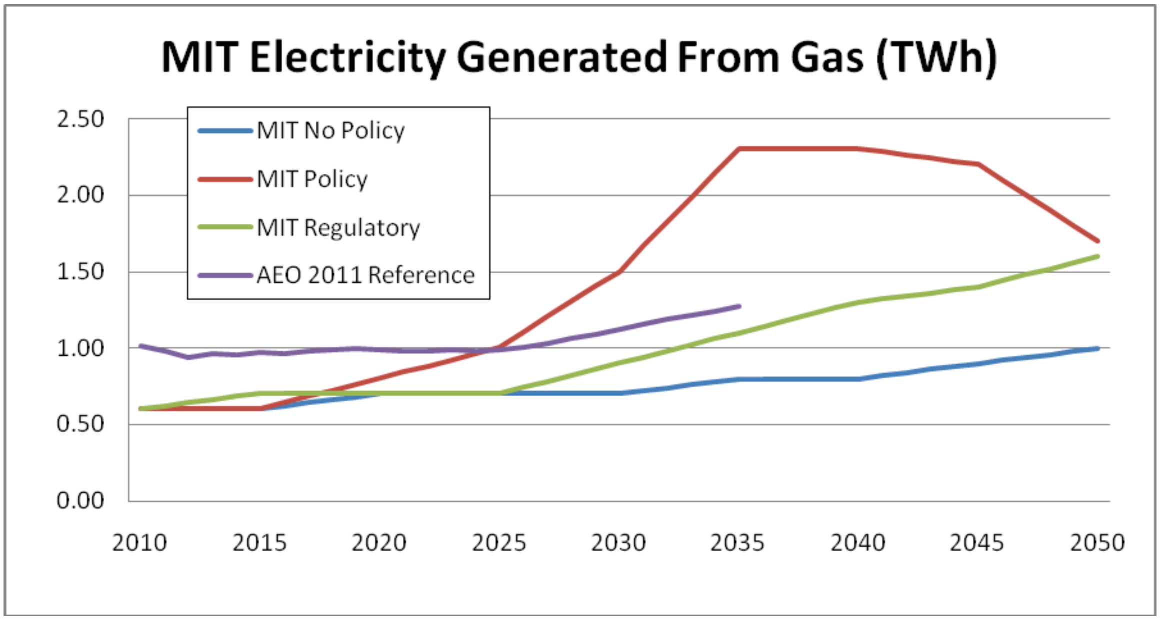
MIT's *Policy Case* shows a similar trend, with gas generation increasing to 53% of the generation mix in 2035, but falling back to 38% in 2050 (See Figure 19). In the MIT *Policy Case,* the decline in natural gas generation past 2035 is offset by new nuclear generation, not renewables. This case also has coal generation being completely eliminated by 2035. Environmental regulations independent of CO_2 may force the retirement of a large number of coal plants. MIT includes a scenario where 55% of the coal fleet was retired through 2050. The results for this scenario show gas generation increasing by over 80% of its 2010 levels in 2035 and 167% in 2050 (the middle course shown in Figure 20). MIT also assumes a 25% *National Renewable Portfolio Standard* in this scenario, and suggested in their report that gas use in the power sector might have been even higher if there were no renewable energy requirement. However, the analysis did not indicate what fraction of the installed renewable capacity would require backup dispatchable capacity, which would most likely be based on natural gas.

Figure 19. Generation by Fuel Type in 2035 (TWh) [slightly revised chart]



[59] U.S. Energy Information Administration, Energy Market and Economic Impacts of the American Power Act of 2010, July 2010 http://www.eia.gov/oiaf/servicerpt/kgl/index.html

Figure 20. MIT electricity generation from natural gas (various scenarios)[60]



F. CO_2 Emissions and Prices

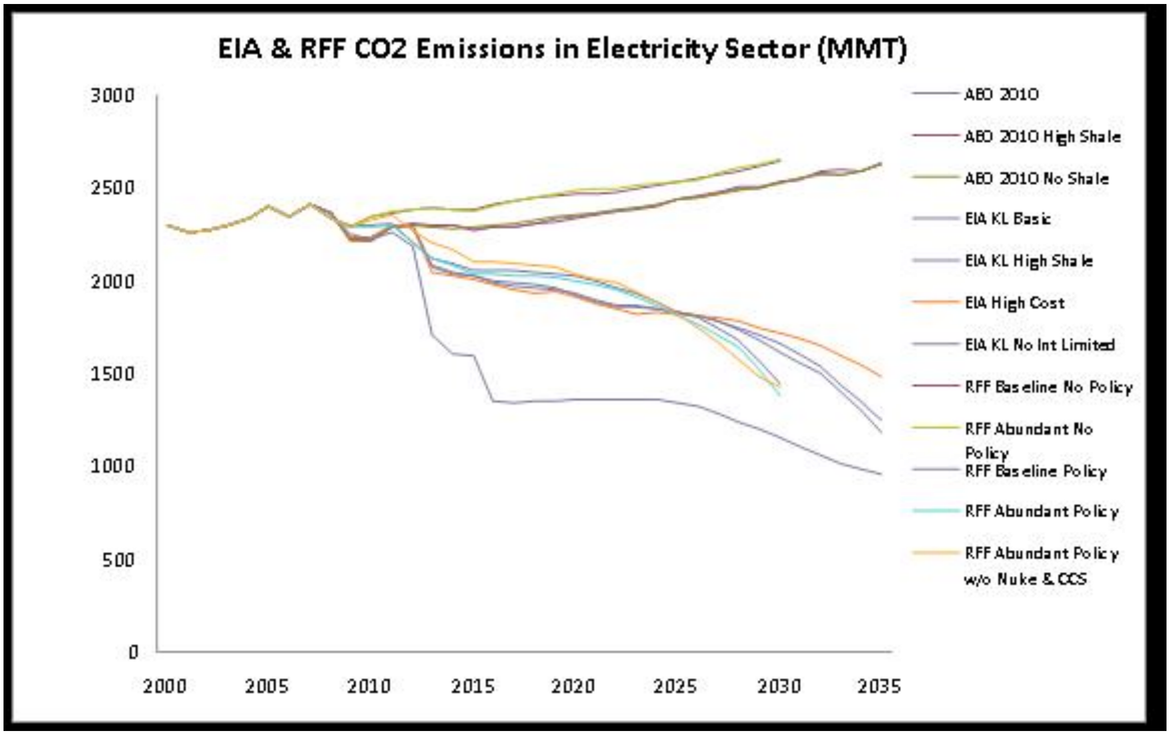
In the absence of climate policy, CO_2 emissions from the power sector could continue to rise (policies at the state level and restrictive environmental standards would act to reduce the emissions of CO_2 from high carbon emitters such as coal or oil). In the *AEO 2010 Reference Case*, CO_2 emissions in 2035 are 12% higher than 2008. Assumptions about the availability of gas shale gas do not significantly affect long term CO_2 emissions trends. In *MIT's No Policy Case*, which measures economy-wide emissions, the rise in emissions is more dramatic, with a 27% increase above 2010 levels in 2035 and a 44% one in 2050

In *the EIA KL Basic Case,* CO_2 emissions fall 47% below 2008 values in 2035, while overall emissions only drop 20% (See Figure 21). This highlights how the power sector will continue to be a significant source of emissions reductions in the advent of a climate policy. In *the EIA KL No International Offsets/Limited Alternative* Case (also in Figure 20), emissions from the power sector fall 60%. This more significant drop is due to the lack of available CO_2 offsets which result in higher CO_2 prices. When coal plants do not have the option of purchasing offsets or retrofitting with CCS, many will be forced to shut down and be replaced with lower CO_2 emitting technologies. This lowers actual emissions because coal plants that were buying offsets to meet their emissions requirements will shut down and stop emitting. It also drives up the cost of CO_2 allowances to almost double that of the basic case, as replacing a plant is more expensive than purchasing offsets, raising the marginal cost of abating CO_2. In the RFF scenarios, emissions reductions didn't change much in the different scenarios, ranging from 38% to 41% below 2008 levels by 2030. The 41% reductions came in the *Abundant Gas Shale Scenario* when nuclear and CCS are assumed to be available (Figure 20).

[60] Massachusetts Institute of Technology,: "The Future of Natural Gas – Interim Report", July 2010, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf

MIT's *Policy Scenario* assumes limited offsets, which results in lower emissions than the *Kerry-Lieberman* basic scenario. The emissions reduction path in the *EIA KL Limited Alternatives Case* and the MIT *Policy Case* is similar, but the costs of CO_2 emissions in 2035 are 26% higher in the EIA case. This is because the MIT case assumes nuclear power and CCS technology will be available, which lowers the cost of compliance. In the MIT *Regulatory Case*, where 55% of coal generation is retired through 2050, CO_2 emissions stay relatively flat over the projection horizon.

Figure 21. EIA CO_2 Emissions from Electricity (tonne equivalent) under various scenarios[61][62]



An important caveat to each of these studies is that capital costs for nuclear, coal with and without CCS, and renewables (with the exception of solar) will be significantly higher in the *AEO 2011* case than they are in any of the scenarios in these studies. Meanwhile, gas plant costs remained essentially the same. The *EIA KL High Costs* scenario assumes costs that are roughly similar to those that will be used in the *AEO 2011 Reference Case* and subsequent analyses that will be done by EIA based off the new reference case. Therefore, this scenario may offer particular insight on the impact of higher capital costs on the power sector when a climate policy is assumed.

---

[61] EIA: 2010 Annual Energy Outlook, EIA**:** Energy Market and Economic Impacts of the American Power Act of 2010

[62]RFF: Abundant Shale Gas Resources: Long-Term Implications for U.S. Natural Gas Markets, Resources for the Future

