DISCUSSION PAPER

March 2010

The Brattle Group

Prospects for Natural Gas Under Climate Policy Legislation

Will There Be a Boom in Gas Demand?

By Steven H. Levine, Frank C. Graves, and Metin Celebi

Contents

The Brattle Group *provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.*

We have offices in Cambridge, Massachusetts; San Francisco, California; and Washington, DC. We also have offices in Brussels, London, and Madrid.

For more information, please visit ***www.brattle.com****.*

Introduction

There has been increased public debate recently about the role of natural gas in reducing greenhouse gas (GHG) emissions in the U.S. Some see natural gas as a bridge to a transformed electricity sector that will eventually rely less on conventional coal-fired generating plants and more on nuclear plants, coal plants with carbon capture and sequestration (CCS), and renewable energy sources.

In the interim, natural gas-fired generation can be the means by which the electricity industry reduces coal-fired generation and GHG emissions. This could occur if there were substantial dispatch switching from coal-fired generation to gas-fired generation following the implementation of a cap and trade program that would place a price on CO_2 emissions.

Others see a larger role for natural gas beyond just a bridge role, especially if low-carbon baseload generating technologies like coal with CCS and nuclear generation are not forthcoming to any substantial degree, and if the supply of low-cost gas, possibly from shales, proves plentiful. In such a world, natural gas-fired generation could be the preferred choice for baseload generation, eventually with its own CCS.

Gas-fired generation also may fill the capacity and CO_2 reduction void if the development of renewable resources is delayed by contractual, financing, or transmission siting issues.

Many market observers are therefore hopeful about a future boom in natural gas under climate policies. The underlying logic for this optimism is clear: natural gas has approximately one-half the carbon content of coal. Increasing its use in electricity generation while reducing coal-fired generation has the potential to substantially reduce GHG emissions.

Moreover, gas-fired generation is attractive due to its low construction costs, short construction lead times, and because it is naturally hedged against fluctuations in gas prices in markets where natural gas is the marginal fuel.

However, despite these advantages of natural gas, the role it will play in electricity generation in the U.S. (and in achieving GHG emission reduction goals) is far from clear, even over the next five to ten years. In fact, some recent forecasts show projected declines in natural gas demand in the U.S. over the next decade.

As shown in Figure 1, the Energy Information Administration's (EIA) recent forecasts show a period of declining demand for natural gas over the next several years, whether or not climate change legislation is passed. **This paper explores why the outlook of declining demand in natural gas might be correct, despite a seemingly strong argument for gas to play a larger role.**

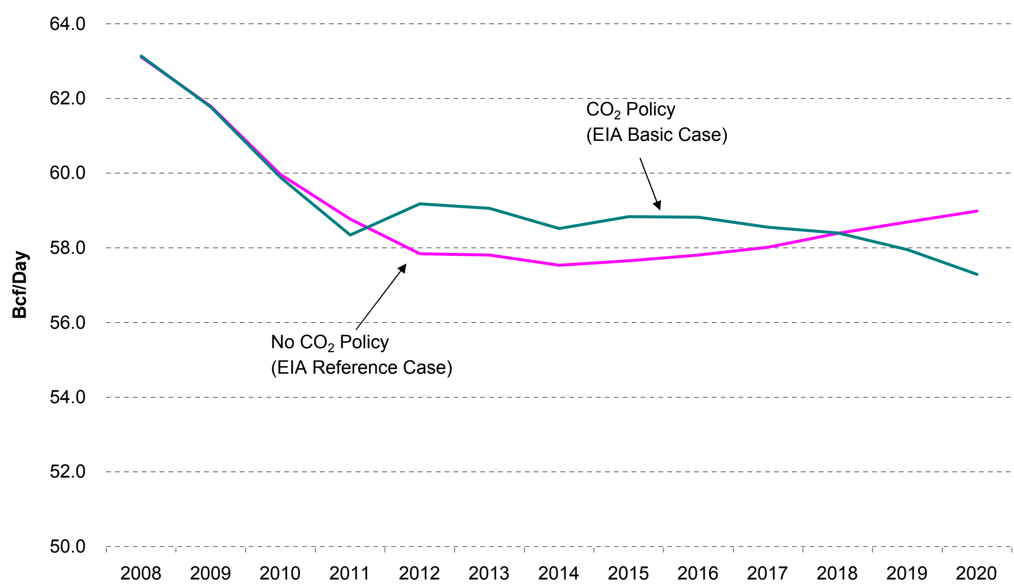
The views expressed in this paper are strictly those of the authors and do not necessarily state or reflect the views of *The Brattle Group, Inc.* or its clients.

