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During the past decade, innovative new techniques involving horizontal drilling and hydraulic fracturing have unlocked a vast resource potential and resulted in the rapid growth in production of natural gas from shale. According to the U.S. Energy Information Administration, gross withdrawals from shale gas wells in the United States has increased from virtually nothing in 2000 to over 23 billion cubic feet per day (bcfd) in 2011, representing over 29 percent of total gross production in the United States. Moreover, a recent Baker Institute analysis indicates shale gas production could reach over 50 percent of all domestic natural gas production by the 2030s.[1]

Without doubt, the natural gas supply picture in North America has changed substantially, and it has had a ripple effect around the globe, not only through displacement of supplies in global trade, but also by fostering interest in shale potential in other parts of the world. Prior to the innovations leading to the recent increases in shale gas production, declining domestic production in the United States and Canada was the consensus view, and was a harbinger of increasing reliance in North America on foreign supplies. This resulted in an expectation that prices would rise, and that the United States would become a major global sink for global supplies. While many producers around the world began to invest in capabilities to move

[1] The techniques have also matriculated into the oil sector triggering an upstream renaissance in U.S. oil production driven by light tight oil, or shale oil. In fact, domestic oil production has increased year-on-year since 2008, something that has not occurred since the 1960s.

liquefied natural gas to the United States, the late 1990s and early 2000s also witnessed a decline in industrial demand for natural gas as gas-intensive manufacturing activities migrated away. Thus, the North American gas market was undergoing a shift in preparation for increasing import reliance, higher prices, and reduced domestic demand for industrial activities. Even in the power sector, higher prices set the stage for more robust growth in renewable energy sources. But the rapid growth in shale gas production has since turned all of these expectations upside down. In fact, there is a valuable lesson in what has transpired. Market stresses encourage responses on multiple margins, and there is nothing different about what is going on currently.

To wit, the past few years of rising shale gas production has contributed to lower domestic natural gas prices. This, in turn, has encouraged the substitution of natural gas for coal in power generation, and a revitalization of gas-intensive industrial demands. There has also been interest in creating *new* demands, such as the use of natural gas in transportation, particularly as the price of crude oil remains well above the price of natural gas on an energy equivalent basis. Finally, there has been growing interest in developing LNG export capability to capture the arbitrage opportunity that currently exists with domestic natural gas prices substantially below prices in Europe and Asia.

This paper discusses the feasibility of the pathways for natural gas that have emerged in the wake of the shale gas revolution. We begin our discussion with the transportation sector, followed by industry, power generation and LNG exports. While this is not meant to be exhaustive, it will highlight some key points that must be brought forth in any policy discussion around natural gas. Namely, there are multiple margins of response to low natural gas prices, and one cannot consider each in a silo; the market certainly does not.

In any case, the domestic supply capability is important in determining the price impacts of growth in demand, regardless of the source. According to a recent Baker Institute study, commercially viable shale gas resources have rendered the domestic supply curve to be very elastic.[2] This means that even modest changes in price will result in significant changes in production. So the capacity for the U.S. market to absorb large increases in demand without significant upward pressure on price is large. In fact, the central tendency of prices is now projected to be between $4.50/mcf and $5.50/mcf over the next few decades.

Altogether, the aim here is to highlight some critical discussion points when considering the pathways for growth in U.S. natural gas demand. In particular, in traditional end-uses, growth in natural gas demand faces few obstacles other than those presented by market forces. In new demand sectors, however, there are substantial barriers to growth, largely due to high fixed infrastructure costs and return on investment considerations. Thus, although the potential for

[2] Indeed, the U.S. supply elasticity with shale included in the resource base is roughly five times larger than when it is not included. See Kenneth B. Medlock, "U.S. LNG Exports: Truth and Consequences," available at www.bakerinstitute.org (2012). Put another way, the domestic supply curve is very flat.

growth is large—especially in transportation where current gas use is very low relative to total transportation energy use —realizing that potential will be challenging.

Natural gas into transportation

The transport sector has historically been dominated by crude oil products, to the tune of 94 percent of all transport uses in 2010.[3] So, as a point of departure, we must understand how natural gas might penetrate the transportation sector. For the purpose of this discussion, we will focus on two avenues for natural gas into transportation, one direct and the other indirect:

- Compressed natural gas vehicles (CNGVs)
- Electric vehicles (EVs).

One could argue that other issues should enter the discussion, particularly if the goal is to reduce reliance on imported oil. For example, fuel efficiency improvements ultimately lower fuel use per mile driven. We could also discuss methanol and gas-to-liquids (GTL) technologies, in particular because they both require natural gas as a feedstock and could displace crude oil in transportation. Moreover, we cannot ignore the developments in light tight oil (LTO) that have been driving U.S. oil production up since 2008, reversing a downward trend that had persisted since the early 1970s. But we will return to all of these options below when discussing the considerations that influence investments in different fuel types.

