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Sector Effects of the Shale Gas Revolution in the United States

Alan Krupnick, Zhongmin Wang, and Yushuang Wang

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

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Abstract

This paper reviews the impact of the shale gas revolution on the sectors of electricity generation, transportation, and manufacturing in the United States. Natural gas is being substituted for other fuels, particularly coal, in electricity generation, resulting in lower greenhouse gas emissions from this sector. The use of natural gas in the transportation sector is currently negligible but is projected to increase with investments in refueling infrastructure and natural gas vehicle technologies. Petrochemical and other manufacturing industries have responded to lower natural gas prices by investing in domestically located manufacturing projects. This paper also speculates on the impact of a possible shale gas boom in China.

Key Words: shale gas, electricity, transportation, and manufacturing

JEL Classification Numbers: L71, L9, Q4

Contents

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1. Introduction

The shale gas revolution in the United States, due to breakthroughs in drilling technologies such as horizontal drilling and hydraulic fracturing, has significantly boosted US domestic natural gas production, which was previously in decline. US dry gas production increased by about 27.4 percent from 18.05 Tcf per year in 2005 to 23 Tcf per year in 2011 (US Energy Information Administration [EIA] 2012b), largely because of the increasing production from shale gas and other unconventional sources. The share of shale gas in total natural gas production in the United States has rapidly increased from 4 percent in 2005 to about 30 percent today (Logan et al. 2012). This trend is likely to continue in coming decades, leading EIA to project, in its 2012 reference case, that by 2035, shale gas will contribute about 49 percent of US domestic natural gas production (EIA 2012a).

This major shift in the supply of natural gas has driven down its price. The annual average Henry Hub natural gas spot price dropped by more than 50 percent, from $8.86 per million Btu (mmBtu) in 2008 to $4.00/mmBtu in 2011, with a low of about $2.50/mmBtu in early 2012 and a return to about $4.00/mmBtu as of late March 2013.[1] These prices contrast to natural gas spot prices in Japan ranging from $13 to $15/mmBtu and in Europe of around $9/mmBtu. However, significant uncertainty is associated with the future price of natural gas, given uncertainty in demand, supply, and regulations, both directly on shale gas extraction and through existing and potential climate policy.[2] Figure 1 shows the wide range of price forecasts EIA uses to describe the future in its Annual Energy Outlook (AEO) 2012 forecast. A larger shale resource base assumption leads to a lower price projection and vice versa. Under a carbon pricing scenario, the natural gas price is projected to be higher relative to the reference case as a result of the demand shift to natural gas from more carbon-intensive fuels like coal.

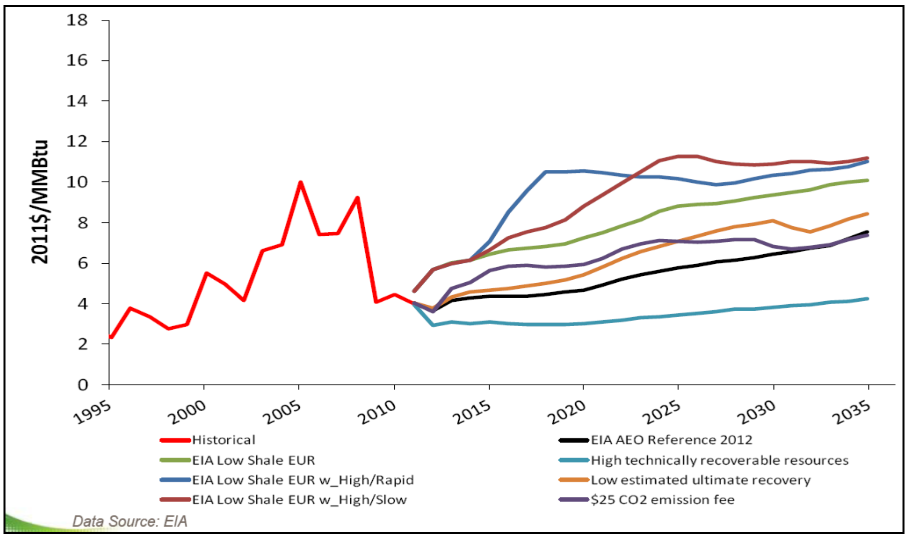
*Krupnick, senior fellow and director of Resources for the Future's (RFF) Center for Energy Economics and Policy; Wang, fellow, RFF; Wang, research assistant, RFF.

[1] See EIA, "Henry Hub Gulf Coast Natural Gas Price", http://www.eia.gov/dnav/ng/hist/rngwhhdM.htm

[2] Natural gas price volatility may be reduced as a result of changes in supply/demand balance and the geographic dispersion of shale plays, which would probably lower the importance of Gulf of Mexico as a source of gas supply (Lipschultz 2012).

The price decline has led to significant changes in the extent to which the United States uses natural gas in various energy-consuming sectors, including gas substitution for other fuels in the electricity, transportation, and industrial sectors. As China and other countries with potentially large resource bases are taking steps to develop their own shale resources, it is useful to reflect on whether such effects are likely to be seen in China should shale gas be developed and lead to similar low prices there. The purpose of this paper is to document the effects in the United States that have already occurred, as well as those forecasted to occur in the future in the US market.

Figure 1. Henry Hub Natural Gas Spot Price



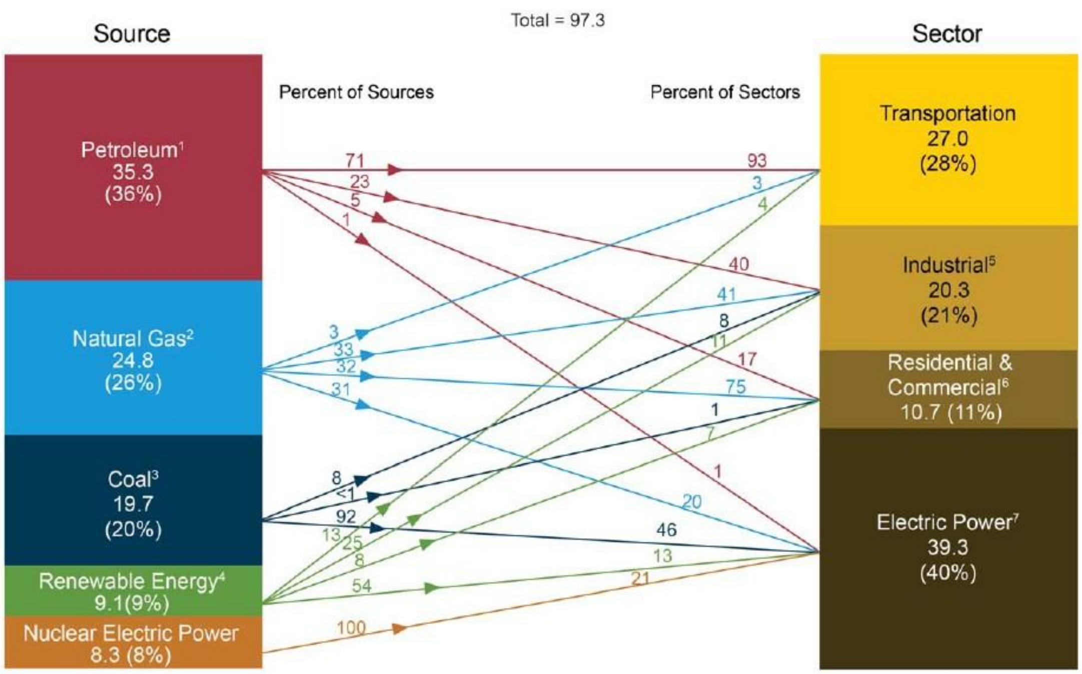
The paper is organized as follows. First, we document the role that natural gas plays in the US economy. Following this, we provide a comprehensive review of the impacts of the shale gas boom on three end-use sectors—electricity, transportation, and manufacturing. At the end of the paper, we consider the economic and regulatory context in China and close with some thoughts on the implications of the US experience for China gas demand sectors.

2. Natural Gas in the US Economy

Natural gas has a unique place in the US economy, as it is a major fuel in the electricity, residential, and commercial sectors and a major feedstock for industry but has almost no role in the transportation sector. As shown in Figure 2, natural gas represented 26 percent of the primary energy consumed in the United States in 2011, accounting for 41 percent of the energy supplied to industry, 75 percent of energy supplied to residential and commercial heating and hot water, and 20 percent of the fuels used to generate electric power. This last fraction has almost certainly risen in 2012. Natural gas supply to these sectors is split evenly across industrial, residential/commercial, and power sectors (about 32 percent to each sector). In contrast, only 3 percent of energy in the transportation sector is supplied from natural gas.

This paper offers limited discussions of the residential and commercial sectors—largely because natural gas has already had a 75 percent share in these sectors. Further penetration would require more pipelines to be built to less densely populated areas and, in any case, turnover of heating and hot water systems would be slow. This is illustrated in Figure 3, which shows that, while use of natural gas in power generation has escalated dramatically in recent years and industrial use of gas is enjoying a recent turnaround, the use of gas for commercial and residential heating has remained flat.

Figure 2. Primary Energy Consumption by Source and Sector in 2011 (Unit: Quadrillion Btu)



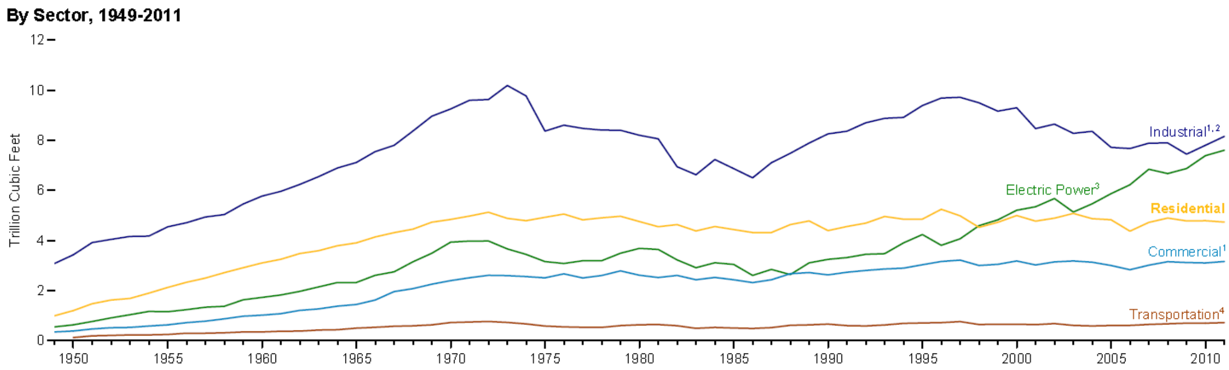
[1] Does not include biofuels that have been blended with petroleum—biofuels are included in "Renewable Energy."
[2] Excludes supplemental gaseous fuels.
[3] Includes less than 0.1 quadrillion Btu of coal coke net imports.
[4] Conventional hydroelectric power, geothermal, solar/photovoltaic, wind, and biomass.
[5] Includes industrial combined-heat-and-power (CHP) and industrial electricity-only plants.
[6] Includes commercial combined-heat-and-power (CHP) and commercial electricity-only plants.
[7] Electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes 0.1 quadrillion Btu of electricity net imports not shown under "Source."

Notes: Primary energy in the form that it is first accounted for in a statistical energy balance, before any transformation to secondary or tertiary forms of energy (for example, coal is used to generate electricity). • Sum of components may not equal total due to independent rounding.

Sources: U.S. Energy Information Administration, *Annual Energy Review 2011*, Tables 1.3, 2.1b-2.1f , 10.3, and 10.4.

Source: EIA 2012b.

Figure 3. Natural Gas Consumption by Sector



1 Includes combined-heat-and-power plants and a small number of electricity-only plants.
2 Lease and plant fuel, and other industrial.
3 Electricity-only and combined-heat-and-power plants whose primary business is to sell electricity, or electricity and heat, to the public.
4 Natural gas consumed in the operation of pipelines (primarily in compressors), and as fuel in the delivery of natural gas to consumers; plus a small quantity used as vehicle fuel.

Source: EIA 2012b.

3. The Electricity Sector

Lower natural gas prices are expected to drive more power plant operators to switch to natural gas from other fuel sources and therefore increase the share of natural gas in the power generation fuel mix. Similarly, and other things being equal, cheaper gas should decrease overall electricity prices and therefore increase the quantity of electricity demanded. At the same time, low natural gas prices can further disadvantage the economic case for nuclear power and renewables, potentially backing out these lower- or zero-carbon fuels.

In the near term, switching from other fuels to natural gas could be achieved by varying the capacity factors of different generating units—that is, running natural gas–powered generators more frequently to take advantage of the cheaper fuels. For the United States, the potential to increase generation from existing gas-fired power plants is huge given its high natural gas generation capacity and relatively low utilization factors for gas-fired units in the years prior to large-scale shale gas production. As of 2011, natural gas represented a total summer generation capacity of 413 GW, which is the largest among all fuel sources (94 GW larger than coal capacity; EIA 2012b). A large number of these natural gas–fired plants were added from 1998 to 2003, and some of these were idle when gas prices were high before the shale gas boom. But as gas prices plummeted, these gas-fired plants became more favored by utility managers. For example, American Electric Power, one of the two biggest coal consumers in the United States, ran its gas plants at a 70 percent capacity level in 2012 while its coal plants ran less than half of the time (Mufson 2012).

In the long term, the change in fuel prices would also affect business decision-making on new power plant investments and old plant retirements, thus changing the fuel mix of generating capacity. Roughly 30 GW of coal-fired plants, which comprise about 10 percent of the total coal generation capacity, will be closed down by 2016, according to the announced retirement plans made by companies as of July 2012 (Celebl et al. 2012). Apart from the abundant supply of natural gas, the expected stricter regulation of air pollution from coal combustion also plays an important role in these anticipated closures. Many companies with older coal power plants have to decide between investing in environmental control facilities to ensure that their coal plants stay in operation versus putting that investment into new, cleaner gas-fired plants. Low gas price has made the latter choice more attractive to the industry, although the history of high gas price volatility acts to dampen the enthusiasm for natural gas.

