WILL NATURAL GAS FUEL AMERICA IN THE 21ST CENTURY?

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Over the past decade he has researched, published, and lectured widely on global energy and sustainability issues in North America and internationally. He is a board member of the Association for the Study of Peak Oil and Gas–Canada and is a Fellow of the Post Carbon Institute. He recently contributed to *Carbon Shift*, an anthology edited by Thomas Homer-Dixon on the twin issues of peak energy and climate change, and his work has been featured in *Canadian Business*, *Walrus,* and other magazines, as well as through the popular press, radio, television, and the Internet. He is currently president of a consultancy dedicated to research on energy and sustainability issues.

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Abstract

Natural gas has increasingly been touted as a “bridge fuel” from high-carbon sources of energy like coal and oil to a renewable energy future. This is based on renewed optimism on the ability of horizontal drilling and hydraulic fracturing to access natural gas from previously inaccessible shale gas deposits. A review of the latest outlook (2011) of the U.S. Energy Information Administration (EIA) reveals that all eggs have been placed in the shale gas basket in terms of future growth in U.S. gas production. Without shale gas, U.S. domestic gas production is projected to fall by 20% through 2035.

Shale gas is characterized by high-cost, rapidly depleting wells that require high energy and water inputs. There is considerable controversy about the impacts of hydraulic fracturing on the contamination of surface water and groundwater, as well as the disposal of toxic drilling fluids produced from the wells. A moratorium has been placed on shale gas drilling in New York State. Other analyses place the marginal cost of shale gas production well above current gas prices, and above the EIA’s price assumptions for most of the next quarter century. An analysis of the EIA’s gas production forecast reveals that record levels of drilling will be required to achieve it, along with incumbent environmental impacts. Full-cycle greenhouse gas (GHG) emissions from shale gas may also be worse than previously understood, and possibly worse than coal.

Even assuming the EIA forecast for growth in shale gas production can be achieved, there is little scope for wholesale replacement of coal for electricity generation or oil for transportation in its outlook. Replacing coal would require a 64% increase of lower-48 gas production over and above 2009 levels, heavy vehicles a further 24% and light vehicles yet another 76%. This would also require a massive build out of new infrastructure, including pipelines, gas storage and refueling facilities, and so forth. This is a logistical, geological, environmental, and financial pipe dream.

Although a shift to natural gas is not a silver bullet, there are many other avenues that can yield lower GHG emissions and fuel requirements and thus improve energy security. More than half of the coal-fired electricity generation fleet is more than 42 years old. Many of these plants are inefficient and have few if any pollution controls. As much as 21% of coal-fired capacity will be retired under new U.S. Environmental Protection Agency (EPA) regulations set to take effect in 2015. Best-in-class technologies for both natural-gas- and coal-fired generation can reduce CO_2 emissions by 17% and 24%, respectively, and reduce other pollutants. Capturing waste heat from these plants for district and process heating can provide further increases in overall efficiency. The important role of natural gas for uses other than electricity generation in the industrial, commercial, and residential sectors, which constitute 70% of current natural gas consumption and for which there is no substitute at this time, must also be kept in mind. Natural gas vehicles are likely to increase in a niche role for high-mileage, short-haul applications.

Strategies for energy sustainability must focus on reducing energy demand and optimizing the use of the fuels that must be burnt. At the end of the day, hydrocarbons that aren’t burnt produce no emissions. Capital- and energy-intensive “solutions” such as carbon capture and storage (CSS) are questionable at best and inconsistent with the whole notion of energy sustainability at worst.

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Foreword

Post Carbon Institute undertook this report in order to examine three widespread assumptions about the role that natural gas can and should play in our energy future:

- Assumption #1: That, thanks to new techniques for hydraulic fracturing and horizontal drilling of shale, we have sufficient natural gas resources to supply the needs of our country for the next 100 years.
- Assumption #2: That the price of natural gas, which has historically been volatile, will remain consistently low for decades to come.
- Assumption #3: That natural gas is much cleaner and safer than other fossil fuels, from the standpoint of greenhouse gas emissions and public health.

Based on these assumptions, national energy officials at the Energy Information Administration (EIA) foresee a major expansion of natural gas in the coming decades. President Obama touted natural gas as a cornerstone of his Administration's "Blueprint for a Secure Energy Future"[1] and endorsed plans for converting a sizable portion of the vehicle fleet to run on natural gas.[2] Some environmental groups, rightly concerned about the greenhouse gas emissions of coal, have called for large-scale replacement of coal-fired power plants with those that burn natural gas, despite increasing concern over the environmental impacts of hydraulic fracturing.

As this report details, all of these assumptions and recommendations need to be re-thought. What emerges from the data is a very different assessment.

But if this report is right, then how could mainstream energy analysts have gotten so much so wrong? It is not our purpose to analyze in detail the social, political, and economic process whereby public relations became public policy. Nevertheless it is fairly easy to trace the convergence of interests among major players. First, the shale gas industry was motivated to hype production prospects in order to attract large amounts of needed investment capital; it did this by drilling the best sites first and extrapolating initial robust results to apply to more problematic prospective regions. The energy policy establishment, desperate to identify a new energy source to support future economic growth, accepted the industry's hype uncritically. This in turn led *Wall Street Journal*, *Time Magazine*, *60 Minutes*, and many other media outlets to proclaim that shale gas would transform the energy world. Finally, several prominent environmental organizations, looking for a way to lobby for lower carbon emissions without calling for energy cutbacks, embraced shale gas as a necessary "bridge fuel" toward a renewable energy future. Each group saw in shale gas what it wanted and needed. The stuff seemed too good to be true—and indeed it was.

The biggest losers in this misguided rush to anoint shale gas as America's energy savior are members of the public, who need sound energy policy based on realistic expectations for future supply, as well as sound assessments of economic and environmental costs.

Implications for the National Energy Conversation

It is understandable that the shale gas industry would fudge supply and price forecasts in the interest of drumming up investment capital. However, the EIA is supposed to be an impartial purveyor of data and analysis. Yet that organization has historically been overly optimistic with regard to fossil fuel supplies and prices. During the past decade several non-profit energy groups, including Post Carbon Institute, warned that depletion of giant oilfields and declining oil discoveries would lead to a situation of higher petroleum prices and tight supplies beginning before 2010. Indeed, a leveling off of world crude oil production and a simultaneous steep rise in oil prices during the past few years have arguably marked the most significant shift in the history of the petroleum industry—a shift whose consequences continue to ripple throughout the entire global economy. Yet EIA oil forecasts in the early years of the decade contained no hint of this impending and wholly foreseeable supply-price shift. In our view, the EIA is making similar mistakes in its too-rosy projections with regard to shale gas supplies and natural gas prices.

Signs at rally in opposition to hydraulic fracturing, Albany NY[3]

With mounting evidence of the environmental and human health risks of shale gas production, environmental groups are rightly questioning the "cleanliness" of shale gas. But if these groups focus their arguments only on the contamination of ground water supplies of shale gas *without at the same time questioning the economics of shale gas drilling*, they will have helped set up conditions for a political battle that could undermine their own influence and credibility. Political interests traditionally funded by the oil and gas industries will once again claim that environmentalism is the only thing standing between Americans and energy security. And if environmentalists are successful in enacting regulations to minimize the risks of water contamination *without clarity about the full lifecycle greenhouse gas emissions of natural gas*, they may inadvertently exacerbate the very crisis they are trying to address.

The stark reality we face is that humanity has embarked on the era of extreme energy, where there are no simple solutions. The inexpensive, high-yield fossil fuels that powered the industrial revolution and that helped make the U.S. the world's wealthiest and most powerful nation are dwindling, and all of them emit dangerous levels of greenhouse gases. While enormous amounts of natural gas, oil, and coal remain, the portions of those fuels that were cheapest and easiest to produce are now mostly gone, and producing remaining reserves will entail spiraling investment costs and environmental risks. Moreover, while alternative energy sources exist—including nuclear, wind, and solar—these come with their own problems and trade-offs, and none is capable of replicating the economic benefits that fossil fuels delivered in decades past. There is no likely scenario in which the decades ahead will see energy as abundant or as cheap as it was in decades past.[4]

If environmentalists are successful in enacting regulations to minimize the risks of water contamination without clarity about the full lifecycle greenhouse gas emissions of natural gas, they may inadvertently exacerbate the very crisis they are trying to address.

None of the major participants in our national energy discussion wants to utter that dismal truth. Yet continued appeals to wishful thinking merely squander opportunities to pre-adapt gracefully and painlessly to a lower-energy future.

The Unavoidable Solution: Energy Conservation

It is past time for policy makers to get serious about the most important strategy we can and must adopt in order to succeed in this new era—energy conservation. Reducing demand for energy and using energy more efficiently are the cheapest and most effective ways of cutting carbon emissions, enhancing energy security, and providing a stable basis for economic planning.

Unfortunately, energy supply limits and demand reduction do not support robust economic growth. This is probably the main reason why policy makers and many energy analysts and environmentalists shy away from conveying the real dimensions of our predicament. However understandable this response may be from a political perspective, it is one that only compromises our prospects as a nation and a species. There is much we can do to ensure a secure social and natural environment in a lower-energy context, but we are unlikely to take the needed steps if we are laboring under fundamentally mistaken assumptions about the amounts of energy we can realistically access, and the costs of making that energy available.

—Richard Heinberg
Senior Fellow-in-Residence, Post Carbon Institute

Introduction

As recently as 2005, natural gas supply in North America was thought to be in terminal decline. Despite near record amounts of drilling, production had fallen from a 2001 peak, and hit a low when Hurricanes Katrina and Rita roared through the Gulf of Mexico in 2005. Gas prices soared to $13/mcf[5] in 2005 and soared again to similar levels in mid-2008 at about the time the price of oil hit an all-time record of $147 per barrel.

Then everything changed. The "Great Recession" struck in late 2008, reducing gas demand and collapsing prices. Meanwhile, production from unconventional gas plays, most prominently the Barnett Shale of east Texas, was rising rapidly and creating a glut. A new era of cheap, abundant natural gas was declared thanks to the latest hydraulic fracturing and horizontal drilling technologies, which unlocked previously uneconomic shale gas and tight sand reservoirs. The "Pickens Plan,"[6] put forward by Texas oil and gas entrepreneur T. Boone Pickens, suggested that a large part of the vehicle fleet (or at least the heavy-truck portion) could be repowered with natural gas, thereby enhancing U.S. energy security. Prominent shale gas driller Aubrey McClendon testified to Congress[7] in 2008 that U.S. gas production could grow by more than 60% in a decade, displacing oil imports. The Energy Information Administration (EIA), the forecasting arm of the U.S. Department of Energy, became ever more enamored with shale gas, suggesting it could provide 45% of an expanded supply by 2035.[8] And most recently, President Obama called for natural gas to be a cornerstone of U.S. energy security in his "Blueprint for a Secure Energy Future"[9]; the NAT GAS Act of 2011, which would provide incentives for the use of natural gas, was introduced in the House of Representatives on April 6, 2011.

President Obama delivers a speech on energy at Pennsylvania State University.[10]

Spurred in part by such optimism about North America's renewed gas supply, several environmental groups are looking at natural gas as a "transition fuel" away from coal for electricity generation on the way to a low-carbon future based primarily on renewable sources. This thinking is based on a consideration of "burner-tip" carbon dioxide (CO_2) emissions (i.e., emissions strictly from burning the fuel), which are approximately half those of coal. There are many other environmental factors that must be considered, however, including full-cycle greenhouse gas (GHG) emissions, the impacts of gas drilling on groundwater, and the disposal of toxic drilling fluids, among other issues.

Are these projections of natural gas supply reliable? And what would be the environmental and other implications of increased reliance on natural gas? Following a brief review of the current U.S. energy system and its emissions, this report endeavors to answer the following questions:

1. How realistic are the current EIA projections for U.S. natural gas supply given that 45% of it is projected to come from shale gas by 2035? What level of effort would it take to achieve this production and what are the environmental implications of doing this?

2. Given that the current EIA projections do not assume a massive switch from coal to natural gas for electricity generation, how much would U.S. gas production have to increase to replace coal? Is this achievable? How much would CO_2 emissions be reduced if this could be done?

3. Given the current enthusiasm for switching transportation to natural gas to decrease oil imports and improve national energy security, what would it take in terms of increased gas supply over and above the EIA projections, which assume very little conversion to natural gas transport through 2035? Is this achievable? How much oil would be saved if this could be done?

4. Given the importance of addressing both carbon emissions and energy security, what are the implications of this analysis in terms of a rational energy strategy for the U.S. going forward?

The U.S. Energy System and Its Emissions

An understanding of energy supply and demand in the United States and the emissions produced by fuel and by sector is crucial for understanding the potential of various mitigation strategies in reducing carbon footprints and enhancing energy security. A good place to start is the EIA's *Annual Energy Outlook 2011*, which looks at existing consumption patterns and provides forecasts through 2035. While one can, and should, argue about the accuracy of these projections, which generally assume there will be *no* physical limits to hydrocarbon (i.e., fossil fuel) supplies through 2035, they serve as a starting point to understand the current energy system, and where we might go in a world without limits.

The current state of U.S. energy consumption by fuel source is illustrated in Figure 1. Hydrocarbons (oil, natural gas and coal) provided 84% of consumption in 2009 and the forecast in this scenario is for hydrocarbons to provide 82% of an expanded energy demand in 2035. Oil was the largest source of energy in 2009 at 39%, followed by natural gas at 24%, coal at 21%, and non-carbon-emitting energy sources—nuclear power, hydropower, biomass (largely wood), and renewables (wind, solar, geothermal)—at 16%. In 2009, renewable energy from wind, solar, and geothermal sources made up less than 1.4% of energy consumption. Of the non-hydropower, non-nuclear, carbon-neutral sources of energy, biomass made up the largest proportion, providing 2.65% in 2009.

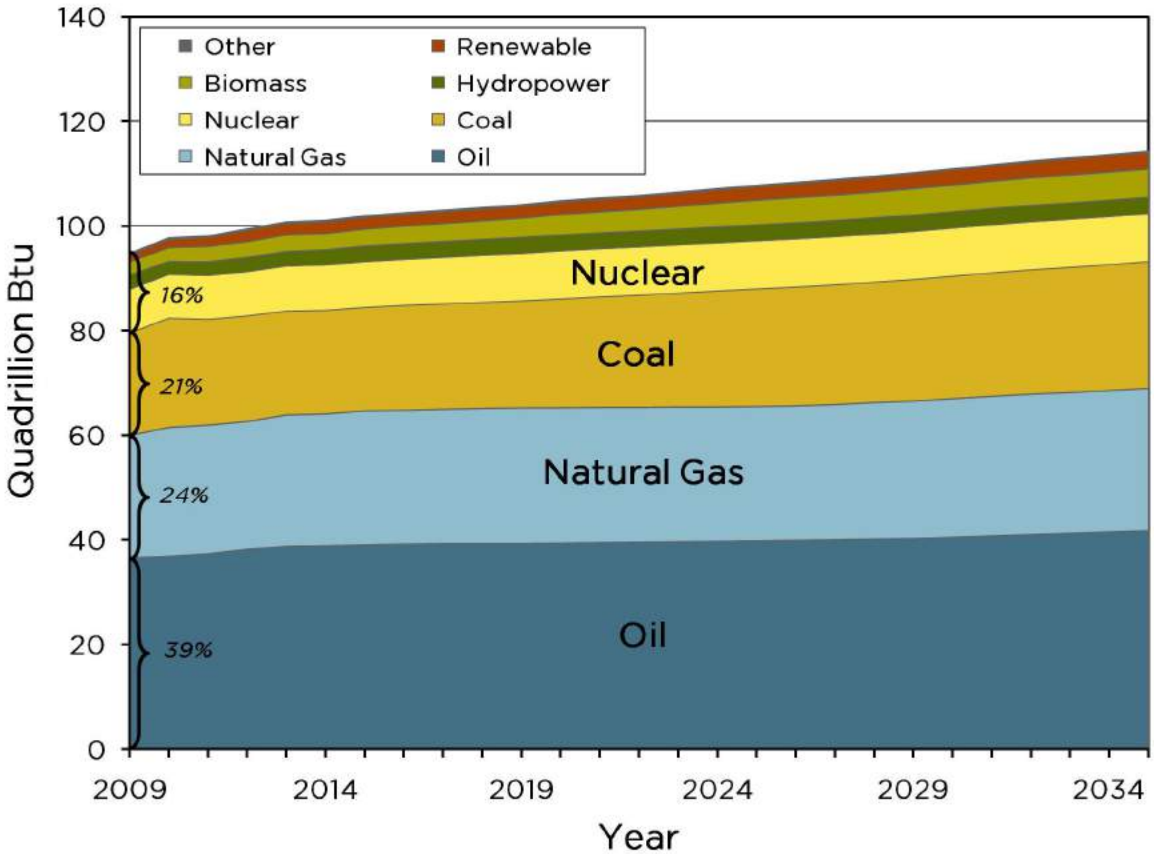

Figure 1. U.S. energy consumption by source projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[11]

Figure 1 illustrates the sheer scale of U.S. dependence on fossil fuels and the difficulty of "getting off fossil fuels," which is the mantra of many organizations on environmental and national security grounds. We have succeeded—in what amounts to a blink of the eye in all of human history—in becoming nearly completely addicted to the dense, convenient stores of "fossilized sunshine" represented by hydrocarbons. Breaking that addiction, of course, will be no easy task.

The consumption of energy by end-use sector is shown in Figure 2. The transportation sector is the largest single consumer of energy, followed by the industrial, residential, and commercial sectors. Interestingly, energy losses in the generation and transmission of electricity constitute the second-largest use of energy in the United States. Only 32% of the energy used to generate electricity is actually delivered to end users. The remainder is lost due to the inefficiency of conversion from coal or natural gas and from losses along the transmission and delivery chain.

Moving away from large, remote, centralized sources of electricity generation to local, smaller-scale, distributed sources of generation can serve to increase efficiency and minimize these energy losses, as well as make cogeneration of both heat and power more feasible.

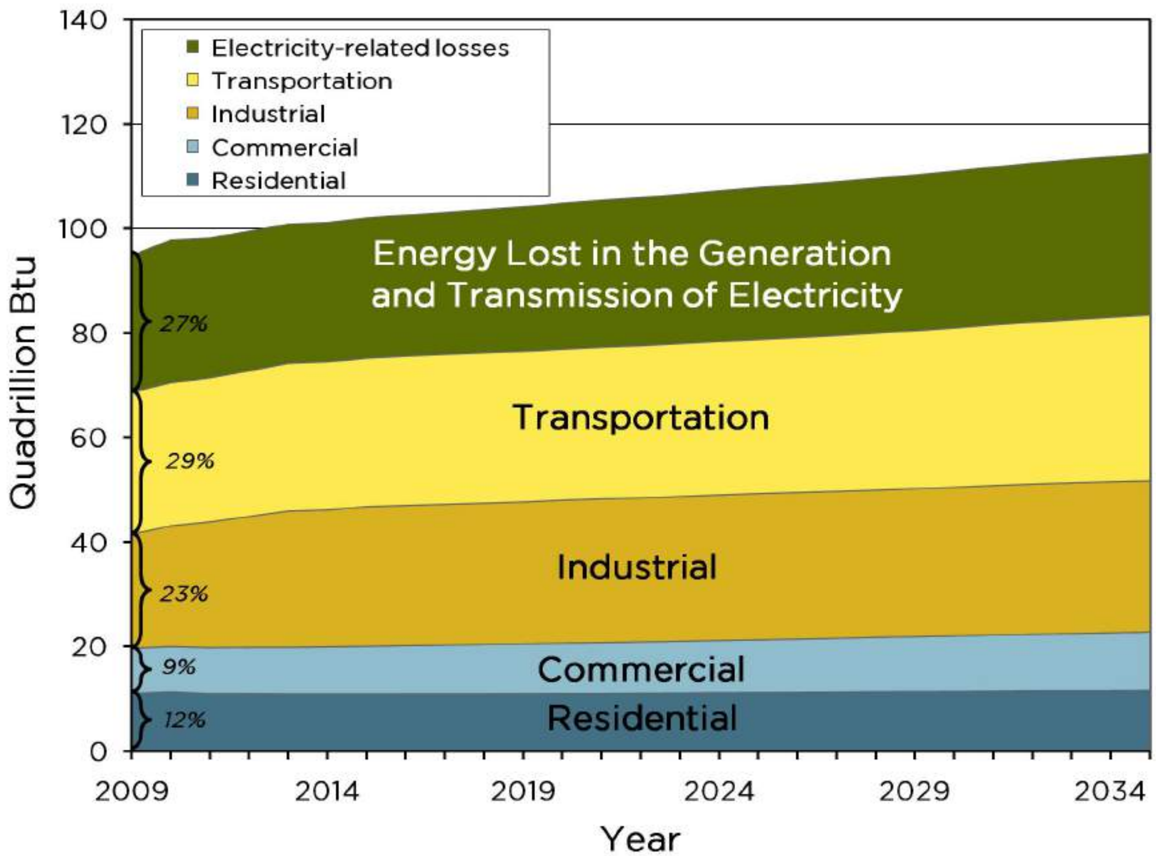

Figure 2. U.S. energy consumption by end-use sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[12] Roughly 68% of the energy used to generate electricity is unavailable due to generation and transmission losses.