CNG Vehicles

Currently, natural gas use in transportation is only 0.13 percent of total gasoline use. So there is a lot of room for growth. In fact, a 10-fold increase in demand would push demand to about 0.9 bcf/day, which is an increase the U.S. market could absorb with relative ease. But for the low levels of demand that currently exist to change, it will take substantial investment in fueling infrastructure and large adoption of compressed natural gas vehicles (CNGV) by consumers.[4]

One thousand cubic feet of natural gas yields eight gallons of CNG. So if natural gas price is \$4/mcf, then the cost of natural gas as a feedstock for CNG production is \$0.50/gallon. Adding the processing costs for CNG of approximately \$1.00/gallon, we have an estimated wholesale price of \$1.50/gallon. In addition, regional prices may differ due to differences in the price of gas, but the price changes by only \$0.10/gallon for every \$0.80/mcf change in the gas price, so the wholesale price will not vary substantially by region. As a basis for comparison, the wholesale price of gasoline on the NYMEX is currently at \$3.00/gallon. If these prices persist, the per gallon fuel cost of CNG is about half the cost of gasoline, before accounting for things

[3] Data sourced from IEA Energy Statistics and Balances. Ethanol comprises another 4 percent, with natural gas making up the remainder. Note, if pipeline uses are excluded, these values shift even more heavily toward oil.
[4] We could also discuss liquefied natural gas (LNG) options into transportation, but this is primarily for large trucks and local maritime transport. The arguments presented herein still generally apply.

such as distribution costs, profits, local and national taxes, and lease payments by station owners. Assuming all these additional costs are equal for CNG and gasoline, we still have a differential between fuels of about $1.50/gallon.

Despite the preceding cost per gallon comparison, cost per *gallon* is not the appropriate metric for comparison. We must compare the cost per *mile* of each fuel option. In order to do this for privately owned vehicles, we need to incorporate the efficiency of a CNGV and a comparable gasoline hybrid vehicle. Then we can calculate the annual fuel cost savings for each vehicle type. Importantly, we compare the CNGV with the hybrid because these are the two "next generation" technology options currently available.

If we compare the Honda Civic, for example, we have a gasoline hybrid engine efficiency of 44 miles per gallon in the city. The Honda Civic CNGV has a city driving efficiency of 27 miles per gallon. Thus, the cost per mile is $0.0126 lower for the Civic CNGV. If we assume annual driving of 12,000 miles, the fuel savings is $151/year. Assuming a seven-year vehicle life, we see an undiscounted lifetime savings of just over $1,060. The current MSRP for a Civic CNGV is $26,305, and the current MSRP for a Civic Hybrid is $24,200, meaning the price difference is currently $2,105. Thus, the fuel cost savings does not compensate the higher upfront cost of the vehicle. If we discount future savings, the disparity grows. So, the CNGV is not the most attractive option to the consumer looking to purchase a vehicle that also reduces gasoline demand. If, however, the annual mileage jumps to 24,000 miles per year, then the undiscounted fuel cost savings just compensates for the fixed cost differential over seven years. So, high mileage is a prerequisite for the CNGV option to make economic sense given these fuel costs.

The current pricing differential between natural gas and gasoline has been sufficient to promote adoption of CNGVs in commercial fleets. However, commercial fleet opportunities are small when compared to the fleet of privately owned motor vehicles. So, while an economic argument can be made for natural gas into high-mileage commercial fleets, the same is not true for private vehicles, which, absent a change in fixed costs differentials, will limit the movement of natural gas into private vehicles.

Aside from the cost differences, another issue that stands in the way of large-scale CNGV adoption is a lack of refueling infrastructure. There are currently about 1,100 CNG fueling stations and 59 LNG fueling stations nationwide. These facilities primarily serve large trucks in the case of LNG and light duty trucks in the case of CNG. But the ability to refuel becomes an issue when one considers the current consumer driving behaviors. In particular, the flexibility implicit in the existing fuel delivery infrastructure (for gasoline) allows drivers the freedom to plan their activities without necessarily planning routes so that they coordinate with refueling opportunities. This point is what leads us to the so-called "chicken-and-egg" problem. Namely, consumers bear a cost if they have to search for refueling stations (a so-called "search cost"), and this cost can prevent them from buying a CNG vehicle, even if the projected fuel savings compensates for the incremental fixed cost. In turn, station owners may be reluctant to install

CNG refueling capability if CNGVs are not prevalent enough in the vehicle stock to guarantee some demand for the station's services. Hence, the conundrum—how does one overcome this mismatch to ensure coordinated growth in both CNGVs and refueling locations?