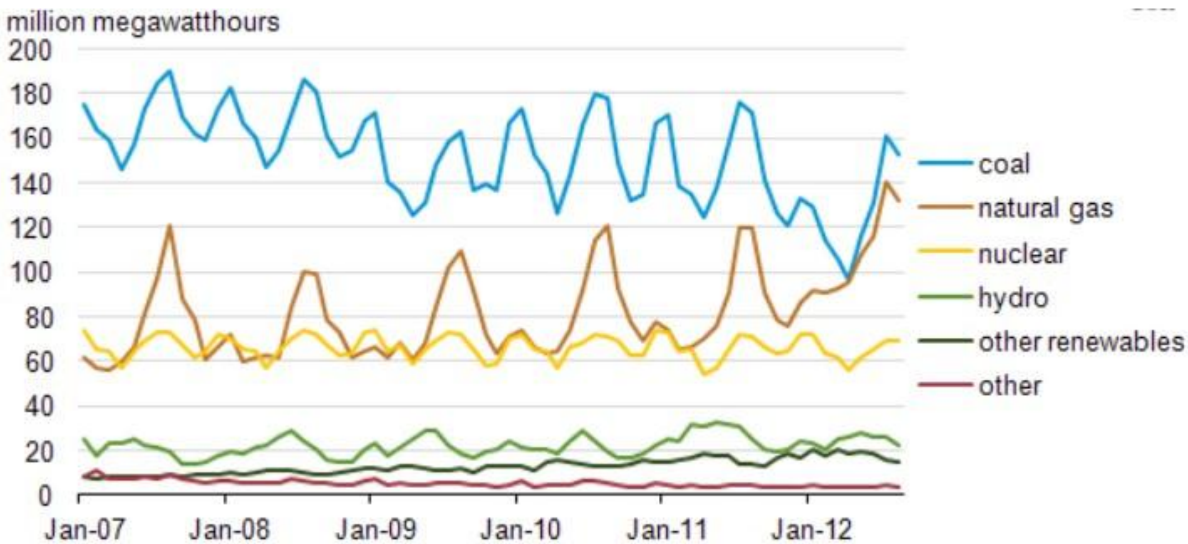
As noted above, lower natural gas prices also affect the share of renewables in the electric power fuel mix. Natural gas can be used by three generation technologies: natural gas combined cycle (NGCC) units, steam turbines, and gas turbines. Of these three technologies, NGCCs and steam turbines are usually used as base-load or intermediate-load units, while gas turbines are more likely to act as peaking units given their high flexibility (Massachusetts Institute of Technology 2009). Cheap gas could potentially displace both coal and renewables since it provides a cheaper fuel option for both base-load and peak generation. Meanwhile, low natural gas price would also make renewable generation more competitive by bringing down the cost of renewable–gas hybrid systems, in which intermittent renewable generation is backed up by flexible gas turbine generation. These two effects work in the same direction to displace coal generation, while having the opposite effects on renewables. Hence, the overall impact of cheaper natural gas on renewable generation depends on the characteristics of the power market, such as current capacity fuel mix, dispatching system, load characteristics and relevant regulations.

3.1. Historical Trends

Although not as coal-dominant as China’s power generation sector, US electricity generation has also relied largely on coal. Recently, however, low natural gas has given natural gas–powered generation a competitive advantage over coal-powered generation, and there has been an evident trend of fuel switching—from coal and other fuel sources to natural gas—in the electricity fuel mix. From 2008 to 2011, the annual share of coal generation dropped from 48.2

percent to 42.3 percent, whereas the share of natural gas generation increased from 21.4 percent to 24.8 percent, and the share of renewable generation[3] increased from 9.2 percent to 12.7 percent (EIA 2012b). In fact, the share of coal in monthly generation dropped to the same level of natural gas generation for the first time in April 2012 (EIA 2012c).[4] See Figure 4. Recent statistics indicate that the share of coal in annual generation hit a low level of 36 percent as of August 2012 (Logan et al. 2012).

Figure 4. US Monthly Net Electric Power Generation by Fuel Sources



Source: EIA 2012c.

Average real electricity prices declined moderately from 2008 to 2011 as a result of the economic downturn, energy efficiency improvements, and changed supply scenarios. After adjusting for inflation, average electricity prices decreased by about 2 percent from 2008 to 2011, from 8.97¢/kWh to 8.81¢/kWh, both measured in 2005 dollars. Among the four end-use sectors, the residential sector faced the highest electricity prices in 2011, at an average of 11.8 cents per kWh. The residential sector was also the only end-use sector to see a slightly higher real electricity price in 2011 compared to 2008. The other three sectors (commercial, industrial,

[3] Renewable generation includes traditional hydroelectric power as well as biomass, geothermal, solar, and wind generation.

[4] Note that this does not necessarily indicate an equal share of coal and natural gas in *annual* generation in 2012. This is because natural gas generation fluctuates a lot across different seasons of the year and is highly concentrated in the summer, when the peaking generators powered by natural gas are used to meet the high demand.

and transportation) experienced a drop in electricity prices during the time period, with a decrease of 5 percent, 3 percent, and 6 percent, respectively, from 2008 to 2011 (EIA 2012b).

Generation fuel mix changes have also led to changes in greenhouse gas (GHG) emissions from electricity generation, which accounts for about 40 percent percen of total carbon dioxide (CO_2) emissions in the United States. The CO_2 emissions from electricity generation, after fluctuating in the range of 2,346 to 2,413 million metric tons from 2005 to 2008, dropped by 9.09 percent to 2,146 million metric tons in 2009, which was then followed by a slight increase to 2,258 million metric tons in 2010. Total fossil fuel–based CO_2 emissions from all end-use sectors followed a similar pattern, with a significant drop from 5,572 million metric tons of CO_2 in 2008 to 5,206 million metric tons in 2009 and a minimal increase from 2009 to 2010 (US Environmental Protection Agency [EPA] 2012).

To examine what might happen in the future, the following subsections review results from Resources for the Future's (RFF's) Haiku electricity model and EIA's National Energy Modeling System (NEMS) model of the US energy economy for quantitative forecasts of the effects of cheap natural gas on the electricity sector.

3.2. Modeling Future Electricity Sector Impacts: Haiku Model Simulation

RFF's Haiku model is a partial equilibrium simulation model that solves for equilibrium outcomes in the US electricity market. RFF researchers recently used Haiku to analyze several relevant scenarios that include different combinations of forecasts of natural gas supply and electricity demand (Burtraw et al. 2012). The scenarios most relevant to this paper include the following.

1. *Cheap Gas*. This scenario reflects EIA's AEO 2011 projections of both electricity demand and natural gas supply.
2. *Expensive Gas*. This scenario uses the same AEO 2011 projection of electricity demand but substitutes EIA's projections of natural gas supply made in AEO 2009, which are much smaller. From AEO 2009 and AEO 2011, the unproved technically recoverable shale gas resource estimate increased by more than three-fold from 267 Tcf to 827 Tcf (EIA 2012a). Relative to the *Cheap Gas* scenario, this scenario shows the effect on the electricity sector of lower natural gas supply and higher natural gas wellhead prices.

Haiku can be calibrated to different levels of electricity demand and natural gas supply, such as the AEO forecasts described above. However, Haiku outcomes can vary from these forecasts according to information and policies represented in the model. Other model characteristics, such as data about the existing generation fleet, assumptions about new generating capacity, and current regulatory structures and pollution policies, remain the same for the two scenarios modeled. In these two scenarios, the Clean Air Interstate Rule is assumed to remain in place.

Natural Gas Price

Delivered and wellhead prices of natural gas appear in Table 1. Under the forecast of lower natural gas supply in the *Expensive Gas* scenario, natural gas prices increase substantially. For example, in 2020, the delivered price is roughly 35 percent higher than in the *Cheap Gas* scenario. The differences in wellhead prices are even larger at about 45 percent.

Table 1. Natural Gas Price Projections Using Haiku

	Cheap Gas			Expensive Gas		
	2013	2016	2020	2013	2016	2020
Delivered Price of Natural Gas (2009 $ per mmBtu)	4.6	4.6	4.9	5.4	5.9	6.6
Percentage Difference				17.4%	28.3%	34.7%
Wellhead Price of Natural Gas (2009 $ per Mcf)	4.0	4.2	4.4	5.1	5.6	6.4
Percentage Difference				27.5%	33.3%	45.5%

Source: Burtraw et al. 2012.

Generation Mix

Figure 5 shows the modeling results on generation mix at the national level, in cost-of-service regions, and in competitive market regions.[5] As Figure 5 shows, more electricity is generated from natural gas under the *Cheap Gas* than the *Expensive Gas* scenario. This trend is

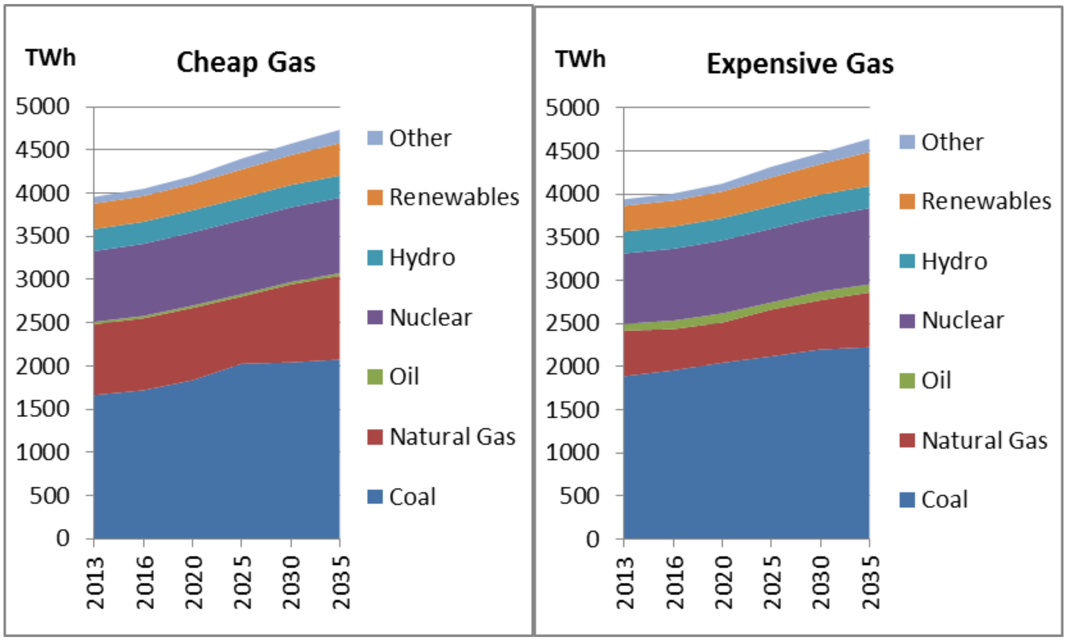
[5] The United States wholesale electric market experienced a deregulation and restructuring reform starting in the 1990s. About two-thirds of the US electricity load is served by independent system operators (ISO) or regional transmission organizations (RTO) at competitive markets. Other regions remain in a cost-of-service pricing regime. In a deregulated market, electricity suppliers are selected following an ascending order of production cost through a competitive bidding process, and the wholesale market price is set by the bidding input from the marginal generating unit. In the cost-of-service regions, prices are regulated based on the average cost of service and are adjusted to allow for a reasonable rate of return for investors (Pacific Northwest National Laboratory 2002; Federal Energy Regulatory Commission 2012).

most pronounced in competitive regions. In all of the *Cheap Gas* scenarios, increased natural gas generation leads to a decrease in consumption of the other fossil fuels, such as coal and oil. While expanded supply of natural gas could have mixed effects on renewables, the modeling results show that, by 2035, renewable generation is projected to be about 5 percent lower in the *Cheap Gas* scenario compared to the *Expensive Gas* scenario. Such an overall “crowding-out” effect of cheap natural gas on renewables is consistent with the dominant industry view and supports the concerns of environmentalists that shale gas might hurt the market share of renewables.

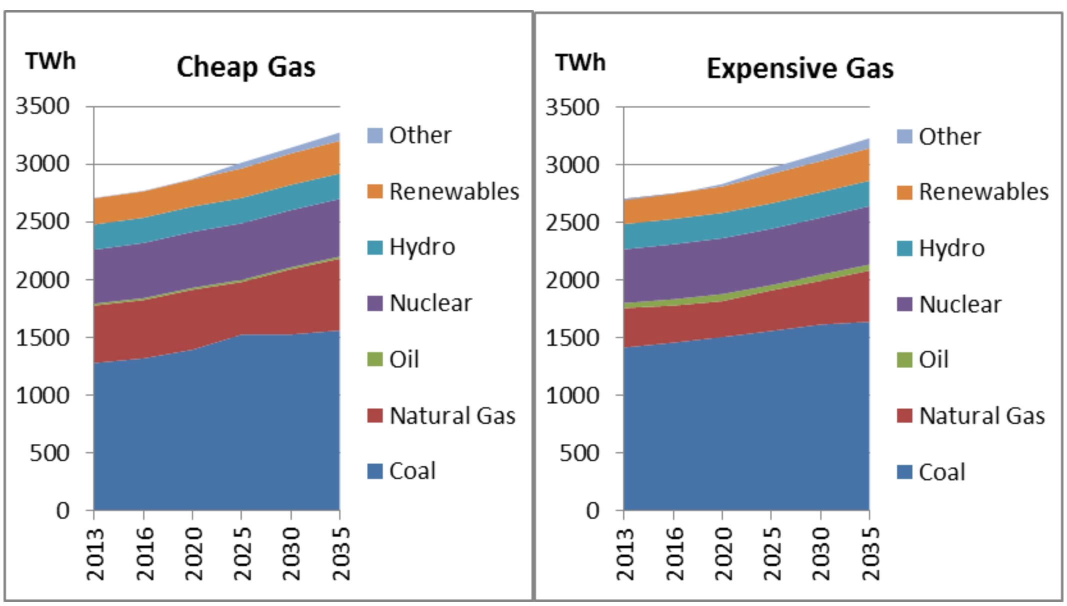
Electricity Price

Modeling in Haiku indicates that the forecasted high levels of supply of domestic natural gas will continue to substantially reduce retail electricity prices over the next 20 years, as shown in Figure 6. The trajectory of average electricity prices over the simulation time horizon under each scenario is shown in Figure 6 at national level, for the cost-of-service regions, and for competitive regions. Nationally and in both types of region, the *Expensive Gas* scenario forecasts that natural gas supply leads to higher electricity prices than in the *Cheap Gas* scenario. These effects are largest in the competitive regions, where projected average electricity price for the year 2020 is 9.6 percent higher under the *Expensive Gas* case compared to the *Cheap Gas* case, while the cost-of-service regions see a smaller price difference at about 3.6 percent in 2020. At the national level, average electricity price in 2020 is projected to climb by about 5.7 percent moving from the *Cheap Gas* to the *Expensive Gas* case.