There are many challenges to natural gas demand growth in the coming decade that could ultimately result in the gas demand trajectory shown in Figure 1. Several factors suggest that gas demand may not increase substantially as a result of future climate legislation. In particular:

- *Coal-fired generation will not be significantly displaced by natural gas-fired generation until CO_2 prices reach relatively high levels, and such high CO_2 prices may not be forthcoming in the next decade under the cap and trade programs now under consideration. This is due to political concern about CO_2 driving up energy costs and/or a desire to rely on international "offsets" to U.S. CO_2 emissions.*
- *The ongoing development of substantial renewable generation resources tends to reduce natural gas demand for electric power generation, especially since renewable resources are developed as "must-take" resources that can displace the marginal fuel from the dispatch stack; in many regions this is mostly natural gas. While gas-fired generation may be necessary as a capacity back-up for intermittent renewable resources, the volume of natural gas consumed in this role will be relatively low, not enough to offset the amount of gas demand that is backed out as a result of new renewables development.*
- *Electricity conservation efforts and demand response to carbon cost increases can also result in displacement of natural gas in regions where gas-fired generation is the marginal resource.*
- *The protections and incentives offered to coal-fired generation under proposed cap and trade policies, including the allocation of free emission allowances to merchant coal generators, may keep coal plants operating longer and more frequently than they otherwise would, again limiting gas demand growth.*
- *Non-electric gas demand growth is likely to be low due to retail conservation programs and price impacts of CO_2 policy that may negatively impact industrial gas demand.*

Many of these pressures work against growth in gas demand over the next decade and beyond. Prognostications of future natural gas demand and prices must take these factors into consideration. The future mix of electricity generation resources in the U.S. is particularly important to understanding the future of natural gas. If coal-fired generation maintains or strengthens its position in meeting U.S. electricity demand, and there is strong growth in renewable (wind and solar) resources, the future of natural gas demand may not be as bright as many industry participants hope or expect.

Figure 1 Projected Natural Gas Consumption



Source: EIA, "Energy Market and Economic Impacts of H.R. 2454," August 2009.

Indeed, there is the possibility that the U.S. may experience a perverse outcome in which renewables serve to back out natural gas-fired generation rather than coal-fired generation. The implication of such a scenario is that U.S. consumers will be paying a lot for CO_2 emission reductions since natural gas does not emit as much CO_2 as coal, and gas can often displace CO_2 from coal at a much lower cost per ton than some renewables.

This paper discusses these issues in more detail. We explain the economics of dispatch switching between coal and gas plants. We review the construction costs of gas-fired generation plants relative to other types of plants, and show how gas-fired plants are likely to be an economic choice under cap and trade, until CO_2 prices become quite high — enough to make nuclear and integrated gasification combined cycle (IGCC) coal with CCS the preferred generation technologies. Nonetheless, gas plants may not be built in proportion to their societal attractiveness.

We conclude that despite the environmental advantages of natural gas and cost advantages of gas-fired generation, a boom in gas demand is far from certain. However, different regions will experience the effects of climate policy more strongly or weakly than others, with different impacts on regional gas demand depending on the specific characteristics of the electric generation fleet.

Section 1 COAL-TO-GAS DISPATCH SWITCHING UNDER CAP AND TRADE PROGRAMS

While the pace of implementation of climate policy in the U.S. is quite uncertain, it is fairly likely that within a few years some form of restrictions of greenhouse gas emissions (mostly from CO_2) will be passed. The climate bills that have been proposed in the U.S. House (the Waxman-Markey bill) and Senate (the Kerry-Boxer bill) both establish a cap and trade program, i.e., a market-based program that caps the amount of allowed CO_2 emissions and creates tradable emission allowances.

Allowance trading sets a price for CO_2 emissions that becomes a surcharge on fossil fuel consumption, which creates economic incentives to reduce CO_2 emissions. The CO_2 price acts as a penalty for electricity generation sources that emit CO_2 (namely coal, natural gas, and oil-fired power plants), which effectively raises the cost of electricity generation for power plants that use these fossil fuels.

Figure 2 shows the impact of a CO_2 price on the dispatch cost for both coal-fired and natural gas-fired electricity generating units. Dispatch costs are shown for both efficient (low heat rate, new, or large) and inefficient (high heat rate, older, or smaller) generating plants.

As shown, the higher the CO_2 price, the higher the dispatch cost for both coal- and gas-fired units. However, as CO_2 prices increase the dispatch cost of coal-fired generation increases more rapidly than it does for natural gas-fired generation. This reflects the higher carbon content of coal relative to natural gas (thus the steeper slope of the lines for coal-fired units).

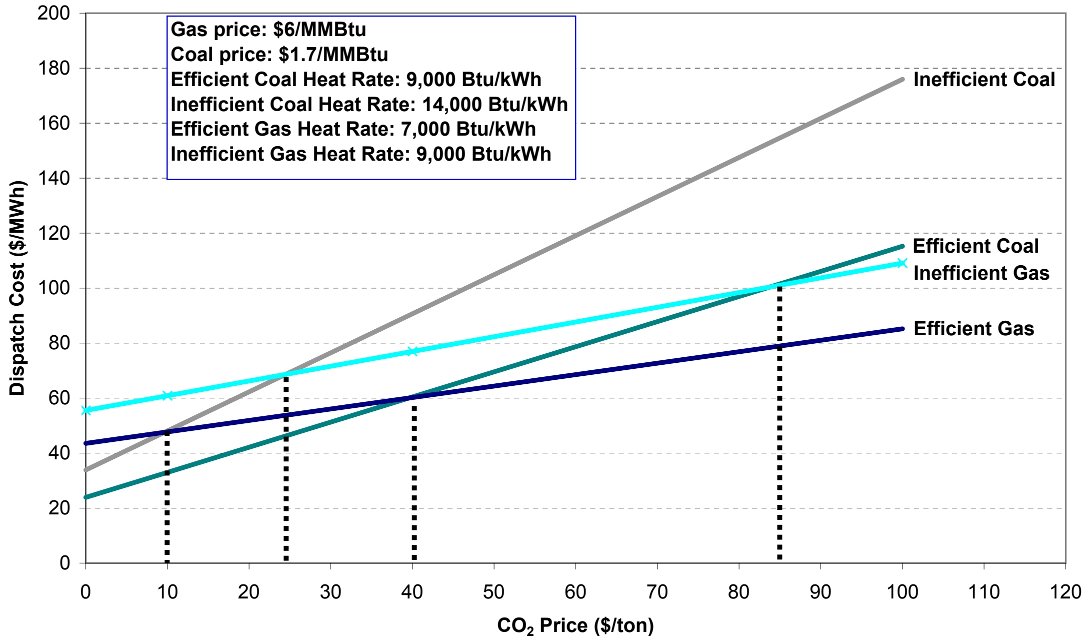
While coal plants emit roughly 1.0 tons or more of CO_2 per MWh, natural gas plants emit roughly 40% as much, or approximately 0.4 tons of CO_2 per MWh. For each $1/ton increase in the CO_2 allowance cost, there is roughly a $1/MWh increase in the dispatch cost of a coal-fired generating plant, but only a $0.40/MWh increase in the dispatch cost of a gas-fired generating plant.