Utility of Hydrocarbon Fuels for Different End Uses

In considering a wholesale transition from one fuel, such as coal or oil, to another, such as natural gas, it is imperative to understand the intrinsic natures of these fuels and their suitability for different end uses. These attributes for oil, natural gas, and coal are discussed below.

Oil

Oil is currently the premier fuel for transportation, although it is also a very important feedstock for the petrochemical industry. The transportation sector consumed 72% of oil demand in 2009 and the industrial sector 22% (Figure 3). Only 6% of oil consumption was in the residential, commercial, and electricity sectors as they are served at much lower cost by natural gas and, in the case of the electricity sector, by coal. Oil accounted for more than 97% of the fuel used by the transportation sector in 2009, which amounted to 29% of total U.S. energy consumption.

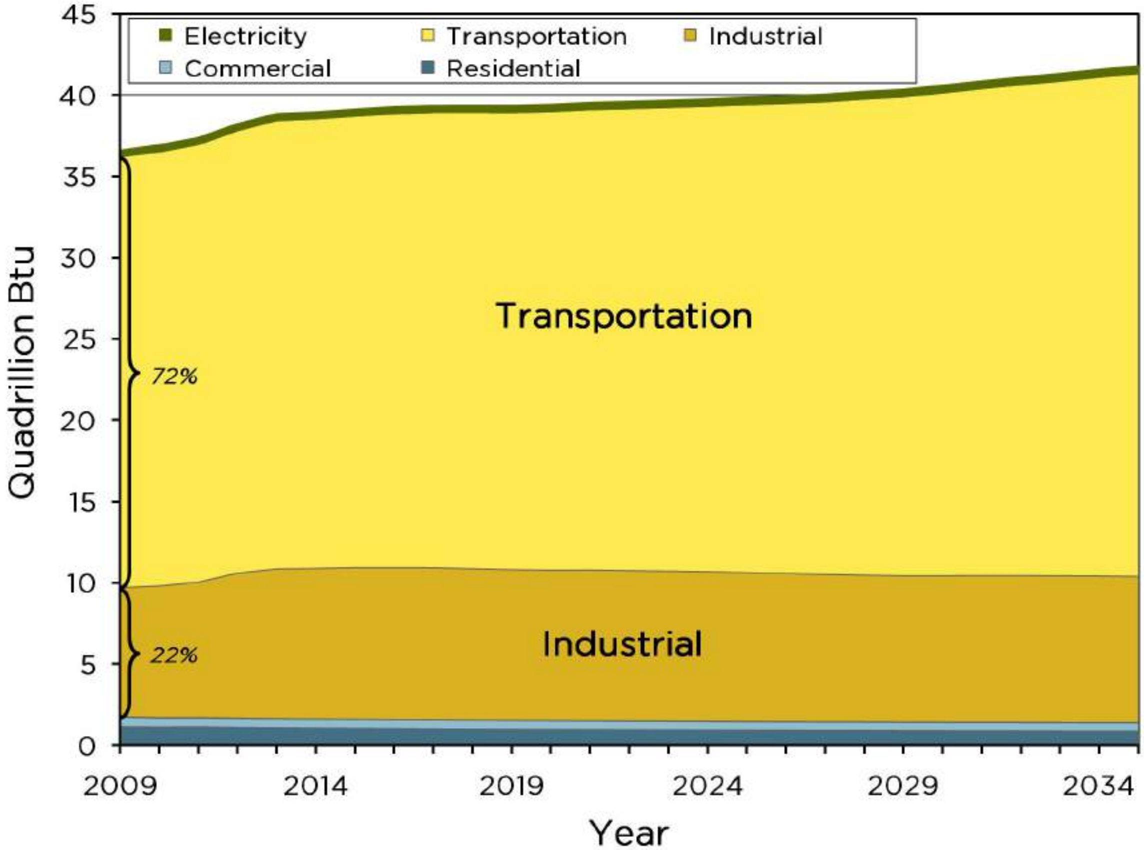

Figure 3. U.S. oil consumption by end-use sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[13] Oil is the premier fuel for transportation but is also very important as a feedstock for the petrochemical industry.

A look at 2009 oil consumption by different end uses reveals that the American predilection for personal vehicles accounts for 62% of oil consumption in the transportation sector and 44% of all U.S. oil consumption (Figure 4). Personal vehicles also account for 19% of all U.S. CO_2 emissions. If heavy trucks and buses are included, motor vehicles account for 81% of oil consumption in the transportation sector, 58% of all U.S. oil consumption, and 26% of CO_2 emissions. More efficient rail and ship transport accounted for a mere 6.7% of oil consumption in the transportation sector, 4.8% of total U.S. oil consumption, and 2.4% of CO_2 emissions. Air travel accounted for 9.4% of oil consumption in the transportation sector, 6.7% of total oil consumption, and 3.3% of CO_2 emissions in 2009.

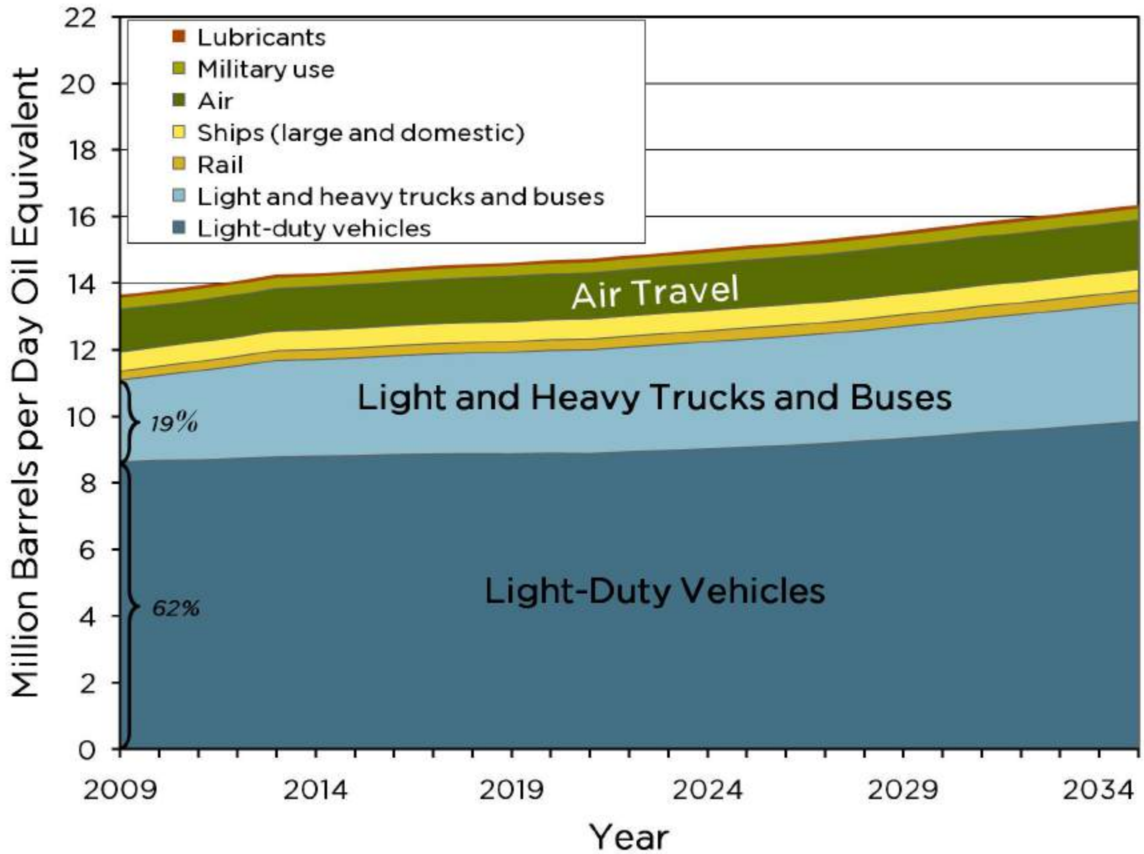

Figure 4. U.S. oil consumption in the transportation sector by end use projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[14] Motor vehicles comprise 81% of transportation sector oil use.

Natural Gas

Natural gas is a very versatile fuel with major uses in all sectors except transportation, where it is mainly used in the pipeline transport of natural gas and to a very limited extent for compressed natural gas (CNG) vehicles (Figure 5). Natural gas is a primary feedstock in the petrochemical industry and underpins the production of nitrogen-based fertilizers, which are responsible for the "Green Revolution" that has improved crop yields by nearly 200% over the past 80 years. Industrial use of natural gas accounted for 32% of its consumption in 2009. Natural gas is also a very useful fuel for distributed use, as in residential and commercial heating applications, and in 2009 these sectors accounted for 21% and 14% of its use, respectively. Electricity generation accounted for a further 30% of U.S. natural gas consumption in 2009, mainly in "peaking" power plants. Peaking plants are used to meet peak electricity demand loads, as opposed to providing base load power, primarily because of fuel costs; however, some of the larger combined-cycle gas plants are used for base loads.

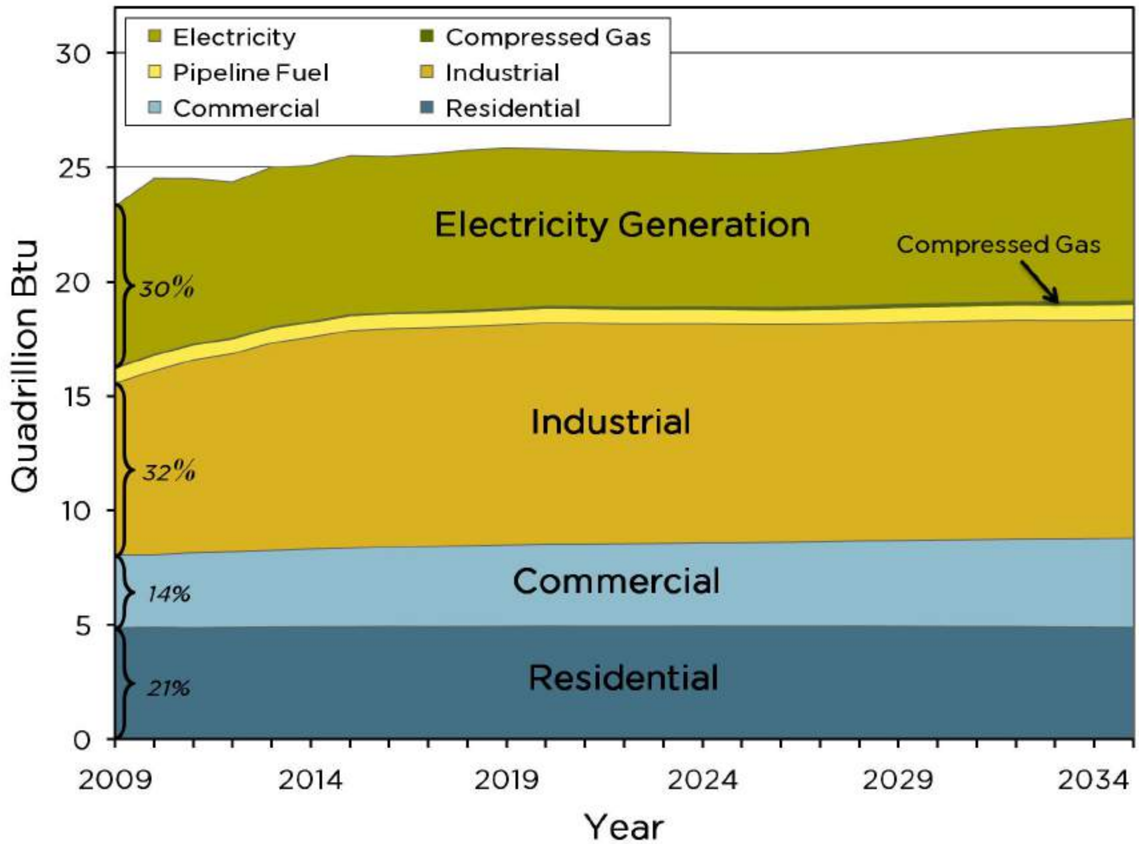

Figure 5. U.S. natural gas consumption by end-use sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[15] Gas is a highly versatile fuel for all sectors except transportation.

Coal

Coal is the poor sister to oil and gas in terms of utility for a variety of uses. It is primarily suited as a source of heat in the electricity generation sector and as a source of coke in the production of steel in the metallurgical industry. In 2009, 93% of U.S. coal consumption was used for electricity generation, with practically all of the balance used in the industrial sector, primarily in the steel industry (Figure 6). Coal is unsuited for use in the other sectors without very costly transformations through coal-to-liquids or coal-to-gas technologies. Transforming coal to gas or to liquids involves large capital investments in infrastructure that are roughly equivalent in scale to those required for oil-sands production, and the transformation process entails large energy losses and GHG emissions. As a result, the conversion of coal to gas or liquids in North America is almost nonexistent, and is a very minor source of end-use energy worldwide.

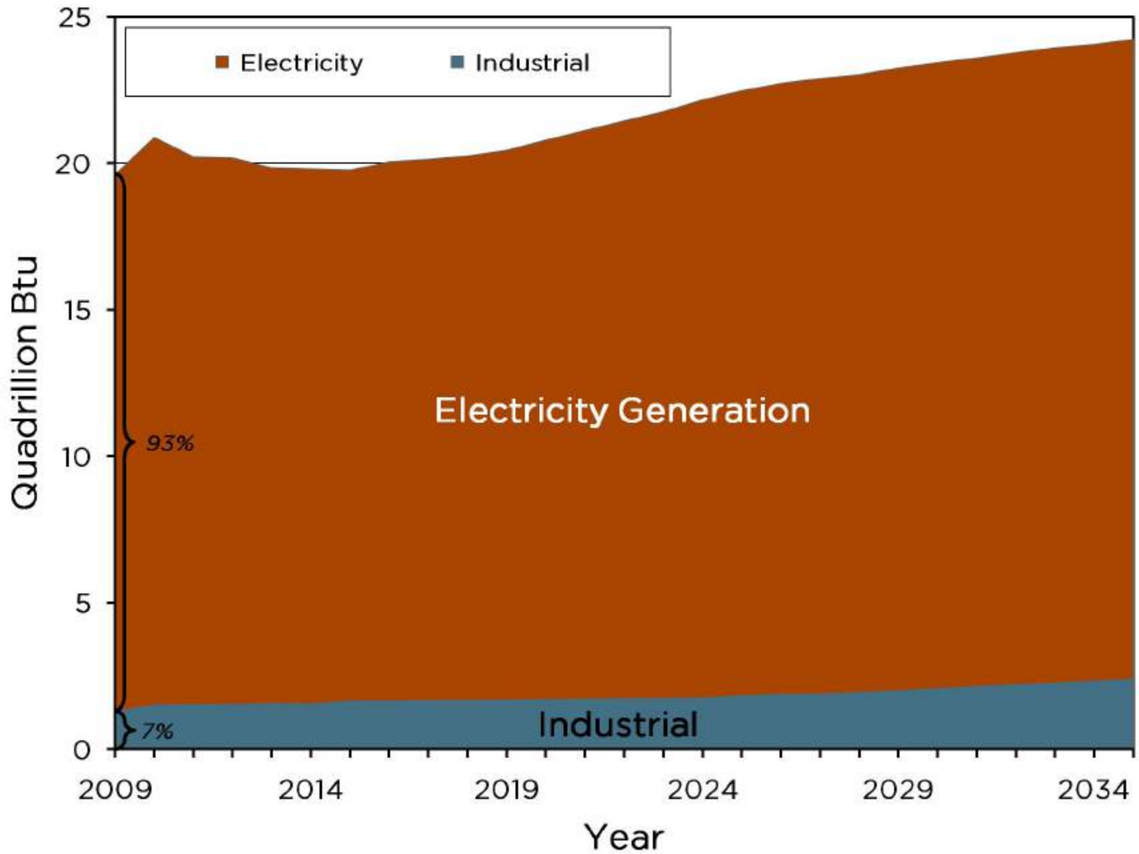

Figure 6. U.S. coal consumption by end-use sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[16] Coal is primarily used for electricity generation and in the steel-making industrial sector.

Electricity Generation by Fuel

Electricity generation is the largest use of energy in the United States. Electricity is an incredibly useful form of energy that powers the myriad gadgets, computers, and appliances that we use daily. It is also a major energy input in the industrial and commercial sectors. As mentioned above, its generation primarily by conversion of hydrocarbons to heat is also very inefficient. In 2009, 45% of U.S. electricity was generated by coal and 23% by natural gas (Figure 7). Non-GHG-emitting sources including nuclear, large hydro, biomass, wind, solar, and geothermal generated only 31% of U.S. electricity in 2009.

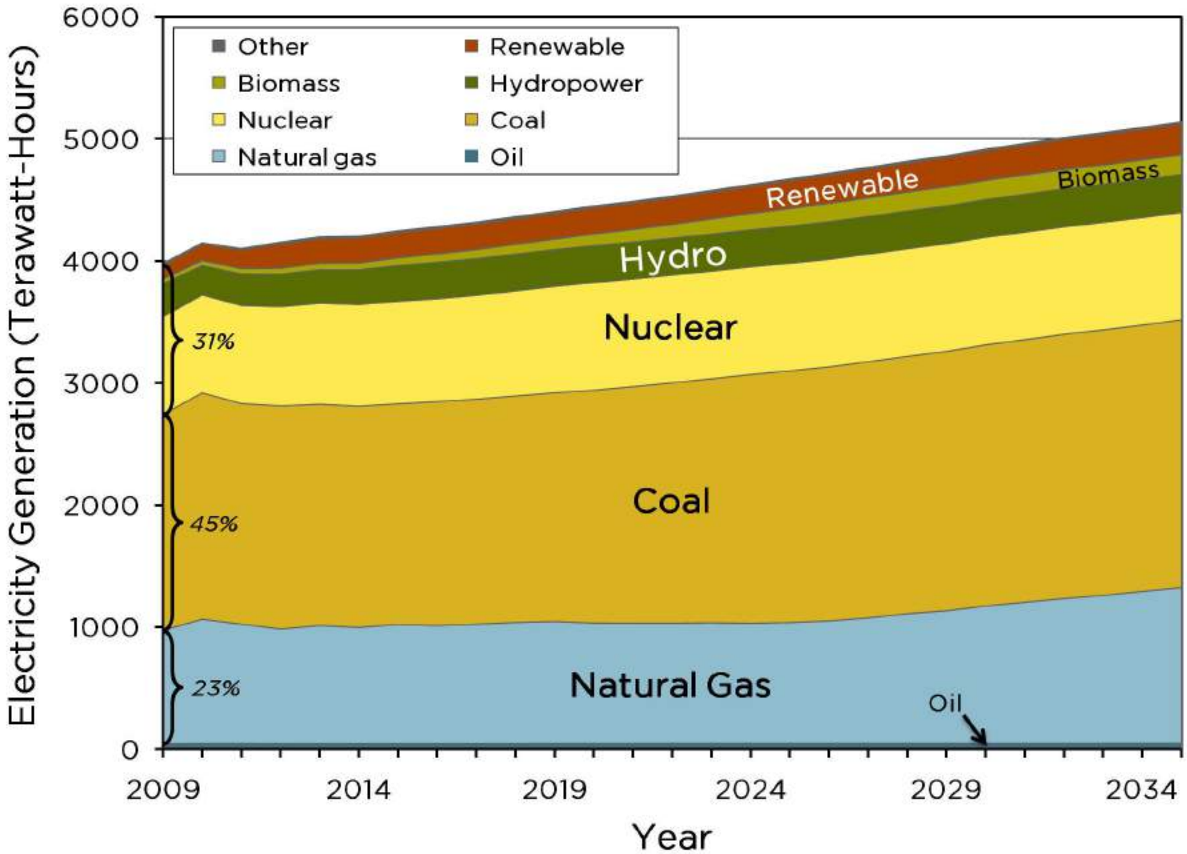

Figure 7. U.S. electricity generation by fuel projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[17] Coal in this scenario is expected to be the major fuel source for electricity generation through 2035, growing in real terms but declining in terms of market share. Gas use will increase both in real terms and slightly in terms of market share.