G. Barriers, Issues and Concerns Related to the Increased Role of Natural Gas Generation

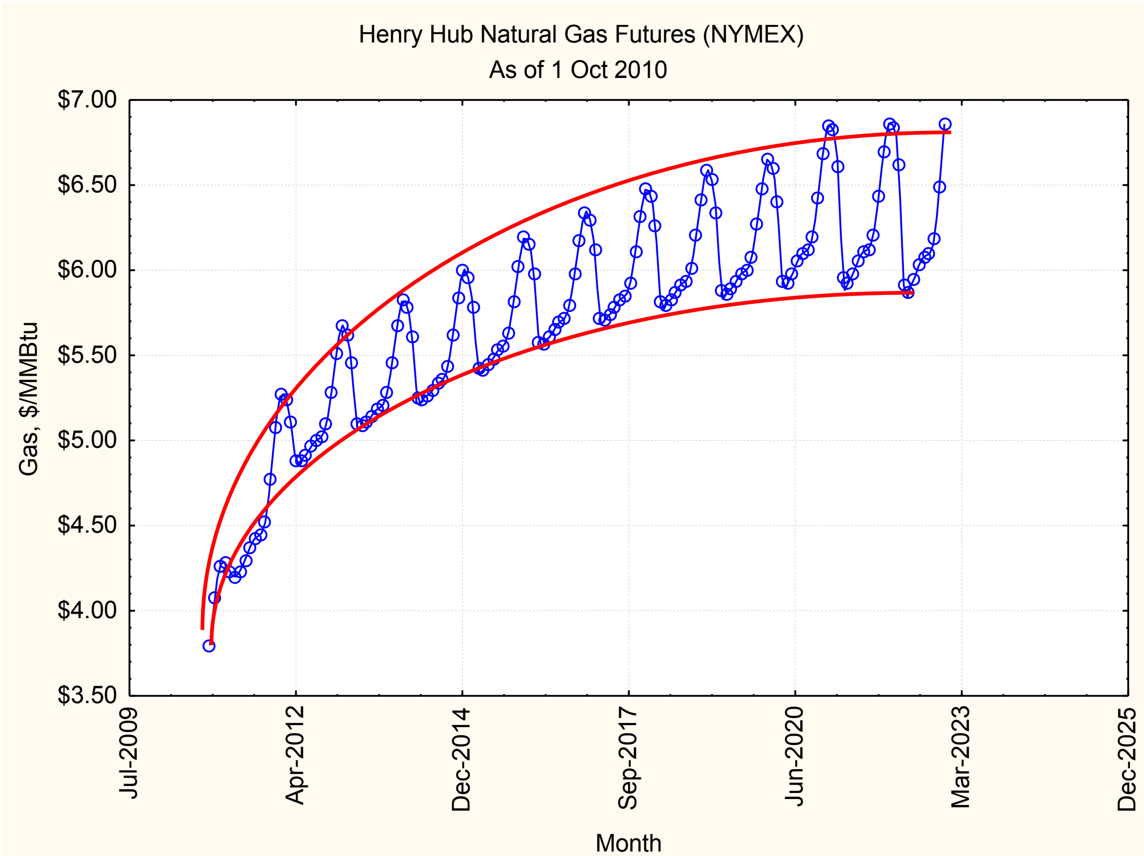
1. Price Stability

An important factor in the future of natural gas is the issue of price stability. Price stability will have an impact on both short term decisions (which units to dispatch) as well as long term decisions (which generating assets to build). While the long term future market predictability may be suspect, natural gas has a long history of volatility of price, and this price volatility can easily change the outlook of a project or dispatch solution. Power generators primarily have three methods to control price volatility, fixed-priced contracts, financial hedging and physical storage. Future policy decisions need to consider how to support actions which increase price stability, or at least create an environment that permits electric generators to mitigate the risk of natural gas price volatility.

One method to help develop price stability is the use of long term fixed-priced contracts between gas suppliers and generators. While some states have taken steps towards this, most have not. Long-term contracts could reduce the amount of gas that generators have to buy in the spot market, thus providing a measure of security. Traditionally, producers have been reluctant to limit their ability to capture higher natural gas prices and many regulated utilities have been hesitant to incur the regulatory risk of disallowance of gas cost recovery that may result from long-term contracts. However, with the shift in market dynamics due to that availability of gas shale, several producers have publicly stated their desire to enter into long-term fixed-priced contracts. As an alternative, many generators use financial hedging to serve this role, but are always subject to the accounting impact of hedges due to changes in price. A regulatory environment that reduced the perceived cost recovery risk from fixed-priced contracts for regulated generators would increase the likelihood of long-term agreements occurring. Another issue related to price stability is the amount of scrutiny and time spent defending hedge gains or losses with state regulators. Hedging is a very valuable tool for reducing volatility but regulators are often uncomfortable with losses in times of declining markets and apply much scrutiny to the hedges. The more price stability that can be applied to the market, the less burdensome hedging activities, scrutiny, etc. will be. It seems that state regulators and their processes are set up to be more accommodating with decisions such as long term capital investments (resource planning, addition of generating units, addition of environmental control equipment) than they are for shorter term issues and impacts such as volatile gas prices and the impacts of that volatility. Another concern for hedging, the main tool in which generators address price volatility, is regulations on market participants and legislation aimed at trading. Any measure that adds costs or risks to generators for a hedging viewpoint would be detrimental to efforts to reduce price volatility.

A major contributor to future natural gas price stability is the development of gas production from shale (and other non-conventional sources of natural gas, including coal-bed methane). This large source of domestic supply is a key to the future natural gas price stability. Accordingly, any policy which limits, threatens or adds costs to shale production could decrease shale gas supplies and increase volatility in gas prices. Looking at the NYMEX futures market, with the assumption of adequate natural gas supplies, the long range expectation is that the dominant variability will be the weather (winter vs. summer) not necessarily the availability of gas (See Figure 22)

Figure 22. Long range NYMEX futures for Henry Hub Natural Gas (source, SNL.com)



Pricing tools, such as long-term contracts and hedges are crucial to address, combined with expanded shale production will lead to more stable natural gas prices and a larger role for natural gas in supplying the electrical generation needs of the future.

2. Legislative and Regulatory Issues Related to Creating a Level Playing Field for Natural Gas Generation

Natural gas is well positioned to play a major role in providing the energy to meet electricity demand while reducing carbon emissions. Natural gas can also play an important permanent role in enabling renewable generation that will lead to a sizeable amount of fairly unpredictable power production. Such intermittent generation will need to be balanced with flexible and reliable backup capacity. It is generally assumed that this capacity will be provided by gas-fired power stations.

At a time when natural gas is being asked to expand its role in the generation energy mix, there has been a significant increase in the subsidies and support mechanisms available for other types of power generation. Energy subsidies are of direct interest because they impact/distort the energy market in terms of the choice of energy types and/or changes in energy prices for consumers. Subsidies to more specific energy technologies can undermine the operation, development or commercialization of natural gas generation.

Too many studies focus on dollar amount of subsidies with little analysis of the market impact on various generation technologies. Regarding natural gas, several questions should be addressed:

- What energy production technologies are currently being subsidized?
- Which subsidies impact natural gas and discourage its production and use?
- What other government barriers and regulations favor other energy technologies such as wind, solar and nuclear at the expense of natural gas?
- What do state and federal governments need to do to level the playing field for natural gas?

H. Historic Subsidies

A recent history of electric production technologies suggests that financial support with grants, government loans at preferential rates, and loan guarantees is not uncommon. Producers can often benefit from special tax facilities. In the case of technologies that produce electricity from renewable energy (hydro-electric power, solar energy, wind, waves and tides, biomass), production costs are often subsidized by regulations that require that a certain proportion of a service area's electricity supply be provided by renewable energy, or by special feed-in tariffs; prices paid to generators of electricity that are higher than those paid to plants that run on fossil fuels. A government (federal, state, or local) may provide tax breaks to purchasers or regulate prices below the market price or even below the cost of the fuel (often the determinant price in establishing the economic dispatch). Further upstream, tax payer supported research, tax credits, project grants, or excessively large loan guarantees are some of the vehicles used by legislative means, although they can also distort the markets for energy supply (and technology choice). Through policy or legislative means, governments may mandate targets, import tariffs and tax exemptions. Regarding fossil fuels, the vast majority of subsidy dollars can be attributed to just a handful of tax breaks, the largest of which is the Foreign Tax Credit and the credit which applies to overseas production of oil.

Finally, although it is outside the scope of this study, in 2009, the Obama administration proposed the elimination of tax preferences for U.S. oil and natural gas production in its FY2010 budget. RFF studied the effects that such policy changes may have on the U.S. oil and natural gas industry[63]. Although the report didn't address subsidies to competing fuels, it concluded that eliminating oil and gas company tax preferences seems likely to have bigger effects on U.S. natural gas markets than oil markets essentially providing a "double whammy" when subsidies for competing fuels are considered. Nearly all of the natural gas consumed in the United States is domestically produced, while world trade of natural gas has little effect on U.S. domestic natural gas prices.

[63] *Eliminating Subsidies for Fossil Fuel Production: Implications for U.S. Oil and Natural Gas Markets* by Maura Allaire and Stephen Brown 12/2009, Resources for the Future

1. The Growth of Non-Fossil Subsidies

In the last decade, domestically and internationally, there has been substantial growth in subsidies for new energy generation technologies. Categories of subsidies or support for generation technologies include:

- Cash transfers paid directly to producers, consumers and other related bodies, such as research institutes.
- Grants given to producers, mainly to support commercialization of technology or industry restructuring, and to consumers.
- Low interest or reduced-rate loans, loan guarantees, administered by government or directly by banks, and state interest rate subsidies.
- Tax exemptions, credits, deferrals, rebates and other forms of preferential tax treatment.
- Market access restrictions, regulatory support mechanisms such as feed-in tariffs, renewable portfolio standards, preferential planning consent and access to natural resources or public lands.
- Government sponsored research and development (R&D) programs that are technology specific.
- Allocation of transmission costs related to new renewables capacity to all users rather than to the new renewable generation

The DOE renewable energy programs are implemented in several ways: through direct funding of R&D at national laboratories, through grants and cooperative agreements with universities, and through various forms of financial and technical assistance to industry partners. In general, the industry partnerships, a prominent part of renewables R&D funding since the mid-1980s, are cost-shared; that is, the industry partner provides a portion of the funding or other resources needed for the work. The cost-sharing can be in the form of direct financial contributions towards the costs of the R&D, or it may be "in kind," meaning that a value is ascribed to some facility or equipment that the industry provides for the effort, or, in the case of the government, the industry partners' use of DOE's national laboratories.

I. Regulations and Subsidies Affecting Gas Generation

1. State Mandates (Renewable Portfolio Standards)

Growth in the U.S. renewable energy market has been driven primarily by renewable portfolio standards (RPS) in various states. An RPS is a state government mandate requiring that load-serving providers supply or acquire a minimum percentage of their power from qualifying renewable energy resources by a designated date. As of June 2010, mandatory RPS policies have been passed in 31 U.S. states and the District of Columbia, with six additional states approving non-mandatory renewables goals. State mandates, and perhaps federal funding can produce some unusual behavior in the markets.

As might be expected, these mandates vary by state, many with unique technology specifications (e.g. wind, solar, or geothermal commitments). Unique geographical features will tend to favor some technologies (e.g. much of the installed wind capacity in the United States is just west of the Rocky Mountain Front Range). But balancing the influx of renewables (which often cannot be scheduled) with load demands can present a steep challenge. For example, in Texas because of the economics of the Production Tax Credit (PTC), wind producers will bid negative numbers ($/MWh) to insure dispatch and then have their final price set by the last generation dispatched.[64]

Impact on Natural Gas Generation. RPS requirements can push natural gas generation to a marginal source of power. Whereas gas generation is needed to offset the intermittency of renewable capacity, the more renewable generation on-line means less opportunity for gas-fired generation has to recover its fixed costs, especially for merchant generators. At a time when the market is calling for more gas-fired generation that will run at even lower utilization rates, it can become less economic to build gas-fired generation needed to support non-dispatchable resources.

Public Utilities Commission. Often overlooked is the role of the public utility commissions. While states may have established legislative RPS objectives, the PUC frequently acts the gate-keeper for technical innovations placed into a rate base. Much of the large fossil and nuclear supply base was approved because the large capital costs were offset with substantially reduced fuel costs. In the last few decades this has shifted to lower capital cost systems—typically gas based—but with greater variability in the fuel pricing. In the regulated power industry, the benchmark has typically been the Return on Equity (ROE) for the utility, and the expected impact of the proposed project (or the technology choice). The massive builds that took place in the 1970's and 1980's focused on large, capital intensive projects, but those that tended to be based on a low-cost, and often locally available fuel supply (while creating a large volume of local construction activity). During that period, most project developments involving gas turbines were relatively small. Gas turbines, primarily oil-fired equipment, were widely deployed as a corrective action to a massive power failure that occurred in 1966 involving much of the Northeastern U.S. In the intervening period, technical improvements introduced multi-fuel capability, larger units (often combined cycle) and cycle efficiencies not available from any other power generation source. Today regulators are faced with a difficult challenge, balancing low capital cost power generation systems (a natural gas combined cycle being the best example) against a higher capital cost fossil or nuclear system with near certainty of low cost fuel supplies for the life of the project. State regulators may be ill-equipped to compare the economic value and ultimate benefit to the consumer of the competing (and often complex) technical choices. Frequently, these regulators may be lacking some critical information or information that is outdated. A survey of power generation CAPEX costs in a primer available to Public Utility Commission regulators reveals facility costs that are substantially different—and lower—than those noted in this report. [65] If regulators are making critical decisions based on such inaccurate data, then there is the likelihood of misallocation of limited resources to future project development.