Figure 2 also shows the "crossover" points where the dispatch cost of a gas unit becomes equal to that of a coal unit such that for higher CO_2 prices, the gas unit will dispatch sooner than the coal unit. Therefore, at a CO_2 price of $10/ton, an efficient gas-fired power plant (e.g., a combined cycle plant with a 7,000 Btu/kWh heat rate) will displace an inefficient coal-fired power plant in the dispatch order (at the assumed $6/MMBtu gas price and $1.70/MMBtu coal price).

At a $40/ton CO_2 price, an efficient gas-fired power plant will displace an efficient coal-fired power plant. However, efficient coal plants can survive against some gas plants up to as high a price for CO_2 as $80/ton, at which point even an inefficient gas plant will displace a typical efficient coal plant (assumed to have a 9,000 Btu/kWh heat rate).

Thus, coal is not thoroughly displaced by gas until CO_2 prices are in the range of $50-$100/ton, levels that may not be observed (per EIA forecasts) until

Figure 2 Dispatch Switching Between Existing Coal and Gas Power Plants



2030 or later.[1] (These results and those in Figures 3 and 4 illustrate operating cost tradeoffs among existing plants. They do not capture commitment or transmission constraints. Tradeoffs that include construction costs are discussed later.)

Figure 3 applies this kind of operating plant substitution analysis to the actual fleet of coal and gas plants in the regions overseen by regional transmission operators (RTOs). The independent system operator (ISO) regions we have modeled are ISO-New England, PJM, Midwest ISO (MISO), Southwest Power Pool (SPP), the Electric Reliability Council of Texas (ERCOT), the New York ISO, and the California ISO. These regions cover roughly 60% of U.S. gas and coal generating capacity (195 GW coal, 250 GW gas).

As shown, at a $5/MMBtu gas price and a $30/ton CO_2 price, there would be significant aggregate coal-to-gas dispatch substitution in the collection of ISO regions we have modeled. Gas-fired units would dispatch more often, with the capacity factor of the gas-fired generation fleet (including peaker units) increasing from 21% to 33% and gas demand increasing from about 7.0 Bcf/d to 11.6 Bcf/d (an increase of 65%). The largest increases in gas demand occur in MISO (205%), PJM (180%), and SPP (90%). However, with $7/MMBtu gas prices and a $30/ton CO_2 price, there would be very little coal-to-gas dispatch substitution, as only the most inefficient coal plants would be displaced.

The right side bars in each pair in Figure 3 also show the impact of likely new capacity from renewables in the ISO regions modeled. Specifically, we have assumed the addition of 51,000 MW of renewables by 2020, which represents about 6.5% of total ISO energy needs in 2008 if supplied mostly by wind at a 35% capacity factor. This is less than the incremental renewable energy output needed to meet those regions' collective renewable portfolio standard (RPS) targets for 2020, but perhaps a more realistic expectation.

These added renewables lower gas demand from 11.6 Bcf/d to 10.2 Bcf/d, a decrease of 1.4 Bcf/d (in the $5/MMBtu gas price, $30/ton CO_2 case). Coal demand is also lowered, especially since wind generation is often most productive in off-peak periods, but both coal and gas are affected. Thus, renewable additions have the effect of backing out material gas-fired generation and reducing gas demand (and, again, the effect would be stronger if RPS targets were satisfied).

Figure 3 shows that a combination of low gas prices ($5/MMBtu) and high CO_2 prices ($30/ton) are needed to result in significant coal-to-gas dispatch switching (and corresponding large increases in natural gas demand). But in the coming decade, there is significant uncertainty as to whether these conditions will occur. While U.S. gas prices have been low recently due to the tremendous success of shale gas development in the lower 48 and weak gas demand as a result of the U.S. recession, there is a real possibility of a return to a $7/MMBtu gas price world.