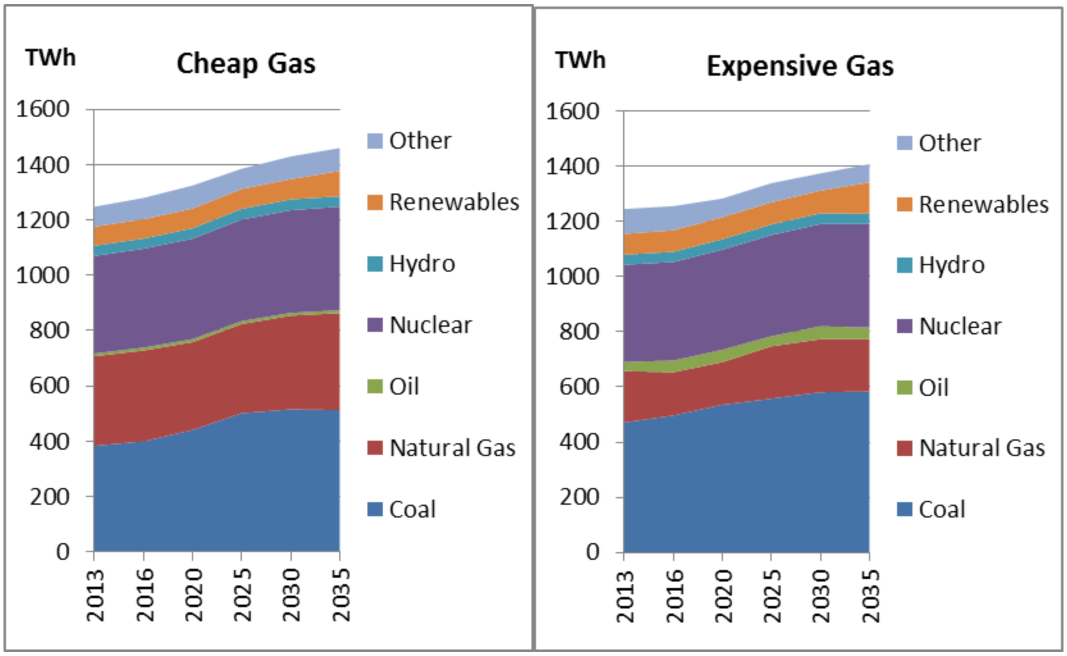
Figure 5. Projected Fuel Mix in Electric Power Generation in the United States
Panel A. National



Panel B. Cost-of-Service Markets

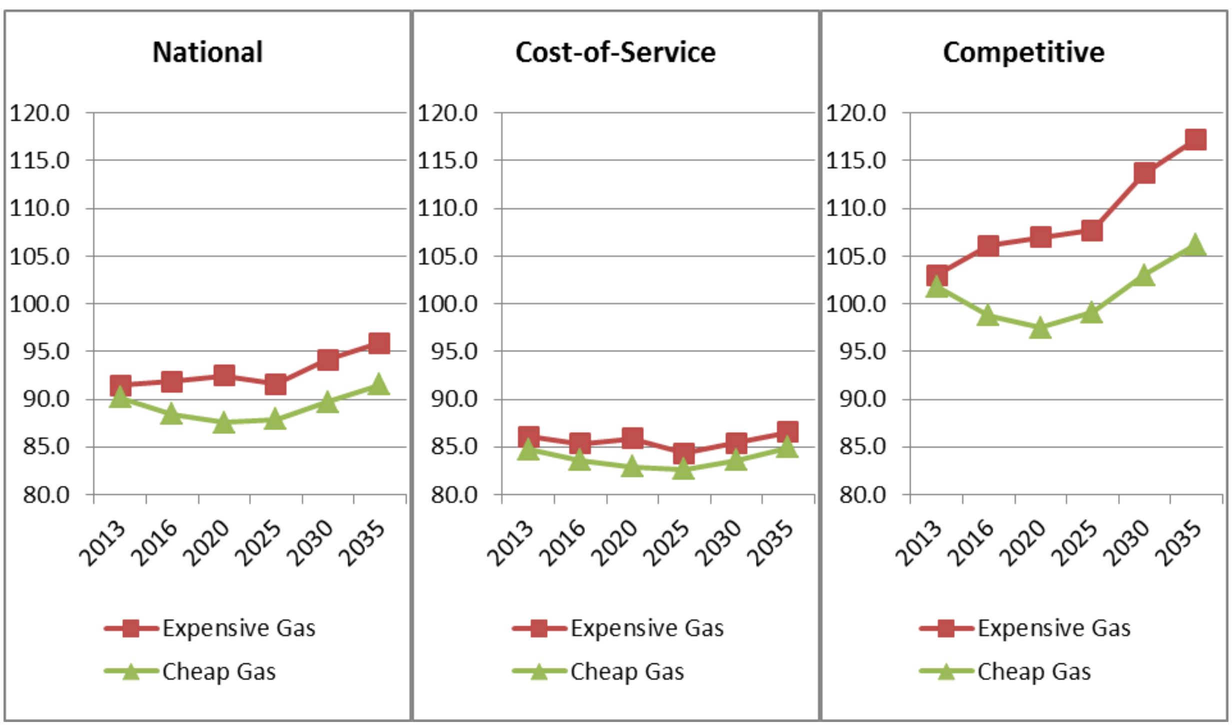


Panel C. Competitive Markets



Source: Burtraw et al. 2012.

Figure 6. Electricity Prices (2009$/MWh) Projected by Haiku



Source: Burtraw et al. 2012.

The pattern described above also holds for the electricity prices facing each customer class (residential, commercial, and industrial), with the *Expensive Gas* scenario forecasting increasing prices. At the national level, the percentage difference is the largest for the industrial users (6.8 percent in 2020), followed by commercial users (5.7 percent in 2020) and residential users (4.6 percent in 2020). For each of the customer classes, competitive regions are projected to see a larger fall in electricity prices compared to cost-of-service regions. Industrial users at competitive markets will probably enjoy the greatest benefit from cheaper electricity, for whom the percentage difference in electricity price is projected to be as much as 14.5 percent in 2020.

Electricity Consumption

Electricity consumption under the two scenarios for the year 2020 is shown in Table 2. This table includes a breakdown of consumption by customer class and electricity market regulatory structure. Given higher gas and electricity prices under the *Expensive Gas* scenario compared to the *Cheap Gas* scenario (as described above), consumers respond by using less electricity in the former scenario. Similar to the effects on electricity price, such effects are the most prominent for industrial users and competitive regions.

GHG Emissions from the Electric Power Sector

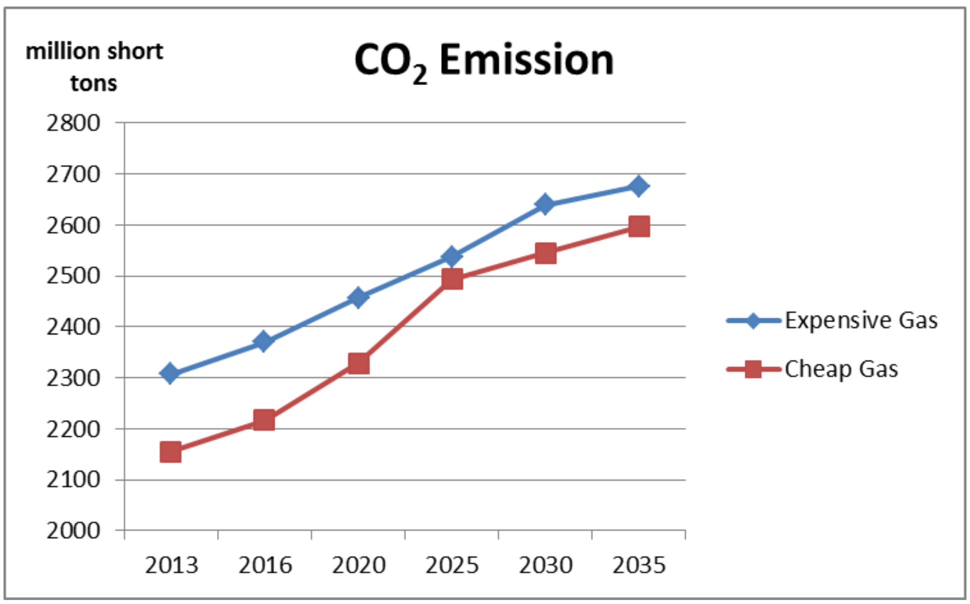
As shown in Figure 7, the increased use of natural gas in the *Cheap Gas* scenario reduces CO_2 emissions from electricity generation by about 6.6 percent compared to emissions under the *Expensive Gas* scenario. Total CO_2 emissions from the electricity sector will reach 2,676 million tons and 2,579 million tons by 2035 in the *Expensive Gas* and *Cheap Gas* scenarios, respectively.

Table 2. Projected Electricity Consumption (TWh) in 2020 by Haiku

	Cheap Gas	Expensive Gas	
	2020	2020	% difference
National			
Total	3,952	3,869	−2.1%
Residential	1,379	1,361	−1.3%
Commercial	1,511	1,488	−1.5%
Industrial	1,061	1,020	−3.9%
Cost-of-Service			
Total	2,699	2,657	−1.6%
Residential	958.2	948.0	−1.1%
Commercial	1,002	988.0	−1.4%
Industrial	739.5	721.1	−2.5%
Competitive			
Total	1,252	1,212	-3.2%
Residential	421.2	412.7	−2.0%
Commercial	509.5	500.0	−1.9%
Industrial	321.7	299.2	−7.0%

Source: Burtraw et al. 2012.

Figure 7. CO_2 Emission from Electricity Generation



Source: Burtraw et al. 2012.

3.3. Modeling Future Electricity Sector Impacts: NEMS Model Simulation

EIA's projections in its AEO are generated using the NEMS, a modular system developed to model the economic activities in various sectors (residential, commercial, industrial, transportation, electricity, and others) involving various energy fuels (petroleum, natural gas, coal, and others) in the United States. It is a market-based system subject to current regulations and has the capability to represent regional differences by running a variety of component models at different regional levels.

EIA produces a reference case and a number of side cases, which represent different views of the future. What is of interest here is the uncertainty around the supply of shale gas resources, which is measured by technically recoverable resources (TRR). The remaining unproved TRR for a shale gas play depends on various factors, including land area, well spacing, percentage of area untested, percentage of area with potential, and estimated ultimate recovery (EUR)[6] per well. In AEO 2012, two EUR sensitivity cases and a high TRR case combining high EUR with a high well spacing assumption were created to examine the impacts of the size variation of the shale gas resource base. Note that "these High and Low EUR cases are not intended to represent a confidence interval for the resource base, but rather to illustrate how different EUR assumptions can affect projections of domestic production and prices" (EIA 2012a, p. 59). NEMS scenarios referenced in this paper (EIA 2012a) include the following.

1. *Reference* Case. The total shale gas unproved TRR assumption in AEO 2012's *Reference* case is 482 Tcf (as of 1/1/2010), with the EURs for selected shale gas plays assumed to vary from 0.34 Bcf/well (Caney Play) to 2.89 Bcf/well (Woodford Play).
2. *Low EUR* Case. In this case, the EUR per shale gas well is assumed to be 50 percent lower than in the *Reference* case, which brings the total shale gas TRR down to 241 Tcf.
3. *High EUR* Case. In this case, the EUR per shale gas well is assumed to be 50 percent higher than in the *Reference* case, which brings the total shale gas TRR up to 723 Tcf.
4. *High TRR* Case. In this case, the EUR per shale gas well is assumed to be 50 percent higher than in the *Reference* case, and the well spacing for shale gas plays is assumed

[6] EUR is an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. EURs vary widely across plays and within a play. "For every AEO, the EUR for each sub-play is determined by fitting a hyperbolic decline curve to the latest production history" (EIA 2012a, p. 57).

to be 8 wells/square mile, rather than a play-specific average well spacing ranging from 2 to 12 wells/square mile, as in the *Reference* case, which brings the total shale gas TRR up to 1,091 Tcf.

Natural Gas Price

Table 3 gives the projected delivered prices of natural gas for electricity generation in the above four cases presented in AEO 2012 (EIA 2012a). The electricity sector faces a relatively low delivered price compared to other end-use sectors. Starting from $5.25/Mcf in 2010, the delivered natural gas price for electricity generation drops to the lowest level at $4.58/Mcf (in 2010 dollars) in 2017 and reverses the trend afterward in the *Reference* case. A larger shale gas resource assumption leads to a lower delivered price projection in general, with the *High TRR* case predicting an even lower delivered price in 2035 compared to the 2010 price level.

Table 3. Projected Delivered Prices of Natural Gas for Electricity Generation

	Reference Case	Low EUR	High EUR	High TRR
Delivered Price in 2020 (2010$/Mcf)	4.83	5.43	4.36	3.46
Delivered Price in 2035 (2010$/Mcf)	7.37	8.11	6.16	4.61
Growth Rate (2010–2035)	1.4%	1.8%	0.6%	–0.5%

Source: EIA 2012a.[7]

Generation Mix

In the AEO 2012 *Reference* case, the gas-powered generation share is forecasted to grow from 24 percent to 28 percent in the 2010–2035 period, with the share of coal falling from 45 percent to 38 percent and renewables increasing from 10 percent to 15 percent. However, in both the *High EUR* and *Low EUR* cases, coal still has the largest generation share through 2035. Only when assuming a high EUR with high well spacing in the *High TRR* case does natural gas replace coal to become the largest source for electricity generation in 2035 (EIA 2012a). Table 4 gives the projected fuel mix in electricity generation in 2035 under different cases in AEO 2012. The share of natural gas generation is projected to be between 24 percent and 38 percent in 2035 across the four scenarios discussed above.

[7] EIA, "Natural Gas Supply, Deposition and Prices", *Annual Energy Outlook 2012* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=3-AEO2012&table=13-AEO2012&region=0-0&cases=htrr12-d050412a,leur12-d022212a,heur12-d022212a,ref2012-d020112c

Table 4. Projected Electricity Generation Fuel Mix in 2035 under Different Cases

Percentage of Generation	Reference Case	Low EUR	High EUR	High TRR
Coal	38.0%	40.0%	35.9%	30.1%
Natural Gas	28.0%	23.8%	31.3%	37.9%
Petroleum	0.6%	0.6%	0.6%	0.6%
Nuclear Power	17.8%	19.0%	17.3%	16.9%
Renewables	15.2%	16.2%	14.4%	14.1%
Other	0.4%	0.4%	0.4%	0.4%

Source: Authors' calculation based on information from EIA website.[8]

The recently released AEO 2013 (early release version) extends the projection horizon to 2040. In AEO 2013's early release, projections on natural gas production and consumption by power plants are both higher in the *Reference* case compared to AEO 2012. Natural gas is expected to account for 27 percent of electricity generation in 2020 and 30 percent in 2040 (EIA 2013).

Generation Capacity

In terms of changes in generation capacity, it is projected that 60 percent of added capacity between 2011 and 2035 in the US power market would come from natural gas–fired plants compared to 29 percent from renewables, 7 percent from coal, and 4 percent from nuclear in the *Reference* case. Natural gas–fired capacity is predicted to account for 47 percent of new additions in the *Low EUR* case and 66 percent in the *High EUR* case. In addition, 49 GW of coal-fired plants are projected to be retired through 2035 in the *Reference* case, while the *High EUR* case projects coal retirement by 2035 to be at a higher level of 55 GW (EIA 2012a). Besides the increased natural gas supply brought by shale gas drilling, other regulatory factors also contribute to make natural gas–fired plants more attractive to investors, including the environmental regulations on local air pollution, energy programs, and tax incentives at both the federal and state levels, and uncertainty about the future US climate policy.

Electricity Price

In EIA's *Reference* case, average real electricity prices decline through 2020 and increase afterward. As a result, real average electricity price is predicted to be 10.1¢/kWh (in 2010

[8] EIA, "Electricity Supply, Deposition, Prices, and Emissions", *Annual Energy Outlook 2012* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=6-AEO2012&table=8-AEO2012&region=0-0&cases=heur12-d022212a,leur12-d022212a,htrr12-d050412a,ref2012-d020112c

dollars) in 2035, 3 percent higher than the 2010 price level. A larger shale gas resource assumption lowers the future electricity price projection, with the electricity price in 2035 (in 2010 dollars) projected to be 10.5¢/kWh, 9.7¢/kWh, and 9.1¢/kWh for the *Low EUR*, *High EUR*, and *High TRR* cases, respectively (EIA 2012a).

Electricity Consumption

Table 5 gives the projected electricity consumption from all sectors under different shale gas resource base assumptions in AEO 2012 (EIA 2012a). Although the lower electricity price brought by a larger assumed shale gas resource base incentivize consumers to consume more electricity, the differences in electricity consumptions across different cases appear to be minimal given that electricity consumption is relatively inelastic to price change.