[64] Wind generators only earn the PTC for hours operated so they are willing to bid negative prices up to the value of the PTC.
[65] Coal Generation Technology & Carbon Capture & Storage-A Primer for State Commissioners, NARUC, May 2009

The long term supply stability of natural gas may shift this balance (or selectivity) much more favorably toward natural gas generation, even though the price of coal (in $/MMBtu) is expected to remain below that of natural gas (except possibly under scenarios where a high economic penalty is assigned to CO_2, or CO_2 from coal specifically). But it also points out that quality data and information are needed for key regulatory personnel to make the appropriate decisions regarding the approval of power projects.

Adding to the complexity of the longer range forecasting is the expected price of power delivered to the end-user. Many of the alternatives, and nearly all of those energy conversion systems that are subsidized, are expected to increase the power price. There is ample data on the likely short-term impact of power increases on electricity demand; however, there is a gap in the understanding of a long-term, persistent rise in power prices might yield in terms of demand, and changes to market dynamics. And can the potential increases in power be off-set by deploying new technologies (e.g. Smart Grid).

2. Federal Programs

Federal involvement in energy projects has historically been focused more on research and development, possibly going beyond this with risk-assumption for construction of potentially new entrants into the market (e.g. Great Plains Gasification). Internationally, the use of a Feed-in Tariff (FiT) is sometimes employed as a vehicle to spur investment for both development and refinement of generation technologies that might otherwise not meet traditional market economic requirements.

Tax Credits. A version of the FiT is the production tax credit (PTC), sometimes used in tandem with an investment tax credit; and accelerated depreciation. Federal law provides an inflation-adjusted federal production tax credit (PTC, now $21/MWh) for ten years to wind projects that come online prior to the end of 2012. The PTC is based on actual production of power each year. The tax code provides an investment tax credit (ITC, available in the first year of operation) for solar and small wind projects worth 30% of the project's qualifying cost. The ITC for solar projects is available for projects beginning commercial operation prior to the end of 2016. Developers may also take advantage of an accelerated depreciation schedule by depreciating the full cost of certain renewable energy projects over five years. The tax credit program for wind remains in place through 2012; the tax credit program for solar remains through 2016.

Section 1603 Cash Grant Program. In response to the flight of tax equity investors, Congress included a temporary provision in economic stimulus legislation in early 2009 (*American Recovery and Reinvestment Act, or ARRA*) allowing new renewable energy projects that begin construction prior to the end of 2010 to receive a 30% cash payment from the government in lieu of the ITC or PTC. This "*Treasury Grant Program"* (*Section 1603* of the tax code) has been essential to continued growth in wind and utility-scale solar in 2009 and 2010. As of July 2010, $4.6 billion of grants had been awarded, mostly to large wind power projects. Last December's tax bill extended the Treasury Grant Program for one year. The same bill that extended the deadline for cash grants also authorized a 100% "depreciation bonus" on new equipment put into service after September 8, 2010 through December 2011 or 2012, depending on the project. The bonus is a timing benefit. Instead of depreciating a project over the normal depreciation period, the entire cost can be deducted in the year the project goes into service.

Federal Loan Guarantees In 2005, Congress created a loan guarantee program (Section 1703 of the tax code) aimed primarily at assisting new nuclear and clean coal projects by providing a government guarantee of financing up to 80% of the project cost, but the program was not fully implemented under the Bush Administration. ARRA extended and increased the loan guarantee program (in *Section 1705* of the tax code), targeting renewable energy systems and facilities that manufacture related components, transmission systems, and biofuel projects. *ARRA* also appropriated $6 billion for payment of the credit subsidy (guarantee) costs, which under Section 1703 were paid by the developer. This amount was estimated to support $60-$100 billion of loans. This program is slowly maturing and having an important impact on both projects and manufacturing. Most utility-scale wind and solar projects now depend on a combination of the *Section 1603* cash grant and either a *Section 1703* or *Section 1705* loan guarantee. However, the loan guarantee program is also time-limited, ending September 30, 2011. Non-U.S. companies are eligible and have been successful in receiving funds, but projects must be in the U.S.

The Recovery Act's allocation of $6 billion to cover subsidy costs for the Department of Energy Section 1705 loan guarantee program made the program much more appealing to renewable energy applicants and effectively jumpstarted the program. The subsidy cost varies by project and is based on the probability of default and the amount of recovery by the government in the event of default. Previously, under the Section 1703 loan guarantee program authorized by the 2005 energy bill, applicants had to pay upfront the subsidy costs for the loan guarantee (nuclear and clean coal projects still must pay subsidy costs). To-date, the Department of Energy's Loan Programs Office has committed support for 21 clean energy projects, 12 of which have closed, totaling nearly $25 billion in loan guarantees and nearly $40 billion in total project costs. However, Congress has rescinded several billion dollars from the 1705 loan guarantee program, leaving it with approximately $2.5 billion for subsidy costs. Moreover, this Recovery Act program is to expire after September 30, 2011. The President's 2011 budget not only provides fresh authority for guarantees for qualifying projects, but it also earmarks $400 million to cover the credit subsidy costs of at least a portion of those guarantees.

Nuclear power receives some measure of subsidization, but it is not generally sufficient to construct a new facility (or even complete some of the units that did not finish construction). In the current budget it only accounts for 8% of total subsidy support and is not expected to be a likely competitor to gas-fired generation. The on-budget support to nuclear energy comes from R&D grants and the loan guarantees are obviously not enough to build a plant. In fact, because of the long lead time for nuclear deployment, gas-fired generation is likely to supplant nuclear generation that is either canceled or not able to meet generation obligations due to construction (or other) delays. In this sense, nuclear and gas-fired generation may co-exist quite effectively.

Research and Development - Carbon Capture and Storage. Natural gas generation offers some advantages with carbon capture. Unlike coal-based systems, gas is cleaner (significantly less SO_2 and NO_x pollutants to be removed); and the CO_2 content is about 70% less per MWh. This would suggest that the investment in carbon controls is likely to be reduced compared to a fossil coal plant. However, this issue is still open to debate. While the CAPEX cost for the facility should be reduced, the cost per ton of CO_2

extracted could be greater than a fossil coal facility.[66] And many of the studies evaluating carbon capture have relied primarily on computer simulations to determine the efficacy of the technology choices.[67] It will likely require several full scale demonstrations of specific technology approaches to determine the optimal path forward for CCS, and which is the preferred fuel. Criticism of gas-fired CCS focuses on the smaller carbon stream but ignores the higher efficiency of NGCCs and the lower need for CO_2 transportation and storage. In general, this technology has been ignored in federal research programs compared to coal with CCS.

But even with massive investment, addition of post-combustion carbon capture to any fossil system will reduce the overall system efficiency. This means reduced output generation (perhaps as much as 10%), and the sunk facility costs will be higher. For a gas turbine, this would reverse the improvements in efficiency that have taken 20 years to achieve; and in terms of plant dispatch, efficiency plays a major role.

Also, it's not at all obvious that capturing all or most of the CO_2 from the gas turbine portion of a NGCC is practical given the expected cycling requirements for a unit. We are entering an era where many units are now required to ramp up quickly, and sometimes cycle back to 30-50% of capacity—right now these are requirements that would be completely at odds with the design of a post combustion capture. Adding to this is the complexity of the facility. Will system reliability be degraded by relying upon the gas treatment system at the outlet? Doubling plant complexity and operating requirements is not likely to improve reliability. See above Chapter 4, Section A.6 *Carbon Capture and Storage.*

J. Policies Affecting Gas Generation

Energy Prices. A number of arguments have been proposed that would put in place a price on CO_2. Since coal power plant with a heat rate of 10,500 BTU/kWh produces almost 1 tonne CO_2/MWh and an NGCC with a heat rate of 7,500 produces about 0.4 tonne CO_2/MWh or about 40% of the coal unit, the expectation is that gas generation would be favored over coal. Regardless of how the price is communicated through the market, it is also expected to raise the price of power to the end user. Favoring the gas generation argument is the widespread development of unconventional natural gas resources, a development still evolving, and one which should act to limit natural gas price increases and volatility.

Renewables. The development of renewable electricity generation resources could result in a reduction of natural gas demand in some regions. Energy injected from renewable power would have to be displaced, and temporary displacement of gas generation is one likely scenario. But this will also have the negative effect of increasing U.S. consumer prices, possibly even more than if the additional energy injected into the system came solely from gas additions. To compensate for variable energy injection, generation with

---

[66] A. Aboudheir and G. McIntyre, "Industrial Design and Optimization of CO_2 Capture, Dehydration and Compression Facilities", Bryan Research and Engineering, http://www.bre.com/portals/0/technicalarticles/INDUSTRIAL%20DESIGN%20AND%20OPTIMIZATION%20OF%20CO2%20CAPTURE,%20DEHYDRATION,%20AND%20COMPRESSION%20FACILITIES.pdf

[67] "Carbon Capture and Storage: Fundamental Thermodynamics and Current Technology", S.C. Page, et al. *Energy Policy*, 37 (2009) 3314-3324

rapid cycling and wide turn-down capability is a prerequisite for balancing a system that includes a large quantity of non-dispatchable resources. This generation is most likely to be gas-fired generation.

Policy and regulatory measures should be developed (e.g., ancillary services compensation) or adapted (e.g., capacity mechanisms, demand charges) to facilitate adequate levels of investment in natural gas generation capacity to ensure system reliability.

Environmental Regulations. Since the passage of the Clean Air Act, and its amendments, fuel switching has been a relatively common solution to meeting stricter environmental requirements. While not advocating tighter environmental regulations (the U.S. already has the strictest requirements in the world), these regulations often favor gas substitution to replace coal or oil. The conversion to gas is simple, it requires much less capital investment, and many heavy oil or coal systems are already "gas-capable" (gas may be used to start the unit). The additional CO_2 burden that might be placed on power generators is also expected to promote greater use of natural gas. Ideally, this conversion should be done with both a fuel switch (high carbon hydrocarbons to gas) and a technology switch (increased use of high efficiency generation). This would yield the largest increment of generation with lowest energy consumption and emissions.

Chapter Five - Harmonization of Natural Gas and Power Markets

In the past decade, the U.S. natural gas and power industries have become more interdependent. From 2000 to 2010 the use of natural gas for generation increased from 16% to 24% of total electric sector generation. For the same period, natural gas demand for power generation grew from 14 to 20 Bcf/d increasing power generation share of total natural gas demand from 22% to 31%. In addition, the expectation of strong growth in renewable generation, while having a negligible impact on the use of natural gas, will impact the demands placed on natural gas infrastructure and supply in multiple ways.[68]

Both natural gas transmission pipelines and electric transmission grids operate under different complex systems of rules and regulations that have evolved over decades, largely independent of each other. As the use of gas for electric generation increases, and there is an increasing need for natural gas generation to backstop intermittent renewable generation, it is increasingly important to resolve certain issues that sit at the intersection of gas supply and transportation markets, and wholesale electric markets.