Electric Vehicles

Many of the issues facing CNGV adoption into the private vehicle fleet are also faced by EVs, but by differing degrees. Cost of ownership is certainly an issue, as most EVs are more expensive than their non-EV counterparts. Of course, the low cost of electricity can provide significant fuel savings, but even if EV fuel costs are driven down near zero, the projected seven-year undiscounted savings approaches $5,600. The base model Ford Focus EV lists an MSRP of $39,200. This compares with the gasoline-powered base model Ford Focus MSRP of $16,200. So, just as with EVs, the difference in fixed cost is not fully compensated by the fuel savings. Even with the federal tax credit of $7,500, the fuel savings is not sufficient. In other words, rational individuals who buy an EV are doing so for some additional derived benefit.

Aside from the issue of cost, there are also issues associated with refueling. Refueling electric vehicles has both short-term and long-term components. In the short term, the existing generating fleet is sufficient to meet almost any expectation of electricity demand growth associated with EV penetration. Moreover, many consumers can recharge at home, and in some cases recharging capability is available at work and other nonresidential locations. But the availability of nonresidential recharging stations is not sufficient to support wider adoption of EVs. As of September 2012, according to the EIA, there were 4,592 nonresidential recharging locations in the United States, where some locations have multiple charging units. Moreover, most of these locations are in only a couple of states.

The location of recharging stations becomes a relevant issue primarily when long distance travel is desired. Currently, range is limited to less than 100 miles per charge in most commercially available EVs on the market today.[5] This creates logistical issues for consumers who wish to drive more than 100 miles for a weekend getaway.

If we think about the prospects of EVs longer term, investments in charging stations can be made, particularly if consumers show a propensity to buy EVs. However, even if the proverbial "chicken-and-egg" problem of vehicles and infrastructure can be overcome, the resulting requirements for new electric generation capacity cannot be understated. For instance, if EVs are widely adopted into the vehicle fleet, a recent Baker Institute report put the projected growth in power generation requirements are 5 percent, 12 percent, and 21 percent higher than the "business as usual" case in 2030, 2040 and 2050, respectively.[6] Given the regulatory burden

[5] For example, the Ford Focus EV has a range of 76 miles and the Nissan Leaf has a range of 73 miles. The Tesla S has an estimated range of over 250 miles, but its cost makes it a prohibitive option for most car buyers.
[6] See "Energy Market Consequences of Emerging Renewable Energy and Carbon Dioxide Abatement Policies in the United States," by Peter Hartley and Kenneth B Medlock III (Sept 2010), available at www.rice.edu/energy.

facing other alternatives, the majority of this incremental demand for electricity would likely be met by natural gas. However, it is important to recognize that this incremental demand will take decades to materialize, absent government regulations that accelerate the process.

Some other factors to consider for natural gas into transportation

There are other costs that exist, some of which are not even in the current discussion. Cost of expanding and upgrading electricity infrastructure can become an issue. Effectively, current mechanisms would force non-EV owners to subsidize EV expansion. This could become a political issue. Moreover, currently 18.4 cents per gallon of gasoline purchased flows into the National Highway Fund to support construction and maintenance of public infrastructure. As the gasoline base diminishes, the fund will still need to be solvent, so electricity and natural gas will need to be taxed accordingly. Currently, no such tax exists, so it is left out of most breakeven calculations for purchase of CNGVs and EVs. In the case CNGVs, assuming refueling infrastructure is added, a tax at the pump can be instituted in much the same manner as is currently done with gasoline purchases. But, its implementation will almost certainly be protested by early adopters of CNGVs as it could represent an *ex post* unexpected increase in the cost of ownership.

In the case of EVs, if mechanisms are proposed whereby electricity sales are taxed, then again, non-EV owners are subsidizing EV expansion. While centralized refueling stations are a possibility, their installation is still a prerequisite capital expense. Moreover, the issue of tax payments is still present. It is more likely that EV owners will recharge at home. So, a mechanism to tax the owners of EVs specifically must be considered. Just as with early adopters of CNGVs, any tax implemented will represent an *ex post* unexpected increase in the cost of ownership, and will likely be met with resistance.