Table 5. Projected Electricity Consumption from All Sectors
(Unit: quadrillion Btu)

	Reference Case	Low EUR	High EUR	High TRR
Electricity Consumption in 2020	13.33	13.27	13.40	13.52
Electricity Consumption in 2035	15.06	14.97	15.17	15.33
Growth Rate (2010–2035)	0.7%	0.6%	0.7%	0.7%

Source: EIA 2012a.[9]

GHG Emissions from the Electric Power Sector

Table 6 gives the projected energy-related CO_2 emissions from the electric power sector under different shale gas resource base assumptions in 2020 and 2035 (EIA 2012a). A higher natural gas supply increases its share in the total generation, replacing more carbon-intensive coal generation and less carbon-intensive renewable generation at the same time. Besides, cheaper gas also leads to slightly higher electricity consumption, as shown above. With all these effects working together, the net effect of expanded gas supply will probably bring down the total GHG emissions from the power sector.

[9] EIA, "Energy Consumption by Sector and Source, United States", *Annual Energy Outlook 2012* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=6-AEO2012&table=2-AEO2012&region=1-0&cases=htrr12-d050412a,leur12-d022212a,heur12-d022212a,ref2012-d020112c

Table 6. Projected Energy-Related CO_2 Emissions from the Electric Power Sector

	Reference Case	Low EUR	High EUR	High TRR
Emissions in 2020 (million tons of CO_2 eq)	2067	2127	2026	1917
Emissions in 2035 (million tons of CO_2 eq)	2330	2340	2310	2173
Growth Rate (2010–2035)	0.1%	0.1%	0.1%	–0.2%

Source: EIA 2012a.[10]

3.4. Comparing Haiku and NEMS Forecasts

While based on different sets of supply and demand scenarios, both Haiku and NEMS modeling results show that: (1) the expanded natural gas supply will probably act to lower the delivered price of natural gas to the electricity sector, increasing the share of natural gas generation and decreasing coal and renewable generation shares in the coming decade; (2) lower electricity prices can be expected with a larger shale gas resource availability, accompanied by a slightly larger amount of electricity consumption; and (3) GHG emissions from the power sector would be reduced mainly by the increasing use of natural gas for power generation.

Given that Haiku and NEMS projections are based on different methodologies (although Haiku uses the current baseline information from NEMS[11]), we might expect their projection results to be very different. However, they are quite similar. Table 7 lists the reference case projections from Haiku[12] and NEMS for the year 2020.

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[10] See EIA, "Energy-Related Carbon Dioxide Emissions by Sector and Source, United States", http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=0-AEO2012&table=17-AEO2012&region=1-0&cases=htrr12-d050412a,leur12-d022212a,heur12-d022212a,ref2012-d020112c

[11] Haiku takes the baseline information from AEO 2011, whereas the NEMS projection presented here is taken from AEO 2012.

[12] Here we take the *Cheap Gas* case in Haiku as the reference case.

Table 7. Reference Case Projections by Haiku and NEMS (2020)[13]

	Haiku Projection by RFF	NEMS Projection by EIA
Delivered Natural Gas Price (2010$)	$5.11/ Mcf	$4.83/ Mcf
Electricity Price (2010$)	8.9¢/ kWh	9.6 ¢/ kWh
Electricity Consumption	3952 TWh	3906 TWh
CO_2 Emissions from Electricity Power Sector	2329 ton	2067 ton

Source: Burtraw et al. 2012; EIA 2012a.

4. The Transportation Sector

Unlike the electricity sector, the US transportation sector currently sees only a small proportion of its energy use coming from natural gas. In 2011, natural gas accounted for 3 percent of the total 27.0 quadrillion Btu of energy consumption for transportation, leaving petroleum the dominant fuel with a 93 percent share (Figure 2; EIA 2012b). Nevertheless, low natural gas prices coupled with relatively high oil prices have made natural gas increasingly attractive as a fuel choice for transportation.

Figure 8 plots the ratio of oil prices to natural gas prices on a per–energy unit basis, showing a rapidly rising ratio in the past few years that soared to 500 percent as of late 2011. While other factors affect the fuel prices paid by consumers at the pump (e.g., fuel taxes,[14] infrastructure cost, supplier competitiveness, and delivery and storage cost), the price gaps between compressed natural gas (CNG) and other alternative fuels at the retail level have also widened recently. Low gas prices have undoubtedly quickened the trend of shifting from oil-based fuels to gas-based fuels in the transportation sector.

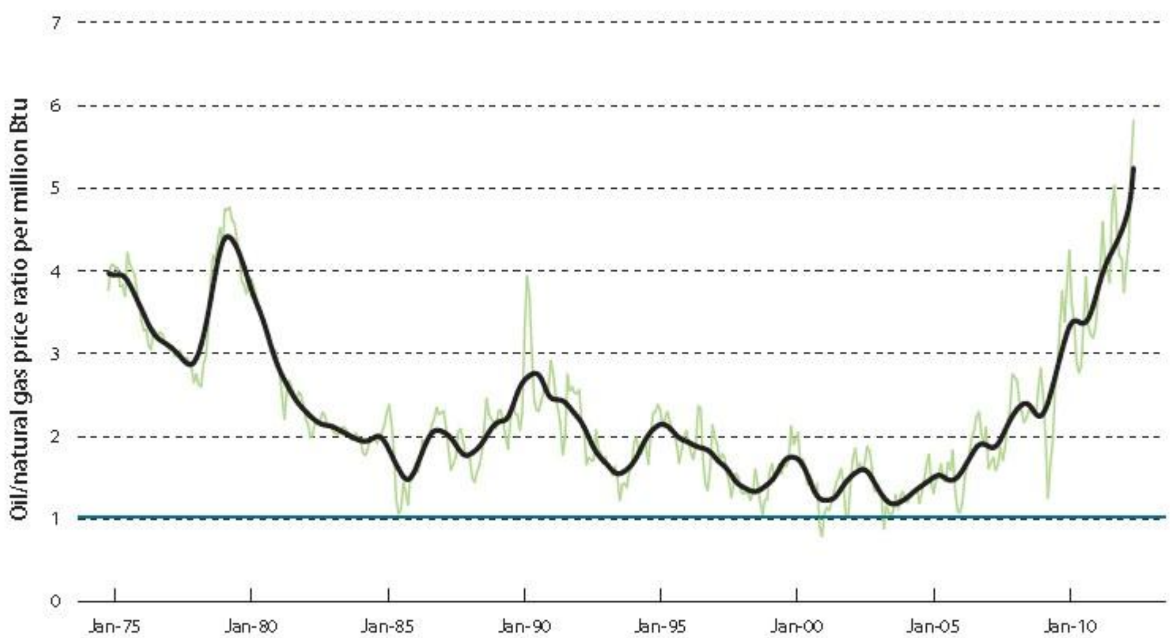
4.1. The Current Status of Natural Gas Use in Transportation

There are three basic ways for natural gas to replace oil for transportation use. First, natural gas can be converted to liquid fuels, such as methanol, ethanol, and diesel, through a gas-to-liquids (GTL) process, from which the liquid outputs can be burned in internal combustion engines with slight modifications. Second, CNG can be burned in light- and medium-duty natural gas vehicles (NGVs) or dual-fuel vehicles, which can run on either CNG or gasoline.

[13] Conversion rate: 1 Mcf natural gas = 1.027 mmBtu; 1 Quad = 293 TWh. Inflation rate for 2010: 1.6%.
[14] "Currently, on a Federal level, [compressed natural gas] is taxed at the same rate as gasoline on an energy-equivalent basis ($0.18 per gasoline gallon equivalent, or 0.21 per diesel gallon equivalent), while [liquefied natural gas] is taxed at a higher effective rate than diesel fuel" (EIA 2012a, p. 38).

Third, natural gas can be cooled and condensed into liquefied natural gas (LNG) that can then be used as a replacement for diesel, for use in heavy-duty trucks.

Figure 8. Ratio of Oil and Natural Gas Prices per Unit of Energy



Source: Knittel 2012.

Market Penetration of Natural Gas Vehicles

NGVs have been a part of global vehicle fleets for decades, with an estimated 14.8 million on the road worldwide.[15] The United States currently ranks 17th globally in the number of NGVs on the road, behind countries such as Iran, Pakistan, Argentina, Brazil, India, Italy, and China.[16] In the past, NGV penetration in the United States was limited for the most part to small market niches: medium- to heavy-duty fleet vehicles, such as buses or trash trucks, and single-unit delivery truck fleets, such as those from FedEx, UPS, AT&T (Taschler 2011), and others. Although between 1999 and 2009, US domestic consumption of natural gas in the transportation sector tripled (Bryce 2011), overall use in the transportation sector remains very small; in 2010, natural gas powered less than 0.4 percent of the 9 million heavy-duty vehicles (HDVs) on the

[15] Natural Gas Vehicles for America, http://www.ngvc.org/about_ngv/index.html
[16] Ibid.

road and accounted for 0.3 percent of total energy use by HDVs (EIA 2012a). In 2009, about 114,000 CNG vehicles were on the road, including passenger vehicles, public transit buses, and trucks, and about 3,000 LNG vehicles, most of which are heavy-duty trucks (Center for Climate and Energy Solutions [C2ES] 2012). Apart from the dedicated NGVs that run only on natural gas, the market offers bi-fuel vehicles, which have two separate fueling systems, enabling them to run on either natural gas or gasoline, and dual-fuels vehicles with fuel systems that run on natural gas and use diesel fuel for ignition assistance.[17]

Public transit buses are the largest natural gas consumers in the transportation sector, with about 20 percent of buses running on natural gas (C2ES 2012). Various public school districts have also converted their fleets to run on natural gas. For example, after taking part in a pilot alternative fuel vehicles project in the late 1980s, Tulsa Public School District in Tulsa, Oklahoma, now has a fleet of 190 CNG vehicles. In 2005, the Tucson Unified School District in Arizona purchased 70 new CNG buses. The Union of Concerned Scientists reports that 130 school districts in 17 states currently use alternative fuel buses, a large number of which run on natural gas (Union of Concerned Scientists 2004).

Considering light-duty vehicle (LDV) manufacturers, Honda plans to significantly expand the availability of its natural gas-fueled Civic from five to over three dozen states, a Hong Kong–based company plans to build CNG/gasoline/electric hybrids in the United States, and Chrysler is gearing up to produce natural gas–fueled LDVs. As for truck engines, competition with industry leader Westport is growing from companies such as Emission Solutions, Inc. (ESI).[18]

An absence of refueling infrastructure remains a significant impediment to broader penetration of NGVs in the United States, particularly outside of fleets that refuel in central locations. Trucks and buses often travel predictable routes and are stored in common areas, meaning that the infrastructure for a CNG fleet can be concentrated in certain specified areas, so long as they are near gas pipelines, whereas the widespread use of CNG in passenger cars would require a much more extensive and costly refueling infrastructure (Alternative Fuels and Advanced Vehicles Data Center [AFDC] 2011). As of May 2012, 1,047 CNG fueling stations

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[17] Natural Gas Vehicles for America, http://www.ngvc.org/about_ngv/index.html

[18] ESI has recently developed the natural gas–fueled Phoenix 7.6L, a 300-horsepower rework of the heavy-duty Navistar MaxxforceDT diesel engine. Currently, ESI has plans to begin sales of the 375-horsepower Phoenix 9.3L, project development on the T444E 7.3L, and research and development on a 475-horsepower Phoenix 13L in the third quarter of 2011 (Turner 2010).

and 53 LNG fueling stations were in the United States, compared to 157,000 gasoline fueling stations nationwide in 2010. According to EIA (2012a), 53 percent of the CNG stations and 57 percent of the LNG stations are privately owned and not open to the public, and many of the public and private stations are concentrated in a few states like California. Accordingly, access to refueling infrastructure remains an obstacle in most parts of the United States. Part of the infrastructure challenge is the "chicken-and-egg" problem: vehicle users will not buy NGVs until they believe there are enough refueling stations, but motivation to build an NGV refueling infrastructure will be limited until a sufficient number of vehicle owners demand the fuel. Both the private and public sectors are working to address this issue, however, as described briefly below.

Gas-to-Liquids

Through GTL technology, natural gas can be converted into diesel and gasoline, which can then be burned in traditional internal combustion engines. The conversion rate of current technology needs around 10 Mcf of natural gas as input for a barrel of oil-equivalent product. Assuming a $4/mcf gas price, this translates into a cost of $40/barrel oil-equivalent (C2ES 2012). However, the high up-front capital cost of about $10 billion for a 100,000-bbl/day plant (Lipschultz 2012) remains a major issue for GTL projects. The use of GTL fuel in transportation remains limited since only a handful of GTL plants are operating commercially in Malaysia, South Africa, and Qatar today, and these plants are producing less than 1 percent of global diesel demand. Nonetheless, the increasing availability of cheap gas has driven Sasol (a South African company) to announce plans to build the first GTL plant in the United States in Louisiana with a total investment of $14 billion (Broder and Krauss 2012); this plant is expected to come online in 2017 and to be fully operational in 2018. Shell also has a proposed GTL plant expected to come online in 2019. These proposed projects may add a total of 17 Tcf of gas consumption in the period 2018–2035 (Lipschultz 2012), the products of which are expected to partly replace the use of petroleum-based diesel fuel in the future.

Natural gas can also be converted into methanol or ethanol, which can be combined with gasoline in various fractions to create an alternative fuel. Common blends include E85 (85 percent ethanol, 15 percent gasoline) and M85 (85 percent methanol, 15 percent gasoline); these blends are currently usable by the 10 million flexible fuel vehicles on the road in the United States. Conversion kits are also available to allow standard internal combustion engine vehicles to run optimally on these blends.

Forthcoming research (Fraas et al. 2013) indicates that, even incorporating the cost of a conversion kit, the wider use of E85 in passenger vehicles may make strong economic sense, given current fuel price differentials. This is based on estimates of the cost of producing ethanol (and eventually E85) from natural gas, using Celanese Corporation's "TCX" process. As more details become available about the costs of this process, the use of blended fuels may very well look increasingly promising to consumers.

Federal and State Efforts

The federal government has been trying to stimulate the use of natural gas in transportation through a series of subsidy programs. The Energy Tax Policy Act of 2005 (PL 109–58) provided an income tax credit for the purchase of a new, dedicated alternative fuel vehicle of up to 50 percent of the incremental cost of the vehicle, plus an additional 30 percent if the vehicle met certain tighter emission standards. These credits ranged from $2,500 to $32,000 depending on the size of the vehicle. However, the credit was effective only on purchases made after December 31, 2005, and expired on December 31, 2010.[19] In August 2009, the US Department of Energy (DOE) announced that funding for natural gas technologies and fueling stations would be included in a $300 million grant under the American Recovery and Reinvestment Act for state and local governments (PL 111–5). A more recent legislative effort was the House of Representatives 1380 bill, the New Alternative Transportation to Give Americans Solutions (NAT GAS) Act in 2011.[20] This proposed legislation offers tax credits for new NGVs at the retail and manufacturing ends, commercial and residential refueling infrastructure, and the gas itself.[21] However, the NAT GAS Act was rejected by the Senate in March 2012.