The market rules and service arrangements that govern these two markets, however, differ from one another so that inefficiencies occur. For instance, in many power markets, generators must request natural gas transportation capacity a day before electric grid operators determine which generation plants will be needed to meet the market demand in a near-term upcoming period. As a result, power generators must schedule pipeline capacity before being scheduled for generation commitment or attempt to find pipeline capacity and gas supplies after other potential gas transportation users have already contracted for capacity. This mismatch in the timing of processes results in an inefficient market and use of resources. Further, while the gas day is uniform across their industry, and pipeline shippers can transport gas across time zones and across different pipelines seamlessly, the electric industry does not have a uniform electric day.

The natural gas industry's reliance on electricity is also increasing. Increased use by pipelines of electric compression to meet air quality requirements in some areas has increased the need for reliable electric service to be able to provide reliable natural gas service.

An example of the increasing interdependence of natural gas and power is what happened in February of this year in the southwest when more than fifty electricity generation units stopped working overnight because of severe weather, reducing capacity by 7,000 megawatts and leading to rolling power outages. Other power plants found their fuel supplies curtailed by local distribution companies under natural gas priority rules that were last updated in the early 1970s. Some of the controlled electric outages also idled natural gas pipeline compressor stations that had switched to electricity to meet air quality requirements reducing pipeline pressure and hampering the ability of natural gas generation plants to get the fuel they needed. The increased use of electric generation has increased the need for reliable electric service to be able to provide reliable natural gas service.

---

[68] See http://www.eia.gov/energy_in_brief/renewable_portfolio_standards.cfm and http://www.eia.gov/analysis/requests/subsidy/

Another example is the dependence of many gas processing plants on electric service as demonstrated by gas processing plants being off line in February of 2011 in the Southwest and in the aftermath of hurricanes Katrina and Rita in 2005, and Ike and Gustav in 2008. If natural gas cannot be processed, the gas will not be pipeline-quality, and pipelines may not accept gas for delivery if acceptance would adversely affect their operations. Both incidents highlight the need to resolve certain issues that sit at the intersection of gas and electric deliverability, and wholesale electric market reliability.

Clearly, the natural gas and power industries are becoming increasingly interdependent. And that interdependency is expected to continue to increase in the future. As natural gas and power industries have become more interdependent various issues have surfaced including:

- How merchant generators can recover costs associated with firm pipeline capacity and firm gas supply. Merchant generators, even those operating in markets with capacity payments, are very reluctant to acquire firm pipeline and natural gas supply as they cannot recover the fixed costs associated with firm supply. Yet many of these merchant generators sell firm electricity and their generation capacity is considered firm for reserve margin purposes.
- The operating day and timelines for scheduling natural gas and electricity are different and inconsistent with each other.
- The electric day for scheduling across regions is not standardized.
- A lack of harmonization between natural gas and power markets on how to deal with intraday variations in demand. Intraday changes in electricity demand requires generation that can quickly respond to unexpected changes in requirements that are not necessarily compatible with either the terms and conditions of firm transportation natural gas service, the natural gas intraday nomination processes or capacity priority rights.
- Very few generators subscribe to either pipeline "no notice" or non-hourly flow services that can be tailored to generators' needs.
- Potential transmission constraints to the use of existing NGCCs to displace coal-fired generation or to replace coal-fired generation that might be retired because of proposed non-GHG EPA regulations.

A. Firm Pipeline Transportation Capacity

Interstate gas pipelines are designed based on the firm contractual commitments made by shippers that support the project. Interstate gas pipelines do not have "reserve capacity," which electric utilities have. For over a decade now, the Federal Energy Regulatory Commission (FERC) has generally required pipeline shippers who need new capacity and will benefit from that capacity, to pay for that capacity. Producers wanting to connect new supply have to contract for any new pipeline capacity needed. Buyers wanting new delivery capacity have to contract for any new pipeline capacity needed. Further, the FERC has held pipelines at risk for any unsubscribed capacity. Generally the costs of new capacity are not allocated to existing customers.

There are no operational impediments to natural gas pipelines serving electric generators provided that the generator has contracted for the appropriate pipeline transportation service. Pipelines have offered tariffed services that provide non-hourly flows that can accommodate generators' quick ramping yet few generators have subscribed to these services. In fact, interstate gas pipelines have begun to develop services designed to meet the needs of gas-fired electric generators to access gas supplies quickly in response to electric system dispatch orders. Since the wholesale electric market rewards generators with the lowest marginal costs, most peaking generators contract only for interruptible pipeline service or rely on the capacity-release market to transport gas on the pipeline. During peak demand periods, pipeline firm transportation (FT) customers use their full contractual entitlements and the pipeline does not have additional capacity to schedule for interruptible transportation customers.

As the January 2004 cold snap in New England highlighted, most merchant generators do not hold firm pipeline capacity and firm gas supply. During this period of record peak electricity demand, pipelines' firm transportation shippers used their full contractual entitlements and the pipelines did not have excess capacity available to schedule for interruptible transportation customers. In most cases, this firm pipeline capacity was held by natural gas local distribution companies and was used by those LDCs to meet their public service obligation to deliver natural gas to residential and commercial space heating customers. While the pipelines met their firm contractual entitlements, and all firm transportation customers received transportation service, customers relying on interruptible transportation did not. Specifically, 6,000 MW of gas-fired generation was unavailable to run because the operators chose to rely on interruptible transportation, which is only available after the pipeline has met all of its firm contractual requirements.

The January 2004 cold snap in New England also demonstrates how local spot gas prices can increase as merchant generators and other non-firm shippers bid against each other to acquire a shrinking supply of pipeline capacity. The result is not only higher local natural gas prices, but higher local wholesale power market prices. Electric grid service reliability also can be threatened, which again happened in New England in 2004. As power-generation gas demand increases, the possibility of constraints could spread to other markets during other times of heavy demand.

To ensure reliability of power service during the winter in regions with substantial heating loads, generators need to be able to either access gas supplies quickly in order to respond to system dispatch orders by holding both firm pipeline capacity and firm gas supply, purchasing appropriate services from interstate pipelines, or have dual fuel capability, i.e., the ability to burn a fuel other than natural gas such as distillate. Unless wholesale markets allow generators to recover the cost of firm pipeline capacity or having dual fuel capability, generators will not enter into long-term pipeline contracts that are a prerequisite for pipelines to provide firm service nor will they build dual fuel capability. An alternative approach would be for grid operators, such as the RTOs/ISOs, to hold some quantity of firm pipeline transportation capacity on behalf of the wholesale market in to ensure that electric reliability could be preserved during coincident peak periods.

As noted above, most generators, particularly those selling into unbundled wholesale electric markets, choose less-expensive interruptible transportation pipeline capacity or short-term capacity release because under wholesale power market rules, there generally is no assurance that they can recover the fixed costs associated with either firm transportation or firm gas supply. For merchant markets with capacity payments, such payments seldom fully compensate for the fixed cost of generation capacity, let alone cover the fixed costs of having firm pipeline transportation contracts.

B. Operating Day and Timeline for Scheduling

For over a decade now, U.S. and Canadian interstate pipelines have operated under a common set of standards developed by the North American Energy Standards Board (NAESB) under the auspices of the FERC. These standards were developed to improve market transparency and efficiency by facilitating computer-to-computer communication for, among other things, scheduling flows of natural gas. All pipelines use a gas day that begins at 9 am central time. In addition, a common set of pipeline location codes have implemented and scheduling processes are standardized. On the other hand, the electric industry does not have a set of North America-wide, or even interconnection-wide standards for when the electric day starts. Moreover, the times for scheduling electricity vary by specific Regional Transmission Organization (RTO) and these are not consistent with standardized natural gas scheduling processes. Thus, the process for scheduling electricity is neither consistent with the standardized natural gas scheduling process nor consistent with other RTOs (See Figures 23 and 24).

As a consequence of these inconsistent timelines, the owner of a gas-fired generator must either buy gas without knowing if its power will be scheduled, or submit a power bid before knowing if the gas can be purchased and scheduled. The cost of covering the risk created by the inconsistency in timelines must be reflected in generators' power offers. During periods when, or regions where power and gas capacity is not constrained and demand is not volatile, this is a manageable risk. However, when pipeline capacity is constrained, a generator relying on interruptible transportation capacity will not be scheduled. A generator relying on firm transportation may not be able to access it primary delivery point if another firm shipper requests service, and is scheduled, at that point.

Intraday timelines are also inconsistent, as between the natural gas and electric scheduling processes. The intraday gas market is generally much less liquid than the electric market, adding to the risk associated with real-time offers. All of this is complicated by the operation of electric generating units (especially gas-fired units) that can be brought on-line with relatively short notice and/or can change generation output level very frequently to adjust for changes in power requirement on the grid. These changes can be related to other generating units unexpectedly going off line, changes in load and/or changes to intermittent renewable generation output. These frequent and sometimes dramatic changes in gas-fired generation requirements can put stress on the pipeline system. Although pipelines have various mechanisms for dealing with these changes including the use of storage, compression and/or line pack, and services tailored to provide non-hourly flows, their firm and interruptible transportation tariffs typically call for gas to be used at an even 24 hour or 'ratable' flow, if pipeline operations could be adversely affected.[69]

[69] Line pack is the volume of gas in a pipeline. Line pack will vary as the pressure within the pipeline varies between minimum and maximum operating pressures. Hourly variations in demand are generally met by variations in line pack. On a daily basis, however, variations in line pack needs to be either restored or depleted by either withdrawing or injecting from natural gas storage.

