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U.S. LNG Exports: Truth and Consequence

by

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Kenneth B. Medlock III, Ph.D., is the James A. Baker, III, and Susan G. Baker Fellow in Energy and Resource Economics at the Baker Institute and an adjunct professor and lecturer in the Department of Economics at Rice University. Currently, Medlock heads the Baker Institute Energy Forum's natural gas program and is a principal in the development of the Rice World Natural Gas Trade Model, which assesses the future of international natural gas trade. He also teaches courses in energy economics and supervises graduate students in the energy economics field. Medlock's research covers natural gas markets, gasoline markets, energy commodity price relationships, energy market forecasting, transportation, national oil company behavior, and the relationships between economic development, energy use and the environment. Medlock is a council member of the International Association for Energy Economics (IAEE), and is the Vice President for Academic Affairs of the United States Association for Energy Economics (USAEE). He is also a member of the American Economic Association and the Association of Environmental and Resource Economists. In 2001, Medlock won (with Ron Soligo) the IAEE Award for Best Paper of the Year in the *Energy Journal*. In 2011, he was given the USAEE's Senior Fellow Award. Medlock has also served as an adviser to the U.S. Department of Energy and the California Energy Commission in their respective energy modeling efforts. He was the lead modeler of the Modeling Subgroup of the 2003 National Petroleum Council (NPC) study of long-term natural gas markets in North America, and was a contributor to the recent NPC studies *Facing the Hard Truths* (2007) and *Prudent Development of North American Resources (2011)*. Medlock received his Ph.D. in economics from Rice and held the MD Anderson Fellowship at the Baker Institute from 2000 to 2001.

Abstract

A decade ago, market players were making large capital investments to facilitate the import to the United States of liquefied natural gas (LNG) from distant locations, such as the Middle East, Africa, and Russia. This was predicated on the consensus at the time that U.S. domestic supply was becoming increasingly scarce. However, innovations involving hydraulic fracturing and horizontal drilling subsequently led to the dramatic growth of domestic production from shale gas. In fact, domestic production growth has been so strong that the U.S. is considered a possible exporter of LNG—an unthinkable notion just a few years ago. This new consensus is fueled by the current reality—one that features abundant supplies and low prices in North America relative to the rest of the world. Importantly, the commercial aspirations of firms that seek to seize the apparent profit opportunity offered by exports run headlong into concerns that allowing exports from the U.S. will force prices up, thereby negatively impacting industrial activity and household budgets. Hence, the issue of allowing LNG exports from the U.S. has entered the political realm.

Several groups—such as the U.S. Energy Information Administration, the Deloitte Center for Energy Solutions, and RBAC—have studied the impact of U.S. exports on domestic prices. These studies generally assume a particular volume of LNG exports from the U.S. when assessing the domestic price impact, but they do not allow interaction between domestic and international markets to influence the volume of trade. U.S. LNG exports will occur in a global setting, so it is an international trade issue. Thus, to separate *truth* from fiction one must apply the appropriate analytical framework grounded in international trade. Specifically, domestic market interactions with the market abroad will determine export volumes and therefore U.S. domestic price impacts.

After introducing a basic international trade framework, the *consequences* of U.S. LNG exports are discussed. This paper argues 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 U.S. will not likely be very large given expected market developments abroad. The bottom line is that certification of LNG exports will not likely produce a large domestic price impact, although the entities involved may be exposed to significant commercial risk.

Introduction

During the past decade, innovative new techniques involving the use of horizontal drilling with hydraulic fracturing have resulted in the rapid growth in production of natural gas from shale in the United States. Although geologists have long known about the existence of shale formations, accessing those resources was long held to be an issue of technology and cost, and recent innovations have made shale gas production a commercial reality. In fact, shale gas production in the United States increased from virtually nothing in 2000 to over 14 billion cubic feet per day (bcfd) by 2010, representing over 25 percent of domestic dry gas production. Moreover, recent Baker Institute analysis indicates it could reach 50 percent of domestic production by the 2020s.