There has been a large reduction in the drilling rig count as a result of the low-price environment, and forward gas prices signal a gas price rebound in the next few years relative to 2009 spot gas prices. This is the case even with ongoing efforts to develop shale gas plays in the lower 48 and reported low finding and development costs by producers active in these plays. Forward gas prices currently show Henry Hub prices in the $6/MMBtu to $7/MMBtu range for 2012 and beyond — well above the $5 range described here needed to bring about significant dispatch switching.

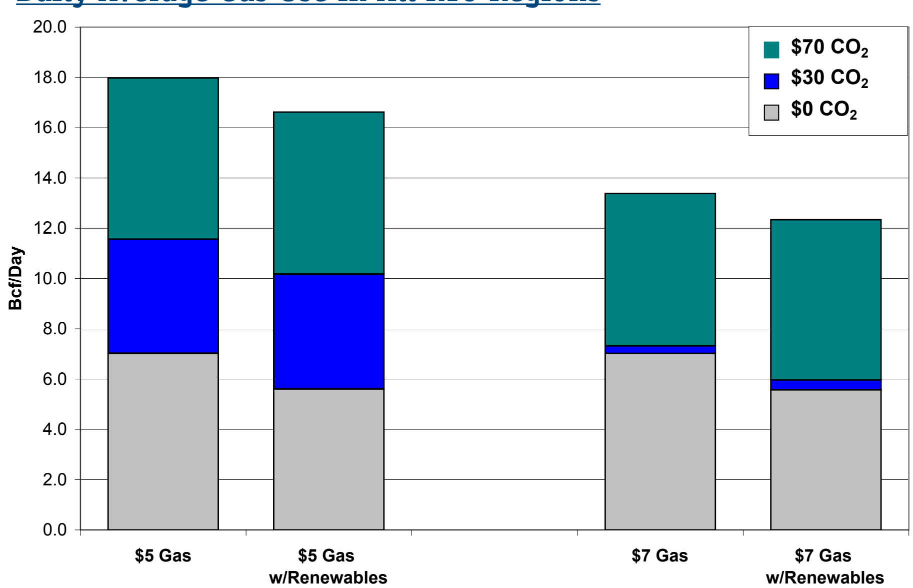
Likewise, most forecasts suggest relatively low CO_2 prices (less than $30/ton) during the first 10 to 15 years of the cap and trade program. This is, in part, because the emission caps are not very stringent in the first decade of the program (i.e., the aggregate number of emission allowances that will be allocated is relatively high). In addition, the availability of emission offsets is also expected to keep CO_2 prices relatively low.

Offsets are emission reduction credits associated with projects that are designed to reduce CO_2 emissions. These credits can be purchased by entities covered by the cap and trade program and used to offset their own emissions. Under currently proposed legislation, offsets associated with both domestic and international emission reduction projects could be used by covered entities.

Recognizing the emission caps and availability of offsets, the U.S. Environmental Protection Agency has forecasted allowance prices of $13/ton in 2015 and $16/ton in 2020 in its core scenario.[2] The real possibility exists that the low natural gas and high emission allowance prices needed for significant coal-to-gas dispatch substitution would not occur in the decade following the implementation of cap and trade. CO_2 price ceilings may also become a factor in limiting coal displacement.

The impacts of CO_2 prices on natural gas demand will differ by region depending on the mix of generation resources and their specific features. For example, our analysis of the SPP in Figure 4 below shows increased gas demand from just CO_2 pricing, much like what was seen in Figure 3. At $5/MMBtu gas prices and $30/ton CO_2 prices, gas demand in SPP increases by about 0.8 Bcf/d (from 1.0 to 1.8 Bcf/d), assuming no additional renewables are added to the generation mix. However, the effect of renewables is more complex than the RTO-wide picture.

Figure 3 Daily Average Gas Use in All RTO Regions



Assuming 6 GW of new renewables are built in SPP, gas demand falls by roughly 0.3 Bcf/d at the $5/MMBtu gas price as renewables displace gas in the no carbon price scenario. Increasing the CO_2 price to $30/ton in the renewables scenario increases gas demand by 1.2 Bcf/d as coal is moved to the margin by the CO_2 price and it is displaced more by renewables than gas.

In both cases (with and without renewables) gas demand is about 1.8 Bcf/d. At a $7/MMBtu gas price, coal is not much handicapped by a $30 CO_2 price, and gas is on the margin getting crowded out by renewables. It is not until CO_2 prices climb to $70 that gas use increases significantly.

Section 2 ECONOMICS OF NEW GAS-FIRED POWER PLANTS

Some of the optimism with respect to natural gas is due to the attractive economics of new natural gas-fired power plants relative to building other types of power plants. Figure 5 shows the real levelized costs of different new power plants, including capital costs, fixed operations and maintenance (O&M), and fuel under different CO_2 price scenarios (the top three layers on the bar charts).

As shown, natural gas-fired combined cycle plants and conventional coal plants are the cheapest alternatives without CO_2 prices, at an all-in cost of just under $70/MWh (assuming natural gas prices of $7/MMBtu and coal prices of $2/MMBtu).

While the costs per MWh of wind output are close to gas combined cycle plants, the output of wind is not equivalent (due to its lower capacity factor, uncontrollability, and often off-peak production compared to coal- and gas-fired plants). Therefore wind has added costs of replacement energy and capacity needed to put it on an equivalent reliability basis. In addition, renewables do not fully avoid carbon costs because their backup resources are likely to be fossil-fired. These implicit extra costs are not shown in Figure 5.[3]

With these additional costs, gas and coal are more economic than wind. A cheap nuclear plant ($4,000/KW) is close to coal or gas without CO_2. At higher construction cost estimates for new nuclear plants (e.g., $7,000/KW) the all-in cost/MWh of nuclear will exceed the cost of a new coal or gas plant.