Electricity generation is the primary use for renewable energy sources such as wind and solar; yet these sources, including geothermal energy, generated only 2.7% of U.S. electricity in 2009, with biomass generating a further 1%. Even if these renewable sources more than double through 2035, as projected by the EIA, they will still constitute only 8% of forecast U.S. electricity demand. Proponents of wind and solar and other renewable sources of generation will argue that this forecast is far too conservative. Perhaps it is, but the scale of the problem of replacing hydrocarbons in electricity generation is simply daunting. Moreover, renewables have well-known issues with intermittency and unpredictability, which compromise their ability to make up a major proportion of electricity supply, especially at current rates of consumption and necessary supply reliability.

Carbon Dioxide Emissions

In any strategy to reduce carbon emissions it is important to understand where these emissions come from in the first place. The current sources of CO_2 emissions in the United States by fuel are illustrated in Figure 8. Oil is by far the largest source of emissions at 43%, followed by coal at 34% and natural gas at 23%. The EIA projection of CO_2 emissions in this figure is viewed as a doomsday scenario by a great many scientists, given the imperatives of reducing carbon emissions as outlined by the Intergovernmental Panel on Climate Change (IPCC)[18]. There are, however, potential supply constraints on the hydrocarbon inputs to this scenario that make it unlikely to happen. Even so, evidence mounts that anthropogenic greenhouse gas emissions are already altering the climate.

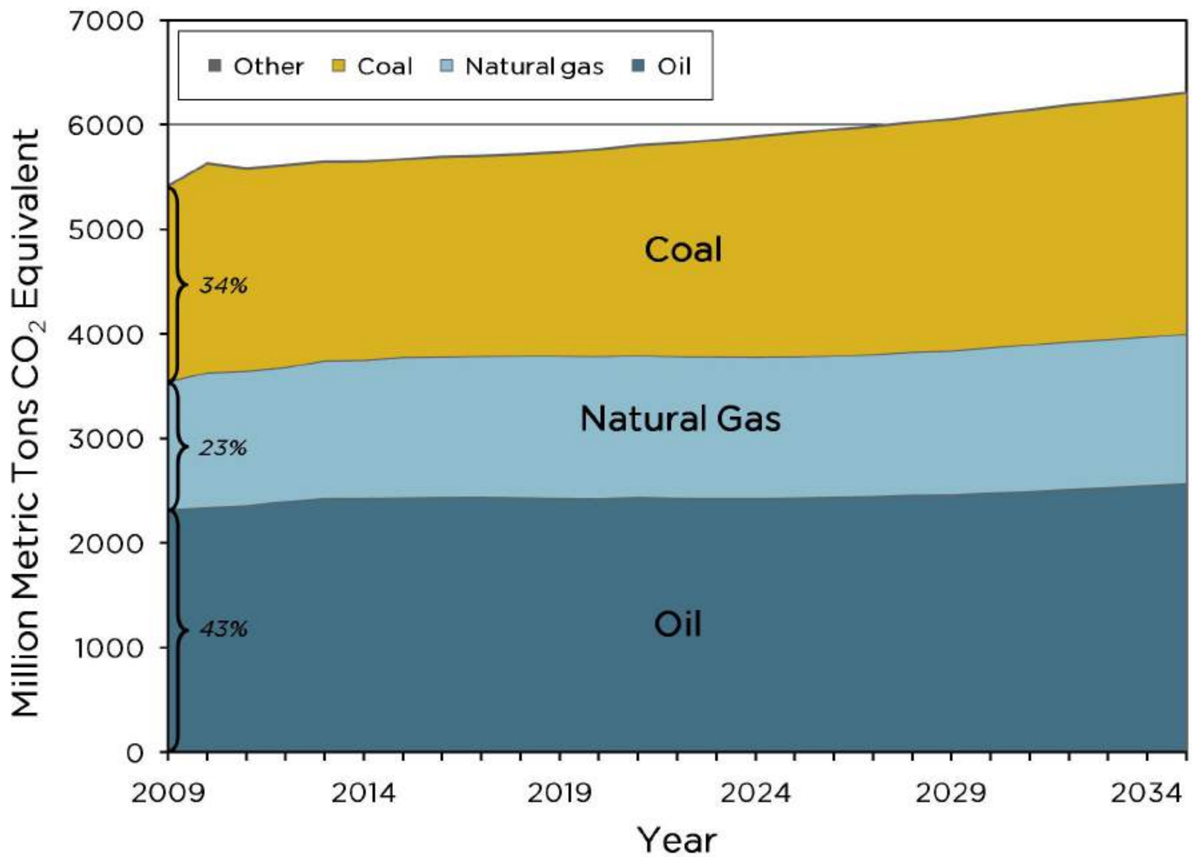

Figure 8. U.S. CO_2 emissions by fuel projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[19] This scenario assumes limited substitution of coal by natural gas through 2035.

Electricity generation is the largest source of CO_2 emissions in the U.S. at 40% (Figure 9). Non-electric use in the transportation sector is next at 34% followed by the industrial (16%), residential (6%), and commercial (4%) sectors. Substituting natural gas for coal in the electricity generation sector and substituting natural gas for oil in the transportation sector have been proposed as solutions for lowering carbon emissions and improving energy security; these proposals are addressed in the following sections.

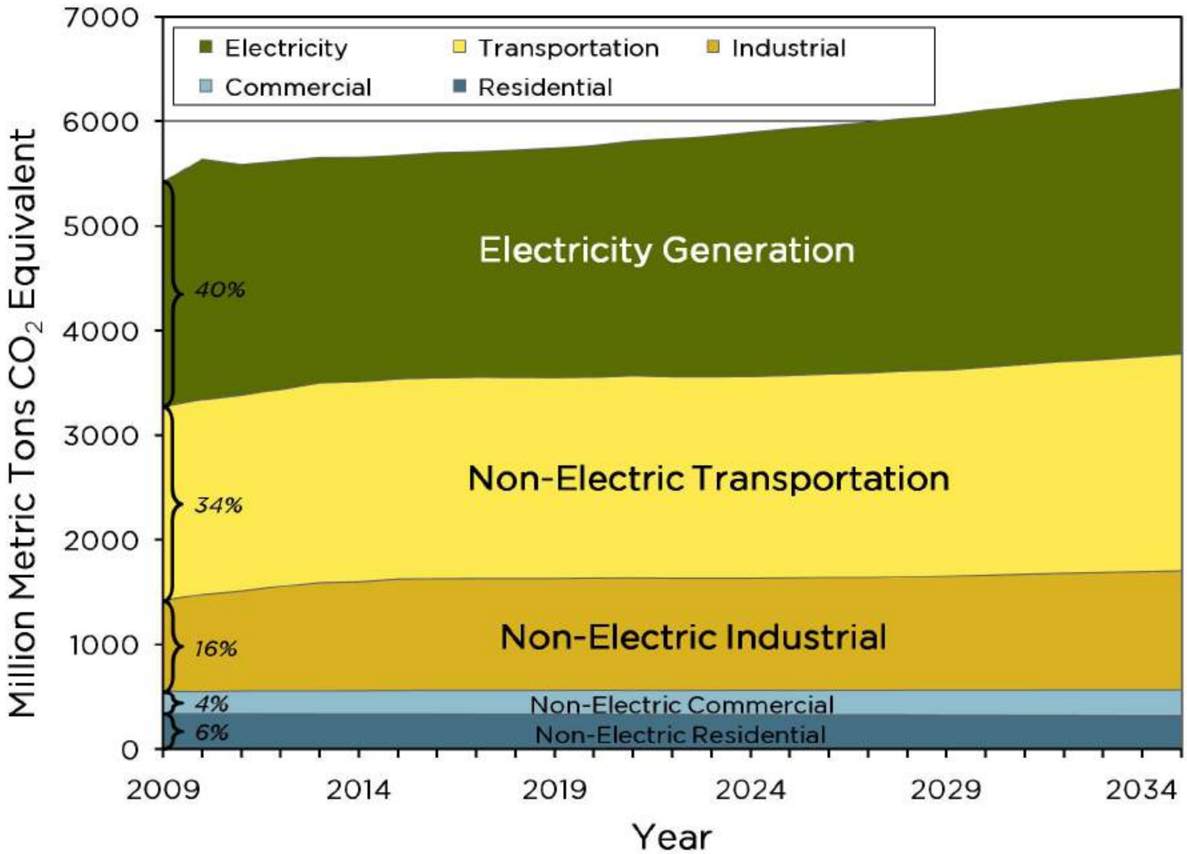

Figure 9. U.S. CO_2 emissions by utilization sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011*.[20] All emissions from electricity use in the transportation, industrial, commercial, and residential sectors are ascribed to the electricity generation sector where they originate.

U.S. Natural Gas Production and Outlook

A natural gas transmission system.[21]

The advent of natural gas production from shale gas reservoirs in the past few years has led to a sharp increase in estimates of U.S. gas resources and sparked a wave of enthusiasm for natural gas as a “transition fuel” away from coal for electricity generation and away from oil for vehicular transport. EIA projections assume that U.S. shale gas production will nearly quadruple by 2035, when it is supposed to account for 45% of U.S. gas supply.[22] Other estimates for increases in shale gas production are even higher. Some of the most prominent voices promoting the benefits of natural gas are the natural gas producers' lobby, in the form of the organization America’s Natural Gas Alliance (ANGA),[23] and major shale gas producers such as Chesapeake Energy Corporation.[24] How realistic are these claims, what are the limits to this enthusiasm, and what could be the environmental costs of realizing them? Let’s have a look at the fundamentals of the U.S. natural gas industry.

The Recent Past

U.S. natural gas production hit its all-time high of 21.73 trillion cubic feet (tcf) per year in 1973. Up until the late 1990s, the majority of U.S. gas production came from conventional reservoirs, which are pressurized pools of free-flowing gas trapped beneath impervious seals. Unconventional gas from coalbed methane became important in the early 1990s and was once heralded as a panacea to offset declines in conventional production, although now coalbed methane production is forecast to decline in the future (see Figure 16). Production from unconventional, very-low-permeability reservoirs in the form of tight gas sands and shale gas became significant in the late 1990s and especially over the past six years.

Natural gas production is a story about a race against depletion. Typically, the production from a new conventional gas well will decline by 25% to 40% in its first year, before tapering off to lower yearly declines as time goes by. The overall yearly decline rate of all U.S. gas wells has been estimated at 32% by EOG Resources.[25] This means that gas production would decline by a third each year, if no new wells were drilled. Sixty percent of U.S. gas production in 2006 came from wells drilled in the prior four years according to the EOG estimates. Chesapeake Energy has estimated that as of year-end 2007, nearly half of U.S. production came from wells drilled in the previous three years. So in order to keep overall gas supply from declining, drilling activity must be sustained.

Natural gas production is also a story about a rapidly increasing number of producing gas wells and a declining amount of gas produced from each. There are now more than half a million producing gas wells in the United States, nearly double the number in 1990 (Figure 10). Yet the gas production per well has declined by nearly 50% over this period. This is a manifestation of the law of diminishing returns, as a complex infrastructure nearly 100% larger than that in 1990 must be maintained today to achieve a 21% increase in natural gas production.

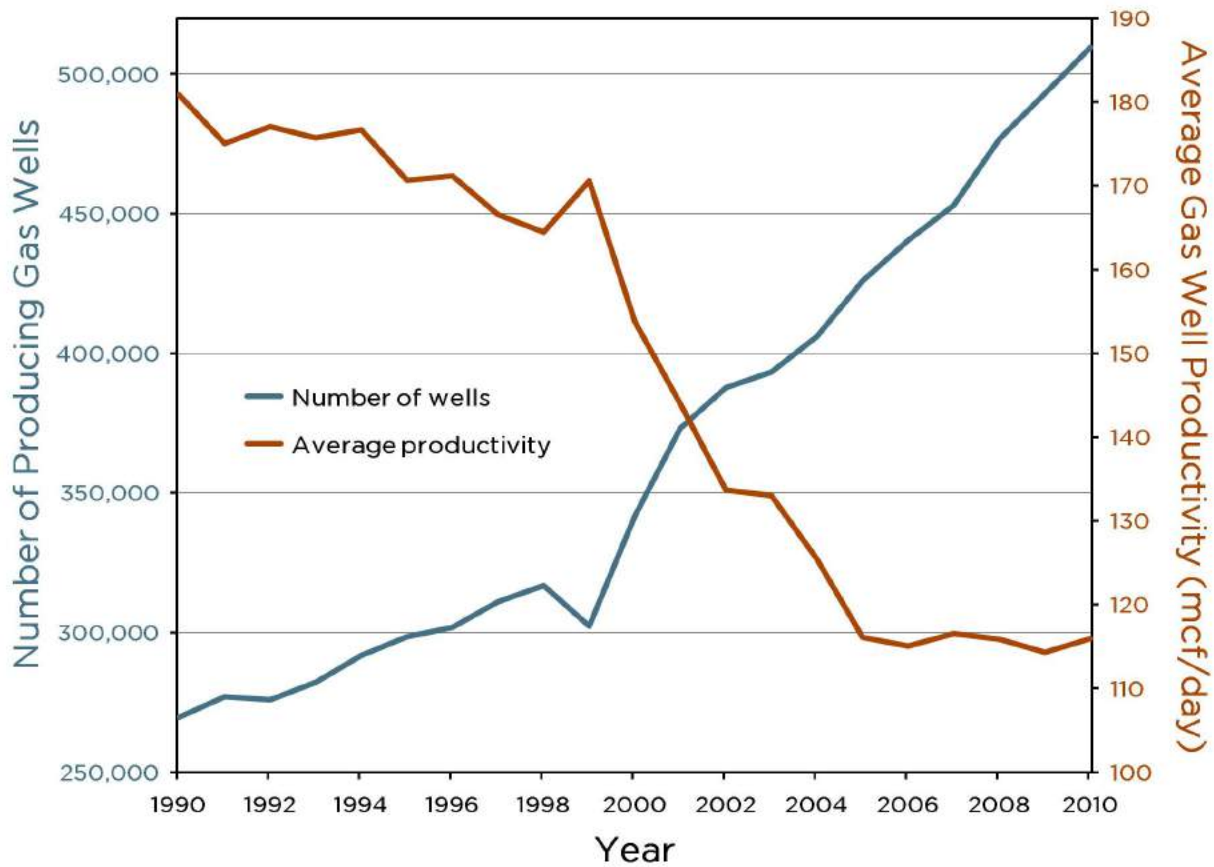

Figure 10. Number of U.S. producing natural gas wells versus the average productivity of each well from 1990 through 2010.[26] The number of wells for 2010 is estimated from the increase in the number of wells in 2009.

The law of diminishing returns is further illustrated in Figure 11, which plots the annual number of successful gas wells drilled versus gas production. When gas production peaked in 1973, about 7,000 gas wells were drilled annually. Throughout the 1990s gas drilling averaged about 10,000 wells yearly, which allowed some growth in production. Despite doubling this rate to more than 20,000 wells annually, gas production hit a post-peak summit in 2001 and began to decline. In the run-up to the Great Recession, gas drilling more than tripled from 1990s levels to 33,000 wells per year in the 2006–2008 time frame before falling back below the 20,000 level. This burst of drilling served to grow production modestly to near the 1973 peak, albeit at more than four times the 1973 drilling rate. This "exploration treadmill" indicates the United States will need on the order of 30,000 or more successful gas wells per year to increase production going forward, which is triple the 1990s levels.

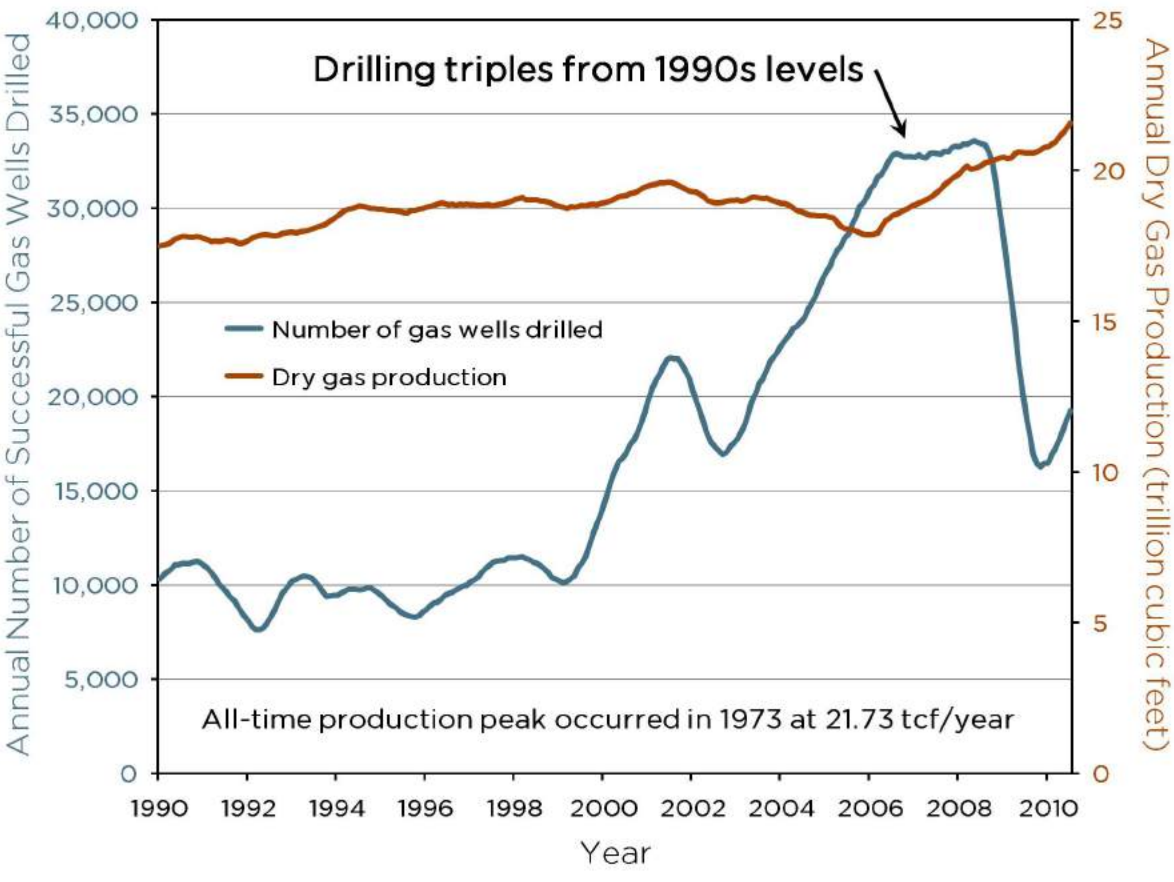

Figure 11. Annual number of successful U.S. natural gas wells versus total U.S. dry gas production 1990 through 2010.[27] Twelve-month centered moving average containing data through December, 2010.

The recent observed growth in U.S. gas production is a result of the unprecedented drilling boom of the 2006 to late-2008 period. Many of these wells are now being tied into production facilities. Of current drilling activity, some is motivated by requirements to retain leases and is likely otherwise uneconomic. It is unlikely that drilling will rebound to 2008 levels in a low-priced gas environment; hence production can be expected to start falling until prices and drilling activity recover. Thus the level of drilling activity that would be required to maintain and grow U.S. gas production in the future would be unprecedented in the history of U.S. gas production.

Another important aspect of natural gas supply is price and price volatility. Price determines the competitiveness of natural gas versus other fuels and energy sources. Figure 12 illustrates the price of U.S. natural gas over the past 16 years compared to European gas from Russia and the price of liquefied natural gas (LNG) in Asia.