Industrial demand for natural gas

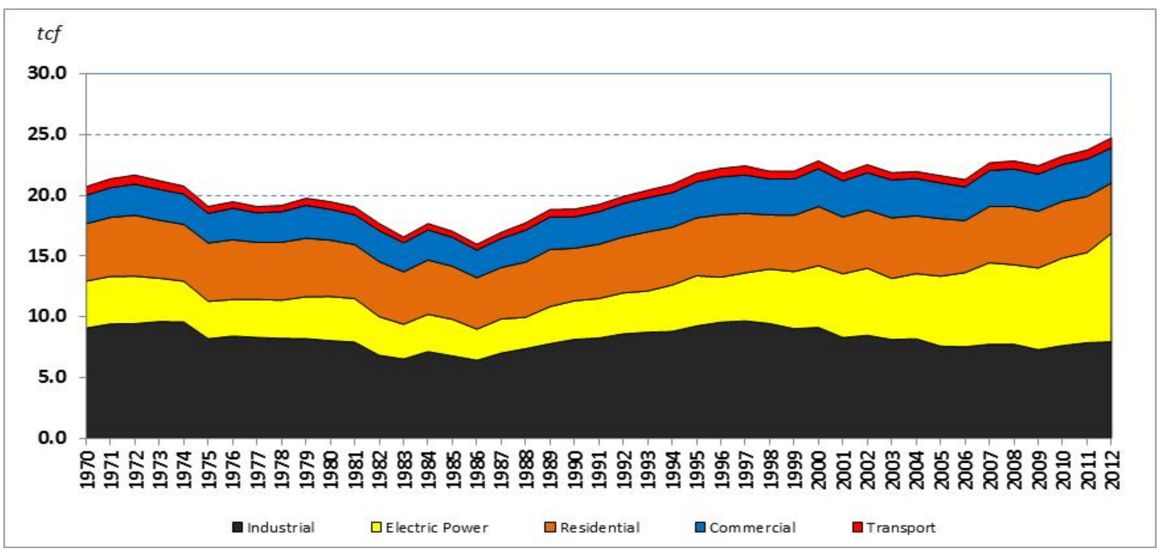
There are, of course, also ample opportunities for demand growth in traditional, non-transportation end uses. Power generation and industrial uses make up the bulk of natural gas demand on an annual basis. Seasonally, the balance shifts more heavily to space heating applications in residential and commercial end uses, specifically in winter months, but the general trends in annual demand growth are set by industrial and power generation uses. In 2012, power generation comprised 36.1 percent of annual demand and industrial comprised 32.1 percent.[7] Moreover, the recent low price environment has natural gas use in both sectors poised to grow.

[7] Data sourced from the U.S. Energy Information Administration (EIA).

Industrial demand most recently peaked in 1997 (see Figure 1), reaching levels similar to what was witnessed in the early 1970s. It steadily declined thereafter due to lower cost natural gas in international locations. Industries such as the ammonia and fertilizer industries were heavily favored by lower cost feedstocks elsewhere, and the late 1990s and early 2000s saw many of these types of industrial gas consumers shutter operations in the U.S. Gulf Coast region, choosing to move abroad. However, much of this has changed in the last few years, and industrial demand has actually grown since 2009, a trend bolstered by low cost natural gas supply due to growth in shale gas production.

An expectation for continued strong supply and stable pricing is being seen in the slate of recent announcements by firms to expand their businesses that rely on natural gas as a feedstock and energy source. Dow Chemical, an industrial user of natural gas, has recently announced a number of significant expansion plans in Texas. Other industrial firms have also announced plans to expand domestically. Methanex has moved forward with plans to relocate its Chilean facility to Geismar, Louisiana, and Sasol has announced intent to move forward with a GTL project in Southwest Louisiana. In short, if price does stay low and relatively stable, it is possible that industrial demand could rise to levels not seen since the mid-1990s. This would represent an over 18 percent increase in industrial gas demand from its current levels.

Figure 1: U.S. Natural Gas Demand by End-Use Sector (1970-2012)



Source: Data from EIA

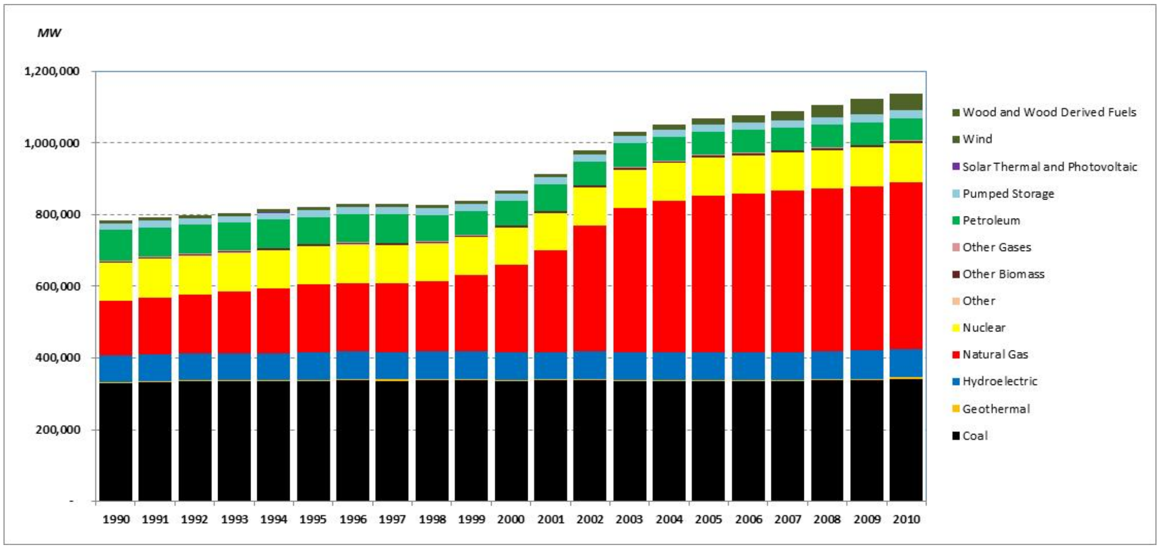
It is important to point out that the long-term trend seen in the industrial demand sector bears resemblance to a cycle. Indeed, even the recent growth in industrial demand has been modest in comparison to power generation use. Nevertheless, the past few years have seen a renewal of industrial demand for natural gas. Moreover, the planned capital expenditures by gas-intensive industrial players are quite large, signaling a substantial comparative advantage exists to siting production in the United States.