Figure 23 Electric Day versus Gas Day

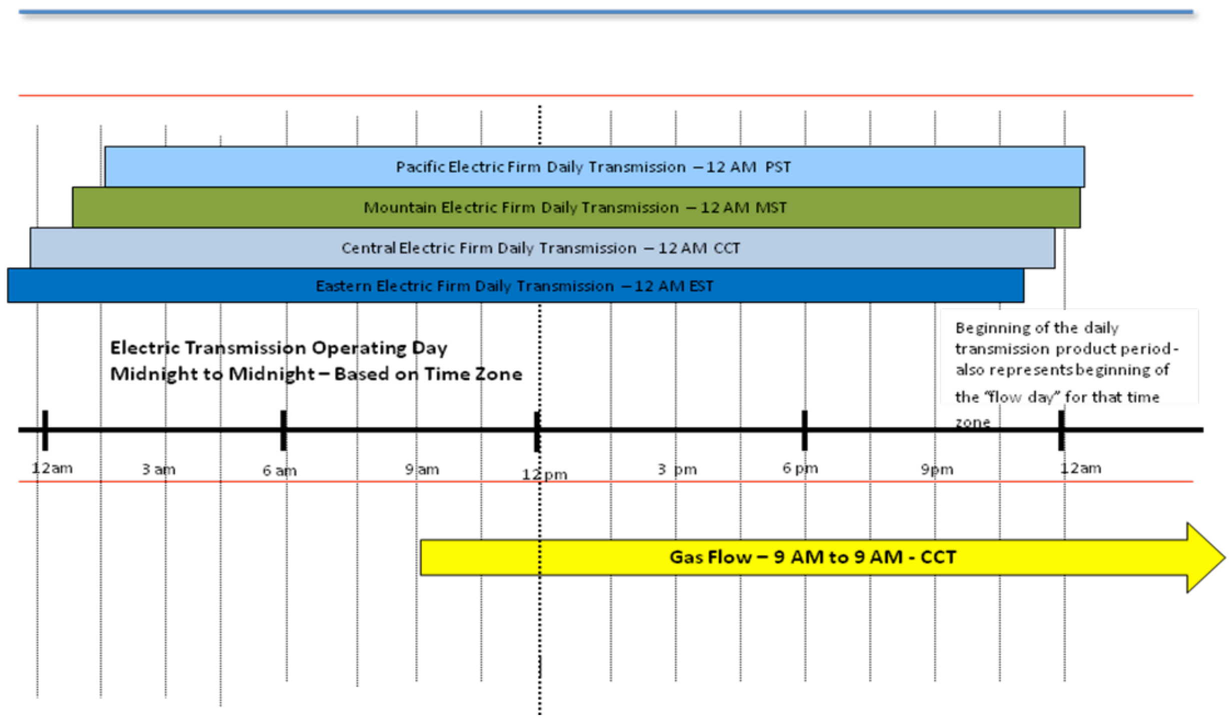
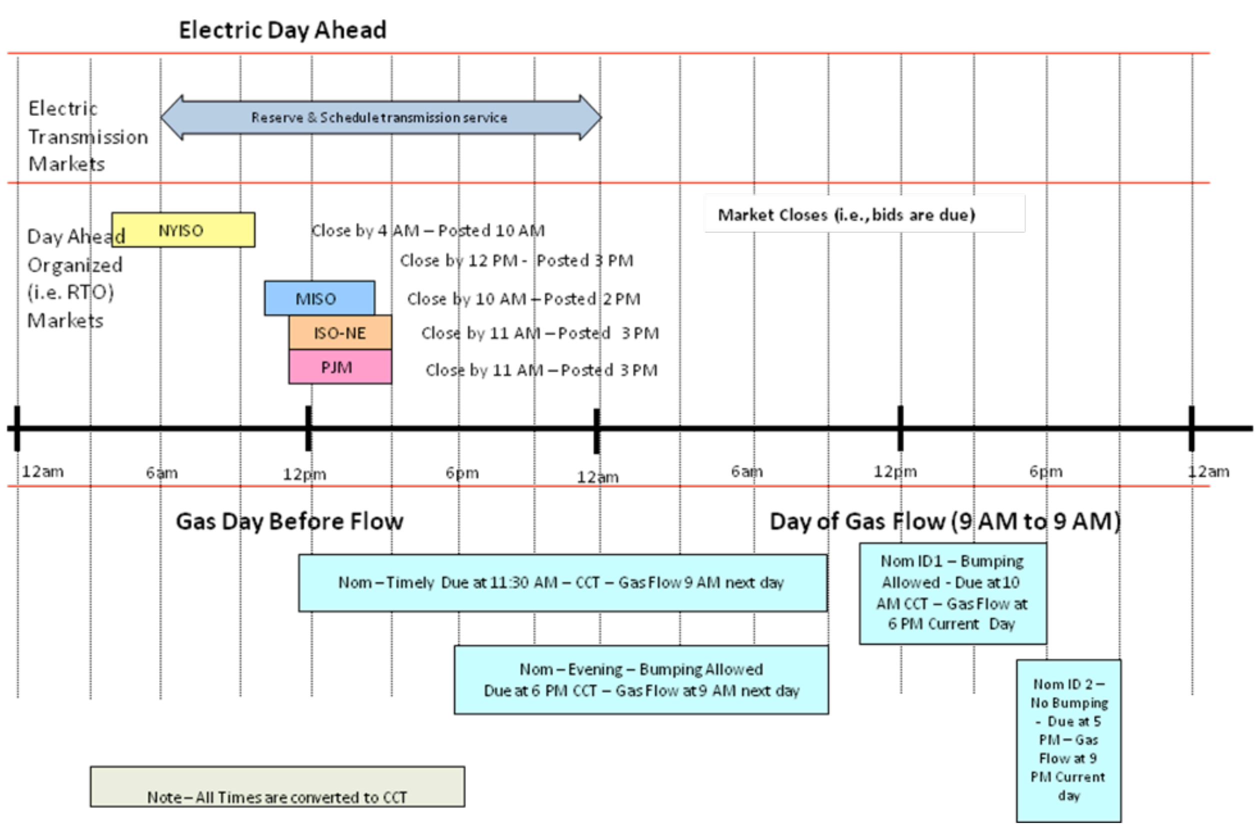


Figure 24 Electric Schedule versus Gas Nomination Schedule



Better coordinated gas and power timelines could help reduce power generator risks but the larger issue that impacts the ability of electric generators to receive service is whether they have contracted adequately for firm pipeline service. However, given that gas processes are based on national standards, but power processes vary by region, it will be difficult to develop uniform, consistent gas and power timelines for North America.

In February 2006 NAESB filed a report[70] on Gas and Electric Interdependency with the FERC that identified and categorized 13 issues that were critical to harmonization efforts. Based on the 13 issues, the Final Report identified six potential areas where Commission guidance could assist NAESB in developing new or updated business practices to improve coordination between the gas and electric industries. Through Order 698 issued by the Commission in June 2007 the FERC adopted NAESB's voluntary consensus standards to ensure that operators of the electric grid and power plant operators could stay abreast of developments on gas pipelines that can affect the reliability of electric service. Pipelines are required to provide gas-fired power plant operators with information as to whether hourly flow deviations can be honored concerning material changes in circumstances that may impact hourly flow rates. The standards also required that, upon request, a gas-fired power plant operator must provide to the appropriate independent electric balancing authority or electric reliability coordinator pertinent information regarding its service levels for gas transportation (firm or interruptible) and for gas supply (firm, f or variable quantity, or interruptible). This information should assist reliability coordinators in assessing the relative reliability of various gas-fired generators. In September 2008 NAESB filed two additional sets of standards in response to FERC Order No. 698 that provide increased receipt and delivery point flexibility through the use of redirects of scheduled quantities and provide for index-based pricing for capacity release transactions. These standards were adopted by the Commission on February 24, 2009 through Order No. 587-T. The Commission's November 18, 2010 "Notice of Proposed Rulemaking on Integration of Variable Energy Resources," has a number of industry comments that highlight other harmonization issues.

C. Firm Pipeline Service

As noted above, most generators outside of the southeast United States do not contract for firm pipeline transportation. Yet for regulated utility generators that do have the ability to recover costs associated with firm pipeline transportation, some have found that standard Firm Transportation Service (FT) may not fully meet their needs for two reasons:

- The use of alternate receipt or delivery points by other firm shippers can restrict the ability of an electric generator holding firm transportation from being able to schedule its firm capacity in any of the three intra-day scheduling cycles. This can happen when another firm shipper schedules gas from an alternate receipt point and/or to an alternate delivery point in the timely nomination cycle which results in gas flows that exceed the capacity of certain points on the interstate pipeline system. When these flows exceed the capacity at a point or points on the interstate pipeline system it creates a constraint. This constraint then restricts the ability of a shipper holding firm

[70] "Docket No. RM05-28-000, "NAESB Final Report on the Efforts of the Gas-Electric Interdependency Committee"

capacity that is scheduled to flow through the constraint to make any changes (increases or decreases) to its scheduled quantities in any subsequent scheduling cycle for that particular gas day. This is often referred to as the "No Bump Rule". Therefore, a shipper holding firm capacity that serves an electric generating facility that is scheduled to flow through a constraint has to manage with the amount of gas that it schedules in the timely cycle and cannot make any changes without losing its firm rights. To the extent that the shipper did not schedule its full primary capacity to a point the remaining capacity is rendered unavailable for that gas day.

- As stated earlier, FT service generally limits hourly flows to 1/24th of the maximum daily quantity, e.g., pro rata or ratable flow; however, both natural gas and electricity demand do vary considerably over the course of a day. Typically natural gas demand, especially in the winter, peaks in the early morning and bottoms out just before sunset. Typically electric demand, especially in the summer, peaks in late afternoon or early evening and bottoms out just before sunrise. For both markets, the pro rata take requirement does not meet basic market requirements. During peak demand periods, pipelines restrict customers to ratable flows. During other periods, pipelines work with their customers on a non-discriminatory basis to provide hourly flexibility. Most of the time non pro rata takes can be accommodated, but there is a risk that they may not always be accommodated. As a result, many pipelines offer two other firm transportation services to address the issue of hourly takes – Enhanced Firm Transportation (EFT) and No Notice Service (NNS). The typical EFT service allows shippers to take up to $1/16^{th}$ of the maximum daily quantity in an hour. The typical NNS further allows shippers to take service without a nomination and to take up to 1/16th of the maximum daily quantity in a hour addressing not only the pro rata issue but the no bump issue. However, EFT and NNS are more expensive than FT as they require more line pack and/or storage.[71]

D. Firming Up Intermittent Renewables

As intermittent renewable generation capacity increases, the power sector is increasingly focused on natural gas-fired generation with its flexible operating characteristics to accommodate day-to-day variations in renewable generation and to firm up intraday variations between scheduled renewable generation (based on a wind forecast) and actual renewable generation or firming requirement. At the heart of all of these issues is how costs should be allocated, whether for maintaining enough pipeline capacity to serve an increase in power generation load or for compensating generators for backing up intermittent renewable energy.

This issue of who pays for the infrastructure to support renewable energy has been raised in the context of new electric transmission lines for transporting expanded renewables generation. On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking

[71] Some pipelines offer "no notice" service only to former sales customers.

(NOPR) that would amend its requirements for electric transmission planning and cost allocation. In this NOPR, FERC seeks to address perceived deficiencies in its transmission planning process and cost allocation requirements that may inhibit the development of new transmission facilities. The central debate is whether electric consumers should be burdened with the costs of new electric facilities from which they receive little or no meaningful benefit given a standard that the cost of transmission projects be allocated in a fashion "reasonably proportionate to measurable economic and reliability benefits." Recent decisions in Southwest Power Pool, 131 FERC 61,252 (SPP) and in Midwest Independent Transmission System Operator, 133 FERC 61,221 involve cost allocation methodologies that, at their heart, merely spread the costs of certain, significant high voltage transmission facilities over the RTO's respective footprint.

On March 16, 2011, the INGAA Foundation released a new study, *Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines.* The study examined the amount of firm transportation capacity that would have to be built to support the forecasted growth in renewable energy and the regulatory policy issues that would have to be addressed to assure the cost of this new capacity was recovered. The highlights of the study include:

- In the next 15 years, up to 105 GW of renewable power generation is forecast to be constructed of which 88 GW could be new intermittent wind generation.
- The natural gas fired generation, most likely a combustion turbine, needed to firm up wind generation could be up to approximately 33 GW generating some 45,500 GWh of electricity.
- Almost 5 Bcf/d of incremental delivery capability could be required over the next 15 years to provide the new gas fired firming generation with firm natural gas supply. But at an expected load factor of only 15%, natural gas demand might increase by only 0.75 Bcf/d over the next 15 years.
- The total annual natural gas use associated with firming intermittent generation could grow to about 440 Bcf by 2025. This is roughly about 2 percent of current annual U.S. gas use.
- The total capital cost of the natural gas infrastructure to support firming requirements could range from about $2 billion to $15 billion. Utilization of the new gas pipeline infrastructure is expected to be quite low, around 15 percent or less. The implied unit cost of firm transportation capacity ($/MMBtu) at a 15 percent utilization rate would be over six times greater than the cost at a full rate of utilization.

The study goes on to conclude that to ensure adequate back-up generation for electric system reliability and that other pipeline customers are not adversely affected by back-up generation, regulators should consider adopting policies that:

- Identify generation units that are providing firming service.
- Provide a mechanism for cost recovery for generators, including the recovery of firm pipeline transportation and storage costs.

- Support tariffs that ensure the recovery of costs of pipeline services that meet the needs of the firming generation.