Gas-fired combined cycle plants remain the most economic choice until CO_2 prices reach relatively high levels. At CO_2 prices of $80-$100/ton, coal with CCS and nuclear plants start to become a more attractive choice, but CO_2 prices are not expected to reach this level until after 2030. This suggests a window of time over the next 20 years or so in which gas-fired power plants ought to be the natural choice for merchant generation, even with CO_2 pricing.

Figure 4 Daily Gas Use in SPP

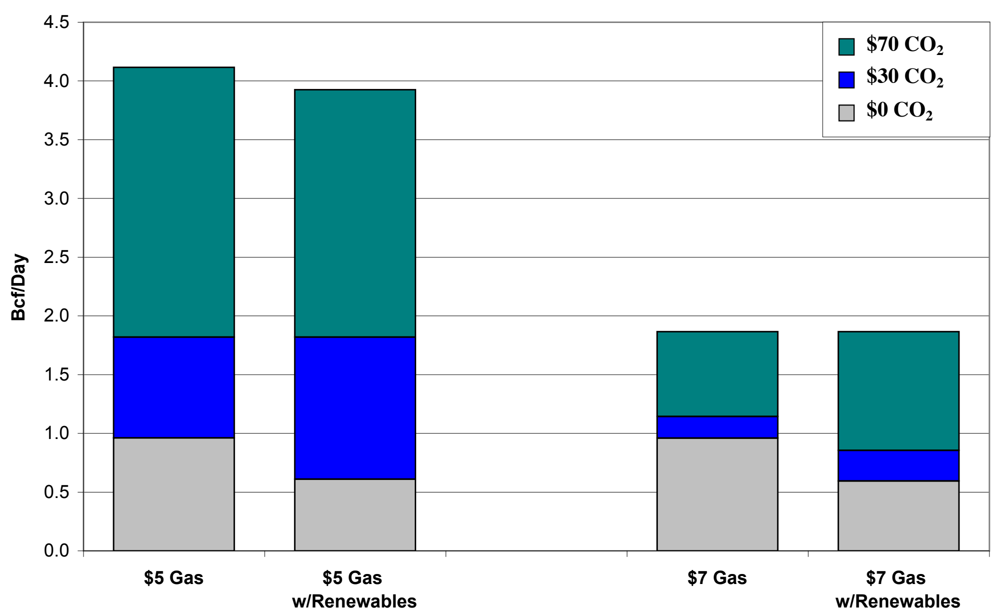
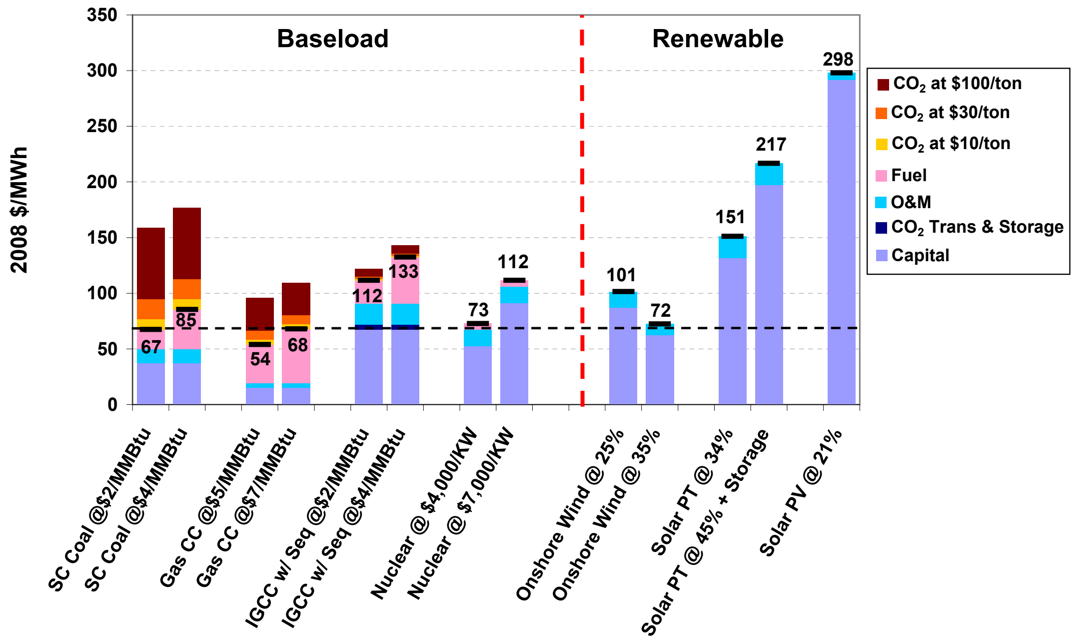


Figure 5 Level Real New Generation All-In Cost Estimates



Notwithstanding this economic appeal, over 50% of announced capacity expansion in the U.S. is currently in renewables (mostly wind). Tax benefits, installment subsidies, RPS mandates, and political pressures are making technologies other than gas-fired generation dominant.