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[19] PL 109–58 also provided for a tax credit of 50¢ per gasoline gallon equivalent of CNG or liquid gallon of LNG for the sale of CNG and LNG for use as a motor vehicle fuel. The credit began on October 1, 2006, and has recently expired. Note that this rebate (which is over twice the excise tax rate paid now), was to the seller, not the buyer. It is not clear if this could have been paid to the ultimate seller—in which case an owner of a trucking company could have qualified for the rebate—or to the wholesaler.

[20] Available at http://www.govtrack.us/congress/bill.xpd?bill=h112-1380.

[21] Specifically, the NAT GAS Act offers (1) a tax credit for new NGV purchases, up to 80% of the price differential, which translates to a maximum of $7,500 for LDVs and $64,000 for HDVs; (2) an infrastructure tax credit of 50% of the cost of a new station, up to a maximum of $100,000; (3) an extension of the 50¢ per gallon fuel tax credit; (4) a $2,000 tax credit to home refueling units; and (5) a tax credit to NGV manufacturers. This bill currently has bipartisan support and has been referred to the House Energy and Commerce Committee (Gray 2011).

At the federal level, in August 2011, EPA and the US Department of Transportation's (DOT's) National Highway Traffic Safety Administration adopted the first-ever program to reduce GHG emissions and improve fuel efficiency of medium-duty vehicles and HDVs, where NGVs and other alternative fuel vehicles were credited based on their GHG emission reduction potentials (EPA and DOT 2011). In March 2012, President Obama announced a new $1 billion National Community Deployment Challenge to "spur deployment of clean, advanced vehicles in communities around the country (White House 2012, p.1)." This "fuel-neutral" proposal includes electrification, natural gas, and other alternative fuels. The program also seeks to develop up to five regional LNG corridors to increase NGV deployment (White House 2012).

States and localities have also intervened. Due in part to air quality management district regulations, 65 percent of all South Coast Air Basin transit buses are now fueled by natural gas. The San Pedro Bay Clean Air Action Plan, approved in late 2006, includes a program to replace all diesel trucks based in the ports of Los Angeles and Long Beach with clean alternatives, such as LNG-fueled vehicles (including LNG-fueled 18-wheelers), within five years (Port of Los Angeles and Port of Long Beach 2011). Currently, 879 natural gas–fueled trucks are in the Drayage Truck Registry, which represents 7 percent of container trips in San Pedro Bay (CAAP 2011). Pennsylvania, a state with significant shale gas reserves, introduced a package of legislation aimed at providing $47.5 million in tax incentives, grants, and loans to promote investment in natural gas truck and bus fleets for municipalities and businesses.[22]

Regional efforts are also in place to address the chicken-and-egg problem by incentivizing or providing refueling infrastructure. Utah has been promoting the use of NGVs, including private automobiles, by working with a local gas utility to build the fueling infrastructure. Trailing only California and New York, Utah currently is one of the top states in terms of the number of CNG refueling stations, with 73 (AFDC 2011). In Colorado, the city of Grand Junction opened its first CNG refueling station in April 2011, completing a chain of CNG stations from California to Denver (Cianca 2011). Texas is building refueling stations between Dallas, San Antonio, and Houston under the Texas Clean Transportation Triangle strategic plan. Similar efforts are also under way in the western coast area (the Interstate Clean Transportation Corridor) and Pennsylvania (the Pennsylvania Clean Transportation Corridor) (EIA 2012a).

[22] The Marcellus Shale Coalition, a natural gas trade group in Pennsylvania, released a study in April 2011 to spearhead a campaign for 17 new refueling stations statewide and subsidies for a proposed 850 new natural gas HDVs for an estimated $208 million (Gladstein, Neandross & Associates 2011).

Private Efforts

Private corporations are playing an important role in promoting natural gas use for transportation, without government subsidies. The most important example is an effort spearheaded by Chesapeake Energy's $150 million commitment, collaborating with GE, Clean Fuels, and Pilot Flying J truck stops to develop 150 CNG and LNG refueling stations on Pilot Flying J footprints on US interstates (150 stations in all). GE will provide modular and standardized CNG compression stations, called "CNG In A Box™."[23,24] Private–public efforts to reduce the cost of home CNG refueling stations from their current cost of $4,000 are also ongoing (Lipschultz 2012).

4.2. The Current Economics of NGVs versus Gasoline- or Diesel-Fueled Vehicles

The future role of natural gas in the US transportation fuel mix depends on the attractiveness of NGVs, compared to their alternatives, to consumers and policymakers. In this section, we investigate the evidence for and against NGVs as a reasonable option to their closest alternatives in the United States, focusing primarily on (1) LDVs running on CNG compared to conventional gasoline vehicles and electric hybrids and (2) heavy-duty trucks running on LNG compared to diesel trucks. Many of the comparisons are based on several original analyses, using data from the NEMS–RFF model, automobile manufacturers, and other key sources.

The results suggest that, under reasonable conditions, LNG heavy-duty trucks have attractive payback periods even without government subsidies. Infrastructure issues may be less challenging than commonly thought because the interstate trucking industry is moving increasingly from a long-haul route structure to a "hub and spoke" structure—a development that could facilitate more judicious placement of LNG refueling stations and therefore make use of LNG trucks more prevalent (Taylor et al. 2006).[25] Furthermore, as noted above, efforts by Shell Oil and Chesapeake Energy to build LNG refueling infrastructure represent a very positive and subsidy-free development. CNG as a fuel for LDVs remains a tough sell without policies in place that price carbon or otherwise favor natural gas over oil.

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[23] "GE and Chesapeake Energy Initiative Targets Natural Gas Fueling Infrastructure Development", *NGV Global News*, http://www.ngvglobal.com/ge-and-chesapeake-energy-initiative-targets-natural-gas-fueling-infrastructure-development-0309

[24] Chesapeake Energy Corporation, "Transform US Transportation Fuels Market and Increase Demand for US Natural Gas", http://www.chk.com/About/BusinessStrategy/Pages/Increase-Demand.aspx

[25] See http://scm.ncsu.edu/public/lessons/less031014.html for a discussion of this system for major retailers in the United States.

Table 8. Salient Differences between NGVs and Alternatives

Characteristic	Civic Natural Gas	Civic Gasoline	Civic Electric Gasoline Hybrid
MSRP (comparably equipped)	$26,240	$19,905	$24,700
Subsidy (eliminated January 2011)	$4,000	0	0
5-Year Maintenance and Repair	$3,321	$2,145	$2,340
Combined Fuel Economy (mpg)	28	29	41
Fuel Capacity (gge)	7.8	13.2	12.3
Range (mile)	218	383	504
Cargo Volume (ft^3)	6	12	10.4
Availability	50 states	50 states	50 states
Total Costs/Year Differential (without infrastructure)	$200	-	$400
Total Costs/Year Differential (with infrastructure)	$721	-	$400
With $2,000 Infrastructure Subsidy and $4,000 Vehicle Subsidy	($100)	-	$400

Note: gge, gallons of gasoline equivalent. Source: Honda website: http://automobiles.honda.com/tools/compare/.

Light-Duty Vehicles

Table 8 displays the relative differences in characteristics and costs among Honda's 2011 model year NGV (the Civic GX Sedan), a comparably equipped Honda Civic Sedan (the LX-S automatic transmission), and the Civic Hybrid (CVT AT-PZEV). Without a subsidy (the appropriate way to compare the costs of vehicles from society's point of view), the NGV is more expensive than the hybrid, but substantially (32 percent) more expensive than the gasoline version. Its maintenance and repair costs are also more expensive than those for the other vehicles, over 50 percent more than the gasoline-powered version.[26] The fuel economy for the NGV is about the same as that of the gasoline alternative (and of course far lower than the hybrid).

Assuming a $1.50 gallon of gasoline equivalent advantage for natural gas over gasoline, seven years of annualization, and a 6 percent interest rate, and without counting infrastructure cost or any subsidies, we found that a natural gas LDV is almost $200 more expensive annually

[26] These estimates are taken from Honda's own website. A similar comparison (Goulding et al. 2011) uses information from a Kansas Gas Service website, which asserts that "Some fleet operators have reduced maintenance costs by as much as 40 percent by converting their vehicles to CNG" (http://www.oneok.com/en/KGS/CustomerCare/BusinessDevelopment/NaturalGasVehicles.aspx).

than its gasoline-fueled counterpart. Infrastructure costs for the NGVs must be considered, however, under the assumption that individuals will not purchase such vehicles unless they have access to a home fueling unit and already have natural gas in their homes. These units cost $4,000 currently. We assume they last 10 years and amortize their costs at the same 6 percent interest rate.[27] Adding this annual amount to the annual cost of an NGV raises its cost premium over a gasoline-fueled counterpart from $200 to $721.

From an individual's perspective, we need to consider the $4,000 subsidy for the investment cost (which ran out at the end of 2010, but may be reinstated by federal legislation currently under consideration), the $2,000 subsidy for home charging stations, and the annual cost of the loan (which we assume is for a five-year period). After these adjustments, amortized costs are about $100 less than a gasoline vehicle. As noted above, however, NGVs have much lower range, less trunk space, and, in almost all US locations, could not reliably be used for long-distance travel because home refueling would be impossible. It remains to be seen if these restrictions are worth more to consumers than $100 per year.

Heavy-Duty Trucks

The 2011 national average retail price of diesel fuel was $3.84/gallon, and the average nationwide nominal retail price was $3.05 per diesel gallon equivalent (dge) for LNG and $2.32/dge for CNG, which indicates a price differential of about $0.80/dge for diesel-fueled HDVs (EIA 2012a).[28] In California, where truckers can fill up with LNG at several stations, LNG is $0.75 per diesel gallon equivalent cheaper than diesel for an independent trucker and $1/gallon cheaper for a fleet vehicle.[29] Indeed, when oil prices were at their highest in 2008 and diesel was $4.75/gallon, LNG was $2/gallon cheaper than diesel, even though natural gas was priced relatively high at $11–$13/mcf of gas (EIA 2008).

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[27] Honda Corporation also notes (personal communication) that high water content in the natural gas and low compression by home refueling units raises risks of fuel fouling in CNG engines.

[28] Irrespective of these price differentials, it is appropriate to consider any tax benefits for natural gas over diesel. Currently, no such benefits are available. Until the end of 2009, LNG sellers were eligible for a credit of 50¢/gallon from the federal government (and some state programs provide per-gallon credits against excise taxes). It is likely that some of these benefits would have been passed on in lower fuel prices.

[29] Interview with Mitchell Pratt, Clean Energy Inc., November 17, 2009.

Table 9 gives the major assumptions used in our analysis while comparing natural gas–powered heavy-duty trucks with their diesel-powered counterparts. According to estimates available online and provided in conversations with experts, the differential ranges from $70,000 to $100,000 (for early models) more than the price of a diesel truck of about $100,000.[30] Detailed information on vehicle prices puts the cost differential at $70,000 for a Westport compression-type LNG engine, with a newer technology relying on an 85 percent LNG/15 percent diesel fuel mix, selling for only $35,000–$40,000 above its diesel counterpart.[31] The price differential for a smaller version of the Class 8 truck (termed a "Baby 8") or a Class 7 truck (both using spark plug technology) is around $40,000.

Table 9. Assumptions for Comparing Natural Gas Heavy-Duty Trucks with Diesel Trucks

Price Differential between LNG and Diesel	**$0.50/dge, $1.00/dge, and $1.50/dge**
Investment Cost Differential	$35,000, $70,000, and $100,000
Fuel Economy	Diesel (Class 8): 5.1 mpg (2007)[32]; LNG: 4.6 DEG to 5.6 DEG[33]
Vehicle Miles Traveled	70,000 miles/year[34] to 125,000 miles/year[35]
Vehicle Lifetime	15 years[36]
Interest Rate	31%[37], 10%, 5%[38]

Note: dge: diesel gallon equivalent.

30 Total Transportation Services recently purchased 22 additional Kenworth T800 LNG trucks to expand its fleet of 8 such trucks purchased six months before. This purchase suggests that fuel and maintenance costs are manageable (Kell-Holland 2009).

31 Interview with Michael Gallagher, Cummins Westport, November 2009.

32 FHWA (2008). This estimate was recently revised upwards to 6.0 mpg (FHWA 2009).

33 Interview with Mitchell Pratt, Clean Energy Inc., November 17, 2009.

34 FHWA (2008).

35 This is based on census data from 2002, which feature average vehicle miles traveled of about 90,000 miles per year and indicate that about one-third of the fleet drives 125,000 miles or more.

36 According to DOT, new combination trucks (Class 8) were purchased in 2007, with registrations in 2007 of 2.221 million combination trucks. Thus, new vehicles are 6.8% of the fleet. Assuming this is an equilibrium situation, where truck retirements and purchases are equal, truck life averages 14.7 years. Industry analysts offer 18–20 years as a realistic average for truck life (FHWA 2008).

37 This rate derives from actual market data showing that buyers demand a payback of investment costs through fuel savings within three to four years and that fuel savings during those first few years are discounted at 10%.

38 Social discount rates used to evaluate public projects are often in the range of 3% to 5%. Although the substitution of NGVs for diesel vehicles is not a public project, it can confer major public benefits in terms of emissions reductions and energy security. Thus, we make calculations with this rate to illustrate the efficiency of LNG truck subsidies or mandates from society's perspective, assuming complete market failure. An interest rate of 10% is added to reflect partial market failure.

The payback period estimates based on the assumptions above are shown in Table 10. To get to payback periods of two years or less—what is commonly believed to be what industry is looking for before it makes investments—for an investment cost difference of $70,000 and fuel economy of 5.1 miles per gallon equivalent, one needs fuel price differentials of around $1.50 per gallon equivalent, rates of interest used to evaluate multiyear fuel savings benefits of 10 percent or less, and vehicle miles traveled of around 125,000 per year. For lower-mileage trucks (90,000 miles per year), payback periods increase about a year. This finding indicates that the high-mileage part of the trucking fleet is most likely to be early adopters. Halving the fuel price differential more than doubles the payback period. Halving the investment cost differential more than halves the payback period (indicating the efficacy of rebates and subsidies). A 10 percent increase in fuel economy of the LNG truck, other things being equal, leads to about a 10 percent decrease in payback period at a fuel price differential of $1.50, but this improvement leads to much greater payback period reductions when the price differential is smaller (i.e., less advantage to LNG over diesel). For instance, at a price differential of only $0.75 per gallon equivalent, payback periods fall by about 20 percent to 25 percent. These results indicate the sensitivity of payback periods to price fluctuations.