Power generation demand for natural gas

Natural gas demand in the power generation sector has substantial growth opportunity through fuel substitution, and it can occur in a relatively short time frame. In 2012 we saw a dramatic increase in the use of natural gas in power generation through substitution with coal. In fact, the natural gas share of power generation in 2012 rose to over 30 percent, which was up from an annual average of 17.9 percent just 10 years ago. This is in stark contrast to coal, which has seen its market share deteriorate from 50.8 percent to 36 percent in the same time frame. In fact, much of the drop in coal's share in power generation is directly attributable to grid-level switching to natural gas.

The rise of gas use at the expense of coal was primarily the result of relatively low natural gas prices, and the fact that there is sufficient natural gas generating capability to allow for large scale, grid-level fuel switching. Much of the existing natural gas fleet that can capitalize on relative price movements was brought into service between 2000 and 2005 (see Figure 2). In fact, natural gas generation capacity surpassed the installed capacity of coal in the United States in the early 2000s. Moreover, most of the capacity that was added employs the latest generation combined cycle technology, meaning its thermal efficiency is substantially higher than the majority of the existing coal fleet.

Figure 2: U.S. Generation Fleet by Type

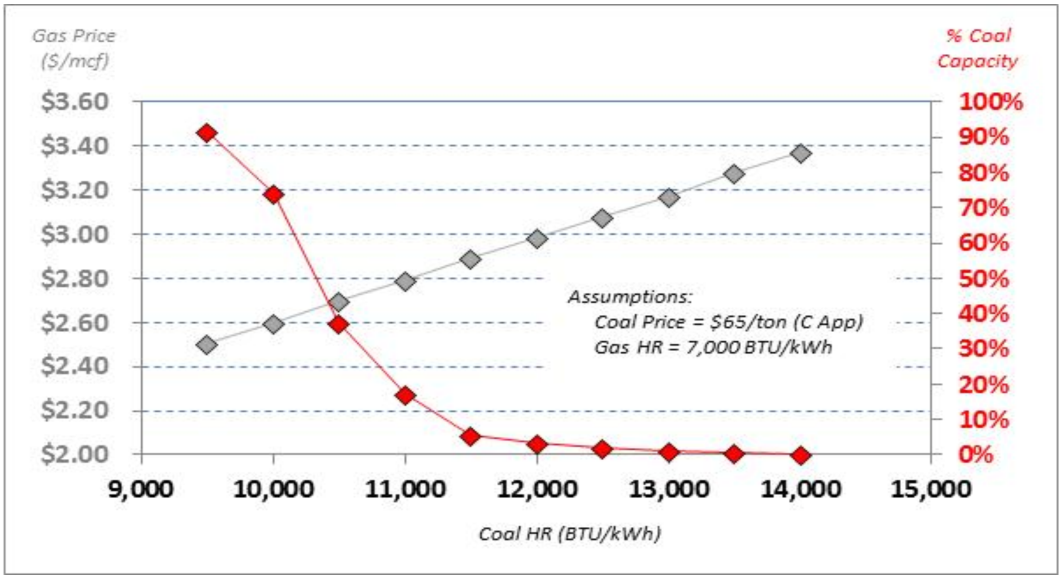


Source: Data from EIA

Figure 3 indicates the prices at which existing capacity of natural gas displaces coal in power generation when the price of coal is $65/short ton (the average 2012 NYMEX price of Central Appalachian coal), and the heat rate of the competing natural gas plant is 7,000 btu/kWh (which is representative of about 30 percent of the existing natural gas fleet). We see that when the price of natural gas drifts below $2.80/mcf, then gas will displace coal capacities with heat rates above 11,000 btu/kWh, meaning roughly 17 percent of existing coal capacity (or 52 GWs) could be displaced. Of course, this example is specific to a coal price of $65/ton, but we can see in general that when gas price falls, we have the possibility to see substantial fuel switching.[8] If coal trades at price levels seen in the international marketplace in the last few years (over $130/ton), then the parity point for natural gas price to displace 17 percent of coal capacity rises to around $5/mcf.