Section 3 RENEWABLES DISPLACING GAS-FIRED GENERATION

Despite the economics shown in Figure 5, the development of renewable resources is likely to grow for the next decade and beyond. While it is not clear whether future climate legislation will impose a federal renewable energy standard, such standards have already been adopted by 29 states.[4] These standards impose binding targets on utilities for the amount of electricity that must be supplied by renewable resources, with many states requiring that as much as 20% of electricity utility sales come from renewable resources by as early as 2020.

While there are plenty of obstacles to meeting such RPS standards, especially financing and transmission expansion, it is clear that the movement to renewables is already underway. Indeed, many incentives have already been created to increase renewable energy development over the next decade, including tax credits and subsidies.

The American Recovery and Reinvestment Act of 2009 also encouraged renewable energy development through appropriations (including stimulus funds for loan guarantees, grants, and research and development programs) and renewable energy tax credits. The incentives provided for renewables seem to be having the intended effect. In 2008, 8,600 MW of wind capacity was built in the U.S., accounting for 42% of all new electric generation capacity.

Likewise, U.S. utilities have also been signing contracts for new solar resources. PG&E Corporation, for example, has recently signed several agreements totaling 830 MW of solar capacity and Southern California Edison has recently signed agreements for 530 MW of solar capacity. In aggregate, of the 410,000 MW of electric generation capacity additions expected in the next ten years in North America, 260,000 MW (or 63%) is expected to be renewable energy resources, primarily wind.[5]

The EIA's recent forecast of electricity generation by fuel type, summarized in Figure 6, shows that natural gas-fired generation is projected to decline as generation from renewables grows in the next decade. The decline in gas-fired generation is most pronounced in the next six years, as the EIA's forecast assumes a substantial buildout of renewable generating capacity.

Specifically, gas-fired generation in the U.S. falls from roughly 900 billion kWh in 2008 to about 700 billion kWh in 2015, while generation from renewables increases from about 400 billion kWh to 650 billion kWh in that same period (while coal increases slightly). The EIA forecasts that 45 GW of renewable energy capacity will be added in this period. After 2015, growth in renewables slows and gas-fired generation increases to 770 billion kWh (but still less than 2008 levels by over 100 billion kWh). Thus, the displacement of gas by new renewables development is the dominant effect.

Another trend contributing to this reduction in electricity sector demand for natural gas is electricity conservation efforts. About 22 states have adopted energy savings goals or energy efficiency resource standards to be implemented over the next five to ten years.[6] Similar to renewable energy development, these energy efficiency targets have the effect of displacing marginal power supply sources, which is natural gas-fired generation in most instances (except for some regions and off-peak periods when coal is on the margin).

The development of renewable energy resources combined with the effects of energy efficiency measures may serve to crowd out natural gas-fired generation in some regions and make gas a more contingent resource than it is today, increasingly subject to unpredictable, short-term power market conditions. This could lead to increased reliance on gas spot markets and potentially higher spot gas price volatility, especially in regions with less natural gas storage capability.

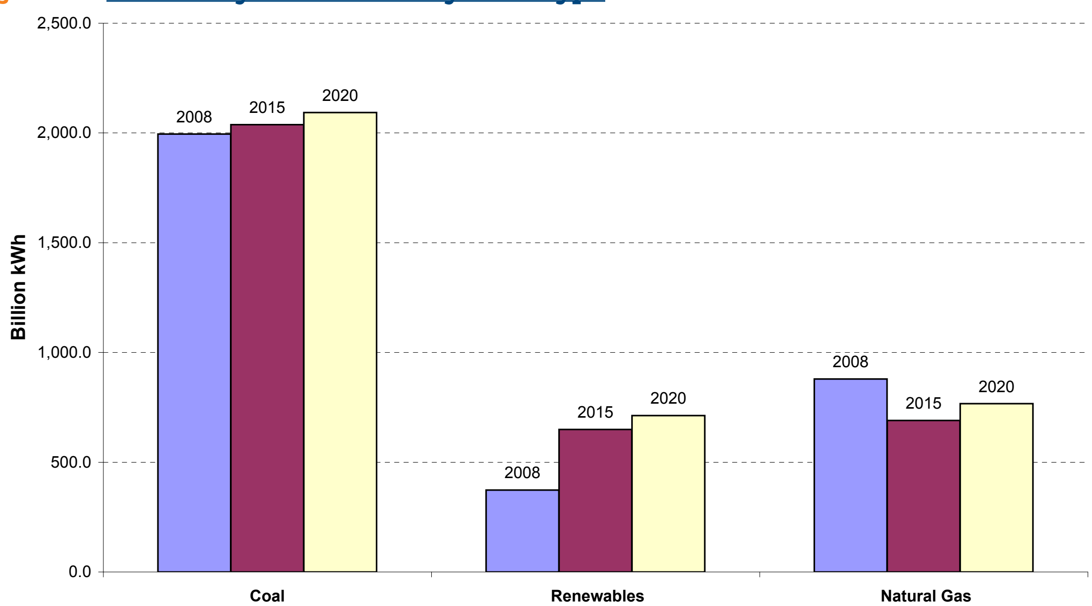
Section 4 INCENTIVES FOR COAL-FIRED GENERATION

Perhaps the biggest factor impacting natural gas demand in the coming decade is the sustainability of coal-fired power plants as part of the U.S. electricity generation mix. A large-scale retirement of coal plants would likely boost natural gas demand substantially. If such retirements are not forthcoming or if new coal-fired plants come on-line, gas demand is likely to be either flat or decline (especially if renewables development is successful).