Table 10. Sensitivity of Payback Periods to Assumptions

Vehicle Cost Differential:		**$35,000**			**$70,000**		
Fuel Economy (mpg):		5.6	5.1	4.6	5.1		
Vehicle Miles Traveled:		70,000			125,000	90,000	70,000
Interest Rate = 0.05	Fuel Price Diff. = $1.50	1.62	1.82	2.14	2.05	2.91	3.82
	Fuel Price Diff. = $0.75	3.04	3.82	5.54	4.33	6.29	8.52
	Fuel Price Diff. = $0.50	4.3	6.03	11.98	6.89	10.36	14.62
0.10	Fuel Price Diff. = $1.50	1.73	1.95	2.31	2.22	3.22	4.36
	Fuel Price Diff. = $0.75	3.39	4.36	6.74	5.03	7.9	11.96
	Fuel Price Diff. = $0.50	4.99	7.48	22.72	8.88	16.54	-
0.31	Fuel Price Diff. = $1.50	12.09	-	-	3.3	6.35	-
	Fuel Price Diff. = $0.75	-	-	-	-	-	-
	Fuel Price Diff. = $0.50	-	-	-	-	-	-

Other Considerations Affecting Cost

Even proponents of natural gas concede that NGVs face significant obstacles to capturing a major share of various market segments. Irrespective of vehicle type, observers have raised concerns regarding economics—NGVs cost more, although fuel costs are likely to be lower—as well as concerns about safety and the availability of refueling stations. There are also concerns about resale markets, which are an important part of the trucking industry and, if fueled by natural gas, require a denser refueling network than is likely to arise in the near term. In addition, for LDVs, cruising range, weight, and cabin space are subjects of concern. Because CNG has such a low energy density and is under pressure, fuel tanks are large and heavy compared to the other vehicle types (Table 8). Thus, cargo space is dramatically (50 percent) lower than that of a gasoline vehicle, as is its range of only 218 miles, compared to 383 miles for the comparable gasoline vehicle and 504 miles for the hybrid.

Notably, the estimates above do not directly account for safety and infrastructure costs. There are arguments on both sides of the safety issue: proponents, for example, suggest that the need to contain high pressures and keep temperatures low requires extremely robust tanks and other equipment that may make natural gas trucks safer in an accident than their diesel counterparts. Opponents refer to concerns about LNG storage facilities and their explosive potential. An independent review of safety concerns (Hesterberg et al. 2009, p. 20) finds that diesel buses have a “significant fire and safety advantage over CNG vehicles [buses].” Whether these conclusions would hold for LNG versus diesel trucks is unclear. A government source[39] focusing on CNG versus LNG concludes that the latter is less corrosive but cannot take an odorant, so leaks could go undetected longer, requiring methane detectors. With respect to LNG, the very cold temperatures required for storage mean that the storage systems require intensive monitoring for tank pressure and systems to vent the gas in an emergency. While the report indicates that rupturing of the tanks is extremely unlikely, it also says that any resulting fire will release 60 percent more heat than from an “equivalent” gasoline tank rupture. Refueling NGVs also requires additional precautions, and the rapid change in temperature from refueling can stress vehicle materials and components. The industry’s response to these points is basically that the fuel is safe if the proper procedures are followed.

In addition, even if the trucking industry had adequate refueling infrastructure for long-haul trucking, economic issues concerning lack of infrastructure appropriate to the truck resale market may remain. Trucks are sometimes taken out of the commercial trucking business and resold for use on farms and within cities after six to eight years of use. Without adequate infrastructure in rural and urban areas, this market could fail, effectively limiting the useful life of these trucks, both from a private and a social perspective.

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[39] See http://www.chebeague.org/fairwinds/risks.html, which is an excerpt from a report produced by the Federal Transit Administration’s Clean Air Program, Section 3.3.4 Liquefied Natural Gas.

4.3. Future Projections of NGV Penetration

Looking ahead, expected future new vehicle cost differentials may be lower. First, NGVs have not yet benefited from economies of scale as gasoline and diesel vehicles have, so costs might decrease significantly if demand for NGVs increases. Second, stricter standards on diesel emissions, which took effect in 2010, may raise prices on diesel vehicles. Furthermore, future costs are highly uncertain. Natural gas engine technologies are less mature than diesel and gasoline technologies, and it is uncertain which particular natural gas engine types will be most successful in the future.

For several reasons, the recent fuel price gap could remain or widen in the future. Greater accessibility and technological advances in recovering shale gas could keep prices of LNG stable or even drive them lower, while prices for oil and, therefore, diesel fuel are believed to be on an upward trend. A recent presentation by IHS Global Insight (2010) shows that, over the long term, the ratio of oil to gas prices may rise to about three to one between now and 2030. However, natural gas prices have a history of instability, and CNG has, at times, been more expensive per gallon equivalent than its diesel counterpart.

Table 11. Major Projections under Two Heavy-Duty NGV Cases in AEO 2012

	2010	HDV Reference Case (2035)	Heavy-Duty NGV Potential Case (2035)
Sales of New Heavy-Duty NGVs	860 (0.2%)	26,000 (3%)	275,000 (34%)
Market Share of Heavy-Duty NGVs	0.4%	2.4%	21.8%
Natural Gas Demand in the HDV Sector	0.01 Tcf	0.1 Tcf	1.8 Tcf
Share of Natural Gas in Total Energy Use by HDVs	0.2%	1.6%	32%

Source: EIA 2012a.

In the AEO 2012, EIA runs a side case known as the *Heavy-Duty NGV Potential* case, in which natural gas refueling infrastructure is expanded (simply by assumption) and a gradual increase is allowed in the share of HDV owners “who would consider purchasing an NGV if justified by the fuel economics over a payback distribution with a weighted average of 3 years” (EIA 2012a, p. 39). In addition, an *HDV Reference* case was developed from the AEO 2012 *Reference* case, assuming that Class 3–6 vehicles use CNG and Class 7 and 8 vehicles use LNG. Table 11 summarizes the projected sales, market penetrations, and natural gas consumptions in the HDV sector in these two different scenarios in 2035. The wide gap between these two cases reflects a great uncertainty over the future prospect of NGVs. The higher consumption of natural gas in the *Heavy-Duty NGV Potential* case slightly pushes natural gas prices up, which results in lower gas consumption in other end-use sectors. The overall impact brings about a 5 percent higher total US natural gas consumption compared with the *Reference* case (EIA 2012a). In the AEO 2013 Early Release, the improved economics of LNG for HDVs, due to a lower natural gas price projection, results in an increase in natural gas use in the HDV sector compared to the projection in AEO 2012. Natural gas use in vehicles is predicted to reach 1.7 Tcf by 2040, including the GTL use, which is about the same level of projected consumption by 2035 in the *Heavy-Duty NGV Potential* case in AEO 2012 (EIA 2013).

In summary, the economics of natural gas penetration into transportation suggests that this fuel deserves more attention. Honda's natural gas–fueled LDV needs investment and infrastructure subsidies at the level being discussed in Congress to compare favorably to its gasoline and hybrid counterparts. Under certain assumptions about fuel and vehicle price differentials, fuel economy, and vehicle miles traveled (such as being driven 125,000 miles per year), LNG-fueled heavy-duty trucks can return their added investment in two years, but generally, payback periods would be much longer. Additionally, this somewhat optimistic assessment does not directly account for infrastructure and safety costs.

Nonetheless, a variety of developments are in play to make NGVs economical even without subsidies on the fuel or the vehicles. First, natural gas prices are projected to remain relatively low given vast new amounts of shale gas becoming available, even if demand increases greatly. Second, technological changes for NGVs are likely to be more rapid than those for conventionally fueled vehicles because the latter are more mature technologies. Third, if demand for NGVs does increase, economies of scale could further reduce prices. Fourth, diesel vehicles may become more cost disadvantaged in the future by a carbon policy combined with increasingly stringent air pollution regulations and tighter restrictions on fuel economy of gasoline and diesel vehicles. Fifth, technological advances in converting gas to liquids look promising and have the potential to replace oil without requiring as much infrastructure investment as CNG or LNG.

5. The Manufacturing/Industrial Sector

US manufacturing has been declining in recent decades, as a result of increased international competition, recession, and a gradual shift toward the service industry. Such changes in economic activities, together with improvement in energy efficiency, have led to a reduction of 20 percent in natural gas consumption from the industrial sector during the past 15 years (Lipschultz 2012). However, the reduction in natural gas prices brought about by shale development has stimulated a series of expansion announcements in manufacturing, especially in gas-intensive industries like petrochemicals and fertilizers. Some big manufacturers are planning to move their production plants back to the United States to take advantage of cheaper natural gas. For example, Huntsman Corp., a chemical maker that used to spend 90 percent of its discretionary growth capital outside of the United States, now is said to be spending 70 percent within the United States because of cheap gas (Johnson and Tullo 2013). And the boom in natural gas has also made the United States attractive to foreign investments, as evidenced by a recently announced plan by German-based BASF to build a chemical plant in Louisiana.[40]

The manufacturing sector could benefit from abundant natural gas in several ways. First, equipment manufacturers and construction material providers could experience a boost in demand due to shale gas expansion. Second, companies in the petrochemical industry would benefit from the cost reduction from cheaper raw materials and energy input, which will subsequently pass on at least some of the cost advantage to downstream sectors (e.g., plastic and rubber) through the value chain. Lastly, the growth in income, employment, and tax revenue resulting from a manufacturing renaissance could stimulate the broader economy by increasing demand in consumption and government spending.

The American Chemistry Council (2012) examined the potential economic benefits of shale gas development among eight energy-intensive manufacturing industries in the United States. The study, which was based on an economy-wide input–output model (the IMPLAN model), assessed the economic gains at three levels: direct effect, indirect effect, and induced effect.[41] According to the study, the direct effects include $121.0 billion in additional industry output and $72 billion in capital investment measured in 2010 constant US dollars over the period 2015–2020, which is equivalent to a 7.3 percent gain above the reference output level. The indirect effect (to supplier industries) was estimated to result in an additional $143.8 billion growth in economic output. Such economic expansion will subsequently lead to increased demand in other sectors of $76.8 billion induced economic gain through income and tax growth. Table 12 provides estimates of direct industry output gains for each of the eight manufacturing

[40] BASF, "Governor Jindal and BASF Dedicate Methylamines Plant in Geismar", http://www.basf.com/group/corporate/en_GB/news-and-media-relations/news-releases/news-releases-usa/P-10-0109

[41] Here, *direct effects* refer to the output and employment effects generated by the sector itself; *indirect effects* refer to such effects supported by the sector via purchases from its supply chain; and *induced effects* refer to the employment and output supported by the spending of those employed directly or indirectly by the sector (American Chemistry Council 2012).

industries along with their natural gas consumption. These gains varied from 1.8 percent to 17.9 percent based on each industry's baseline output. Among these eight industries, chemicals and plastic and rubber products are the most important contributors to these gains (about 85 percent of total estimated output gain).

Table 12. Natural Gas Consumption and Direct Output Gain in Manufacturing Industries

Manufacturing Industries	Annual Natural Gas Consumption	Share of Natural Gas in Total Energy Consumption	Direct Industry Output Gain in 2015–2020 (%)	Direct Industry Output Gain in 2015–2020 (2010$ billions)
Chemicals[42]	1.7 Tcf	33%	14.5%	70.2
Paper	460 Bcf	20%	2.2%	3.7
Plastic and Rubber Products	125 Bcf	38%	17.9%	33.28
Glass	150 Bcf	53%	3.3%	0.656
Iron and Steel	375 Bcf	35%	4.4%	5.03
Aluminum	180 Bcf	49%	7.6%	1.69
Foundries	120 Bcf	44%	2.4%	0.617
Fabricated Metal Products	235 Bcf	61%	1.8%	5.81

Source: American Chemistry Council 2012.

A number of other research institutes and consulting firms have come up with their own estimates of the economic and employment benefits of the shale gas boom on the US manufacturing industry. A report from PricewaterhouseCoopers ([PwC] 2011, p.1) estimates that "lower feedstock and energy costs could help US manufacturers reduce natural gas expenses by as much as $11.6 billion annually through 2025."

Table 13 shows a list of new or expanded projects announced in recent years that are partially credited to the shale gas boom. Dow Chemical has assembled a list of 107 ongoing or announced projects in various gas-intensive manufacturing industries, including chemicals and fertilizer, steel and aluminum, tires, plastics, GTL, and glass, totaling $95 billion in new investment. The planned online dates for these projects vary from 2012 to 2018. Texas, Louisiana, Oklahoma, and Pennsylvania—which are big shale gas–producing states—are on top of the list in terms of the project locations. These projects, once brought online, would add significant base-load demand for natural gas. For example, an ammonia plant with a production

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[42] This excludes pharmaceuticals.

capacity of 1,500 tons per day could consume 44 MMcf of natural gas per day, which is equivalent to the estimated gas consumption of 165,000 CNG vehicles (Lipschultz 2012).

Table 13. Announced Manufacturing Projects in the US Related to Shale Gas Availability

Industry	Company	Project	Location	Announced Investment	Time of Announcement
Petrochemical[43]	Methanex Corp.	Methanol manufacturing plant moved from Chile	Ascension Parish, Louisiana	$550 million	Jan. 2012
Petrochemical[44]	Williams	Expansion of an ethylene plant	Geismar, Louisiana	$350-400 million	Sep. 2011
Petrochemical[45]	Dow Chemical	a new ethylene plant	Freeport, Texas,	N/A	Apr. 2012
Textile[46]	Santana Textiles LLC	Denim plant	Edinburg, Texas	$180 million	Jul. 2008
Fertilizer[47]	CF Industries	Expansion of a nitrogen fertilizer manufacturing complex	Donaldsonville, Louisiana	$2.1 billion	Nov. 2012
Fertilizer[48]	Orascom Construction Industries	Nitrogen fertilizer production plant	Southeast Iowa	$1.4 billion	Sep. 2012

However, unlike the electric power sector, where existing gas-fired plants are present for fuel switching, most of these projects require a large amount of investment with a payback period of up to five years before they can generate positive cash flows. Therefore, the economic

[43] Office of the Governor, State of Louisiana. 2012. "Governor Jindal, Methanex Announce $550 Million Methanol Plant." Jul 25. http://gov.louisiana.gov/index.cfm?md=newsroom&tmp=detail&articleID=3545

[44] Williams, Inc. 2011. "Williams Expanding Geismar Facility to Serve Petrochemical Industry." Sep 20. www.energy.williams.com/profiles/investor/ResLibraryView.asp?ResLibraryID=47352&GoTopage=5&Category=1799&BzID=630&G=343

[45] Dow Chemical Company. 2012. "Dow to Build New Ethylene Production Plant at Dow Texas Operations." April 19. www.dow.com/texas/freeport/news/2012/20120419a.htm

[46] Edinburg Politics. 2008. "Santana Textiles Corporation of Brazil to build $180 million manufacturing plant in Edinburg." July 4. www.edinburgpolitics.com/2008/07/04/santana-textiles-corporation-of-brazil-to-build-180-million-manufacturing-plant-in-edinburg/

[47] Louisiana Economic Development. 2012."CF Industries Announces $2.1 Billion Expansion In Donaldsonville." Nov 1. www.louisianaeconomicdevelopment.com/index.cfm/newsroom/detail/217

[48] Wall Street Journal. 2012. "Egyptian Bets $1.4 Billion on Natural Gas—In Iowa." Sep 5. http://online.wsj.com/article/SB10000872396390443589304577633932086598096.html

benefits in manufacturing are more vulnerable to gas price volatility and to underlying concerns about LNG exports boosting price.