[8] Of course this is only a necessary condition. It may not be sufficient. For example, if contracted coal deliveries continue to pile into inventory, then the shadow value of coal will drop toward zero when inventory nears capacity. Then, coal-fired generating stations will operate even if the price of natural gas dips below this level. This is, however, distinctly a short run phenomenon.

Figure 3: Natural Gas vs. Coal—Existing Fleet Price Parity and Coal Capacity



Source: Price data from EIA; heat rate and capacity data from EPA NEEDS database

If we see the price of natural gas regularly at a competitive advantage to coal in power generation, then older units of the coal fleet will be retired. Initially, the existing natural gas generation fleet will pick up the slack, but eventually, new builds of high efficiency natural gas combined cycle units will be required. This raises the natural gas pricing point for parity because a greenfield expansion must include the cost of capital. However, when one also accounts for the environmental regulations that the U.S. Environmental Protection Agency (EPA) seeks to impose via recent rule-makings, then the competitive balance shifts in favor of natural gas.[9]

[9] The current EPA rule-makings are all under various levels of protest in U.S. courts. So it remains to be seen exactly how binding the recent EPA actions may ultimately be.

Table 1: Summary of Impacts of EPA Regulations on U.S. Coal Capacity

Study Author	Regulation Studied	Capacity Loss (GW)	Date by when Capacity Likely to be Lost
Edison Electric Institute[10]	All- CSAPR, MATS, NAAQS (Ozone rule), CO2 rule, Cooling water intake, clean water effluent guidelines, coal ash	76	2020
Energy Information Administration[11]	All	27	2016
North American Electric Reliability Corporation[12]	Slightly Stricter than MATS	6.5-9.9	2015
Committee for a Constructive Tomorrow[13]	MATS	17-60	2017
Brattle Group[14]	MATS	40-55	2015
ALEC[15]	MATS	15	2015
Department of Energy[16]	MATS, CSAPR	21	N/A
Institute for Energy Research[17]	MATS, CSAPR	34	2015
EPA[18]	MATS, CSAPR	9.5	2015

The importance of EPA action cannot be overstated in this context. Table 1 summarizes the findings of various studies aimed at understanding the impact of various EPA rule-makings. The quantity of coal retirements that could be seen ranges up to 76 GWs of capacity, or up to a quarter of the existing coal fleet. According to analysis done at the Baker Institute, this could result in up to 3.5 trillion cubic feet per year (or about 9.5 bcf/d) of natural gas demand in the power generation sector alone by 2020.

Importantly, the EPAs recent rule-makings are focused on pollutants other than carbon dioxide. However, a displacement of coal by natural gas will have a substantial impact on U.S. CO_2

[10] J. E. McCarthy and C. Copeland, "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?" Congressional Research Service, August 8, 2011.
[11] "27 Gigawatts of Coal-Fired Capacity to Retire Over Next Five Years," Energy Information Administration, Department of Energy, July 27, 2012.
[12] J.E. McCarthy, "EPA's Utility MACT: Will the Lights Go Out?" Congressional Research Service, January 9, 2012.
[13] P. Driessen, "The EPA's Unrelenting Power Grab," Committee for a Constructive Tomorrow, 2011.
[14] S. Levine, "Natural Gas Demand and Environmental Policies," The Brattle Group prepared for the Northeast Gas Association Regional Market Trends Forum, April 13, 2011.
[15] "Economy Derailed: State-by-State Impacts of the EPA Regulatory Train Wreck," American Legislative Exchange Council, April 2012.
[16] "Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations," U.S. Department of Energy, December 2011.
[17] "Impact of EPA's Regulatory Assault on Power Plants: New Regulations to Take 34GW of Electricity Generation Offline and the Plant Closing Announcements Keep Coming," Institute for Energy Research, June 12, 2012.
[18] M. Bastasch, "GAO Estimate May Lowball Effect of Coal Plant Regulations," *Daily Caller,* August 21, 2012.

emissions. Evidence of this was seen in 2012. The low price of natural gas encouraged significant fuel switching to natural gas away from coal, and U.S. CO2 emissions were the lowest they have been since 1992. In fact, according to the EIA, CO2 emissions were 5,293 million metric tons in 2012 and 5,343 million metric tons in 1992. Moreover, this occurred without the EPA rule-makings in force, and the real price of electricity was on average lower in 2012 than in 1992, dropping from $0.1361/kWh to $0.1187/kWh on an average basis delivered to residential customers.