As of October 2009, there were roughly 15,000 MW of coal-fired generation capacity under construction in the U.S., with the majority of this capacity projected to come on-line between 2010-2012.[7] Some of this capacity may displace existing or new gas-fired generators. Of course, NIMBY pressures and reduced demand due to the recession are also slowing expansion of all types.

In some areas, plans for new coal-fired generation or retrofits of existing coal plants have been canceled

Figure 6 Electricity Generation by Fuel Type



Source: EIA Annual Energy Outlook, 2010.

and replaced with plans to develop additional gas-fired generation capacity. For example, Progress Energy announced that it will close a total of 11 coal-fired units (1,500 MW of capacity) in North Carolina by the end of 2017 and replace them in part with new gas-fired generation. In making its decision, Progress Energy noted the significant expense in installing emission controls on smaller coal-fired power plants.[8]

One factor that will impact the viability of the existing coal plant fleet in the U.S. is the incentives given to coal-fired generation in any climate legislation that is ultimately enacted. Both the Waxman-Markey and Kerry-Boxer bills provide free emission allowances to merchant coal generators as a transition mechanism.

In both bills, the number of free emission allowances provided to each merchant coal unit in each year is equal to half of their emissions for the preceding year (with a phase-down factor that also applies). These provisions serve to protect coal-fired power plants and make it more likely that these plants will continue to operate rather than face a quick retirement under climate legislation.

Indeed, by making the allocation of allowances dependent on prior year emissions, coal plants will have the incentive to maintain their production (and their emissions) in order to obtain free allowances in the following year. These free allowances for merchant coal generators may also alter the economics of power system dispatch. Free allowances to coal-fired generators will reduce their variable costs (by the present value of next years' allowances earned this year), which could cause their owners to offer them at artificially low prices.

With such free allowances to coal generators, even higher CO_2 prices than those shown in Figure 2 will be needed before gas plants will displace coal plants in the dispatch ladder. While in principle, the coal plant owner could keep these savings, in practice it may be compelled to bid the savings into its offer-price for competitive dispatch, thereby:

1) Distorting the dispatch decisions.

2) Passing on the reduction to wholesale customers, whereby end-users will not get an efficient price signal about the carbon costs of their consumption.

As discussed earlier, high CO_2 prices may not be forthcoming in the next ten years. Moreover, given that CO_2 prices are expected to be low initially and increase over time, coal-fired generators may seek to maximize production and emissions in the early years when CO_2 allowance prices are low. This would allow them to bank allowances and use them in later years when emission allowance prices may be more expensive.

While transitional mechanisms are doubtless inevitable, and perhaps even essential, this particular mechanism is ill-conceived in a U.S. climate policy. The protections it offers to merchant coal generators are inefficient and probably unnecessarily broad for the purposes of keeping the merchant coal fleet viable. A more surgical and equitable mechanism could be devised that also would be more environmentally effective.

Section 5 NON-ELECTRIC GAS DEMAND

While the discussion thus far has focused on electric sector demand for gas, some trends in non-electric gas demand suggest limited overall gas demand growth under potential future climate legislation. Non-electric gas demand refers to gas demand by the residential, commercial, and industrial sectors, which together account for over 60% of U.S. gas demand.

There has been little growth in residential and commercial demand for gas over the last 30 years. This is in part because of substantial declines in gas use per customer as a result of improved building and appliance efficiencies and other conservation efforts during a period of increasing prices.

Natural gas conservation efforts are ongoing and may even increase due to growth in spending for energy efficiency programs. Budgets for natural gas energy efficiency programs have increased substantially in recent years, doubling from $238 million in 2006 to $530 million in 2008.[9] In addition, the American Recovery and Reinvestment Act of 2009 included billions of dollars in appropriations for energy efficiency programs including home weatherization, energy efficiency in federal buildings, energy efficiency grants, and research and development funding.

The Waxman-Markey bill also contains provisions requiring improved energy efficiency. These include building code efficiency targets and improved standards for lighting, furnaces, and appliances. The Kerry-Boxer bill includes similar provisions to establish building code efficiency targets. Both bills also allocate allowances to local natural gas distribution companies and mandate that not less than one-third of the value of these allowances be used for cost-effective energy efficiency programs for natural gas consumers.

Separate from these conservation programs are potential feedback effects from climate policies on industrial natural gas demand. The industrial sector is the most price-sensitive sector, and industrial gas demand in the U.S. has been steadily falling over the last decade as natural gas prices have increased. Climate legislation that puts a price on CO_2 emissions effectively raises retail natural gas prices and could lead to a further decline in industrial natural gas demand.

The EIA's recent modeling of the impact of potential climate legislation provides some indication of these feedback effects on industrial natural gas demand. The EIA's highest gas demand growth scenario assumes that international offsets are not available and the development of nuclear and coal with CCS generating capacity does not occur.