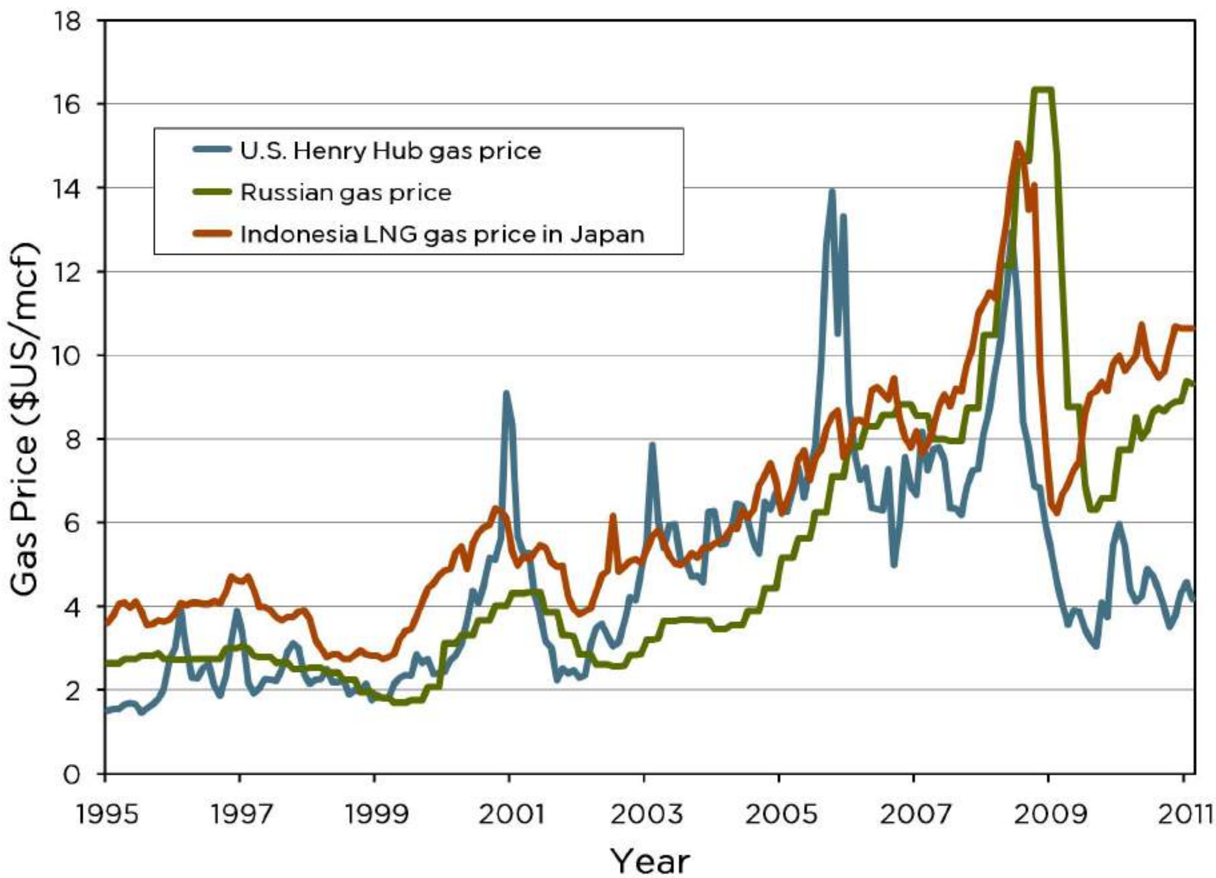

Figure 12. Price of natural gas in the United States versus European gas (incl. Russia) and Asian LNG.[28] The wide spread between U.S. and European prices is a recent phenomenon developing only over the past three years.

The low U.S. natural gas prices observed since late 2008 are a recent phenomenon, yet it is assumed by proponents of natural gas for electricity generation and vehicle transport that prices will remain low for the foreseeable future. The high and volatile prices over most of the past decade have restricted the use of gas for electricity generation mainly to balancing peak loads. Comparatively little gas has historically been used for base load generation, although it is now being contemplated on a large scale. Notwithstanding the fact that the United States was a net importer of 12% of its gas consumption in 2009, the enthusiastic assumption in many quarters of ever-growing U.S. gas production has owners of several LNG import facilities planning to add LNG *export* capacity to take advantage of much higher gas prices outside of North America. The spread between North American gas prices and the rest of the world has, however, been relatively short-lived, and is unlikely to persist indefinitely into the future. This is obvious to economists like Jeff Rubin, who notes that "far from being the game-changer it's supposed to be, North American shale gas production isn't even sustainable at today's natural gas prices."[29]

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The bottom line with natural gas is that it isn't so much a matter of the resources in the ground that count. What really counts are the flow rates at which these resources can be produced. The flow rate will determine the ability of natural gas to contribute to future energy requirements, as well as to the social and environmental impacts of this production.

Shale Gas

Shale gas has been declared a "game-changer," with the application of new technologies of horizontal drilling and multi-stage hydraulic fracturing. These technologies were first proven at scale in the Barnett Shale of east Texas, and demonstrated that gas locked in previously inaccessible very-low-permeability reservoirs could be recovered. Shale gas deposits throughout North America have since become candidates for the new drilling technology (Figure 13).

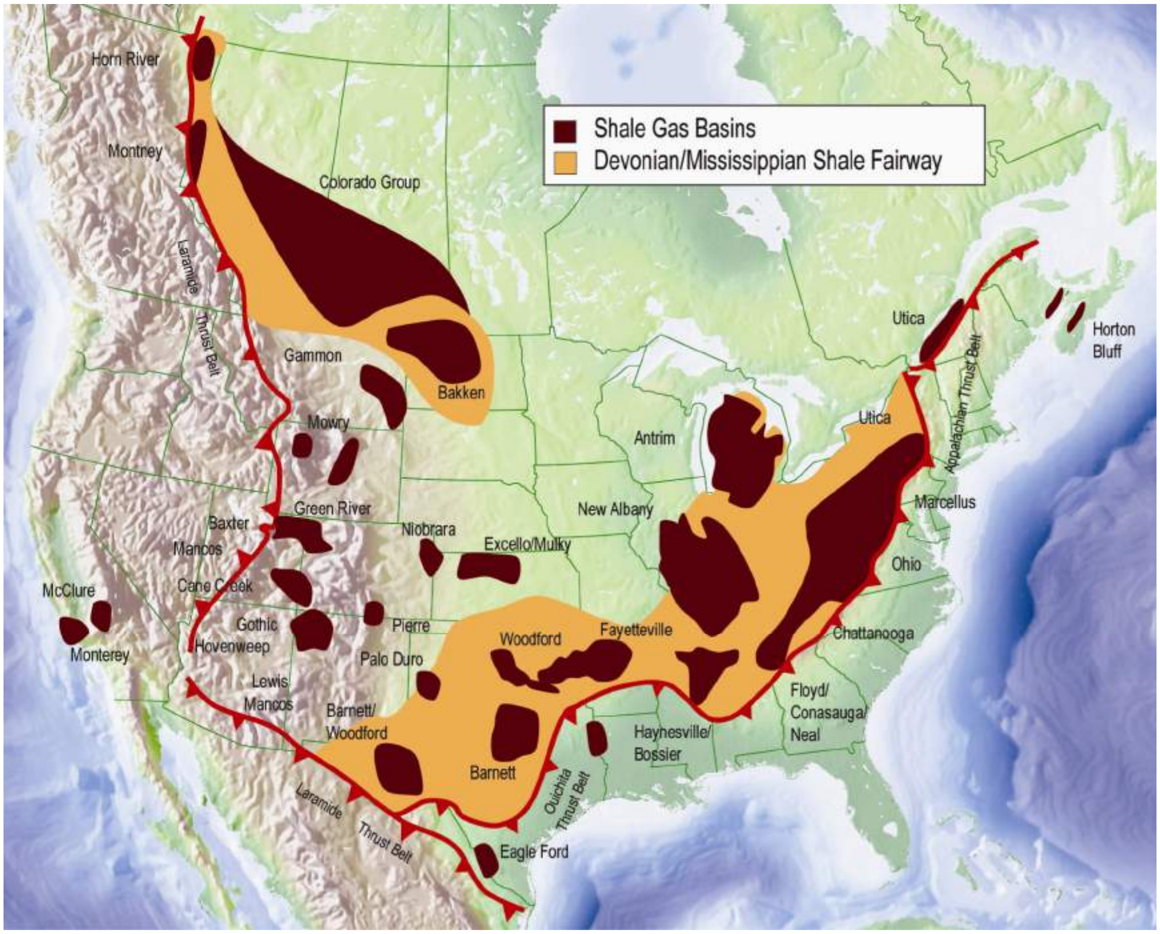


Figure 13. Shale gas plays in North America.[30]

In a 2011 report, the U.S. Potential Gas Committee (a non-profit organization made up of members of the natural gas industry) estimated total U.S. gas resources at 1739 tcf of probable, possible, and speculative resources (of which 687 tcf are shale gas) and a further 159 tcf of coalbed methane, for a total of 1898 tcf.[31] Coupled with proven reserves of 272 tcf, this indicated a potential of 2170 tcf. It has been widely reported that the United States "has 100 years of gas" even though 2170 tcf, if it could actually be recovered, would last much less in actuality given the proposed ramp-up of shale gas production and the proposed increased use of gas for electricity generation and vehicle transport.

As mentioned earlier, the most important consideration for the outlook of natural gas is not the estimated volumes of potential resources and proven reserves in the ground, it is the rate at which they can be produced to meet present and future demand. Of the potential resources identified by the U.S. Potential Gas Committee, two-thirds are in conventional and unconventional tight sand and coalbed methane reservoirs, sources that are projected to decline in production going forward. Virtually all growth in gas supply in the current EIA reference case is projected to come from shale gas, which constitutes only a third of estimated U.S. gas resources.[32]

An Overview of Some of the Issues with Shale Gas

Shale gas is a complex and hence high-cost source of natural gas fraught with environmental issues that are now becoming apparent. There have been many reviews of the potential of shale gas and the technical details of production, including primers by the U.S. Geological Survey[33] and Canada's National Energy Board.[34] The EIA has looked at the global aspects of shale gas,[35] and MIT has also published an assessment of the future of gas.[36] There have also been hundreds of articles published recently on the geology, economics, and environmental issues surrounding shale gas.

PRODUCTION

Shale is a very-low-permeability reservoir rock that must be fractured to allow conduits for gas to migrate to the production well bore. This is typically accomplished using multiple horizontal wells drilled from a common well pad (Figure 14), with multiple slickwater hydraulic fracture treatments in each (from as few as 5 to more than 20 fracture treatment stages per well). Because of the very low permeability of shale, minimum well spacing of 40 to 80 acres[37] or less is required—much closer than well spacing for conventional gas drilling, which is typically 160 acres or more.

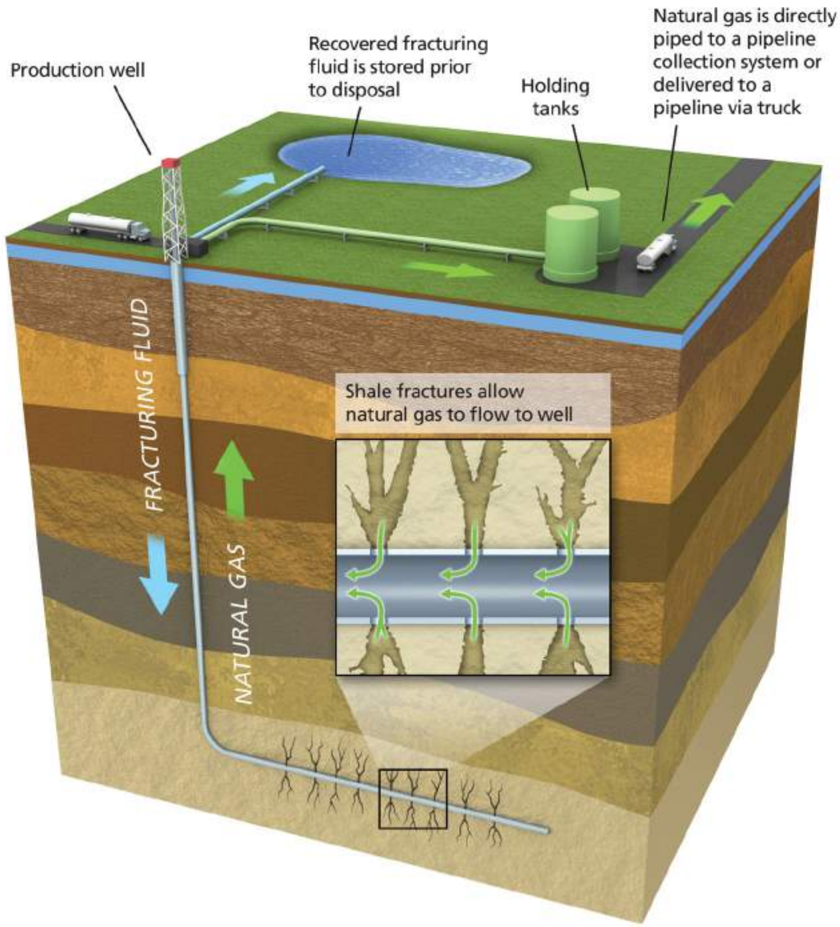


Figure 14. Schematic diagram of a horizontal shale gas well. Multiple horizontal shale gas wells are often drilled from a common platform, with each well stimulated with multiple hydraulic fracture treatments.[38]

Water used in drilling and particularly in hydraulic fracturing can amount to between 2 million and 8 million gallons per well. Injected water contains a previously mostly confidential combination of proprietary additives (sand, acid, gelling agents, friction reducers, biocides, corrosion and scale inhibitors, crosslinkers, etc.)[39] to facilitate the fracturing and propping open of the fractures after their creation. The U.S. House of Representatives has recently released a report on the chemicals used for hydraulic fracturing, several of which are carcinogenic and are hazardous air pollutants.[40] Anywhere between 15% and 80% of the injected water is brought back to the surface, along with formation water if it is present (Figure 15). Most of this water is produced in the first few months of production and, as it is toxic, must be disposed of through recycling, through reinjection, or, on the surface, through processing at wastewater treatment facilities.

Figure 15. A waste pit in the Catskill Mountains containing drilling fluids from the hydraulic fracturing process.[41]

These and other factors make shale gas wells expensive. Wells typically range between $2 million and $10 million (or more), each one's cost depending on location, depth, the number of hydraulic fracturing stages required, and other technical considerations.

Another key aspect of shale gas wells is the high rate at which their production declines. Conventional gas wells typically decline by 25% to 40% in their first year of production, whereas shale gas wells decline at much higher rates, typically between 63% and 85%.[42] The initial productivity of shale gas wells can be very high. In plays like the Haynesville Shale in Louisiana, initial rates can be more than 10 million cubic feet per day (Barnett Shale wells are typically much lower at about 2 million cubic feet per day). However, their steep production decline rates suggest that relying on shale gas for a large proportion of U.S. gas production will only exacerbate the "exploration treadmill" problem of the number of wells that must be drilled to maintain production.

There is simply too little history of shale gas production to substantiate the 40-year well life purported by many shale gas producers. Analyst Arthur Berman, who has studied the Barnett Shale (the oldest and best-known shale gas play) in depth, suggests that the estimated ultimate recovery from shale gas wells and overall recoverable reserves have been overstated by operators, and that shale gas plays are marginally commercial at best in the current low gas price environment.[43]

A further issue is the extrapolation made in assuming all parts of shale gas plays will be equally productive. Initially, it was assumed that shale gas plays would be "manufacturing" operations, where wells would be equally productive regardless of where they were drilled. This proved to be erroneous. As Berman pointed out,[44] quoting Chesapeake Energy CEO Aubrey McClendon, in the Barnett Shale all 17 counties were thought to be equally prospective a few years ago, but today just two and a half counties have been proven to be highly productive core areas. In the Haynesville Shale play of Louisiana, which in 2008 was promoted as the fourth-largest gas field in the world, the focus of interest has retracted to a core area about 10% of the original area assumed in the optimistic projections.[45] The many geological characteristics that combine to make shale plays commercially viable will certainly prove to be restricted to small "core areas" of the broad expanses of individual shale plays currently outlined, as more drilling defines the most productive areas.

Conventional gas wells typically decline by 25% to 40% in their first year of production, whereas shale gas wells decline at much higher rates, typically between 63% and 85%.

ENVIRONMENTAL ISSUES

Hundreds of articles have been published over the past couple of years on the environmental impacts of shale gas production.

In 2010, the documentary movie *Gasland*[46] brought many of the issues involved with hydraulic fracturing and shale gas production to the forefront. The gas lobby launched a major offensive against *Gasland*[47] and started a website dedicated to countering articles providing information contrary to its interests.[48] What is clear is that the production of shale gas involves extraordinary environmental impacts compared with conventional gas drilling. These include:

- **Contamination of groundwater directly through hydraulic fracturing and as a result of compromised cementing jobs in near-surface casing.**[49] This is a critical and controversial issue, and has resulted in the initiation of a major U.S. Environmental Protection Agency (EPA) study with preliminary results to be released in 2012 and a final report in 2014.[50] New York State has recently imposed a temporary moratorium on new drilling permits involving hydraulic fracturing.[51]

- **Contamination of surface water, and potentially drinking water, through improper disposal of toxic produced drilling fluids containing salts, radioactive elements, and other toxins.** Toxic produced drilling fluids, which amount to 15% to 80% of the 2 million to 8 million gallons of water injected during hydraulic fracturing for each well,[52] are disposed of through either reinjection, surface disposal and treatment at wastewater treatment facilities, or, less commonly, recycling. Recycling involves distilling purified water from the drilling waste, which still leaves a residue of toxins[53] and is very energy intensive. The surface disposal of toxic drilling fluids and the fluids' potential to contaminate drinking water with radionuclides and other contaminants has recently been documented by the *New York Times*.[54] Indeed, efforts by shale gas producers to remain exempt from the Safe Drinking Water Act are surely counterproductive and counterintuitive if the production of shale gas is really as benign as the industry contends.[55]

- **Very high water consumption**, between 2 million and 8 million gallons per well, which is potentially problematic, particularly in arid areas.

Container Trucks with Hydraulic Fracturing Liquids at a Drilling Site, Dimock, Pennsylvania.[56]

- **The surface impacts of road and drill pad construction and the requirement for hundreds of truck trips for each well** to move the drilling rig, storage tanks, water, proppant, chemicals, compressors, and other equipment.

- **Higher full-cycle greenhouse gas (GHG) emissions.** Full-cycle GHG emissions from shale gas are far larger than the burner-tip emissions of the gas itself. This potentially defuses a major argument of the natural gas lobby that natural gas is a significantly lower source of GHG emissions than coal or oil. A comparison of the life-cycle analyses of GHG emissions from shale gas and coal is given in the following section.

- **Induced earthquakes through fluid injection** both during the hydraulic fracturing process and during the disposal of waste fluid through injection wells. To date, seismic activity related to the injection of waste flowback fluids from hydraulic fracturing seems to be the largest source of induced seismic activity.[57]

CO_2 Emissions from Shale Gas Production and LNG

A major argument put forth by natural gas proponents as to why there should be a wholesale switch from coal to natural gas for electricity generation is the fact that CO_2 emissions from burning natural gas compared to coal are about 44% less[58] per unit of heat generated through combustion. This assumes there are no emissions in the upstream exploration, production, and transport of natural gas or coal to the point of use.

The EPA has released a new study detailing upwardly revised estimates for fugitive methane and CO_2 emissions in the natural gas supply chain, and in particular emissions from unconventional gas well completions and workovers. This study states that "the natural gas industry emitted 261 [million metric tons of CO_2 equivalent] of CH_4 and 28.50 [million metric tons] of CO_2 in 2006."[59] This amounts to 290 million metric tons of CO_2-equivalent emissions, which is 5% of total U.S. end-use emissions and 22% more than the emissions of natural gas included in Figure 8 (which only considers end-use emissions). According to EPA estimates, vented and flared gas amounted to 4.2% of production over 2006–2008, exclusive of emissions in the transportation and distribution process.[60] ProPublica reviewed the new EPA emissions report and concluded that natural gas may be as little as 25% cleaner than coal, or perhaps even less.[61] An in-depth analysis comparing the full-cycle GHG emissions from shale gas, conventional gas, and surface- and underground-mined coal has been completed by Howarth et al. of Cornell University. In their paper published in April 2011, they state:

> Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.[62]

Clearly, any assessment of the relative merits of different fuels in terms of GHG emissions must consider life-cycle emissions to be meaningful. The Howarth et al. analysis and the EPA report indicate that shale gas may have few or none of the GHG-reduction benefits much advertised by natural gas proponents when life-cycle emissions are considered on a 20-year time frame. Howarth et al. and the many commentators and critics of this study point out, however, that the data used are sparse and need to be improved. In this regard the EPA has developed new regulations for the reporting of GHG emissions from the oil and gas industry, which were to start at the beginning of 2011 with the first reporting in March 2012.[63] Whether this will happen or not remains to be seen as the American Petroleum Institute has filed a petition to have these regulations reconsidered.[64]

A Liquid Natural Gas tanker at port with LNG liquefaction plant in background.[65]

Another option for gas supply, should the United States commit to large amounts of new gas-fueled infrastructure that cannot be supplied by domestic gas production, is imported LNG. Aside from its higher costs (see Figure 12), the life-cycle emissions of CO_2 are much higher for LNG than for conventional gas due to the energy required for liquefaction, transportation, and regasification. Jaramillo et al. concluded in 2005 that, on average, LNG-transported natural gas adds 20% more CO_2 emissions than conventional gas on a full life-cycle basis.[66] They also concluded that LNG increases emissions for the overall delivery process before the burner tip by 137% on average compared to the emissions for conventional gas (which includes the sum total of emissions in production, processing, transmission, storage, and distribution). A further consideration with LNG is increased reliance on potentially unstable foreign suppliers.