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 a growing interest in shale resource potential in other parts of the world. Thus, North American shale gas developments are having effects far beyond the North American market, and these impacts are likely to expand over time. Prior to the innovations leading to the recent increases in shale gas production, huge declines were expected in domestic production in the United States and Canada, which comprise an integrated North American market. This foretold an increasing reliance on imported supplies of liquefied natural gas (LNG) at a time when natural gas was becoming more important as a source of energy.

Throughout the 1990s and early 2000s, natural gas producers in the Middle East and Africa, anticipating rising demand for LNG from the United States in particular, began investing in expanding LNG export capability, concomitant with investments in regasification being made in the United States. At one point in the early 2000s there were over 47 regasification terminals with certification for construction, which was a clear signal regarding industry-wide expectations for significant declines in future U.S. production. But rapid growth in shale gas production has since turned such expectations upside down and rendered many of those investments obsolete. Import terminals for LNG are now scarcely utilized, and the prospect that the United States will become highly dependent on LNG imports has receded.

Rising shale gas production has contributed to lower domestic natural gas prices, which recently dipped below $2 per thousand cubic feet (mcf) and are currently in low $3 per mcf range. In addition to rendering the import terminals virtually obsolete, this has led to greater use of natural gas in power generation through substitution opportunities with coal, and growth and renewal of industrial and petrochemical demands, some of which had previously moved offshore. There has also been interest in creating new demands through the use of natural gas in transportation, particularly as the price of crude oil remains substantially higher than the price of natural gas on an energy equivalent basis. Finally, and to the point of this exposition, there has been growing interest in developing LNG export capability to capture the arbitrage opportunity that currently exists with U.S. domestic natural gas prices substantially below prices in Europe and Asia.

When considering international natural gas trade, it is important to recognize that the issue is indeed *international*. Thus, we must not only consider what is happening in North America; we must also consider what is happening abroad. For one, the emergence of shale gas in the United States has already had an impact on natural gas markets in Europe and Asia. LNG supplies whose development was anchored to the belief that the United States would be a premium market have been diverted to European and Asian buyers. As discussed in Medlock, Jaffe, and Hartley (2011),[1] this has presented consumers in Europe with an alternative to Russian and North African pipeline supplies, and it is exerting pressure on the status quo of indexing gas sales to the price of petroleum products. In fact, Russia has already accepted lower prices for its natural gas and is even allowing a portion of its sales in Europe to be indexed to spot natural gas markets, or regional market hubs, rather than oil prices. This change in pricing terms signals a major paradigm shift in Europe, and could be the harbinger that oil-indexation will eventually become a thing of the past. In fact, as natural gas becomes an increasingly fungible commodity, which would be the case as the volume of global natural gas trade increases, the paradigm of oil-indexation will come under increasing pressure. This is an important factor when considering the current profit margin available to potential LNG exports.

[1] See the Baker Institute Energy Forum study entitled "Shale Gas and U.S. National Security" available online at http://www.bakerinstitute.org/news/shale-gas-and-us-national-security.

The policy discussion in the United States has heretofore centered on the domestic price impact of LNG exports, should they occur. The results of the various studies that have been commissioned to investigate this issue reveal for a pre-specified volume of exports of 6 billion cubic feet per day an impact of anywhere between $0.22 per mcf and $1.50 per mcf.[2] Interestingly, none of the recent studies performed by various groups in attempt to lend an analytical voice to the discussion actually considers whether or not exports will occur. Each simply takes as given particular export volumes under different scenarios. While this allows for a more direct comparison across studies, it belies a fundamental issue in determining the price impact of allowing exports. Namely, allowing exports does not mean exports will occur in any particular volume, and policymakers should understand this very salient point. Regional price differentials around the globe will be affected by LNG trade because prices both domestically *and* abroad will be influenced by the introduction of trade. As prices adjust to new volumes there will be a feedback that is important in determining the volume of trade that ultimately occurs. In other words, export volumes should be treated as *endogenous* in a context that allows prices both domestically and abroad to adjust. Previous studies have treated export volumes as *exogenous*, which is a critical assumption.

There are several key factors that determine the impact of LNG exports on domestic prices and whether or not LNG exports actually occur. Critical factors addressed herein are (i) the elasticity of domestic supply, (ii) the elasticity of foreign supply, (iii) the role of short-term capacity constraints, (iv) the cost of developing and utilizing export capacity, and (v) the value of the U.S. dollar, an oft ignored issue in this context.