In this scenario, emissions allowance prices are very high, reaching $52/ton in 2012. This scenario results in gas demand growing, from 63 Bcf/d in 2008 to 71 Bcf/d by 2030, with the increase driven almost entirely by growth in electric demand for gas (from 18 Bcf/d in 2008 to 32 Bcf/d in 2030).[10] However, this scenario is the worst for the economy in general as the high allowance prices cause high energy prices and industrial production declines as a result. Industrial gas demand in this scenario therefore falls from 18 Bcf/d in 2008 to 13.5 Bcf/d in 2030. Other EIA scenarios show 2030 total gas demand ranging from 56 to 61 Bcf/d, a reduction in gas demand relative to 2008 levels.[11]

Conclusion

Natural gas has many attractive features as a fuel for electricity generation. The fuel itself now appears to be plentiful and fairly low cost. For new capacity, gas-fired generation is a relatively inexpensive choice for electricity supply. Finally, it is a low-carbon alternative compared to coal-fired power plants. Nonetheless, there are many challenges to growth in natural gas demand in the next decade, and gas may end up as a lost opportunity when it comes to reducing CO_2 emissions.

Among the factors that could either prevent gas demand growth or cause declines in gas demand in the electric sector:

- *Delayed and potentially low CO_2 prices that prevent significant coal-to-gas dispatch switching.*
- *Generous transitional protections offered to coal-fired generation that maintain coal's significant role in the U.S. power industry.*
- *Incentives and mandates for renewable sources of generation and energy efficiency measures that crowd out natural gas-fired generation, but at a relatively high cost in terms of the emissions reductions that are achieved.*

Policy-makers may want to take a second look at the potential role of natural gas in meeting climate goals, especially in the coming decade. If we miss the opportunity to induce greater use of natural gas, we may create a greater emission reduction burden as well as financial burden in later years.

A more carefully targeted and efficient set of transition protections than those included in currently proposed legislation would likely result in increased natural gas demand and should be considered in light of the substantial emission reductions that can be achieved with natural gas-fired generation. Policies that are designed to keep CO_2 prices low in the early years of a cap and trade program should also be reexamined.

High CO_2 prices have the potential to accelerate the retirement of the most inefficient fossil units, including old coal and gas units. While some industry participants and policy-makers are concerned about high CO_2 prices, they would serve to increase coal-to-gas substitution in the electric sector. They also facilitate the entry of new technology (including new coal generation with carbon capture and sequestration).

In addition, high CO_2 prices serve to put renewable resources on a level playing field with other generation technology choices. They may make politically mandated installation of renewables unnecessary, instead allowing the market to decide on appropriate generation technologies for meeting U.S. climate goals.

Overall, the prospects for a boom in natural gas use due to climate policy look a bit doubtful. This is because the policy itself is uncertain and the likely policy formulations may be too gradual to induce a material shift in electric supply, other than to mandated renewables that often displace gas. The delay in reaching closure on a climate policy may provide an opportunity for a re-evaluation of the role gas could play in our energy security and climate protection. Industry participants should be active in the debate and cautiously optimistic about a potentially greater role for gas in the future.

Endnotes

[1] See, for example, EIA's basic case in its analysis "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009," August 2009.

[2] See "EPA Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the *111th Congress*," June 23, 2009, slide 3.

[3] Renewable developers, however, see a lower break-even cost per MWh than shown in Figure 5 because they enjoy large tax subsidies for their output.

[4] See "Database of State Incentives for Renewables & Efficiency" at www.dsireusa.org.

[5] North American Electric Reliability Corporation, "2009 Long-Term Reliability Assessment," October 2009, p. 22.

[6] American Council for an Energy-Efficient Economy, "State Energy Efficiency Resource Standard (EERS) Activity," November 2009, at http://aceee.org/energy/state/toolkit.htm.

[7] See National Energy Technology Laboratory, "Tracking New Coal-Fired Power Plants," October 8, 2009 at http://www.netl.doe.gov/energy-analyses/index.html.

[8] See Progress Energy News Release, "Progress Energy Carolinas plans to retire remaining unscrubbed coal plants in N.C.," December 1, 2009.

[9] See Consortium for Energy Efficiency at http://www.cee1.org/ee-pe/2008/us_gas.php.

[10] Energy Information Association, "Energy Market and Economic impacts of H.R. 2454,the American Clean Energy and Security Act of 2009" August 2009.

[11] *Ibid*.

About the Authors

Steven H. Levine
Principal

Phone: +1.617.864.7900
Email: Steve.Levine@brattle.com

Mr. Levine specializes in energy and regulatory economics, and focuses on matters involving pricing/ratemaking, market manipulation, procurement and risk management decisions, and damage claims in energy contract disputes. He received his M.B.A. from Columbia University.

Frank C. Graves
Principal

Phone: +1.617.864.7900
Email: Frank.Graves@brattle.com

Mr. Graves specializes in finance and regulatory economics in the energy industry. He assists clients in securities litigation, special purpose audits, tax and contract disputes, and risk management issues. He received his M.S. in Finance from the MIT Sloan School of Management.

Metin Celebi
Senior Associate

Phone: +1.617.864.7900
Email: Metin.Celebi@brattle.com

Dr. Celebi provides expertise in electricity markets, game theory, industrial organization, and econometrics. He consults in the areas of electricity spot pricing, market design, and generation market power. He received his Ph.D. in Economics from Boston College.