The above highlights a substantial opportunity for growth in natural gas demand, particularly if resource abundance translates into relatively stable and low prices of natural gas. Moreover, increased use of natural gas in power generation, particularly if it comes at the expense of coal, conveys desired environmental benefits. Government action on air and water emissions and mandated pollution control mechanisms will provide a substantial push in this direction.

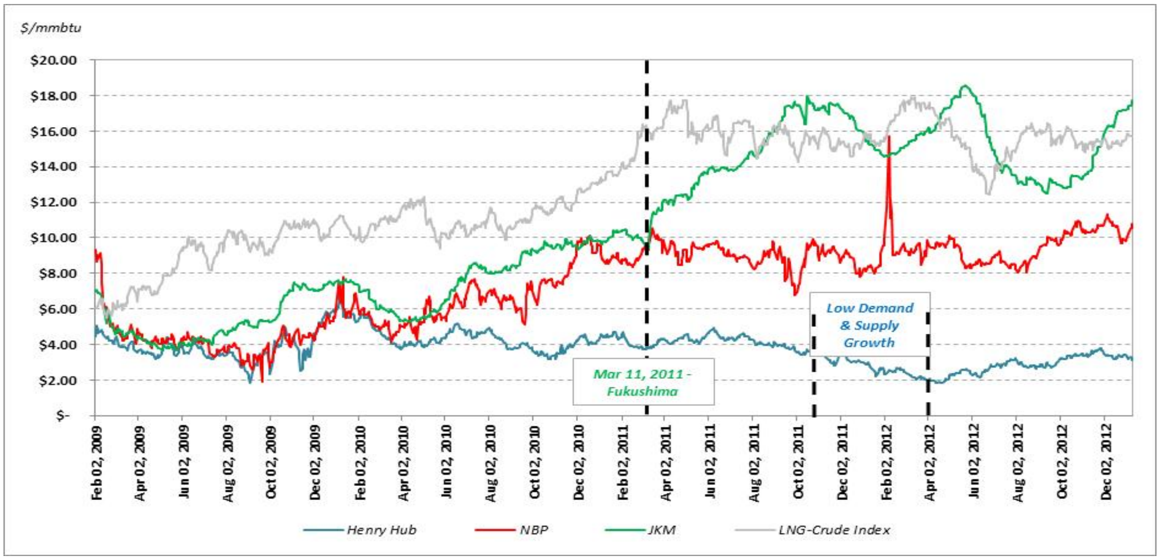
LNG exports

A recent paper by Medlock (2012)[19] argues that the volume of LNG exports from the United States will ultimately be contingent upon domestic market interactions with the international market. This is because U.S. LNG exports will occur in a global setting, meaning the entire issue must be considered as a classic international trade problem. Only then will any insight be gained with regard to export volumes, and thus U.S. domestic price impacts. The paper goes on to argue that (a) the impact on U.S. domestic prices will not be large if exports are allowed, and (b) the long-term volume of exports from the United States will not likely be very large given expected market developments abroad. The bottom line is that the entities involved in LNG export projects may be exposed to significant commercial risk.

Much of this conclusion derives from a relatively straightforward analysis of domestic and international natural gas prices taking into consideration the effects of short-term deliverability constraints. Indeed, the argument is made that the existing spread in prices between the United States, Asia, and Europe is transitory. Referencing Figure 4 can illustrate this argument. Specifically, spot prices in the United Kingdom, United States, and Asia all move together until the middle of 2010. At that point, the U.S. price begins to drift below the prices in the UK and Asia. This is largely the result of growth in shale gas production in the United States.

[19] "U.S. LNG Exports: Truth and Consequence," available at www.bakerinstitute.org.

Figure 4: Regional natural gas prices (Daily, Feb 2009–Jan 2013)