Outlook for U.S. Natural Gas Production

The EIA's latest, *Annual Energy Outlook* report (2011), makes projections of U.S. natural gas production and supply to 2035.[67] Its reference case of gas supply by source is illustrated in Figure 15. Several things are noteworthy about this forecast:

- Virtually all growth in U.S. gas production is forecast to come from shale gas. Shale gas production is forecast to grow by 265% from 2009 levels, or nearly quadruple, notwithstanding the environmental and other issues with shale gas production documented above. According to this forecast, the United States will be dependent on shale gas for 45% of production by 2035.

- The only other area of growth, albeit minor, is a forecast 9% growth in offshore gas production from the Gulf of Mexico, which has long been in decline.

- The steep declines in production from sources other than shale gas, including conventional, tight gas, and coalbed methane, are forecast to flatten out going forward, although the aggregate decline is 20% through 2035. This may be too good to be true as production declines have rarely been observed to stop as producing fields become ever more mature.

- Gas production growth from shale gas is forecast to be so robust that imports from Canada will be virtually eliminated by 2035. This also reflects Canada's gas supply situation, as production in Canada has fallen 17% since peaking in 2006, despite Canadian optimism for a shale gas windfall.

- Gas production growth from shale gas in the lower 48 is forecast to be so robust that the long-planned Alaska gas pipeline to tap into stranded gas in the Arctic is no longer needed.

- Gas production growth from shale gas is forecast to be so robust that only minimal imports of LNG will be required to meet demand.

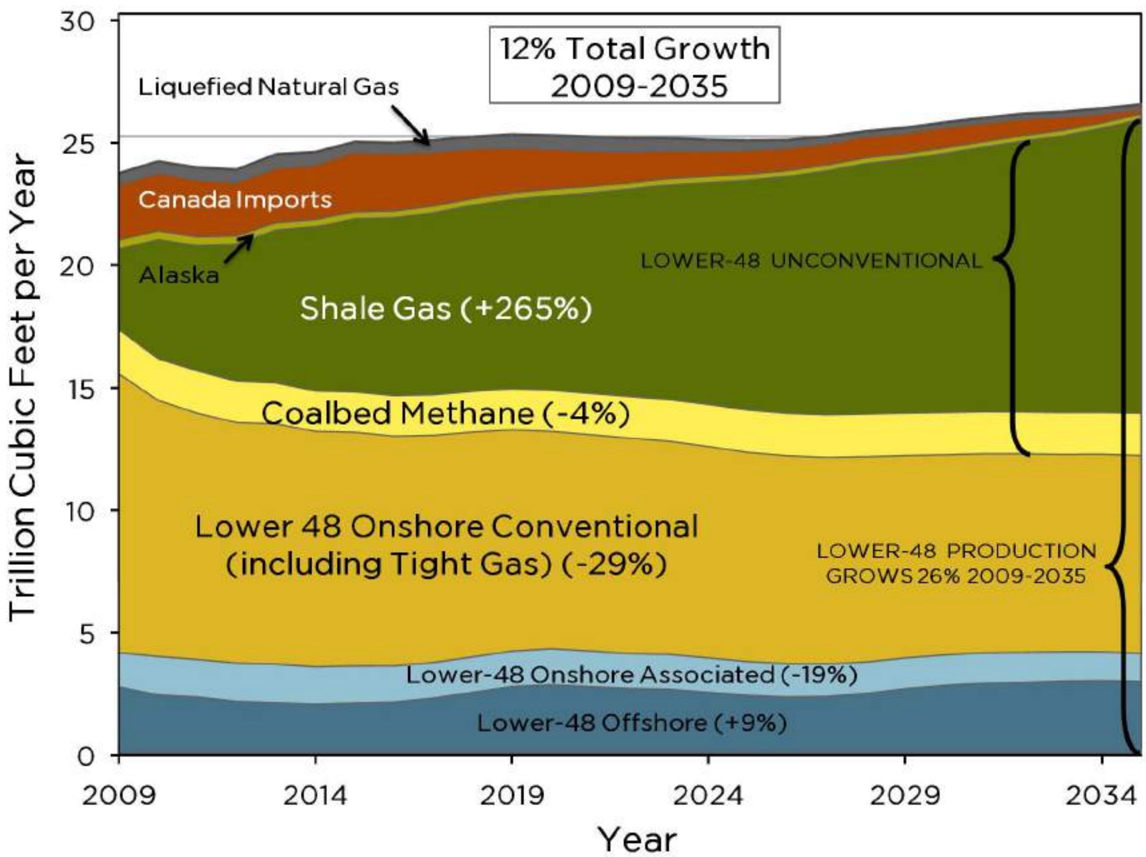


Figure 16. U.S. natural gas supply by source in the latest EIA Annual Energy Outlook.[68] Associated gas is gas recovered during the production of oil. Tight gas and coalbed methane are considered to be "unconventional" sources.

The question is, how realistic is this forecast given the production and environmental issues outlined earlier for shale gas, and what level of effort would it take to achieve it in terms of drilling and impacts? And, given that this forecast does not include substantial increases in the market share of natural gas for electricity generation or natural-gas-fueled vehicles, what are the realities for the enthusiasm for ramping up the use of natural gas in these sectors?

A Reality Check on the EIA U.S. Gas Production Projection

The EIA has become increasingly enamored with huge production increases from shale gas to meet its forecast natural gas demand requirements for the United States. Shale gas is, unfortunately, the only hope as all other sources of domestic gas supply are in decline. The production and environmental issues associated with shale gas strain the credibility of such forecasts and make them increasingly unlikely. The enthusiasm of the EIA for shale gas is illustrated in Figure 17, where yearly forecasts for the production of shale gas have increased from 16% of U.S. production in 2030 in its 2009 forecast to 45% of U.S. production in 2035 in its 2011 forecast.

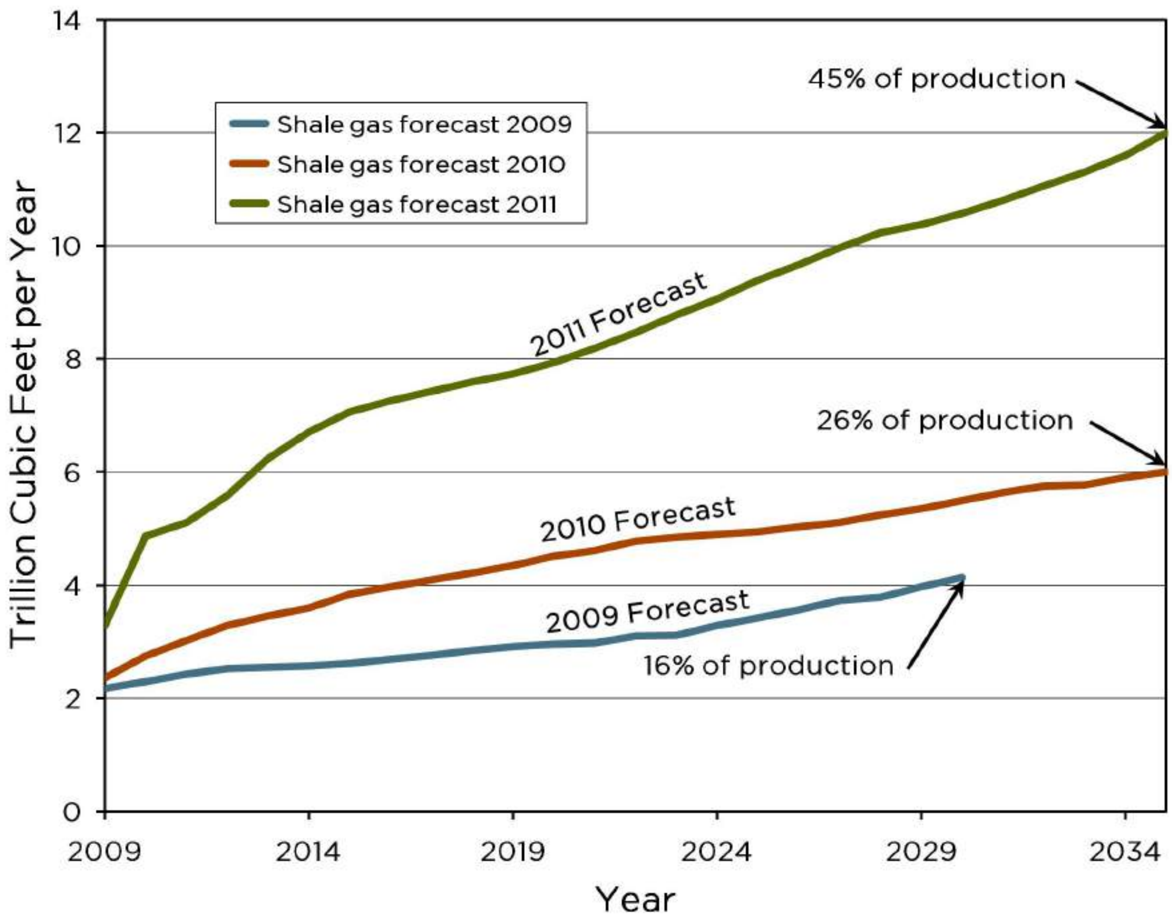


Figure 17. Forecast growth in U.S. shale gas production in the 2009, 2010, and 2011 EIA reference case forecasts.[69] Shale gas production is now forecast at 45% of U.S. supply by 2035, up from 16% in 2030 in the EIA's 2009 forecast.

A major consideration is the level of effort in terms of drilling and infrastructure development that would be required to meet this forecast growth. The recent history of annual successful gas wells drilled and gas production was discussed earlier and illustrated in Figure 11; this figure suggests that drilling rates of fewer than 30,000 wells per year won't be sufficient to grow gas production. The current growth in U.S. gas production is a hangover from the drilling boom at rates in excess of 33,000 wells per year in the 2006–2008 time frame. The drilling rates of about 20,000 wells per year in early 2011 will likely lead to production declines unless increased markedly.

The reality is that the U.S. will likely have to endure record amounts of drilling to meet the EIA production targets, a large proportion of which will be shale gas, with all of the attendant environmental consequences.

The drilling rates assumed by the EIA to meet its forecast are inadequate. Although the EIA does not differentiate in its drilling projections between oil, gas, and dry holes,[70] the historical proportions suggest that about half of its projected oil and gas well drilling would be successful gas wells. If this is the case, the EIA is suggesting that gas production can continue to grow with fewer than 17,000 wells drilled per year in 2011 and 2012. This is highly unlikely given the historical relationship between the rate of drilling and gas production. These projected drilling rates will likely mean falling gas production going forward of at least 1% per year, as illustrated in Figure 18.

To increase U.S. gas production as projected by the EIA, U.S. drilling rates will likely have to increase to at least 30,000 wells per year in the near term and continue to grow to 40,000 wells per year to meet production requirements by 2035. Although it is true that when gas prices are low companies tend to drill their best prospects and hence production might possibly be maintained with fewer wells, it is unlikely that the EIA production projections could be met in the longer term given its drilling outlook. The reality is that the United States will likely have to endure record amounts of drilling to meet the EIA production targets, a large proportion of which will be shale gas, with all of the attendant environmental consequences. This will necessitate sustained gas prices considerably higher than the current price of about $4.00/mcf, which has seen gas producers selling shale gas assets.[71]

Another key question in the reality check is the marginal cost of production of shale gas. Analysts like Arthur Berman suggest the marginal cost is about $7.50/mcf[72] compared to a current price of about $4.00/mcf. Others, such as Kenneth Medlock (2010), suggest that the break-even price ranges from $4.25/mcf to $7.00/mcf.[73] The Bank of America (2008) has placed the mean break-even cost at $6.64/mcf with a range of $4.20/mcf to $11.50/mcf.[74] One thing seems certain: Shale gas, which appears to be the only hope for significantly ramping up U.S. gas production, is expensive gas, much of which is marginally economic to non-economic at today's gas prices.

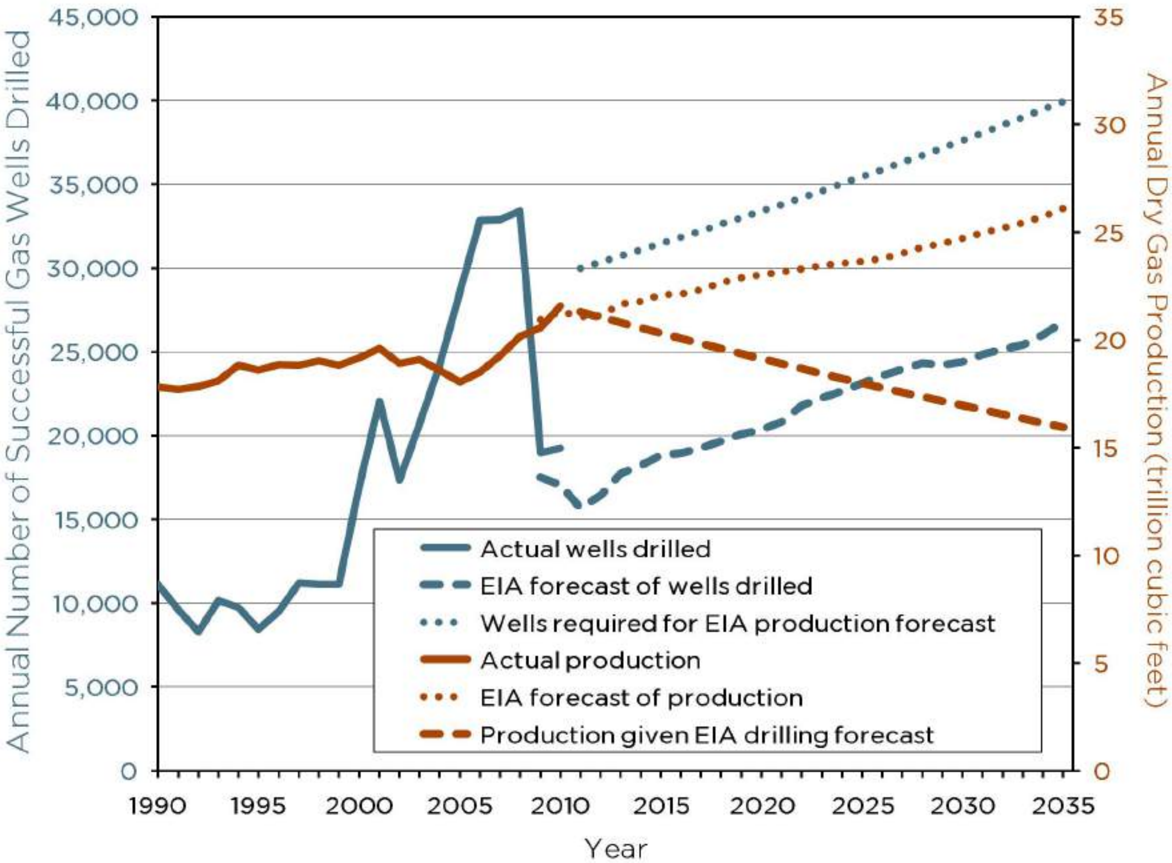


Figure 18. Historical and projected U.S. gas production and drilling rates for the EIA forecast[75] and author's best estimate of the drilling rates that would be required to achieve the EIA forecast, based on historical performance. Also indicated is the level of gas production that can be expected given the EIA's projection of drilling rates going forward.

The future gas price projection of the EIA along with historical price data are shown in Figure 19. As can be seen, the price of natural gas has been extremely volatile and generally higher than current prices over much of the past decade. Yet the EIA forecast suggests prices will remain at or below the marginal cost of shale gas production for several years while production rises. This is likely wishful thinking of the highest order. Low prices will reduce drilling activity which will reduce supply and likely renew the price volatility observed in the past. The current penchant for selling off shale gas assets noted just above is for a good reason—they are high risk and marginally economic to non-economic at today's gas prices.

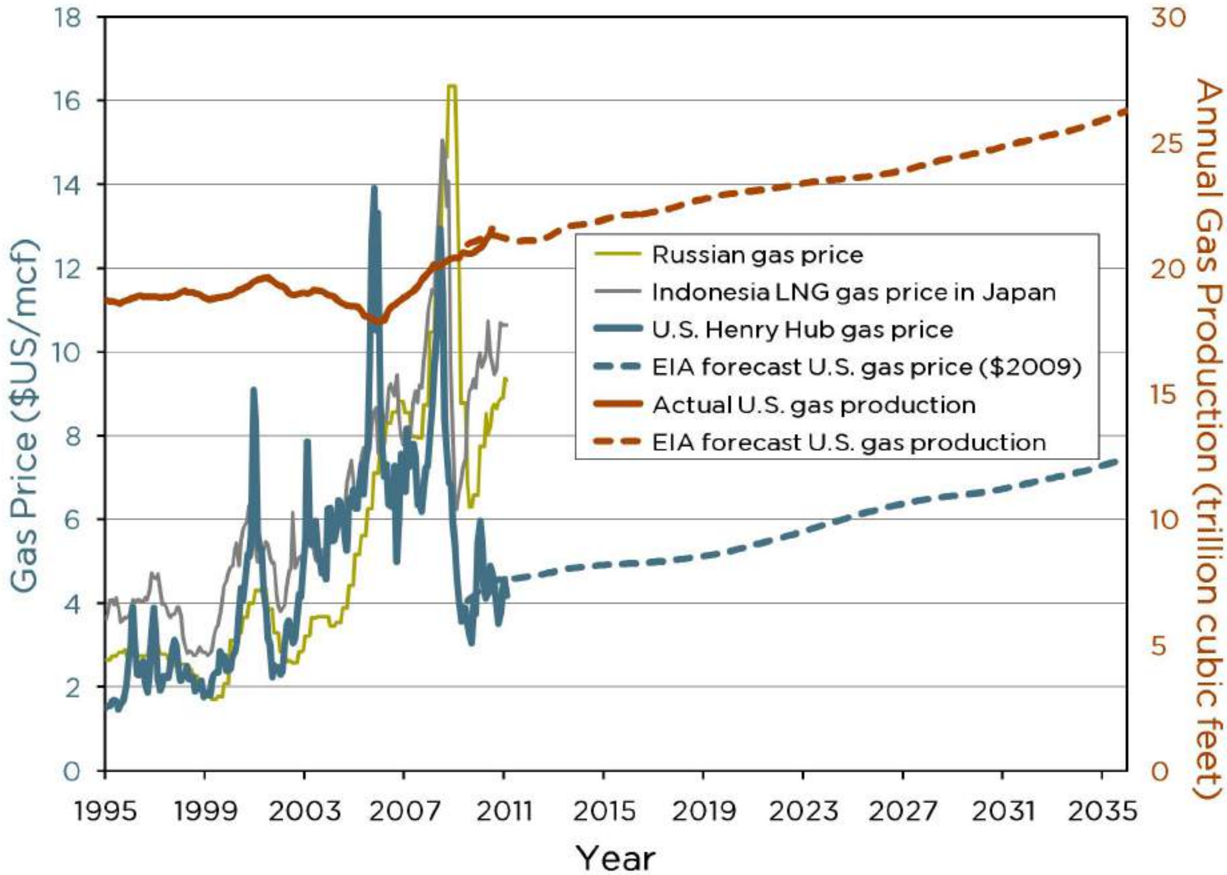


Figure 19. Historical U.S. gas prices compared to European gas (incl. Russia) and Asian LNG prices and the EIA forecast of U.S. gas prices through 2035.[76] The historical and forecast U.S. dry gas production is also illustrated. According to this forecast, U.S. gas prices are expected to stay at or below the marginal cost of production while production continues to rise—very likely a too-good-to-be-true scenario.