E. Curtailment Rules

Curtailment of interstate pipeline capacity is generally done on a pro rata basis based on shippers' firm entitlements. In contrast, state or LDC level curtailment rules may curtail industrial customers before "human needs" customers such as homes, hospitals and schools. Unfortunately, in some cases power generators are lumped in with industrial load. Curtailment of power generators could adversely affect "human needs" customers as most such customers need electricity to operate their natural gas equipment. Also, curtailment of power generators could adversely affect the delivery of natural gas if the pipeline or distributor uses electric compression. This is an area that state regulators and LDC's ought to examine to ensure reliability of service.

F. Transparency

Unexpected changes in demand or supply are drivers of price volatility. One way to reduce volatility is to minimize surprises by increasing transparency of supplier operations. The FERC has done this by requiring interstate pipelines to post on the web extensive data on their operations. Increasing the transparency of power and transmission operations could also add predictability and reduce surprises.

G. Transmission Issues

Much has been written about transmission bottlenecks related to wind generation. However, little has been published on possible transmission bottlenecks related to increased use of existing NGCCs to further displace or replace coal-fired generation. Since 2009 lower natural gas prices have resulted in over 2.7 Bcf/d of incremental natural gas demand from displacement of coal-fired generation with an estimated reduction in CO_2 emissions of about 78 million $MtCO_2e$/year versus current emissions of 7,300 million $MtCO_2e$/year.[72] A Congressional Research Service (CRS) study estimated the potential for coal-to-gas displacement at 12.7 Bcf/d.[73] However, that estimate assumed that there are no electric transmission barriers to inhibit use of existing NGCCs. This CRS study estimated the displacement potential for NGCCs within 25 miles of a coal plant at a more limited 3.5 Bcf/d. This study as well as others reviewed, including the ones analyzing the impact of proposed non-GHG EPA regulations on coal plants, did not identify transmission bottlenecks to maximizing coal displacement.

[72] Bentek Energy Market Alert August 3, 2010 Power Burn Head Fake Catches Market Off Guard.
[73] Congressional Research Service, Displacing Coal with Generation from Existing Natural Gas Fired Power Plants, January 19, 2010.

Chapter Six – Conclusions

A number of studies (both public and private) have been reviewed on the subject of gas utilization and its relationship to the U.S. power sector. It is clear that, except in rare cases, natural gas based power generation is expected to grow over the coming decades based on an expanding resource base, tighter environmental regulations, a competitive capital structure and operating profile, and possible carbon regulations.

However, the growth in natural gas use will be uneven as alternative generation sources (solar and wind, much of which is mandated or subsidized by government policies) marginalizes gas power production, while the rate of retirement of fossil units (coal and oil) follows is unpredictable. Retirement rates for older, coal thermal plants range from as low as 40 GW to as high as 90 GW, with potential additional gas consumption increasing by 5.9 Bcf/d. Many of these older facilities would likely retire just based on age (which also usually means higher maintenance costs). But tightening regulatory compliance issues, and even some less obvious concerns like demographics of the workforce, are expected to accelerate that speed of retirement. And there is likely to be some direct conversion of existing fossil (coal/oil) thermal capacity to natural gas. This achieves a rapid improvement in the emissions profile, with minimal costs. But this only sidesteps a key issue: to achieve the largest reduction in emissions (including CO_2), natural gas should be used in a system like a NGCC where the conversion efficiency is highest.

The unexpected growth of unconventional gas sources (shale gas, coal bed methane, tight sands, etc.) is likely to facilitate the growth of the gas power markets. In fact, the gas power markets are probably the only market that could absorb the massive amounts of gas resources becoming available. Increased gas power generation will also have the benefit that it will reduce the U.S. "carbon footprint". The new generation of gas turbines entering the market provides efficiencies starting at 40% and increasing from there. Thus, even without a specific regulatory requirement for lowering CO_2 emissions, a combination of gas generation and increased renewables will help reduce the CO_2 profile from the power sector.

But the U.S. will still require the use of a broad range of power conversion systems. Much of the existing coal fleet will remain in place twenty years from now (11,000+ MW is under construction today; and coal is a relatively inexpensive fuel), and the lowest LCOE fossil based energy producers in the U.S. are coal or natural gas (See Table 6 and Figure 4). For the U.S. to maintain a competitive industrial market position, it will be difficult to lobby for use of more expensive generation in the near term. And in the near term, it does not appear that CO_2 control technology has reached a stage where it could be deployed even with direct subsidies. As a strategy for carbon mitigation, fuel displacement switching from (coal to gas), efficiency upgrades, and some mix of renewables represent the best path forward, at least in the near to mid-term.

Longer term it will likely require greater investment of R&D and demonstration plants to replace the installed capacity with innovative technologies that may be available in the coming decades. This is a role for federal support, and not one that is likely solved by legislative/regulatory means. But control of CO_2 through emission controls is no simple task. CO_2 is essentially inert (unlike SO_2 and NO_x), it cannot be filtered (as can PM_{10} and

$PM_{2.5}$ particulates), and the concentrations are about 10,000x that of the trace pollutants that are routinely processed with environmental controls. A low chemical reactivity and high mass emission rate are the prime reasons why the energy demands (and capital costs) associated with CO_2 control are so great, and the technical challenges so significant.

Almost equally challenging is the expected cost of under-developed technologies. Historical data suggests that if there is little experience with a specific and complex technology, the long range cost forecast becomes much less certain. Gas turbines represent a highly developed technology, and there are thousands operating in the U.S., and hundreds of them are of very recent design. Their forecast market prices are very predictable, hinging primarily on the cost of steel, nickel, and copper. But there are no scale demonstration carbon capture plants, and estimates of their cost vary widely. Projected costs for technologies that have not been constructed in decades (e.g. nuclear) also appear to vary widely. Part of this reason may be rooted in the method of construction. The bulk of a NGCC can be factory-built, and in less than 2 years. Such does not seem to be the case (yet) for many of the proposed nuclear plants, although there is great expectation that new construction methods and design features will greatly reduce the time to market.

Natural gas generation currently has advantages over these other generation resources due to its relatively low capital cost, highly reliable and very flexible operating characteristics. In addition, gas-fired turbines can be ordered and installed in time frames ranging from six-months to twenty-six months, with capacities in the range of 25 MW to 500 MW. Future power generation decisions will be driven by the economic balance between natural gas generation and practically every other method of electricity production. Unlike other generation technologies that are more capital intensive (solar, coal with CCS and nuclear), natural gas generation is heavily dependent on the fuel supply, primarily on domestic energy reserves. On a 50-to-100-year horizon, no fuel supplies are totally secure; they are all subject to the unforeseen and unpredictable events that could significantly alter such a long term forecast. However, if the natural gas industry is successful in maintaining a highly reliable and competitively priced source of supply over the next 50 years, natural gas fired generation has the potential to be a sustainable fuel of choice well beyond the mid-century mark. It is a combination of resource base (an abundance of natural gas) and technology (use of high-pressure/high efficiency gas turbines) that will make the case for economics of selecting the gas generation option. Those key factors influencing the long-term market forecasts are summarized in the final table.

Table 15. Summary of key market drivers for power generation.

	Fuel	**Availability**	**Cost Certainty**
Generation Technology	**Fossil**	Widely available, all fossil fuel types, but predominantly gas-based for most projects in development.	Reasonably narrow and predictable cost estimates; smaller factory produced units much more predictable.
	Non-Fossil	Nuclear and hydro are widely available; wind development is continuing; others are in development (solar thermal, utility scale PV).	New costs are less certain. Very few units under construction Cost variability appears to correlate with number of installations already in place.
Fuel Selection	**Low Carbon**	Natural gas abundant, widely available due to new extraction methods pioneered in the U.S.	Price level and volatility has greatly diminished, but uncertainty over environmental rules surrounding the use of hydro fracking could impact long range supply estimates.
	High Carbon	Typically coal; widely available, and at very competitive prices. Expected to continue to provide substantial generation.	Relatively predictable, and potentially decreasing with pressure to reduce/retire fossil plants
GHG Control	**Post Combustion**	Only 25 operating plants (est) that extract CO_2, yet none treat more than a few percent of exhaust gas.	Like any new technology, capital costs vary widely. Expected to be expensive. No demonstration at scale systems operating on any power plants.
	Pre-combustion	Few operating plants in the world today, all are based on gasification technology. One of the largest CO_2 emitters in the world uses CO_2 extraction, but eventually vents the gas to the atmosphere.	Costs continue to be high; significant financial challenges with current IGCC plant under construction

Appendix A: Participating Individuals and Organizations

NAME	ORGANIZATION	E-MAIL
Blake, Thomas M.	ConocoPhillips	thomas.m.blake@conocophillips.com
Braitsch, Jay	Department of Energy	jay.braitsch@hq.doe.gov
Charlton, Susan C.	Dominion Resources, Inc.	susan.c.charlton@dom.com
Dalla-Longa, Luciano	EnCana Corporation	luciano.dalla-longa@encana.com
Eskin, Leo D.	Combustion, Science & Engineering, Inc.	leskin@csefire.com
Grasso, Thomas M.	ConocoPhillips	tom.m.grasso@conocophillips.com
Grubb, Jeffery R.	Southern Company Generation	jrgrubb@southernco.com
Ihle, Jack	Xcel Energy, Inc.	jack.ihle@xcelenergy.com
Jessee, Jim	Duke Energy Corporation	jim.jessee@duke-energy.com
Kah, Marianne S.	ConocoPhillips	marianne.s.kah@conocophillips.com
Kendell, James	Department of Energy	james.kendell@eia.doe.gov
Layton, Salud A.	Dominion Virginia Power	
Leff, Michael T.	Department of Energy	michael.leff@eia.doe.gov
Martin, James K.	Dominion Resources, Inc.	james.k.martin@dom.com
McKay, Bruce C.	Dominion Resources, Inc.	bruce.c.mckay@dom.com
Moura, John	North American Electric Reliability Corp.	john.moura@nerc.net
Osten, Jim	IHS CERA	jim.osten@ihsglobalinsight.com
Pablo, Jeanette	PNM Resources, Inc.	jeanette.pablo@pnmresources.com
Rising, Bruce W.	Siemens Energy, Inc.	bruce.rising@siemens.com
Sun, Guodong	Stony Brook University	guodong.sun@stonybrook.edu
Thorn, Terence H.	JKM Consulting	tthorn@txthorns.net
Wallace, Jeffrey L.	Southern Company Generation	jlwallac@couthernco.com
Wood, III, Patrick	Wood3 Resources	pat@wood3resources.com
Yeasting, Ken	IHS CERA	ken.yeasting@ihscera.com

Appendix B: Reference Information

Table B-1 Cost Comparison of Primary Power Generation Systems[74]