Currently, discussions are ongoing over whether DOE should grant the licenses for LNG to be exported to countries that lack a US free-trade agreement.[49] Though several applications are pending at DOE, only Cheniere Energy's 2.2 Bcf/day Sabine Pass project, located in Louisiana, has been approved. Manufacturers, especially those in the petrochemical industry, are the most vocal opponents to LNG export with concerns about higher domestic gas prices. An advocacy group, America's Energy Advantage, was recently formed by four of the largest US chemical firms (Celanese, Dow, Eastman Chemical, and Huntsman Corp.) to advance their position (Johnson and Tullo 2013). Indeed, the chemical industry would face declines in profits and revenues, but the loss was estimated to be manageable (NERA Economic Consulting 2012). The costs from liquefaction and transportation to Japan and China could add up to about $5.50 per Tcf (Johnson and Tullo 2013). And landed LNG rates are typically linked to oil prices, with an oil price of $100/bbl translating into a landed LNG rate of $12.00–$15.50/mmBtu (Lipschultz 2012), which would probably keep the US gas price well below the prices in gas-importing countries.

The subsections below take a closer look at three industries where the impacts of cheap gas availability are believed to be the most prominent: petrochemical, fertilizer, and steel production.

5.1. Petrochemicals

The petrochemical industry is one of the largest natural gas consumers, where natural gas and natural gas liquids (NGLs) are used as fuels and as feedstock. It is estimated that chemicals and petroleum refining account for 46 percent of total industrial gas consumption (Lipschultz 2012). Important NGLs for the petrochemical industry include ethane, propane, and butane. Ethane and propane are the primary feedstocks used in the United States to produce ethylene, which is a key component in plastics and one of the world's most common chemical building blocks. An expansion in the production capacity of ethylene will probably boost production from

[49] Only four free-trade agreement countries (South Korea, Australia, Mexico, and Canada) are big natural gas consumers; of these, only South Korea is a major LNG importer. The world's largest LNG importers, such as Japan, China, and the U.K., are non-free-trade-agreement countries (Johnson and Tullo 2013).

a wide variety of manufacturing industries, such as electronics, clothing, and packaging, therefore leading to far-reaching impacts on the entire manufacturing industry.

An American Chemistry Council (2011) study focusing on the petrochemical industry indicates an investment of $16.2 billion to build new petrochemical and derivatives capacity arising from the availability of cheap gas over several years; this is projected to increase US ethane capacity by about 25 percent. Similarly, PwC (2012, p. 3) estimates that NGL production is "expected to increase more than 40 percent over the next five years, reaching more than 3.1 MMBD [million barrels per day] in 2016," and the US chemical industry investment of $15 billion will have increased its ethylene production capacity by 33 percent.

A number of petrochemical manufacturers, including Dow Chemical, Formosa Plastics, Chevron Phillips Chemical, and Bayer Corp., have announced plans to build new plants or expand existing capacity for ethane and ethylene production partly because of the availability of shale gas feedstock (PwC 2011). Dow Chemical (2011, p. 11) stated that its "investments on the US Gulf Coast will increase [its] US ethylene production capabilities by 20 percent over the next three years." An analysis based on economic cost models of petrochemical products shows that, as the price of natural gas falls from $12.5/mmBtu to $3.00/mmBtu, the estimated price of ethylene declines from $1,009/ton to $323/ton, with the prices of polyethylene and ethylene glycol falling by a similar degree (PwC 2012). Such a cost reduction will give the US chemical manufacturers a significant cost advantage over its international competitors.

In addition, petrochemical manufacturers are shifting from petroleum-based feedstocks to their gas-based substitutes. The petrochemical producers who were using naphtha (a generic term for a variety of petroleum refining products) as a feedstock for ethylene production, primarily located in Europe and Asia, are shifting to ethane to reduce costs, which has caused the naphtha prices to fall in the United States and international markets (Pirog and Ratner 2012). It is expected that research and development efforts leveraging ethylene-based chemistries that replace petroleum-based products will surge in coming years. Finally, a variety of downstream manufacturing sectors will subsequently benefit from the availability of cheaper chemical raw materials, which are used in an estimated 90 percent of all manufactured products and may replace higher-cost materials such as metals, glass, and leather (PwC 2012).

5.2. Fertilizers

Natural gas is used to produce ammonia, which serves as the primary ingredient in most nitrogen fertilizers and is an essential ingredient in many finished phosphate fertilizers; the cost of ammonia corresponds to about 70 percent to 90 percent of the estimated production cost faced by nitrogen-based fertilizer producers (Pirog and Ratner 2012). Although the United States is the fourth-largest producer of ammonia in the world, US ammonia production capacity shrank by 40 percent during the 2000s, before the shale gas boom changed the situation.[50] Many ammonia plants were moved overseas or closed because of the increasing natural gas price for industrial users. However, the emergence of large, low-cost shale gas resources has reversed the trend and brought significant cost savings to the industry. With the high demand for fertilizers in the past few years, the cost savings brought by cheap natural gas were mainly reaped by the producers rather than the consumers (Pirog and Ratner 2012). CF Industries, a major manufacturer and distributor of fertilizer products in the United States, reported a more than three-fold increase in gross margin of its nitrogen segment from 2009 ($784 million) to 2011 ($2,563 million; CF Industries 2012). Accordingly, new investment decisions to expand capacity by both domestic and foreign producers have been announced recently. Nevertheless, this industry is cautious because of its past suffering from gas price volatility (Pirog and Ratner 2012).

5.3. Steel Production

The benefit of expanded shale gas development for steel production comes from two factors: the increase in product demand caused by higher demand for drilling equipment and the decrease in operating costs due to cheaper natural gas. For example, US Steel (the largest US steelmaker) saw a 17 percent increase in production of tubular goods used in oil and gas drilling and transmission facilities in 2011 (Miller 2012). The increasing demand for drilling equipment, together with the demand-driven increase in steel prices and downturn in costs, has increased the company's profits.

In addition, the steel industry can benefit directly from fuel switching, from coal to natural gas, both by directly replacing coal with natural gas in manufacturing processes, and by experiencing lower electricity prices made possible partly by the increased gas supply. For example, Nucor and US Steel have both indicated interest in investing in the use of natural gas for direct reduced iron production (PwC 2011)—a process that has traditionally used coal to create the requisite "reducing gas."

[50] The Fertilizer Institute, "Natural Gas Access/ Supply," http://www.tfi.org/issues/energy/natural-gas-accesssupply

However, the cost reduction from switching to natural gas from coal falls into the range of \$8–\$10/ton, compared to the overall steel production cost of around \$600/ton (Miller 2012; Pirog and Ratner 2012). Therefore, the cost reduction effect is less important to the industry than the upward shift in demand.

Looking into the future, as projected by EIA (2013, p. 1), "natural gas use (excluding lease and plant fuel) in the industrial sector increases by 16 percent from 6.8 Tcf per year to 7.8 Tcf per year in 2025." Industrial production from the bulk chemical industries and primary metal industries are projected to grow 1.7 percent and 2.8 percent per year, respectively, from 2011 to 2025, partly powered by the increased production of natural gas and NGLs (EIA 2013). In the AEO 2012 projections (EIA 2012a), industrial natural gas use grows by 8 percent in the period 2010–2035.

6. Possible Impact of a Potential Shale Gas Boom in China

In the United States, the drop in natural gas prices caused by the shale gas revolution has resulted in big increases in the quantity of natural gas demanded by the power sector. In the transportation and manufacturing sectors, the effects of low natural gas prices have so far been felt mainly in the planning for future increases in natural gas use, through major investments in refueling infrastructure in the transportation sector, and in chemical and other plants that use natural gas as a feedstock. Investments into new transportation options using natural gas directly or as a feedstock to liquid fuels are also beginning. Finally, and not discussed above, major investments are being planned for natural gas export facilities. Shale gas has not caused much change in natural gas use in the residential and commercial sectors. These sectors had expanded years earlier to take advantage of the availability of natural gas in urban areas. Further growth in this demand would require major new pipeline right-of-way acquisition and pipeline construction to underserved urban areas as well as conversion of home and business use of (primarily) oil (and propane) to natural gas. As most of the population using these fuels is rural, the economics is quite unfavorable to further natural gas growth in the residential and commercial sectors.

In China, natural gas is used, priced, and managed so differently than in the United States that one must be quite cautious in applying to China any lessons learned from the United States.

6.1. How Is Natural Gas Used in China?

Natural gas currently plays a relatively small role in China's energy fuel mix. As of 2011, natural gas made up only about 5.0 percent of China's total primary energy consumption. While this represents nearly a doubling compared to 2001,[51] it is still a small fraction compared to the global average share of around 24 percent and the US share of 26 percent.

Looking across sectors, consumption from almost all sectors has grown during the past decade (Figure 9). As of 2010, 44 percent of the natural gas consumption is in the industrial sector, with the residential sector taking up 28 percent of the total and electric power 20 percent (Energy Research Institute [ERI] 2012). This is in sharp contrast with the even split in the United States among the power, industrial, and residential sectors. Transportation accounts for 6 percent of the natural gas consumption in China. Thus, transportation takes up a relatively small share in both the United States and China.

The industrial sector currently consumes the largest amount of natural gas among all end-use sectors, with the chemical and petrochemical industries as the major natural gas consumers. Fertilizer producers enjoy the benefit of low-priced gas as feedstock for the sake of subsidizing agriculture. Gas consumption from this sector has been steadily increasing from 2000 to 2007. However, triggered by the shortage of gas supply and overproduction in some chemical and petrochemical plants using cheap gas, the Chinese government started to restrict industrial natural gas use in 2007, which led to a leveling off of gas consumption (Figure 9; International Energy Agency [IEA] 2009). This is indicative of the influential role of the Chinese government's directives in affecting gas consumption distribution among various sectors.

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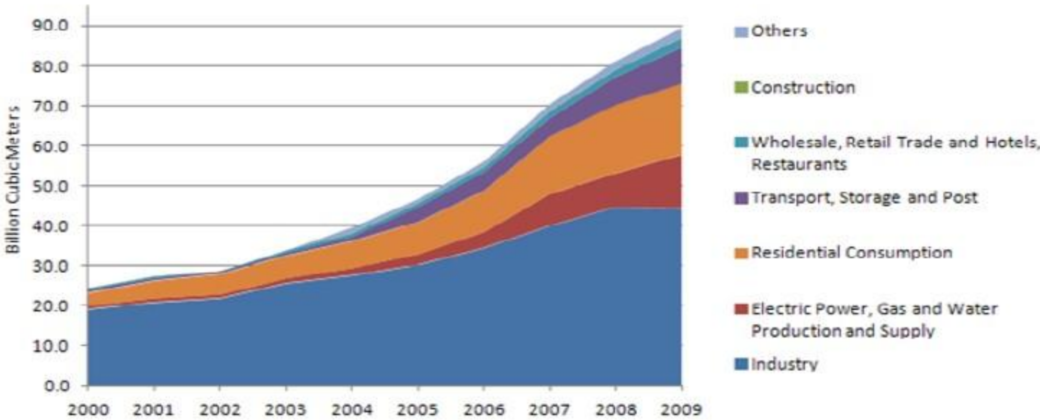
[51] National Bureau of Statistics of China, *China Statistical Yearbook 2012*, http://www.stats.gov.cn/tjsj/ndsj/2012/indexch.htm

Figure 9. China's Natural Gas Consumption by Sector (2000–2009)



Source: International Energy Agency (2012b)

The residential sector, which takes up about a quarter of China's total natural gas consumption, is one of the fastest-growing end-use sectors of the past few years (Figure 9). This increased demand was powered by the development of distribution infrastructure and by rapid expansion and modernization of cities. Since natural gas has been relatively cheap, while the price of liquefied petroleum gas (LPG) has rapidly increased since 2005 (IEA 2009), we see fuel switching, from LPG and coal-based gas to natural gas, in urban areas during the past decade (Figure 10). As of 2011, 27.8 percent of the 691 million urban residents in China have access to pipeline natural gas,[52] a doubling from 2005 (IEA 2009). Since the government has a target of 65 percent urban penetration of pipeline gas by midcentury (IEA 2009), residential use of natural gas is expected to continue to soar in coming years. This is very different from the situation in the United States, where there is little room for further increases in residential consumption of natural gas.

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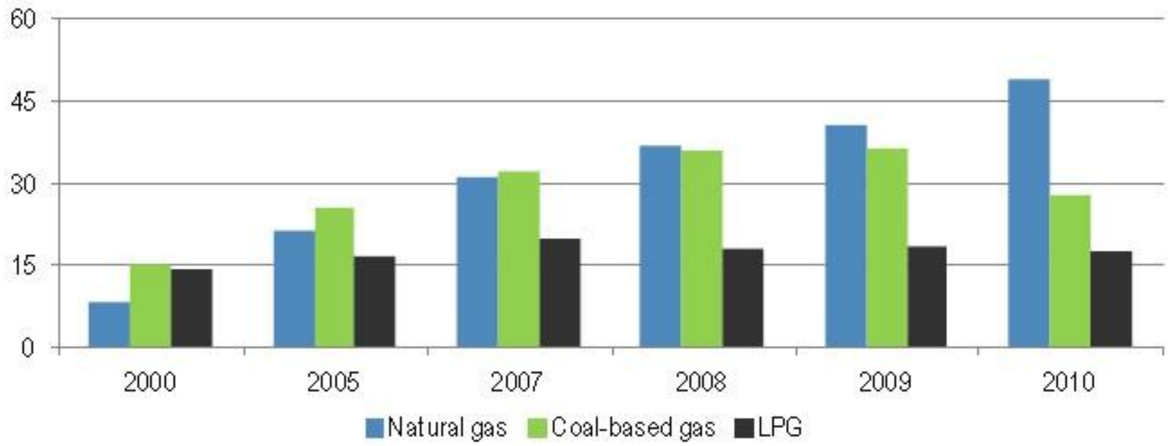
[52] National Bureau of Statistics of China, *China Statistical Yearbook 2012*, http://www.stats.gov.cn/tjsj/ndsj/2012/indexch.htm

Figure 10. Sources of Gas for Urban Consumption (City Gas), BCM/Year



Source: Tan and Bustnes (2012)

Natural gas currently takes up a fairly small share of China's electricity generation fuel mix. In 2010, natural gas accounted for only about 1.9 percent of the primary energy used for electricity generation, whereas coal was the dominant primary fuel with a share of 88.2 percent.[53] Gas-fired generation capacity remains relatively low at around 33 GW, making up only about 3 percent of China's 1,073-GW installed electricity capacity as of 2011, with coal and hydropower taking the largest shares in generation capacity (65 percent and 22 percent, respectively; EIA 2012d). This situation is in contrast to that in the United States, where natural gas accounts for 52 percent of the net summer capacity and about 20 percent of the primary fuels used for power generation (EIA 2012b).[54]

In the transportation sector, according to the National Development and Reform Commission of China (NDRC), China now has about 1 million NGVs (a penetration rate below 5 percent),[55] which is nevertheless almost 10 times that of the United States and from a far lower base of vehicle ownership. These vehicles consumed about 8 billion m^3 of natural gas in 2012,

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53 This is the authors' calculation based on data from China's Energy Flow Chart 2010 (ERI 2012).

54 Note the difference between the share of electricity generated from natural gas and the share of natural gas in primary fuel mix for electricity generation. Because of a generally higher efficiency for natural gas generation compared to coal generation, the former is usually larger than the latter. In 2011, about 25% of US electricity was generated from natural gas.