The EIA reference case of growth in future gas supply through radically ramped-up shale gas production stretches believability without considerably higher rates of drilling than projected. Based on a historical analysis, the annual number of new gas wells will have to be nearly double its projection to achieve its production forecast. This is unlikely to happen without significantly higher prices, which the EIA projection rules out. A more likely scenario, in my opinion, is for declining gas production over the next few years, unless prices go considerably higher to spur increasing amounts of drilling, along with increased price volatility. Based on such forecasts, the assumption of a business-as-usual future with abundant gas supplanting imported oil and replacing coal is folly.

Gas versus Coal for Electricity Generation

Natural gas is a cleaner fuel than coal for electricity generation with lower CO_2 and other emissions, yet, as illustrated in Figure 7, coal generated 45% of U.S. electricity in 2009 versus 23% for gas. The distribution of electricity generation facilities by fuel in the United States is shown in Figure 20. Coal is concentrated in the eastern half of the country and in the west from Arizona through Montana and North Dakota, whereas gas is widely dispersed, often at much smaller facilities than coal.

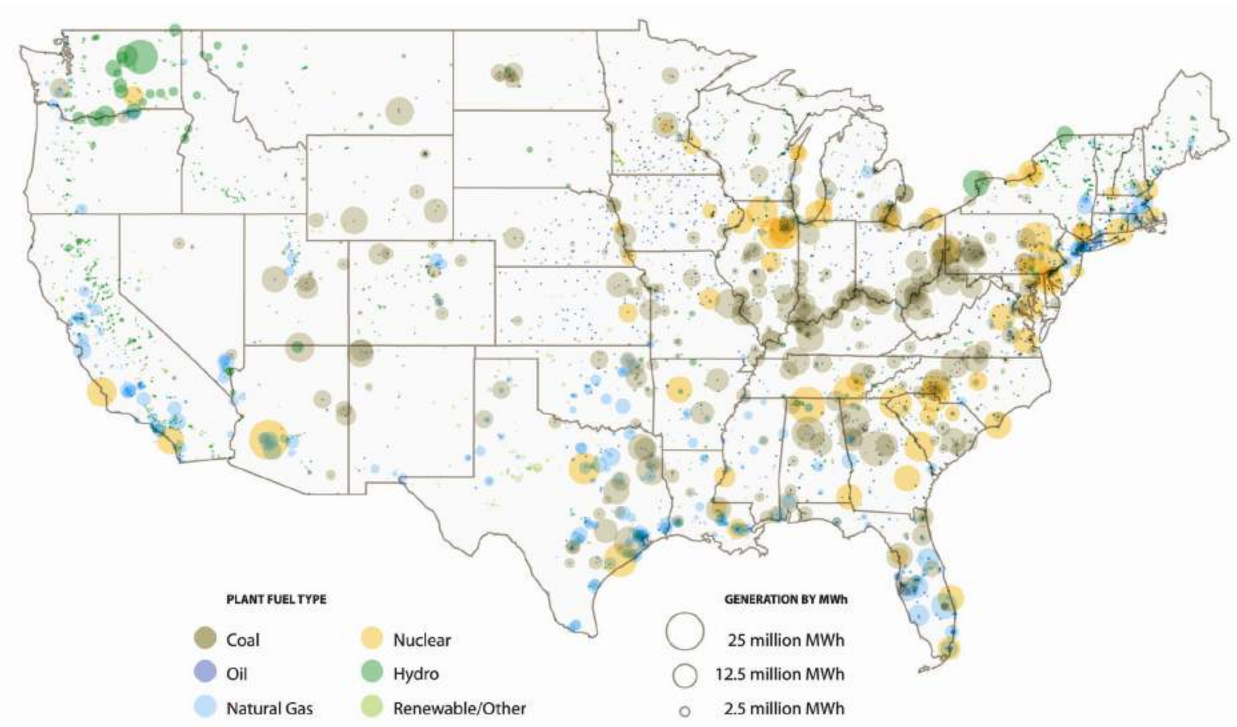


Figure 20. Location and relative size of U.S. electricity generating capacity by fuel.[77]

There have been calls from the gas lobby and environmental groups alike to shut down coal-fired generating plants and replace them with gas. Figure 20 illustrates the magnitude of increased gas production that would be required to replace coal-fired electricity generation with gas over and above the EIA reference case projection. Electricity generation from gas would have to more than double from current levels and overall gas production from the lower 48 would have to increase by 64% to offset the electricity generated by coal in 2009. Given that achieving the 265% growth in shale gas production in the existing EIA reference case is likely to be extremely challenging in itself, and will involve major environmental impacts, the concept of replacing coal with gas is likely wishful thinking at best. The Aspen Environmental Group reviewed some of the logistical bottlenecks to the wholesale transition from coal to natural gas.[78] These include the lack of sufficient pipeline capacity in 21 states as well as the lack of storage capacity on the East Coast, in the Central Plains states, and in Nevada, Idaho, Arizona, and Missouri. Aspen concluded that the cost of building gas plants to replace all existing coal plants, plus new pipeline requirements and ancillary infrastructure, would be more than $700 billion.

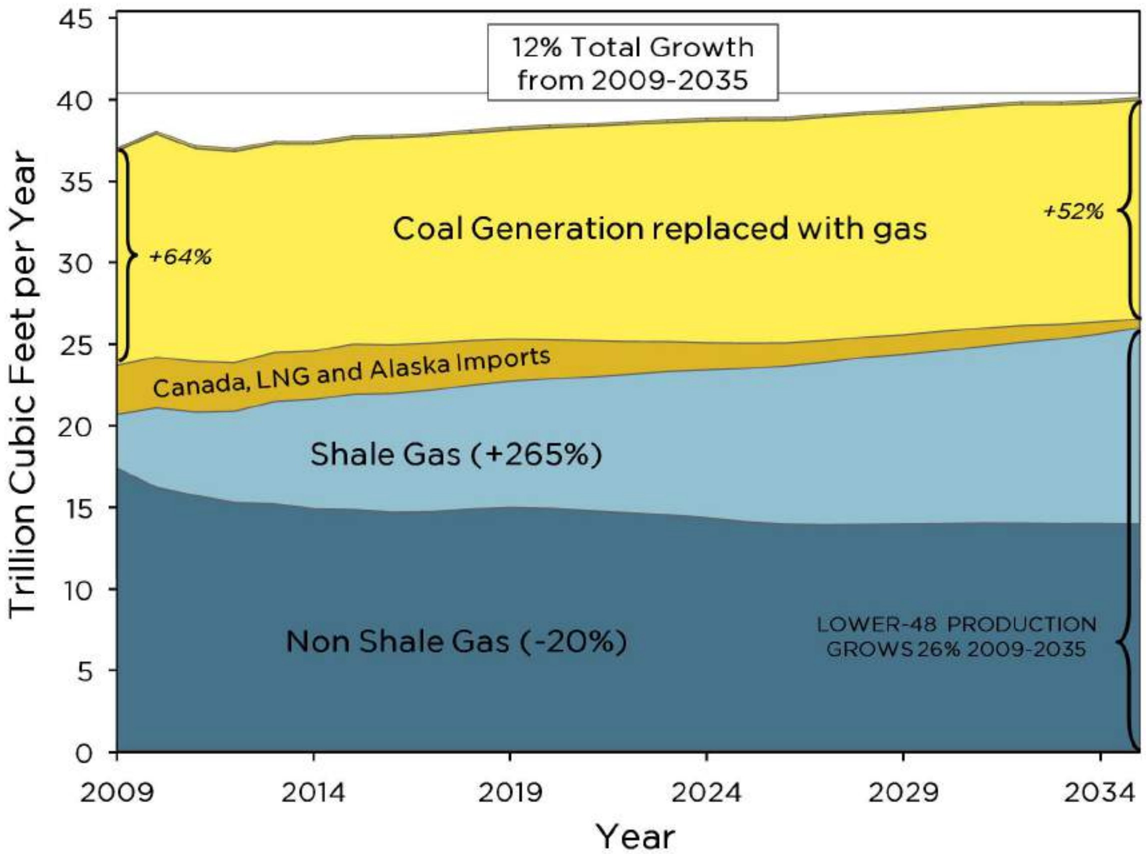


Figure 21. Amount that U.S. Lower-48 natural gas production would have to increase to cover the electricity generated by coal in the EIA *Annual Energy Outlook 2011* forecast.[79] Gas production would have to increase by 64% as of 2009 and by 52% of an expanded supply by 2035.

One of the principal appeals of replacing coal-fired plants with natural gas is reduced CO_2 emissions. Table 1 illustrates the efficiencies of various coal-fired and natural-gas-fired generating technologies and their burner-tip emissions expressed as pounds of CO_2 per kilowatt-hour. Considering burner-tip emissions only, the existing natural gas fleet emits 56% less CO_2 per kilowatt-hour than the existing coal fleet. The most efficient current generation technologies can further reduce burner-tip CO_2 emissions by 24% for coal and 17% for gas compared to the average of the existing electricity generation fleets.

Fuel	Technology	Heat Rate (BTU/kWh)	Efficiency (%)	Pounds CO_2/kWh
Coal	Existing U.S. Fleet	10414[80]	32.8	2.19
Coal	Subcritical Pulverized Coal	9950[81]	34.3	2.09
Coal	Subcritical Fluidized Bed	9810[82]	34.8	2.06
Coal	Supercritical Pulverized Coal	8870[83]	38.5	1.86
Coal	Ultrasupercritical Pulverized Coal	7880[84]	43.3	1.65
Coal	Integrated Gasification Combined Cycle	8891[85]	38.4	1.87
Coal	Supercritical Oxyfuel	8865[86]	38.5	1.86
Gas	Existing U.S. Fleet	8157[87]	41.8	0.96
Gas	Combined Cycle	6800[88]	50.2	0.80
Gas	Combustion Turbine	10842[89]	31.5	1.28

Table 1. Efficiency and burner-tip CO_2 emissions per kilowatt-hour for various coal- and gas-fired electricity generation technologies. Emissions per million BTUs for coal were assumed to be 210 pounds of CO_2 and for gas 117.8 pounds of CO_2.[90]

Of course, as discussed earlier, it is misleading to consider only burner-tip emissions when comparing gas- to coal-fired generation, considering the fugitive methane and indirect CO_2 emissions from upstream gas production, processing, transmission, and distribution operations and similar emissions from mining, transporting, and processing coal. Full-cycle GHG emissions provide a more objective basis for comparison. The full-cycle GHG emissions from shale gas may be higher than both conventional gas and coal when considered on a 20-year time frame (over which methane has between 72[91] and 105[92] times the Global Warming Potential of CO_2 as a greenhouse gas).[93] Figure 22 illustrates the various gas- and coal-emissions estimates of Howarth et al. (based on estimates of Shindell et al.) over both 20- and 100-year time frames in terms of carbon-equivalent emissions per unit of heat. As can be seen, coal has a lower global warming impact compared to shale gas only over the first few decades of emissions, and is equal to or greater than any of the Howarth et al. estimates for gas when considered over a 100-year time frame.

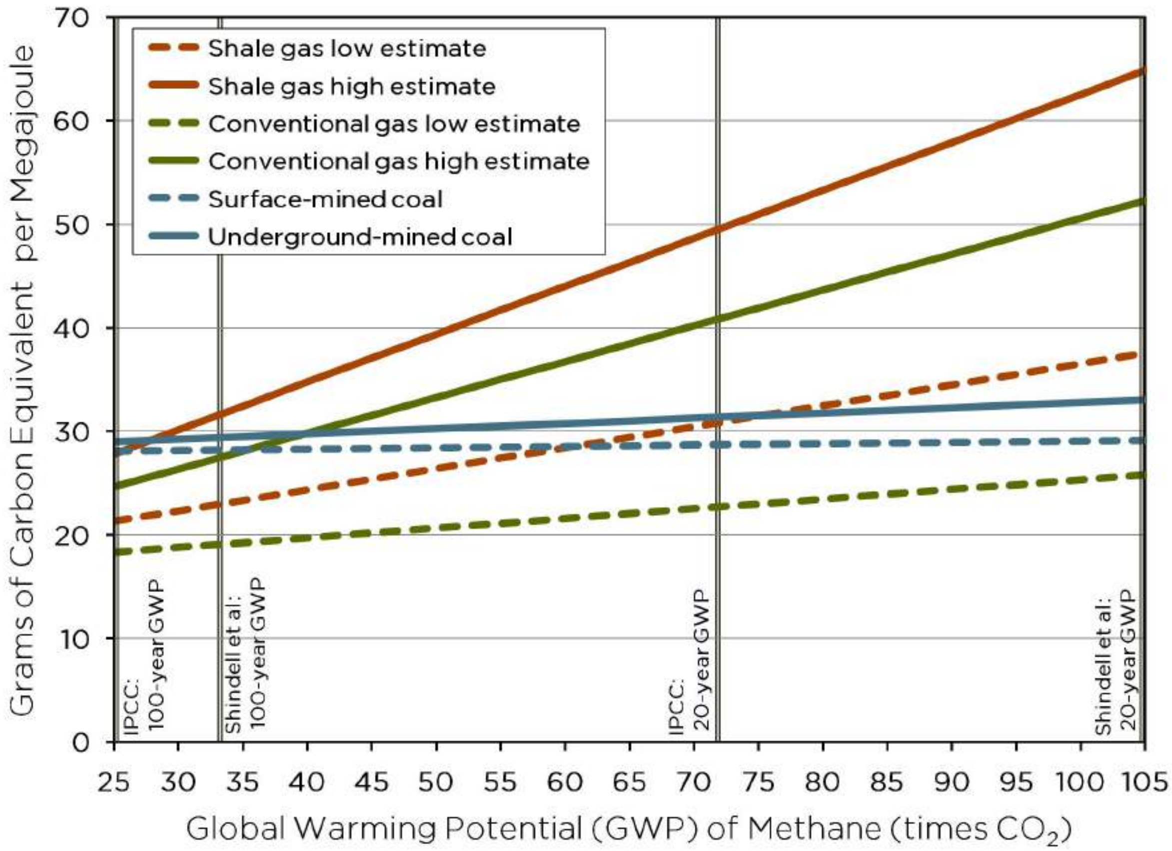


Figure 22. Comparison of Howarth et al.[94] estimates for shale gas, conventional gas and coal in terms of carbon emissions per unit of heat versus Global Warming Potential (GWP) using the estimates of the IPCC[95] and Shindell et al.[96] on 20- and 100-year timeframes.

Given that coal has higher carbon emissions than natural gas per unit of heat, a comparison of coal- to gas-fired electricity generation must be done on an emissions per kilowatt-hour basis. As shale gas is virtually the only source of gas production growth in the EIA's reference case, incremental gas supply to fuel a transition from coal would have to involve shale gas. Table 2 illustrates the impact of considering full-cycle emissions on various coal- and gas-fired electricity generation technologies utilizing the low, high, and mean emissions estimates of Howarth et al. (2011) comparing shale gas to surface-mined coal (the main source of coal for power generation) on a 20-year time frame basis. As this comparison is highly dependent on the Global Warming Potential (GWP) assigned to methane, both the newer GWP estimate of Shindell et al. (2009)[97] used by Howarth et al. and the older GWP estimate of the IPCC (2007)[98] are included. The mean estimates of Howarth et al. for shale gas suggest that GHG emissions from the existing U.S. gas generation fleet, fuelled by shale gas, *would be 38% higher than the existing coal generation fleet* using the GWP of Shindell et al. and *10% higher than the existing coal generation fleet* using the GWP of the IPCC. On a 20-year time frame basis*, the best-in-*

class gas technology (combined cycle) fueled by shale gas would produce 52% more emissions than the best-in=-class coal technology (ultrasupercritical) using the GWP of Shindell et al. and 21% more emissions using the GWP of the IPCC.

			Pounds CO_2 Equivalent per kWh					
			GWP=105 (Shindell et al.)			**GWP=72** (IPCC)		
Fuel	**Technology**	**Heat Rate (BTU/Kwh)**	**Low**	**High**	**Mean**	**Low**	**High**	**Mean**
Coal	Existing U.S. Fleet	10414[99]	2.38	2.38	2.38	2.35	2.35	2.35
Coal	Subcritical Pulverized Coal	9950[100]	2.28	2.28	2.28	2.24	2.24	2.24
Coal	Subcritical Fluidized Bed	9810[101]	2.24	2.24	2.24	2.21	2.21	2.21
Coal	Supercritical Pulverized Coal	8870[102]	2.03	2.03	2.03	2.00	2.00	2.00
Coal	Ultrasupercritical Pulverized Coal	7880[103]	1.80	1.80	1.80	1.78	1.78	1.78
Coal	Integrated Gasification Combined Cycle	8891[104]	2.03	2.03	2.03	2.00	2.00	2.00
Coal	Supercritical Oxyfuel	8865[105]	2.03	2.03	2.03	2.00	2.00	2.00
Gas	Existing U.S. Fleet	8157[106]	2.41	4.15	3.28	1.98	3.18	2.58
Gas	Combined Cycle	6800[107]	2.01	3.46	2.73	1.65	2.65	2.15
Gas	Combustion Turbine	10842[108]	3.20	5.52	4.36	2.63	4.22	3.42

Table 2. Full cycle CO_2 equivalent emissions per kilowatt-hour for various coal- and gas-fired electricity generation technologies comparing shale gas to surface-mined coal using the full-cycle greenhouse gas emission estimates of Howarth et al. (2011).[109] This is based on the 20-year impact of methane emissions as a greenhouse gas. The methane Global Warming Potential of Shindell et al[110] and the IPCC[111] are both included.

Figure 23 compares emissions per kilowatt-hour for the existing coal- and gas-fired electricity generation fleets and best-technology coal and gas using the mean estimate for shale gas GHG emissions of Howarth et al. over the spectrum of the GWP range for 20- and 100-year time frames. The existing coal fleet produces less GHG emissions than the existing gas fleet fuelled by shale gas only when compared on a time frame of 30 to 40 years. Best-technology coal compared to best-technology gas produces less emissions over a 50- to 60-year time frame, but more emissions after that. When compared on a 100-year time frame, the existing coal fleet would produce 46% more emissions than the existing gas fleet, and best-technology coal would produce 32% more emissions than best-technology gas.

The GHG emission impacts of natural gas are clearly frontloaded, and will exacerbate near-term global warming impacts compared to coal. Moving to best-technology gas and coal can reduce emissions by 17% and 24%, respectively, compared to the existing fleets. Clearly the choices going forward are not as simple as the oft-touted rhetoric that "gas produces half of the emissions of coal." *Greenhouse gas impacts over the next 30 to 40 years could be made considerably worse by a wholesale switch to gas for electricity generation.* Thus the concept of natural gas as a low-carbon bridge fuel to a future powered largely by renewable energy is cast in considerable doubt as a strategy to reduce global warming. Indeed, it may in fact be a strategy that increases global warming over the next few decades. This is a critically important consideration for those concerned about global climate change, who recognize that reducing greenhouse gas emissions in the near term is the only solution to avoiding climatic tipping points.

Greenhouse gas impacts over the next 30 to 40 years could be made considerably worse by a wholesale switch to gas for electricity generation.