		Case		1	1a	2	2a	3	3a	4	5	6
		Technology		*SCPC*	*SCPC with CCS*	*IGCC*	*IGCC with CCS*	*Advanced NGCC*	*NGCC with CCS*	*Combustion Turbine*	*Fuel Cells*	*Advanced Nuclear*
A		Size, MW		600	600	550	380	400	400	230	10	1350
B		Capacity Factor		90%	90%	80%	80%	80%	80%	10%	80%	80%
C	CO_2	tonne/MWh		0.800	0.080	0.800	0.080	0.300	0.060	0.450	0.000	0.000
D	CO_2	$/tonne		$0	$0	$0	$0	$0	$0	$0	$0	$0
	Operating Units	2009		1100	0	2	0	1500	0	3000	0	104
	US Capacity 2010	GW		346	0	1.249	0	255	0	146	0.07	100
	CO2 Emitter			Yes	Partial	Yes	Partial	Yes	Partial	Yes	Partial	No
CAPEX				$/kW								
E1	EPA 3.02			$ 2,062		$ 2,371	$ 3,462	$ 947		$ 633		$ 3,295
E2	EPA 4.10			$ 2,980		$ 3,335	$ 4,821	$ 997		$ 713		$ 4,720
E3	EEI/AEO			$ 2,285		$ 2,631	$ 3,849	$ 994		$ 664		$ 3,902
E4	AEO 2010			$ 2,223		$ 2,569	$ 3,776	$ 968	$ 1,932	$ 648	$ 5,478	$ 3,820
E5	AEO 2011			$ 3,167	$ 5,099	$ 3,565	$ 5,348	$ 1,003	$ 2,060	$ 665	$ 6,835	$ 5,335
		Avg CAPEX		$ 2,543	$ 5,099	$ 2,894	$ 4,251	$ 982	$ 1,996	$ 665	$ 6,157	$ 4,214
Heatrate[6]				(Btu/kWh)								
F1	EPA 3.02			9,200		8,765	10,781	6,752		9,289	#N/A	10,434
F2	EPA 4.10			8,874		8,424	10,149	6,810		10,720	#N/A	10,400
F3	EEI/AEO			9,200		8,765	10,781	6,720		9,183	#N/A	10,488
F4	AEO 2010			9,200		8,765	10,781	6,752	8,613	9,289	7,930	10,488
F5	AEO 2011			8,800	12,000	8,700	10,700	6,430	7,525	9,750	9,500	#N/A
Variable O&M				(2008 $/MWh)								
G1	EPA 3.02	$/MWH		$ 4.69		$ 2.99	$ 4.54	$ 2.04		$ 3.24	#N/A	$ 0.51
G2	EPA 4.10	$/MWH		$ 3.50		$ 1.35	$ 1.71	$ 2.62		$ 3.67	#N/A	$ 0.79
G3	EEI/AEO	$/MWH		$ 4.69		$ 2.99	$ 4.54	$ 2.04		$ 3.24	#N/A	$ 0.51
G4	AEO 2010	$/MWH		$ 4.69		$ 2.99	$ 4.54	$ 2.04	$ 3.01	$ 3.24	$ 49.00	$ 0.51
G5	AEO 2011	$/MWH		$ 4.25	$ 9.05	$ 6.87	$ 8.04	$ 3.11	$ 6.45	$ 9.87	$ -	$ 2.04
Fixed O&M				($2008/kW)								
H1	EPA 3.02	$/kW-yr		$ 28.15		$ 39.53	$ 47.15	$ 11.96		$ 10.77	#N/A	$ 92.04
H2	EPA 4.10	$/kW-yr		$ 29.52		$ 48.92	$ 61.79	$ 14.71		$ 12.56	#N/A	$ 94.37
H3	EEI/AEO	$/kW-yr		$ 28.15		$ 39.53	$ 47.15	$ 11.96		$ 10.77	#N/A	$ 92.04
H4	AEO 2010	$/kW-yr		$ 28.15		$ 39.53	$ 47.15	$ 11.96	$ 20.35	$ 10.77	$ 5.78	$ 92.04
H5	AEO 2011	$/kW-yr		$ 35.97	$ 76.62	$ 59.23	$ 69.30	$ 14.62	$ 30.25	$ 6.70	$ 350.00	$ 88.75
I	MWh/yr	A*B*8760		4.73E+06	4.73E+06	3.85E+06	2.66E+06	2.80E+06	2.80E+06	2.01E+05	7.01E+04	9.46E+06

74 http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

		Case		1	1a	2	2a	3	3a	4	5	6
		Technology		*SCPC*	*SCPC with CCS*	*IGCC*	*IGCC with CCS*	*Advanced NGCC*	*NGCC with CCS*	*Combustion Turbine*	*Fuel Cells*	*Advanced Nuclear*
A		**Size, MW**		600	600	550	380	400	400	230	10	1350
B		**Capacity Factor**		90%	90%	80%	80%	80%	80%	10%	80%	80%
C	**CO_2**	**tonne/MWh**		0.800	0.080	0.800	0.080	0.300	0.060	0.450	0.000	0.000
D	**CO_2**	**$/tonne**		$0	$0	$0	$0	$0	$0	$0	$0	$0
	Operating Units	**2009**		1100	0	2	0	1500	0	3000	0	104
	US Capacity 2010	**GW**		346	0	1.249	0	255	0	146	0.07	100
	CO2 Emitter			Yes	Partial	Yes	Partial	Yes	Partial	Yes	Partial	No
Fixed Cost, $/MWh				**($/MWh)**								
J1	**EPA 3.02**	A*H*1000/I		$ 3.57		$ 5.64	$ 6.73	$ 1.71	$ -	$ 12.29	#N/A	$ 13.13
J2	**EPA 4.10**	A*H*1000/I		$ 3.74		$ 6.98	$ 8.82	$ 2.10	$ -	$ 14.34	#N/A	$ 13.47
J3	**EEI/AEO**	A*H*1000/I		$ 3.57		$ 5.64	$ 6.73	$ 1.71	$ -	$ 12.29	#N/A	$ 13.13
J4	**AEO 2010**	A*H*1000/I		$ 3.57		$ 5.64	$ 6.73	$ 1.71	$ 2.90	$ 12.29	$ 0.82	$ 13.13
J5	**AEO 2011**	A*H*1000/I		$ 4.56	$ 9.72	$ 8.45	$ 9.89	$ 2.09	$ 4.32	$ 7.65	$ 49.94	$ 12.66
Total Capital												
	EPC											
K1	**EPA 3.02**	$ million	**TCR**	$ 1,237.1	$ -	$ 1,304.1	$ 1,315.7	$ 378.7	$ -	$ 145.50	#N/A	$ 4,447.87
K2	**EPA 4.10**	$ million	**TCR**	$ 1,788.2	$ -	$ 1,834.1	$ 1,831.9	$ 398.7	$ -	$ 163.97	#N/A	$ 6,371.62
K3	**EEI/AEO**	$ million	**TCR**	$ 1,371.1	$ -	$ 1,447.0	$ 1,462.8	$ 397.4	$ -	$ 152.75	#N/A	$ 5,267.41
K4	**EIA 2010**	$ million	**TCR**	$ 1,333.8	$ -	$ 1,413.0	$ 1,434.9	$ 387.2	$ 772.80	$ 149.04	$ 54.78	$ 5,157.00
K5	**EIA 2011**	$ million	**TCR**	$ 1,900.2	$ 3,059.4	$ 1,960.8	$ 2,032.2	$ 401.2	$ 824.0	$ 153.0	$ 68.4	$ 7,202.3
L	Capital Recovery	%	**CRF**	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
M	Fuel Cost	$/MMBtu	**FC**	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 2.00
N	Fuel Cost	$/MWh	**Fuel**	$ 22.64	$ 30.00	$ 21.71	$ 26.60	$ 40.16	$ 48.41	$ 57.88	$ 52.29	$ 20.91
O	CO_2	$/MWh		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LCOE	**$/MWh**			**$/MWh**								
P1	**EPA 3.02**	K*L/I+G+J+N+O		$ 62.28		$70.94	$ 97.15	$60.12		$160.07		$ 90.96
P2	**EPA 4.10**	K*L/I+G+J+N+O		$ 75.25		$87.14	$119.67	$61.95		$173.54		
P3	**EEI/AEO**	K*L/I+G+J+N+O		$ 65.68		$75.39	$103.78	$60.92		$164.39		$101.36
P4	**EIA 2010**	K*L/I+G+J+N+O		$ 64.74		$74.33	$102.52	$60.48	$ 87.41	$162.18	$195.91	$ 99.95
P5	**EIA 2011**	K*L/I+G+J+N+O		$ 79.65	$126.38	$98.08	$136.10	$62.53	$ 94.45	$166.49	$219.27	$126.96
	Average			$ 69.52	$ 126.38	$ 81.18	$ 111.84	$ 61.20	$ 90.93	$ 165.33	$ 207.59	$ 104.81
	Maximum			$ 79.65	$ 126.38	$ 98.08	$ 136.10	$ 62.53	$ 94.45	$ 173.54	$ 219.27	$ 126.96
	Relative to NGCC			114%	207%	133%	183%	100%	149%	270%	339%	171%

		Case		7	8	9	10	11	12	13	14
		Technology		*Biomass*	*Geothermal*	*MSW-Landfill*	*Conventional Hydro*	*Wind Onshore*	*Wind Offshore*	*S-CSP*	*PV*
A		**Size, MW**		50	50	50	50	50	100	100	5
B		**Capacity Factor**		80%	90%	80%	80%	30%	30%	35%	30%
C	**CO_2**	**tonne/MWh**		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
D	**CO_2**	**$/tonne**		$0	$0	$0	$0	$0	$0	$0	$0
	Operating Units	**2009**		200	250	?	4000	750	0	15	500
	US Capacity 2010	**GW**		3.6	3.6	2	98	38	0	0.48	0.5
	CO2 Emitter			Partial	No	Partial	No	No	No	No	No
CAPEX											
E1	**EPA 3.02**			$ 3,733		$ 2,548		$ 1,920		$ 4,897	$ 5,888
E2	**EPA 4.10**			$ 3,733		$ 2,548		$ 1,920		$ 4,897	$ 5,888
E3	**EEI/AEO**			$ 3,927		$ 2,672		$ 2,020		$ 5,022	$ 6,223
E4	**AEO 2010**			$ 3,849	$ 1,749	$ 2,599	$ 2,291	$ 1,966	$ 3,937	$ 5,132	$ 6,171
E5	**AEO 2011**			$ 3,860	$ 4,141	$ 8,232	$ 3,076	$ 2,438	$ 5,975	$ 4,692	$ 6,050
		Avg CAPEX		$ 3,821	$ 2,945	$ 3,720	$ 2,684	$ 2,053	$ 4,956	$ 4,928	$ 6,044
Heatrate[6]											
F1	**EPA 3.02**			9,646	#N/A	13,648	#N/A	#N/A	#N/A	#N/A	#N/A
F2	**EPA 4.10**			9,646	#N/A	13,648	#N/A	#N/A	#N/A	#N/A	#N/A
F3	**EEI/AEO**			9,451	#N/A	13,648	#N/A	#N/A	#N/A	#N/A	#N/A
F4	**AEO 2010**			9,451	32,969	13,648	9,884	9,884	9,884	9,884	9,884
F5	**AEO 2011**			12,350	#N/A	18,000					
Variable O&M											
G1	**EPA 3.02**	**$/MWH**		$ 6.86		$ 0.01		$ -		$ -	$ -
G2	**EPA 4.10**	**$/MWH**		$ 6.86		$ 0.01		$ -		$ -	$ -
G3	**EEI/AEO**	**$/MWH**		$ 6.86		$ 0.01		$ -		$ -	$ -
G4	**AEO 2010**	**$/MWH**		$ 6.86	$ -	$ 0.01	$ 2.49	$ -	$ -	$ -	$ -
G5	**AEO 2011**	**$/MWH**		$ 5.00	$ 9.64	$ 8.33	$ -	$ -	$ -	$ -	$ -
Fixed O&M											
H1	**EPA 3.02**	**$/kW-yr**		$ 65.89	#N/A	$ 116.80		$ 30.98		$ 58.05	$ 11.94
H2	**EPA 4.10**	**$/kW-yr**		$ 65.89	#N/A	$ 116.80		$ 30.98		$ 58.05	$ 11.94
H3	**EEI/AEO**	**$/kW-yr**		$ 65.89	#N/A	$ 116.80		$ 30.98		$ 58.05	$ 11.94
H4	**AEO 2010**	**$/kW-yr**		$ 65.89	$ 168.33	$ 116.80	$ 13.93	$ 30.98	$ 86.92	$ 58.05	$ 11.94
H5	**AEO 2011**	**$/kW-yr**		$100.50	$ 84.27	$ 373.60	$ 13.44	$ 28.07	$ 53.33	$ 64.00	$ 16.70
I	**MWh/yr**	A*B*8760		3.50E+05	3.94E+05	3.50E+05	3.50E+05	1.31E+05	2.63E+05	3.07E+05	1.31E+04