55 "Tianranqi Qiche Qianjin Lushang Mianlin Pingjing" ["NGVs Are Facing Obstacles"], *21 Shiji Wang [21 cbh.com]*, June 11, 2012. Available at http://www.21cbh.com/HTML/2012-6-11/1NNDg0XzQ1MTE1Nw.html

increasing from 1.79 billion m^3 in 2010 (ERI 2012). NGVs currently are mainly public transportation buses, cabs, long-range fleet bus carriers, and heavy-duty trucks.

6.2. How Is Natural Gas Priced in China?

China administers gas prices rather than letting them be determined in markets. The delivered price of natural gas is a sum of wellhead price, transportation cost, distribution cost, and retailer's profit margin. The wellhead price and the transportation tariff are set nationally by the NDRC on a cost-plus basis, while distribution cost and retailers' profit margins are regulated by local governments.[56] Some sectors are cross-subsidized at the expense of others. Residential and commercial sectors are heavily subsidized to keep prices low, while gas importers are taking big losses by importing high-priced gas via pipeline from Turkmenistan or via terminals on the Asian LNG market. Table 14 (IEA 2012a) shows that this situation has led to great regional variations in prices as well as sectoral price differences, to the detriment of transportation. Cross-subsidization may lead to inefficient allocation of resources across regions and sectors.

Table 14. End-Use Gas Prices in Selected Chinese Cities, 2011

$/mmBtu	Residential	Public Services	Industry	Transportation
Beijing	9.01	12.48	12.48	20.79
Tianjin	9.67	13.85	13.85	17.36
Shanghai	10.99	16.22	17.10	20.66
Nanning, Guangxi	19.21	25.19	25.19	21.76
Shenyang, Liaoning	13.80	16.31	16.31	16.31
Hefei, Anhui	8.78	14.97	10.37	14.97
Wuhan, Hubei	10.58	15.39	12.55	19.82
Chongqing	7.19	9.58	9.37	19.24

Source: IEA 2012a.

[56] "Jiage Shichanghua Gaige Zhuzhang Tianranqi" ["Market-based Natural gas Pricing Reform Will Push Up Natural Gas Prices"], *Zhongguo Nengyuan Wang [China5e.com]*, July 11, 2012. Available at http://www.china5e.com/show.php?contentid=232484

Table 15. Natural Gas Use Categories in the *Natural Gas Use Guidelines*

End-user Group	Sectors Included
Prioritized	Residential use in urban areas (especially metropolitan areas) Public facilities (e.g., airports, schools, and hospitals) NGVs (especially dual-fuel vehicles and LNG vehicles) Collective home heating Air conditioning Interruptible industrial uses, including building materials, mechanical and electrical equipment, textiles, petroleum chemicals, and metallurgical industries Interruptible users for hydrogen production from natural gas Distributed energy systems with efficiency greater than 70%, including hybrid systems with renewables Natural gas vessels (especially LNG vessels) Load-smoothing storage facilities in urban areas Electricity generation projects from coal-bed methane Combined heat and power generation projects
Permissible	Distributed home heating Industrial use displacing oil and LPG Industrial use for newly built projects where natural gas is used as heating fuel Industrial use displacing coal with evident environmental and economic benefits Natural gas–powered boiler projects in urban areas (especially metropolitan areas) Electricity generation from natural gas, except those specified in other groups Noninterruptible uses for hydrogen production from natural gas Small-scaled liquefaction plants for load smoothing and storage
Restrictive	Expanded and coal-to-gas projects for synthetic ammonia production Feedstock for chemical projects (e.g., ethane and chloromethane production) Feedstock for newly built fertilizer production projects
Banned	Base-load electric power generation projects in 13 coal-rich areas, excluding coal-bed methane projects Feedstock for newly built, expanded, or coal-to-gas projects for methanol production

Source: NDRC 2012a.

6.3. Natural Gas Use Guidelines in China

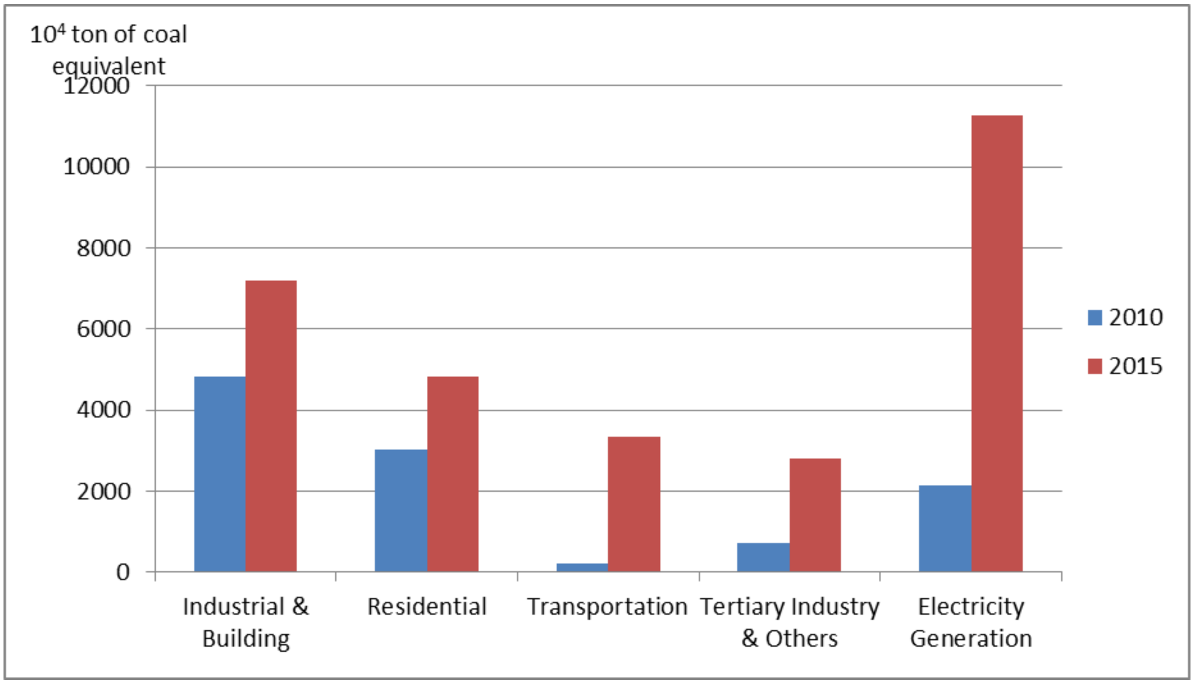
Besides a regulated pricing system, allocations among different end-use sectors in China are subject to government directives. In the *Natural Gas Use Guidelines* issued by NDRC in October 2012, natural gas end-use sectors were categorized into four groups in a descending order of priority (Table 15; NDRC 2012a). The category of prioritized use continues to emphasize residential and commercial users but, in an apparently big change, now includes transportation uses as well. The emphasis on storage capacity near urban areas is another interesting inclusion as such capacity is sorely needed to meet growing demand in the residential and commercial sectors. Including power generation from coal-bed methane (and in the future probably shale gas) is another interesting choice, indicating that the government wants to encourage these unconventional fuel sources. The category of permissible use includes certain industrial uses that displace coal and oil for the environmental and economic benefits. The restrictive use category includes the use of natural gas for chemical feedstock, another interesting choice as this use has led many experts in the United States to conclude that low natural gas prices have been leading to a revitalization of manufacturing that uses natural gas as a feedstock. The lowest priority category is actually banned use. Notably, the guideline bans the use of natural gas for base-load electric power generation in 13 coal-rich areas and for producing methanol (a fuel that could be used as a transportation fuel and in some industrial applications).

It is expected that China's total gas consumption will more than double from 2010 to 2015 and will take up about 7.7 percent of its total primary energy consumption by 2015.[57] However, it is not clear if the Chinese government took into account the need for much more natural gas infrastructure to process and transport the gas to markets. Although the two countries are relatively similar in total area, China had just 27,000 miles of main natural gas pipelines as of the end of 2011[58] (EIA 2012d) compared to 300,000 miles for the United States (EIA 2007).

With consumption from all sectors projected to increase, transportation and electricity generation are the two sectors that are expected by Chinese experts to experience a more rapid growth in consumption (Figure 11). As projected by ERI (2012), natural gas used for power generation will increase by more than five-fold in the period 2010–2015, becoming the largest gas consumer and accounting for about 38 percent of total gas consumption by 2015. Gas consumption in transportation is expected to increase by 1,500 percent over the same time horizon and is expected to consume about 11 percent of total gas consumption by 2015 (ERI 2012). Such higher projected growth relative to other end-use sectors is consistent with the priorities that the government has indicated in its current *Natural Gas Use Guidelines.*

[57] This is the authors' calculation based on data from China's Energy Flow Chart 2010 (ERI 2012).
[58] The Chinese government plans to construct another 24,000 miles of new pipelines by 2015 (EIA 2012d).

Figure 11. China's Natural Gas Consumption by Sector: 2010 and 2015 (Projected)



Source: China's Energy Flow Chart 2010 and 2015; ERI 2012.

In the electric power sector, starting from the marginal role of gas-fired generation in the current power generation capacity mix, China is in the process of building gas-fired power plants. Gas-fired power capacity is expected to reach 70 GW by 2020 (IEA 2009), almost doubling the current level. Some of these plants in the coastal areas are connected to LNG regasification terminals and are paid higher tariffs for addressing peak demand. Although the current price of natural gas in China cannot compete with coal in general, in areas like Shanghai and Guangdong with coal supply shortages due to a railway transportation capacity constraint, natural gas plays a significant role in the fuel mix for power generation.

Environmental protection gives China another reason to promote natural gas for electricity generation, especially in metropolitan areas, where the social costs associated with air pollution are extremely high. In October 2011, for example, NDRC set the on-grid price for electricity generated from natural gas in Beijing to be 0.573 yuan/kWh, compared to 0.472 yuan/kWh for electricity from other sources. At the same time, Beijing's local government issued a subsidy of 0.14 yuan/kWh for electricity generated from natural gas to reduce coal combustion in the metropolitan area.[59] The higher price for electricity generated from natural gas is a correction for at least some of the negative externalities from coal generation. How closely these prices match the appropriate market price is not possible to say with precision, but most analysts think that it carries a welfare benefit for China to switch from coal to natural gas because of the severe air pollution problems prevalent in cities all over the country.

In the transportation sector, China is actively promoting NGVs as an effort to combat air pollution and to diversify its fuel sources so as to reduce its reliance on oil imports. However, China's southwestern region—where shale gas development is most likely to take off—is the major sales market for natural gas passenger vehicles, the home to the major natural gas automakers,[60] and the region in which CNG/LNG refueling infrastructure is more developed compared to other parts of the country. China has the world's largest production capacity for vehicle-use natural gas storage cylinders, about 800,000 cylinders per year.[61] In 2010, NDRC set a price floor for natural gas use for vehicles to be 75 percent of the gasoline price (NDRC 2010), while some experts propose to bring down the price floor to 60 percent to make NGVs more economically attractive. These factors lead us to speculate on a promising NGV market if China does significantly expand its shale gas production.

6.4. Natural Gas Trade and Global Market Impact

Unlike the United States, China is expected to be a major net importer of natural gas. China became a net gas importer in 2007, and its imported gas, about half LNG and half pipeline gas, took up about 22 percent of total gas consumption in 2011 (EIA 2012d). Currently China imports pipeline gas mainly from Turkmenistan and Myanmar, and it recently signed a Memorandum of Understanding with Russia's Gazprom for a 30-year contract for gas supplies from Russia to China.[62] According to EIA (2012d), China's major LNG import sources include

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[59] "Beijing Tianranqi Tidai Ranmei Fadian, Nandu Keneng Yuandayu Dongli" ["Fuel Switching from Coal to Natural Gas for Electricity Generation in Beijing: Big Challenges, Limited Incentives"], *Zhongguo Nengyuan Wang [China5e.com]*, July 11, 2012. Available at http://www.china5e.com/show.php?contentid=232357

[60] "Tianranqi Qiche Damu Xuxu Lakai, Longtou Qiye Dayoukewei" ["Big Opportunities in NGVs for Leading Companies"], *Fenghuang Wang [ifeng.com]*, July 02, 2012. Available at http://finance.ifeng.com/stock/hybg/20120702/6691116.shtml

[61] "Daguimo Tuiguang Tianranqi Qiche Haixu Chuangsanguan" ["Three Issues Need to be Addressed to Make Large-scale Use of NGVs Possible"], *Renming Wang [people.com.cn]*, November 07, 2012. Available at http://gx.people.com.cn/n/2012/1107/c179486-17687275.html

[62] Gasprom. "Gazprom and China Sign Memorandum of Understanding on Gas Supplies via Eastern Route". *Gasprom News*, March 2013. Available at http://www.gazprom.com/press/news/2013/march/article158716/

Australia (30 percent), Qatar (19 percent), and Indonesia (17 percent). According to IEA (2012a), China has been doing a good job of building import terminals, gasifiers, and pipelines to get the gas to markets. Its gas imports are projected to continue the rapid growth in the years to come. China’s total gas demand is projected to reach 250 billion m^3 by 2015, of which about a third will come from gas imports.

Against this backdrop, and given China’s targeted production for shale gas at 6.5 billion m^3 (0.23 Tcf) by 2015 and 60–100 billion m^3 (2.12–3.53 Tcf) by 2020 (NDRC 2012b), shale gas development is unlikely to have large impacts on China’s gas imports in the near term. However, in the longer term, if China successfully exploits its potentially large shale gas resources, this expanded domestic supply will probably substitute for the expensive gas imports and perhaps even lead to downward pressure on the Asian gas price.

6.5. Comparing China with the United States

Cheaper gas, should it occur in China, will provide an unambiguous improvement in public welfare,[63] but the pattern of growth in natural gas use in China is unlikely to match that of the United States. In the United States, residential and commercial natural gas use already saturated the market, natural gas already had a major share of the power generation sector prior to the shale gas boom, the manufacturing sector is undergoing a rebirth, and transportation demand for natural gas is still in its infancy. In China, government policy will have a big impact on the ultimate allocation of natural gas across sectors. The Chinese authorities plan to direct natural gas to residential and commercial uses, giving the industrial sector less emphasis, as the latter already uses a large percentage of China’s natural gas. The power sector will also be a major winner, but not in coal-rich areas. Transportation in China already uses more natural gas than does the US transportation sector, and the authorities plan to increase such use markedly. It is interesting, but beyond the scope of this paper, to study the extent to which the natural gas use guidelines issued by the Chinese government are socially and economically optimal policy.

The US experience does provide some lessons for China. Cheap gas can help and hurt the environment by substituting for fuels in the power sector. While low natural gas prices may enable natural gas to back out coal in China’s non-coal-producing regions, it may also dampen enthusiasm for renewables. It is useful for the Chinese government to take this possibility into

[63] In terms of climate change, the benefit of natural gas depends critically on the issue of methane leakage.

consideration. Low natural gas prices in the United States have started to stimulate innovations in the uses of natural gas in transportation. With China already moving in this direction, the country has an opportunity to serve as a model for the gasification of transportation around the world. International chemical companies have shown a remarkable willingness to enter new markets if their feedstock costs are low enough. Such investment in China, however it is regulated by authorities, can potentially benefit technology transfer and keep the economy growing.

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