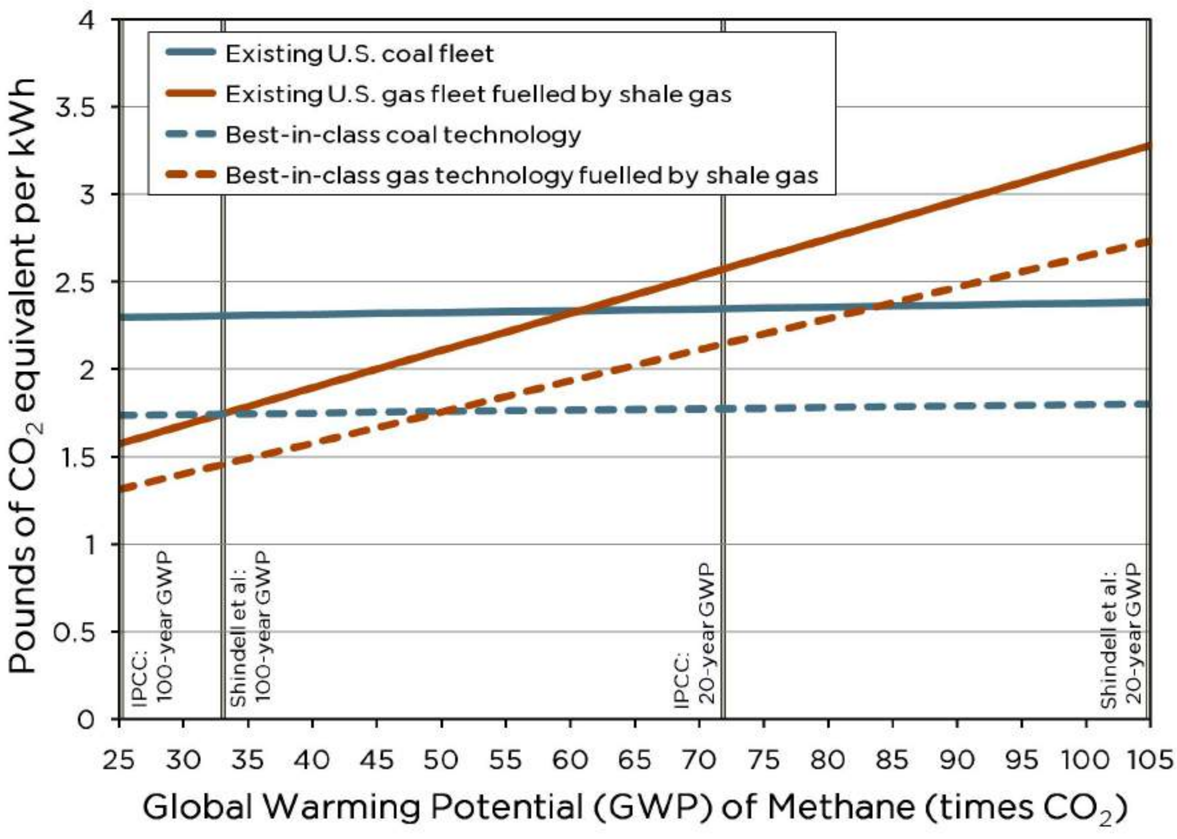


Figure 23. Comparison of CO_2 equivalent emissions per kilowatt-hour for the mean shale gas emission estimate of Howarth et al.[112] compared to surface-mined coal for both the existing coal and gas electricity generation fleet and best-technology coal and gas. This comparison covers the range of Global Warming Potential (GWP) highlighting the estimates of the IPCC[113] and Shindell et al.[114] on 20- and 100-year timeframes.

A legitimate question in this comparison of various gas- and coal-fired electricity generation technologies is the extent to which fugitive methane could be reduced through the application of available technology to capture these emissions. A considerable effort to capture fugitive methane emissions has already been underway for some time through the EPA's Gas Star Program.[115] Howarth et al. (2011) attribute fugitive methane emissions to five components of the supply chain: well completions; leaks at well sites; liquid unloading; gas processing; and transport, storage, and distribution.[116] The two largest components for shale gas are well completions (1.9% of total production) and transport, storage, and distribution (1.4% to 3.6% of total production).

Gas flaring from a natural gas rig[117]

The U.S. Government Accounting Office (GAO) has suggested that vented and flared emissions from onshore natural gas wells on federal leases amounted to 4.2% of total production between 2006 and 2008 (citing EPA data), excluding transport and distribution, and could be reduced by up to 40% using available capture technologies.[118] This estimate of emissions, although not specific to shale gas, agrees well with the upper end of the Howarth et al. range for shale gas, excluding emissions from transport, storage and distribution. Figure 24 illustrates the impact of reducing the Howarth et al. shale gas emission estimates, exclusive of transport, storage and distribution, by 40%, based on mean estimates per kWh. Although the degree to which shale gas emissions would exceed coal in the short term is considerably less than the current case, *shale gas still exceeds coal on a 20 year timeframe basis in terms of global warming potential.*

There is a major incentive to capture fugitive methane emissions from unconventional gas wells, both in terms of lost revenue and greenhouse gas emissions. The Howarth et al. estimate of emissions from flowback during a well completion in the Haynesville Shale amounts to a million dollars of lost gas at current prices. The equipment to capture these emissions is expensive, but, given the magnitude of lost revenue, payback is normally within about two years.[119] Nonetheless, full deployment of fugitive methane capture to achieve the 40% reduction target of the GAO is likely take many years.

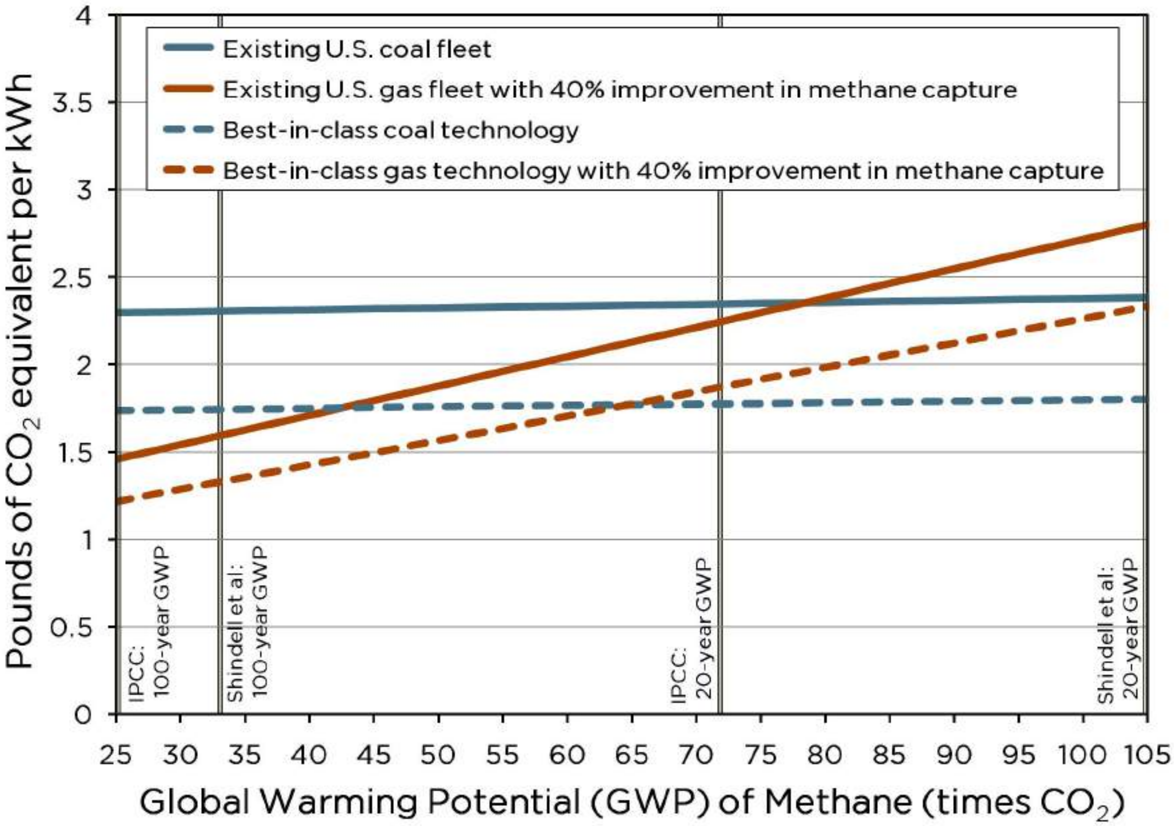


Figure 24. Comparison of future CO_2 equivalent emissions per kWh, if a 40% reduction is achieved in current methane emissions, for the mean shale gas emission estimate of Howarth et al.[120] compared to surface-mined coal for both the existing coal and gas electricity generation fleet and best-technology coal and gas. This comparison covers the range of Global Warming Potential (GWP) highlighting the estimates of the IPCC[121] and Shindell et al.[122] on 20- and 100-year timeframes.

Coal-Fired Electricity Generation: The Current Situation

In any consideration of large-scale transition from coal to gas it is important to understand the nature and opportunities provided by the existing fleet, the scaling issues, the capital costs, the time frame to accomplish the transition, and what might be achieved in emissions reduction going forward.

The U.S. coal-fired electricity generation fleet is aging. Fifty-nine percent of the existing 1466 plants are more than 42 years old.[123] These plants represent 34% of total coal-fired generating capacity. As illustrated by Figure 25, the real construction boom in U.S. coal plants in terms of added generation capacity occurred from the late 1950s through 1990. There has been little added capacity over the past two decades. The older plants are generally of smaller capacity and much worse in terms of efficiency and overall emissions.

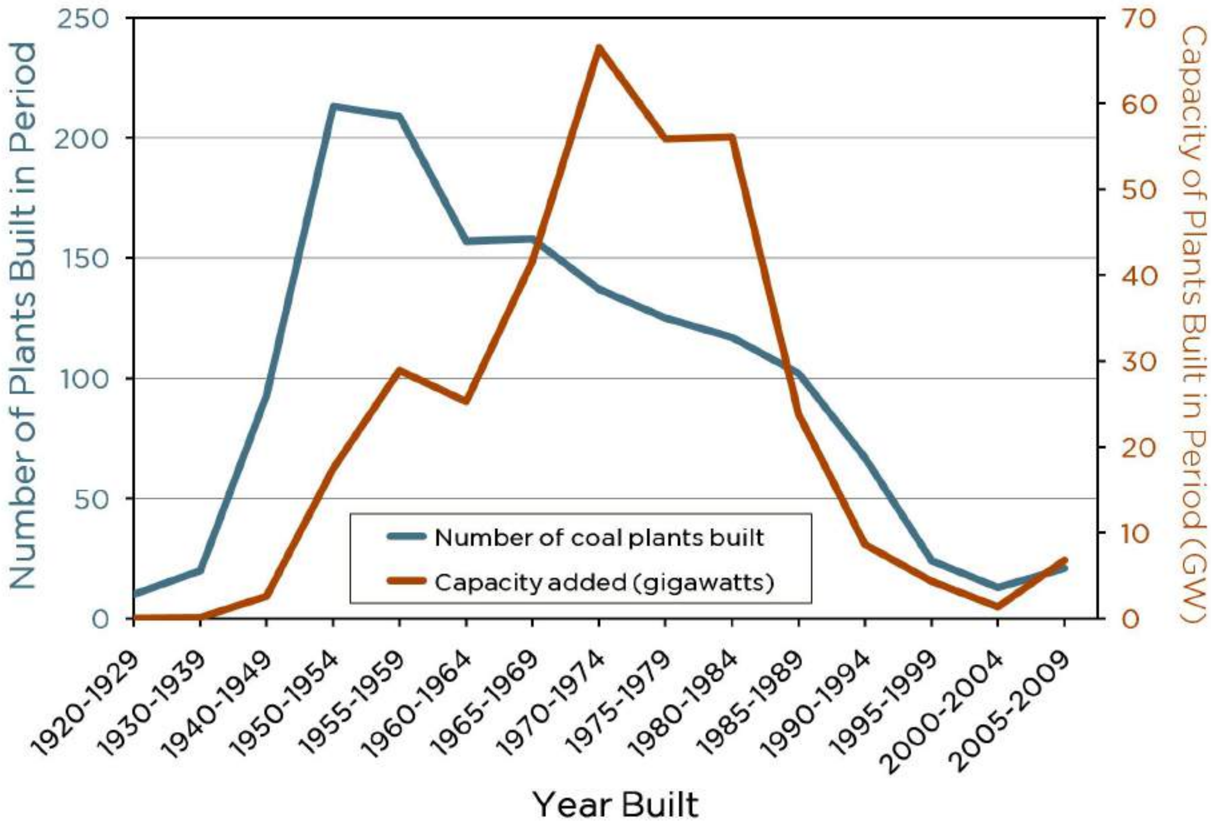
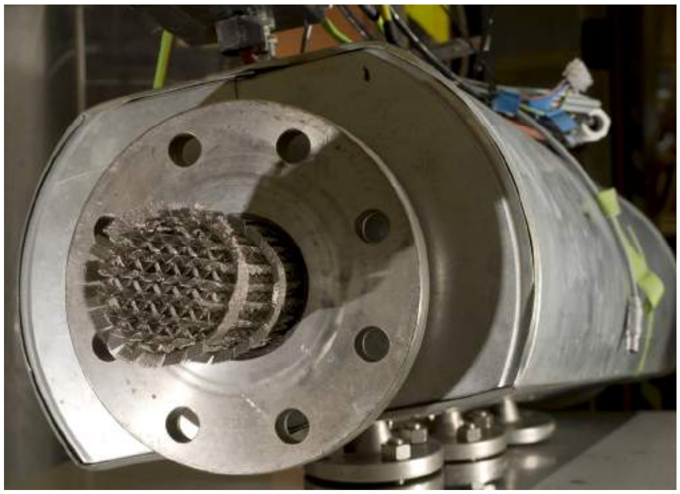


Figure 25. Age of the existing coal-fired generation plants in the United States according to the number of plants commissioned in each period and their generating capacity.[124]

The environmental issues associated with these coal plants, aside from CO_2 emissions, include emissions of sulfur oxides, oxides of nitrogen, mercury, particulates, and a host of other contaminants. Pollution control technology exists to greatly reduce emissions, but a significant proportion of the coal fleet, in particular the older units, has no pollution controls. Pollution control technologies include:

- Scrubbers to remove sulfur oxides and mercury.
- Activated carbon injection (ACI) and baghouse (filtration) to remove particulates and mercury.
- Selective catalytic reduction (SCR) to remove oxides of nitrogen and mercury.
- Electrostatic precipitators (ESPs) to remove particulates and sulfuric acid mist.

In 2010, 52% of U.S. coal-fired capacity had no scrubbers, 57% had no SCR capability, and 96% had no ACI systems.[125] Other issues are water for cooling, which is commonly used once and discharged, and ash disposal. The U.S. Environmental Protection Agency is looking to put new regulations in place by 2015 that would require the installation of scrubbers and other emission control devices on all coal plants.[126] These may also include controls on cooling water as well as regulating ash, which are currently exempt either as a hazardous waste or, less stringently, as a nonhazardous municipal waste.



An absorber for a coal-fired power plant, through which special scrubbing agents are used to absorb CO_2.[127]

The implementation of strict pollution regulations (if requirements for scrubbers, SCR, and cooling towers are included) will force the retirement of up to 21% of the current coal-fired generating capacity for economic reasons. If this retired capacity, which is estimated at between 50 and 66 gigawatts, is replaced by natural gas it would increase total gas demand by roughly 10% and result in a reduction of CO_2 emissions of 150 million metric tons annually, or about 10% of total coal CO_2 emissions by 2020[128] (much less if upstream gas emissions were included).

A fundamental characteristic of coal-fired electricity generation is that it is best suited for base load requirements, as output cannot be efficiently cycled up and down to balance the output of variable generation sources such as wind, photovoltaics, and concentrated solar. A recent study by Bentek Energy suggests that the cycling of coal plants to balance intermittent wind in Colorado resulted in no net CO_2 emissions reduction benefit from the added wind, as the coal plants operate less efficiently when cycled.[129] In fact, this study suggested that overall emissions of sulfur oxides, oxides of nitrogen, and CO_2 were greater than if wind had not been integrated into the system. The Colorado situation is unique, however, given the high reliance on coal in this jurisdiction and is not replicated in jurisdictions that have a higher proportion of gas-fired generation, which is better suited to cycling to balance intermittent generation from wind and other renewables.

The fundamental attraction of coal for utilities is its lower and generally more stable price compared to the volatility of natural gas prices. Furthermore, older plants are generally fully capitalized so the only inputs are fuel costs and operating costs. This is reflected in the "capacity factor" of coal plants, which is the amount of electricity generated compared to the amount that would be generated if the plants ran continuously. The capacity factor of coal plants averaged 65% in the United States as a whole and ranged up to 77% in some jurisdictions in 2009.[130] This compares to capacity factors of 35% or less for gas[131] in 2008 and 31% for wind.[132]

Natural-Gas-Fired Electricity Generation: The Current Situation

Natural-gas-fired electricity generation capacity in the United States more than doubled during a huge build-out in the 2000–2004 period (Figure 26). Although there are some large plants with generating capacities of greater than 500 megawatts, there are a large number of smaller units such that there were 5467 gas plants operating or on standby, in total, in the United States in 2008.[133]

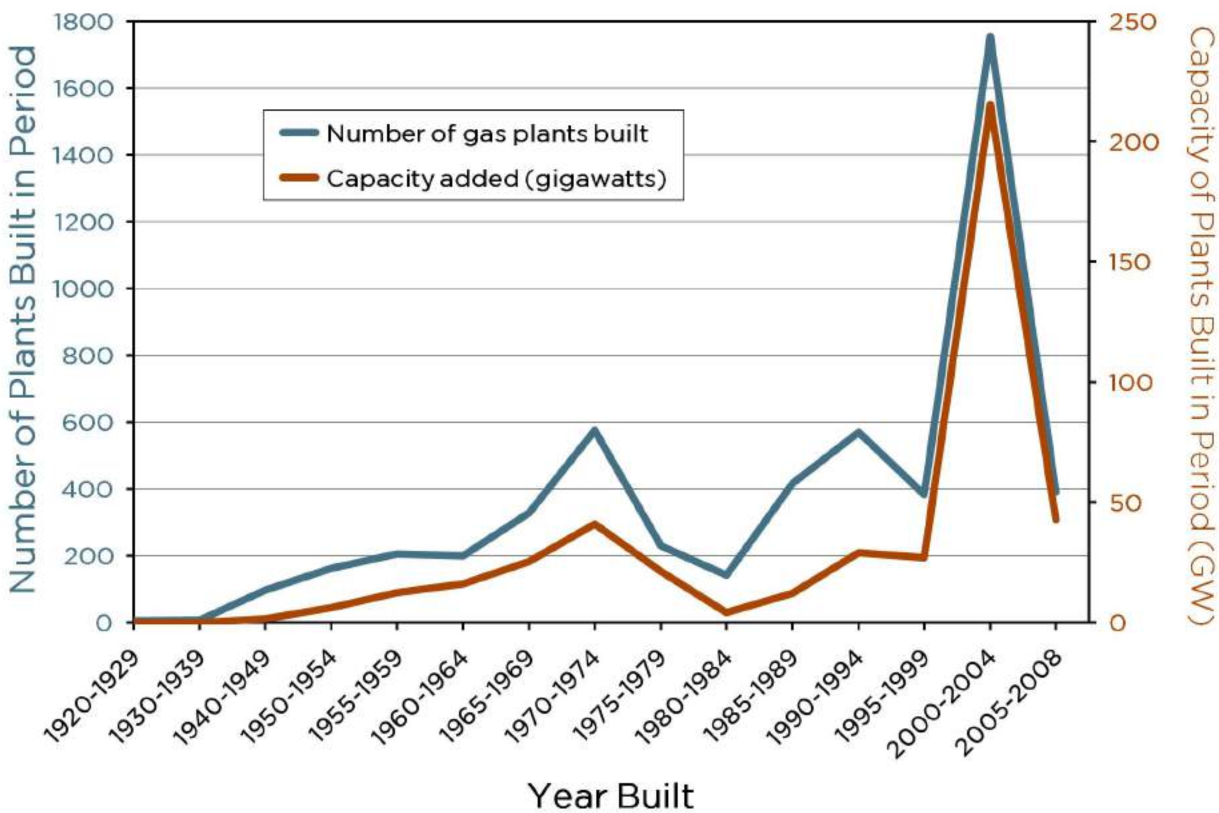


Figure 26. Age of the existing natural-gas-fired generation plants in the United States according to the number of plants commissioned in each period and their generating capacity.[134] This includes all operational and standby gas plants of all types.

Historically, the price of natural gas has been much higher than coal on a cost per unit of heat basis, which favored coal as a base load fuel and natural gas as a peak load fuel. Natural gas combustion turbines are well suited to cycling up and down to match peaks in demand and the intermittent output of renewable sources like wind, photovoltaics, and concentrated solar. Natural gas combined-cycle plants are much more efficient than combustion turbines but are less amenable to cycling and more suited to base load. There has been a large build-out of combined-cycle capacity over the past decade.