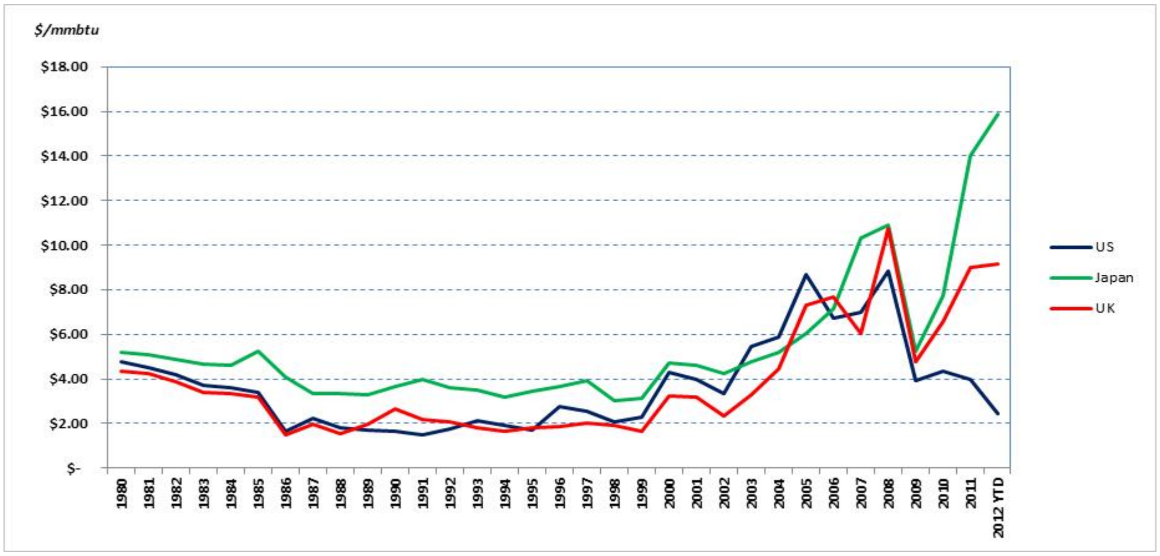


Source: Data from Platts

A significant break in the pricing relationship between Asia and Europe occurs at a specific date, March 11, 2011, the day of the disaster at Fukushima. The Asian spot price jumped by almost $2/mmbtu within a week and continued to climb through the end of the year with the closure of every nuclear power plant in Japan. This was the result of an unexpected demand shock as Japanese utilities scrambled to buy any available LNG for power generation. At the same time, the spread between the United States and Asia was exacerbated by a negative demand shock in the U.S. Namely, the winter of 2011/12 was one of the warmest on record in the U.S., resulting in very low winter heating demands. As a result, natural gas inventories remained very robust and the market was oversupplied, leading to a price collapse to below $2/mmbtu in April 2012. As a result, the spread between the U.S. and Asia rose to as high as $15/mmbtu. The interest in exporting LNG from the U.S. also accelerated during this period. However, it is reasonable to expect Asian price to revert back to its pre-Fukushima relationship with European price as the current deliverability constraints subside—due to new supplies and reactivation of nuclear capacity in Japan. The LNG export opportunity looks a bit more sobering if that occurs.

Importantly, if we consider a longer term view of regional prices, we can begin to understand the potential risk in myopic decision making. Figure 5 indicates annual average price delivered to consumers in Asia, the UK and the United States from 1980 through 2012. We can see from 2000-2008 the U.S. price was rising, and it coincides with the period during which LNG regasification capacity was constructed with an aim to import LNG to the U.S. However, the period since 2008 is characterized by a wide divergence in regional prices, and this coincides with the emerging interest to export LNG.

Figure 5: Regional natural gas prices (Annual, 1980-2012 [year-to-date through Nov.])



Source: Data compiled from Platts, IEA, and EIA

One must consider the longer term price relationships because the recent past is not a prelude to the future. In fact, the 20 years prior to the 2000s is characterized by a relatively stable relationship between the regional market prices that saw Asian prices at a consistent but relatively small (to recent history anyway) premium to prices in Europe and the United States. One must, therefore, question the nature of the recent divergence in regional prices.

The conclusion reached in the study by Medlock was one of very low export volumes from the U.S. because the pricing premiums that exist today will not likely persist due to new supplies from a variety of sources as well as reactivation of nuclear reactors in Japan. In effect, the high prices in Asia encourage responses on many margins and thus result in a reduction in price. This follows from the adage, "the best cure for high prices is high prices."

Concluding remarks—Bringing it all together

All the information, when taken together, points to a series of cause-and-effect relationships that present challenges for some margins of response and opportunities for others. It will be surprising if "all of the above" actually results in a market-driven equilibrium. The traditional consuming sectors, specifically industry and power generation, face fewer obstacles because the mechanisms for demand growth—infrastructure and technology—are already in place. Natural gas into transportation may be a mixed outcome, with fleet vehicles—because they are high mileage vehicles—being the most successful in migrating natural gas into the fuel mix. Absent a policy intervention or a cost reduction, passenger vehicles still face hurdles to large scale penetration of CNG due to lower mileage.

The likelihood of demand pull coming from international sources in the form of LNG exports is high, but not in large quantities. This follows from the fact that U.S. prices will likely rise to reflect marginal costs and international prices are not likely to remain at their current premiums. In fact, if the Asian price reverts back to its pre-Fukushima relationship with European price, then the margin for profitable export of LNG from the United States becomes razor thin. Thus, market forces will ultimately limit the volume of U.S. LNG exports.

So perhaps what is needed for demand growth for natural gas is a relatively simply prescription—economic growth. Economic growth stimulates demand for electricity and industrial goods, both of which favor natural gas. Moreover, as demands in these traditional sectors grow, this will create competition for supplies of natural gas for LNG exports and *new* demands. It is for this reason that the most likely demand for the robust supply of natural gas in the U.S. will come from industrial and power generation uses. Transportation and LNG exports will likely remain marginal influences at best.