		Case		7	8	9	10	11	12	13	14
		Technology		*Biomass*	*Geothermal*	*MSW-Landfill*	*Conventional Hydro*	*Wind Onshore*	*Wind Offshore*	*S-CSP*	*PV*
A		**Size, MW**		50	50	50	50	50	100	100	5
B		**Capacity Factor**		80%	90%	80%	80%	30%	30%	35%	30%
C	CO_2	**tonne/MWh**		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
D	CO_2	**$/tonne**		$0	$0	$0	$0	$0	$0	$0	$0
	Operating Units	**2009**		200	250	?	4000	750	0	15	500
	US Capacity 2010	**GW**		3.6	3.6	2	98	38	0	0.48	0.5
	CO2 Emitter			Partial	No	Partial	No	No	No	No	No
Fixed Cost, $/MWh											
J1	**EPA 3.02**	A*H*1000/I		$ 9.40		$ 16.67	$ -	$ 11.79	$ -	$ 18.93	$ 4.54
J2	**EPA 4.10**	A*H*1000/I		$ 9.40		$ 16.67	$ -	$ 11.79	$ -	$ 18.93	$ 4.54
J3	**EEI/AEO**	A*H*1000/I		$ 9.40		$ 16.67	$ -	$ 11.79	$ -	$ 18.93	$ 4.54
J4	**AEO 2010**	A*H*1000/I		$ 9.40	$ 21.35	$ 16.67	$ 1.99	$ 11.79	$ 33.07	$ 18.93	$ 4.55
J5	**AEO 2011**	A*H*1000/I		$ 14.34	$ 10.69	$ 53.31	$ 1.92	$ 10.68	$ 20.29	$ 20.87	$ 6.35
Total Capital											
	EPC										
K1	**EPA 3.02**	$ million	**TCR**	$ 186.67	$ -	$ 127.40	$ -	$ 95.99	$ -	$ 489.66	$ 29.44
K2	**EPA 4.10**	$ million	**TCR**	$ 186.67	$ -	$ 127.40	$ -	$ 95.99	$ -	$ 489.66	$ 29.44
K3	**EEI/AEO**	$ million	**TCR**	$ 196.34	$ -	$ 133.58	$ -	$ 101.02	$ -	$ 502.17	$ 31.12
K4	**EIA 2010**	$ million	**TCR**	$ 192.45	$ 87.45	$ 129.95	$ 114.55	$ 98.30	$ 393.70	$ 513.20	$ 30.86
K5	**EIA 2011**	$ million	**TCR**	$ 193.0	$ 207.1	$ 411.6	$ 153.8	$ 121.9	$ 597.5	$ 469.2	$ 30.3
L	Capital Recovery	%	**CRF**	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
M	Fuel Cost	$/MMBtu	**FC**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N	Fuel Cost	$/MWh	**Fuel**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O		CO_2 $/MWh		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
					$ -						
LCOE	**$/MWh**										
P1	**EPA 3.02**	K*L/I+G+J+N+O				$ 60.31		$ 99.45		$210.58	$273.39
P2	**EPA 4.10**	K*L/I+G+J+N+O				$ 60.31		$ 99.45		$210.58	$273.39
P3	**EEI/AEO**	K*L/I+G+J+N+O				$ 62.42		$104.04		$215.48	$288.70
P4	**EIA 2010**	K*L/I+G+J+N+O		$82.17	$ 47.97	$ 61.18	$ 43.70	$101.56	$212.85	$219.80	$286.33
P5	**EIA 2011**	K*L/I+G+J+N+O		$85.44	$ 83.36	$202.60	$ 54.59	$122.01	$293.12	$204.51	$282.61
	Average			$ 83.80	$ 65.66	$ 89.36	$ 49.15	$ 105.30	$ 252.98	$ 212.19	$ 280.89
	Maximum			$ 85.44	$ 83.36	$ 202.60	$ 54.59	$ 122.01	$ 293.12	$ 219.80	$ 288.70
	Relative to NGCC			137%	107%	146%	80%	172%	413%	347%	459%

SCPC: Super-critical pulverized coal	**IGCC**: Integrated Gasification Combined Cycle	**CCS:** Carbon Capture and Storage	**NGCC**: Natural Gas Combined-cycle
MSW: Municipal Solid Waste	**S-CSP**: Solar, Concentrating Solar Power	**PV:** Photovoltaic	MW: MW rating, nameplate of unit, ISO, sea level.

Table B-2 Summary of studies evaluated in this report.

Organization: U.S. Energy Information Administration
Study Title: Energy Market and Economic Impacts of the American Power Act of 2010[1]
Projection Horizon: 2035

Scenarios	Capital Costs (2008$/kW)[3]	Natural Gas Shale Supply	CO_2 Policy	Offset Assumptions	Technology Availability
Basic	AEO 2010 Ref	AEO 2010 Ref: 347 TCF	Represents provisions of the Kerry-Lieberman American Power Act of 2010. Economy with cap and CO_2 emissions incrementally declining from 2005 levels to 17% by 2020, 42% by 2030, and 83% by 2050. Includes financial incentives for nuclear power and bonus allowances for coal with CCS. Includes rebates to electricity consumers.	2 billion metric tons (BMT) CO_2 equivalent of offsets allowed annually to meet compliance. 0.5-1.0 BMT can be from international sources	No restriction on available technologies
High Shale	AEO 2010 Ref	AEO 2010 High Shale: 652 TCF		Same as Basic	No restriction on available technologies
No International Offsets Limited Technology	AEO 2010 Ref	AEO 2010 Ref: 347 TCF		The use of international offsets is not allowed	Nuclear, fossil with CCS, and dedicated biomass, are limited to AEO 2010 Reference Case
High Capital Cost	AEO 2010 Ref: Except **Nuclear** **$5,730** **Coal CCS** **$6,042** **Biomass** **$5,774**	AEO 2010 Ref: 347 TCF		Same as Basic	No restriction on available technologies

Organization: U.S. Energy Information Administration Study Title: *2010 Annual Energy Outlook*
Projection Horizon: 2035

Scenarios	Capital Costs (2008$/kW)[3]		Natural Gas Shale Supply	CO_2 Policy	Offset Assumptions	Technology Availability
Reference	Nat Gas CC:	$968	Assumed domestic shale available: 347 TCF	None	N/A	No restriction on available technologies
	Nat Gas CC with CCS:	$1,932				
	Natural Gas CT	$648				
	Pulverized Coal:	$2,223				
	IGCC:	$2,569				
	IGCC with CCS:	$3,776				
	Nuclear:	$3,820				
	Onshore Wind:	$1,966				
	Offshore Wind:	$3,937				
	Solar PV:	$6,171				
	Solar Thermal:	$5,132				
	Biomass	$3,849				
	Geothermal:	$1,749				
High Shale	AEO 2010 Ref		Assumed Domestic Shale Available: 652 TCF	None	None	No restriction on available technologies
No Shale	AEO 2010 Ref		Assumed Domestic Shale Available: None after 2008	None	None	No restriction on available technologies

Organization: Massachusetts Institute of Technology-Study Title: *The Future of Natural Gas*
Projection Horizon: 2050

Scenarios	Capital Costs (2005$/kW)[3]		Natural Gas Shale Supply	CO_2 Policy	Offset Assumptions	Technology Availability
No Climate Policy	Pulverized Coal	$2,049	Assumed domestic shale available: 616-631 TCF	None	N/A	No restriction on available technologies
	NGCC	$892				
	NGCC with CCS	$1,781				
	IGCC with CCS	$3,481				
	Nuclear	$3,521				
	Wind	$1,812				
	Biomass	$3,548				
	Solar Thermal	$4,731				
	Solar PV	$5,688				
	Wind Plus Biomass Backup [a]	$5,360				
	Wind Plus NGCC Backup [a]	$2,705				
Cap and Trade Policy	Same as No Climate			Economy wide 50% reduction in CO_2 emissions below 2005 levels by 2050. The cap linearly declines over the projection horizon.	No provision for offsets is included	No restriction on available technologies
Regulatory Policy	Same as No Climate			25% RES share of generation by 2030, holding through 2050. 55% of coal generation is retired 2020 through 2050.	N/A	No restriction on available technologies

Organization: Electric Power Research Institute-Study Title: ***The Power to Reduce CO_2 Emissions***
Projection Horizon: 2050

Scenarios	Capital Costs (2007$/kW)[3]		Natural Gas Shale Supply	CO_2 Policy	Offset Assumptions	Technology Availability
Full Technology Portfolio	Pulverized Coal	$2460	Assumed domestic shale available: 616 TCF	Economy wide 83% reduction in 2005 CO_2 emissions by 2050. The cap linearly declines over the projection horizon.	CO_2 offsets are limited to 200 million metric tons per year	No restriction on available technologies
	IGCC	$2900				
	IGCC with CCS	$4000				
	Coal Fluidized Bed	$2460				
	NGCC	$820				
	Nuclear	$3980				
	Wind	$1995				
	Solar	$4600				
	Biomass	$3235				
Limited Technology Portfolio	Same as Full					Nuclear is limited to current production value. Fossil with CCS is not available

Organization: Resources for the Future-Study Title: Abundant Shale Resources: Some Implications for Energy Policy
Projection Horizon: 2030

Scenarios	Capital Costs (2007$/kW)[3]		Natural Gas Shale Supply	CO_2 Policy	Offset Assumptions	Technology Availability
Baseline	Nat Gas CC:	$948	Assumed domestic shale available: 269 TCF	None	N/A	No restriction on available technologies
	Nat Gas CC with CCS:	$1,890				
	Natural Gas CT	$634				
	Coal:	$2,058				
	IGCC with CCS	$2,378				
	Coal with CCS:	$3,496				
	Nuclear	$3,318				
	Onshore Wind:	$1,923				
	Offshore Wind:	$3,851				
	Solar PV:	$6,038				
	Solar Thermal:	$5,021				
	Biomass	$3,766				
	Geothermal:	$1,711				
Abundant Natural Gas Supply	Same as Baseline		Assumed domestic shale available: 615 TCF	None	N/A	No restriction on available technologies

Organization: Resources for the Future-Study Title: Abundant Shale Resources: Some Implications for Energy Policy
Projection Horizon: 2030

Low-Carbon Policy without Abundant Natural Gas	Same as Baseline	Assumed domestic shale available: 269 TCF			No restriction on available technologies
Low-Carbon Policy with Abundant Natural Gas	Same as Baseline	Assumed domestic shale available: 615 TCF	Represents reductions required by Waxman-Markey American Clean Energy and Security Act of 2009. Economy wide cap and CO_2 emissions incrementally declining from 2005 levels to, 17% by 2020, 58% by 2030, and 83% by 2050.	Assumes 1 billion metric tons of offsets are allowed for annual compliance	No restriction on available technologies
Limits on Nuclear and Renewable Power Generation	Same as Baseline	Assumed domestic shale available: 615 TCF			Nuclear, fossil with CCS, and dedicated biomass, are limited to AEO 2009 Reference Case