There is currently more natural gas generating capacity installed in the United States than coal generating capacity (Figure 27). Yet coal generates nearly twice as much electricity as gas. This is a function of the higher and historically volatile price of gas, as well as gas-fired generation's utility to balance peak loads on the grid versus coal's use as base load. Another fundamental factor is that new gas-fired capacity is 40% or less of the capital cost of new coal-fired capacity.[135]

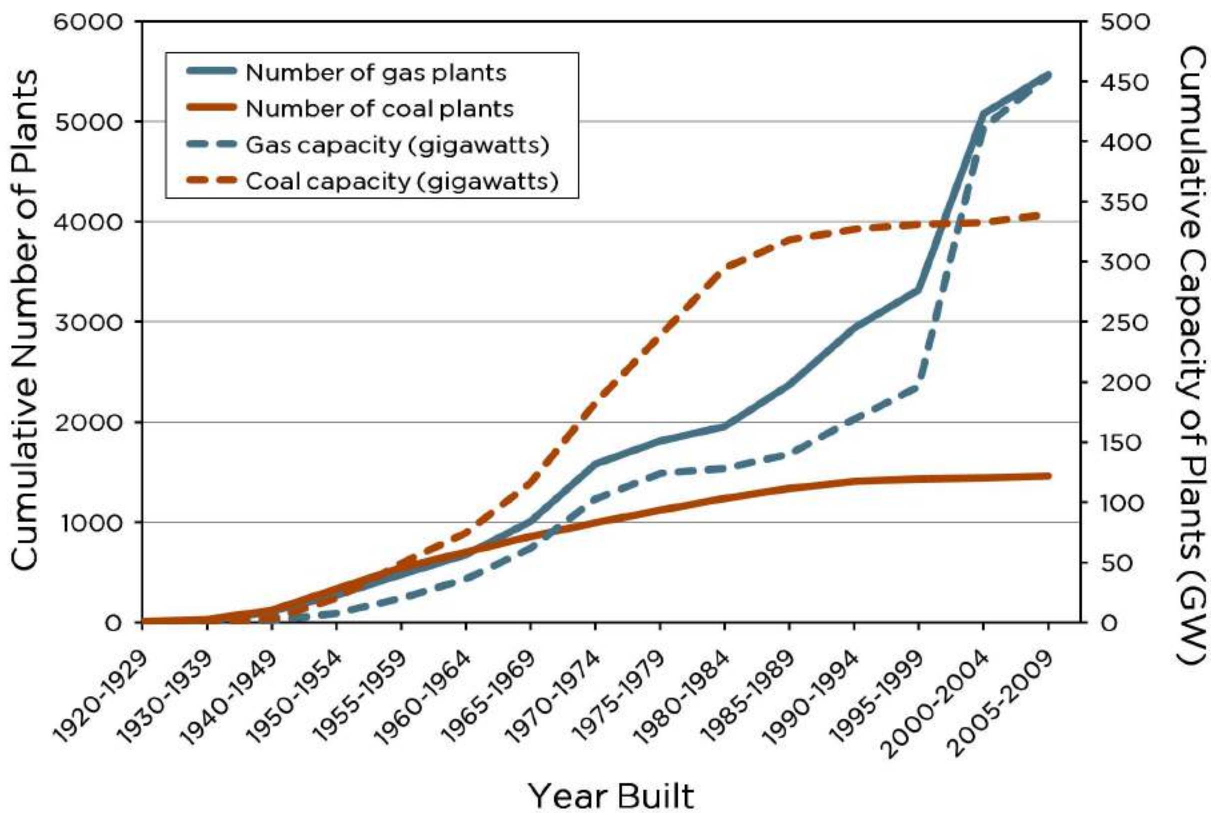


Figure 27. Cumulative additions of coal- and natural-gas-fired generation plants in the United States over time according to the number of plants commissioned in each period and their generating capacity.[136]

Natural-Gas- and Coal-Fired Electricity Generation: The Future

At the top of any list on how to reduce emissions and improve energy security must be reducing energy demand by all conceivable methods.

There is that old saying "there is no such thing as a free lunch." Both coal and gas have serious environmental impacts throughout the supply and utilization chain. We have looked in detail at the environmental issues surrounding the production and movement of shale gas. Coal also has serious environmental impacts in the supply chain, from mountaintop removal operations in the East to huge surface mining operations in the Powder River Basin and elsewhere in the West. Both fuels have serious emissions problems at the scale they are being used. Nonetheless, these fuels supplied 45% of all primary energy consumption and 68% of all electricity generation in 2009 (see Figures 1 and 7). Although the scaling of non-hydro renewable energy technologies is crucial, they provided only 4% of primary energy and electricity generation in 2009. Hence we are likely to be using natural gas and coal for a very long time to come. The question is how to minimize their impacts on the environment in both upstream production and downstream utilization and maximize their efficiency and utility.

Mountaintop removal near Hazard, Kentucky[137]

At the top of any list on how to reduce emissions and improve energy security must be reducing energy demand by all conceivable methods. Ask any installer of solar and wind equipment at a household scale and the first thing they will tell you is to reduce loads as much as possible as it is far more cost effective than trying to meet existing loads with additional supply. This is a solution that also applies at the state and national levels with electricity supply. California is perhaps the best example in the United States with a per capita electricity consumption of 7013 kWh/person, which has remained flat for three decades, compared to the U.S. average of 12,326 kWh/person, which has grown by one-third over the past three decades.[138] After aggressive efforts at demand-side management to cut electricity requirements as much as possible, there are several other principles that can further cut requirements for fuels and reduce emissions; there are also counterproductive initiatives being pursued by governments.

Retire Inefficient Plants and Replace if Necessary with Best-in-Class

We have seen that 59% of U.S. coal plants, accounting for 34% of total coal-fired electricity generation capacity, are more than 42 years old. Most of these plants are inefficient with few or no pollution controls. The new EPA regulations to be put in place in the 2015 time frame will see many of these plants retired. All remaining coal plants will be retrofitted with pollution control technology for sulfur oxides, oxides of nitrogen, mercury, and particulates. Currently available ultrasupercritical coal-fired generation technology can reduce coal requirements and CO_2 emissions by 24% for the same level of electricity output (see Table 1). Projected future advancements, which may or may not materialize, could push this to 35% less fuel consumption and CO_2 emissions. Clearly, retiring inefficient plants and replacing them, if that capacity is required, by best-in-class technology can significantly reduce both the amount of fuel required and CO_2 emissions.

Similarly, combined-cycle natural gas plants are much more efficient than combustion turbines, although less flexible in terms of cycling to meet peak loads. Further advancements in the efficiency of gas-fired generation are also projected.

Implement Cogeneration—Production of Both Heat and Power

A co-generation power plant in Denmark.[139]

The production of electricity while capturing and utilizing waste heat can significantly increase the overall efficiency of both coal- and gas-fired electricity generation plants and reduce both fuel consumption and emissions. Europe, and particularly Denmark, is a world leader in combined heat and power (CHP), also known as cogeneration. An ultrasupercritical coal plant in Denmark is reportedly operating at 47% efficiency, not including heat capture. Including heat capture, which is utilized for district heating, the overall efficiency of an ultrasupercritical coal plant with CHP increases to more than 70%.[140] More than half of Danish homes are heated with district heating and more than 80% of Danish district heating is generated in conjunction with electricity production.[141] The CHP plants in Denmark range from small biomass-fueled units to natural-gas-fired plants to large-scale ultrasupercritical coal plants. A challenge with cogeneration is that plants must be located in close proximity to users of the waste heat.

To date there has been relatively little application of cogeneration in the United States. Denmark's example suggests that there is a major opportunity to reduce both fuel consumption of coal and gas as well as the emissions from burning them through district and process heating, cogeneration, and best-in-class technology.

Use Fuels that Must Be Burned in Their Highest-Value Applications

As outlined earlier, natural gas is a high-value fuel with major applications in the industrial, residential, and commercial sectors (see Figure 5). Only 30% of U.S. natural gas production is used for electricity. Nonetheless, natural-gas-generated electricity is very useful for balancing the intermittent output from renewable sources—this is its forte. Coal, on the other hand, is a low-cost fuel best suited to base load. The environmental costs of both coal and gas are substantial, on the extraction side and from emissions on the utilization side. And the environmental costs of the "game-changer"—shale gas—are perhaps worse than coal on a full-cycle basis. There is a saying in the petrochemical industry that burning natural gas to generate electricity, or to extract bitumen from the oil sands, is akin to "turning gold into lead" or "lighting candles with hundred-dollar bills." Site-specific decisions made on future generation options must consider the full-cycle environmental impacts of fuels, their reliability and costs of supply, the scope for alternatives, and whether base load or peaking is required to maintain stability in the grid.

Carbon Capture and Storage—A Waste of Energy and Money?

Carbon capture and sequestration project in Weyburn, Saskatchewan, Canada.[142]

Carbon capture and storage (CCS) technologies are being promoted by politicians as a panacea for expanding the consumption of fossil fuels globally while minimizing carbon emissions. Examples of CO_2 flooding to produce extra oil at Weyburn,[143] in Saskatchewan, Canada, and CO_2 stripped from natural gas and injected at Sleipner,[144] in the North Sea, are touted as proof that CCS can work. However, both examples are red herrings when it comes to the large-scale capturing, injecting, and long-term sequestering of CO_2 from sources such as coal plants. CO_2 injections at Weyburn, for example, are economical because they result in greater oil recovery. The recovered oil, though, is then burnt, creating as much or more CO_2 than was ever sequestered. CO_2 flooding to recover remaining oil in depleted reservoirs has been under way for decades, and will continue to be conducted. This procedure is about recovering extra oil, not net reductions of CO_2. Sleipner produces natural gas that is over 9% CO_2, which must be removed for the gas to be salable; thus there are few of the punitive energy and capital costs entailed in trying to sequester CO_2 from coal plants.

The holy grail of CCS for politicians is so-called clean coal, whereby CO_2 is stripped from flue gas, compressed to a liquid or supercritical state, and then injected into saline aquifers. Although there are dozens of research and pilot projects globally, commercial-scale CCS from a coal plant has yet to be demonstrated. There are four major issues with CCS that make it counterproductive:

- The safety and long-term integrity of CO_2 storage in deep saline aquifers. This has recently been investigated in depth by Thomson (2009),[145] who outlined many concerns, including the largely untested nature of disposal in saline aquifers and the potential for leakage.

- The parasitic energy loss in separating CO_2 from flue gas and compressing it to a liquid or supercritical state. These losses range from 18.8% to 26.8% of the power output from a coal plant, depending on the technology, as shown in Table 3. A CCS-equipped coal plant will also require between 23.1% and 36.7% more fuel to overcome parasitic losses, again depending on technology (Table 3), with all the environmental, energy, and capital costs of providing it.

- The capital cost of a CCS-equipped power plant is estimated to be between 32.2% and 74.2% higher than a conventional plant, depending on the technology (Table 3).

- The additional capital and energy costs of building CO_2 pipelines, drilling injection wells, and monitoring storage sites for a few hundred years.

Notwithstanding the potential risks of large-scale CCS, and the fact that it has yet to be demonstrated at a commercial scale, its projected costs represent a lost opportunity for this capital, which could instead be invested in alternative energy and infrastructure to radically lower energy footprints. Not burning coal or natural gas is a low-tech but very effective way of reducing CO_2 and other emissions while at the same time retaining nonrenewable resources to enhance future energy security.

Technology	Efficiency (%)	Efficiency with CCS (%)	Energy Penalty with CCS (%)	Additional Fuel Required with CCS (%)	Additional Capital Cost with CCS (%)
Subcritical Pulverized Coal	34.3	25.1	26.8	36.7	74.2
Subcritical Fluidized Bed	34.8	25.5	26.7	36.5	70.7
Supercritical Pulverized Coal	38.5	29.3	23.9	31.4	60.9
Ultrasupercritical Pulverized Coal	43.3	34.1	21.2	27.0	53.7
Integrated Gasification Combined Cycle	38.4	31.2	18.8	23.1	32.2
Supercritical Oxyfuel	38.5	30.6	20.5	25.8	39.7

Table 3. Comparison of the efficiency of various coal-burning technologies with and without CCS, as well as the parasitic power loss, additional fuel required and additional capital costs of CCS.[146]

Vaclav Smil perhaps best summed up the futility of large-scale CCS in his comment published in *Nature* in 2008[147]:

> Carbon sequestration is irresponsibly portrayed as an imminently useful large-scale option for solving the challenge. But to sequester just 25% of CO_2 emitted in 2005 by large stationary sources of the gas (9.6 Gm^3 at the supercritical density of 0.468 g cm^{-3}), we would have to create a system whose annual throughput (by volume) would be slightly more than twice that of the world's crude-oil industry, an undertaking that would take many decades to accomplish.

Gas versus Oil for Transportation

A compressed natural gas vehicle being refueled.[148]

Another initiative promoted by the gas lobby[149] and by the Pickens Plan[150] formulated by T. Boone Pickens is refitting the vehicle fleet, or at least the heavy-vehicle portion of it, to burn natural gas either in a compressed or liquid form. This argument is based on the fact that natural gas burns more cleanly than either diesel or gasoline, and making the switch would improve energy security by displacing foreign imports of oil. The existing U.S. vehicle fleet consumed 11.1 million barrels of oil per day in 2009, which is substantially above 2009 oil imports of 9.5 million barrels per day.[151]

Figure 26 illustrates by how much gas production would have to increase to replace the oil consumed by the heavy- and light-vehicle fleet. Clearly, it is highly unlikely that U.S. gas production could be increased enough to make significant inroads into the oil-fueled fleet at its current rates of energy consumption, let alone the 95% to 100% that natural gas production would have to increase to replace it.

Nonetheless, the 130,000 natural-gas-fueled vehicles in the United States provide a useful, less polluting alternative, particularly in municipal applications for short-haul, high-mileage vehicles (buses, taxis, refuse trucks, etc.). This fleet will increase going forward, but is likely to remain only a niche player in overall transportation given the current scale of the oil-fueled fleet.

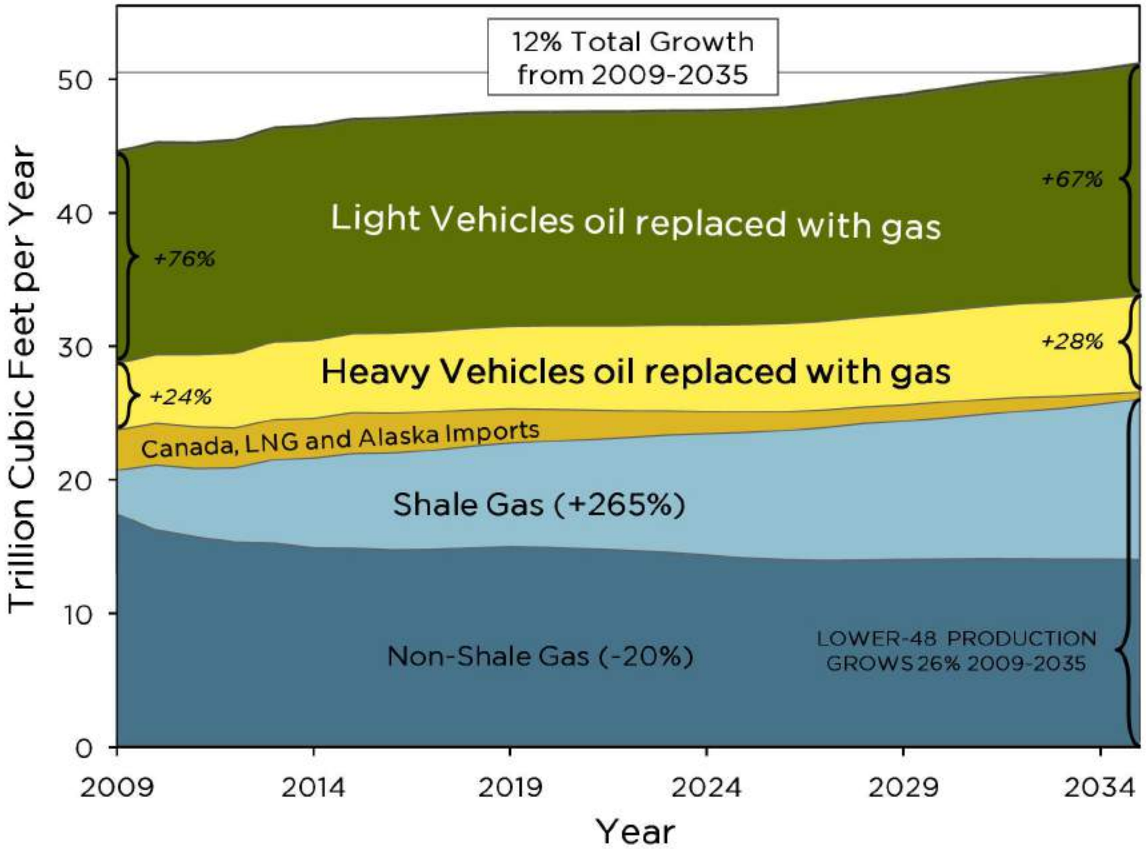


Figure 28. Amount that U.S. Lower-48 natural gas production would have to increase to cover the oil burned by light and heavy vehicles in the EIA *Annual Energy Outlook 2011* reference case projection.[152] Gas production from the Lower 48 would have to increase by 100% as of 2009 to completely fuel the existing vehicle fleet and by 95% of the expanded EIA supply projection by 2035.

Several issues—besides the unlikely possibility of increasing gas supply substantially over and above the EIA forecast—limit the wholesale takeover of the vehicle fleet by natural gas. These include:

- The high incremental cost of natural-gas-fueled vehicles (e.g., $5500 for a Honda GX[153]) and the high cost of retrofits to existing vehicles (approximately $10,000 in the United States[154]).
- The need to establish a national fueling infrastructure for compressed natural gas (CNG).
- The fact that CNG is not sufficiently energy dense to provide enough range for long-haul trucks. LNG (liquefied natural gas), which is sufficiently energy dense, has been

proposed as an alternative source of natural gas fuel but is problematic as it must be kept at –162°C and a national refueling system would have to be established.

The other option, should a miraculous surfeit of natural gas arise, would be to convert natural gas to conventional liquid fuels—diesel, gasoline, and ethanol—through the Fischer-Tropsch process in gas-to-liquids plants to fuel the existing fleet. There is little gas-to-liquids capacity in the world at present, nor is there projected to be over the next quarter century.[155] The energy loss in this conversion process is also substantial, as are the associated emissions.

Implications and Conclusions

Natural gas has been an important part of the U.S. energy supply and will continue to be for the foreseeable future. However, the notion that natural gas is a panacea that can substantially offset oil imports as a transportation fuel or replace coal-fired electricity generation in business-as-usual growth scenarios is wishful thinking at best.

The current (2011) EIA reference case projection of gas supply growth in the United States is based almost entirely on shale gas, which would have to grow more than threefold and supply 45% of U.S. production by 2035. Given past experience, it will take much higher drilling rates and much higher gas prices than forecast for this to happen. The environmental impacts of shale gas drilling and hydraulic fracturing are becoming highly evident to the public and its elected officials. There is a great deal of public pushback against these practices, which could restrict the rates at which these wells are drilled and hence reduce the forecast growth rates of shale gas production.

When it comes to fossil fuels there is no such thing as a free lunch. Coal and natural gas have heavy environmental impacts throughout the supply and utilization chain. The most essential first step in minimizing these impacts is to reduce consumption to the maximum extent possible, followed by optimally utilizing the fuels that must be burnt and minimizing their environmental impacts. Natural gas is a high-value fuel suited to many uses besides electricity generation, which currently is only 30% of consumption. Coal is a low-value fuel best suited to base load electricity generation applications. Natural gas can be used for base load but, because of fugitive methane emissions along the supply chain, may actually be worse than coal in terms of full-cycle greenhouse gas emissions. Natural gas is, however, unlike coal, well suited to balancing the intermittent output of renewable sources such as wind, photovoltaics, and concentrated solar.

Replacing coal with natural gas for electricity generation would require increasing gas production by 64% at 2009 consumption rates. This is an impossibility and, given the full-cycle greenhouse gas emissions of shale gas, may make the pollution situation worse, even if it were possible. There are, however, several options to reduce emissions from coal plants, reduce coal consumption, and hence reduce the ecological impacts of coal mining and transportation. These include shutting down old, inefficient coal plants that do not have pollution controls and replacing them, if necessary, with best-in-class technology with cogeneration of heat where possible.

Reducing the consumption of energy through efficiency and conservation is paramount in reducing emissions, enhancing energy security and promoting a more sustainable energy future.

Replacing the oil-fueled vehicle fleet with natural-gas-fueled vehicles would require increasing gas production by 100% at 2009 consumption rates. This is an impossibility. Natural gas is, however, likely to be an important and potentially growing niche fuel for short-haul, high-mileage light and heavy vehicles.

Reducing the consumption of energy through efficiency and conservation is paramount if we are to reduce emissions, enhance energy security, and promote a more sustainable energy future. The growth mindset that has served us so well for the past few centuries no longer suits the situation we find ourselves in. Fossil fuels are a finite, one-time resource. Neither natural gas nor oil nor coal can fuel the 21st century to its end in the manner to which we have become accustomed. Understanding the full-cycle environmental costs of future energy choices is crucial. Although there are no silver bullets, there are many options in planning a more sustainable way forward, and I have tried to outline some of them here. We'd best get on with them.

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