The results of any analysis on the subject of U.S. LNG exports have important policy implications. At the core of the issue is whether or not the U.S. should export the raw material or the manufactured good. In this context, the political debate is really a matter of who collects the rents associated with an abundance of domestic natural gas resource. On the one hand, domestic

[2] See, for example, U.S. Energy Information Administration, "Effect of Increased Natural Gas Exports on Domestic Energy Markets" (January 2012). Other notable studies on this issue are "Made in America: The Economic Impact of LNG Exports from the United States," a report by Deloitte Center for Energy Solutions and Deloitte MarketPoint LLC; "Using GPCM® to Model LNG Exports from the U.S. Gulf Coast," by Robert Brooks, RBAC (March 2012); "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Charles Ebinger, Kevin Massy, Govinda Avasarala, Brookings Institution (May 2012).

producers can earn higher prices for their output by selling to a higher priced *foreign* market. On the other hand, domestic manufacturers can earn higher profits by selling their final output, produced with the aid of low cost natural gas, both domestically and abroad. In both cases, natural gas provides a competitive advantage, but the debate need not be so simple.[3] Specifically, if domestic supply is sufficiently abundant relative to supplies abroad, then rents can be shared on both fronts, meaning there is room for both exports and increased domestic manufacturing. Of course, we need to look at data and evidence to ascertain where the truth may lie.

We begin with a relatively simple discussion of U.S. LNG exports as a classic problem in international trade. This will allow an assessment of the likely price impacts of LNG exports should they occur, where the result is appropriately couched in the context of *international* trade. We then discuss whether or not LNG exports from the U.S. are likely to be a *profitable* long-term opportunity, and present results from the latest Reference Case of the Rice World Gas Trade Model (RWGTM) as support. This, of course, has implications for the position that policy-makers, many of whom have recently taken a strong interest in the question of LNG exports, should take. In particular, concerns about domestic price impacts may be overblown if market forces are likely to prevent any significant influence on domestic prices. In turn, the question the Department of Energy (DOE) faces regarding LNG export licenses is less contentious because market adjustments will ultimately limit the construction and/or utilization of terminal capacity, in much the same way they have done with LNG import facilities.

Importantly, there is a distinction that must be made between long-run and short-run market equilibrium. In fact, this distinction is vital to assessing the long-run viability of LNG exports from the U.S. For example, the current price for natural gas in the United States reflects some short-run, or transitory, features of the market. However, these features are not reflective of the central tendency about which price will converge. Specifically, the winter of 2011-12 was one of the warmest on record, which translated into a far below-normal winter heating demand for natural gas. Coupled with growth in production from shale gas, this triggered a large surplus in natural gas inventories, which, in turn, pushed price well below where it would typically be

[3] Although we do not explore it in any detail here, there is also the issue of economic efficiency that should be addressed. In particular, the efficient allocation of resource rents should fully reflect the opportunity costs of alternatives so that no other allocation would be overall welfare improving.

during winter. In fact, it touched below $2 per mcf this winter. The subsequent response in the U.S. market has been as expected—reductions in gas-directed rig counts and increases in natural gas demand at the expense of coal in power generation—thus pushing price up by early August to about $3.20 per mcf. While prices could fall over the next few months as inventory levels approach capacity, the long-term sustainable price must reflect the marginal cost of supply.[4] Our work at the Baker Institute indicates this is likely in the $4 to $6 per mcf range for the next couple of decades. Of course, unexpected events can cause short-term deviations from this, but market responses should generally push prices back toward their long-run equilibrium level.

Identifying unexpected, transitory events is crucial to characterizing the current natural gas market. As we shall argue below, in addition to the current weakness in U.S. market price, the strength seen in Asian prices coincides with the unexpected increase in demand due to the phased shutdown of all of Japan's nuclear reactors in the wake of the disaster at Fukushima in March 2011. This demand shock created tightness in the LNG market that has dramatically influenced the spot price of LNG in Asia. In general, unexpected changes in demand can create transitory price movements, both up and down, because supply cannot react quickly enough. We will present evidence below that this point is critical to understanding the current state of domestic and international natural gas markets, and how markets are likely to evolve over time.

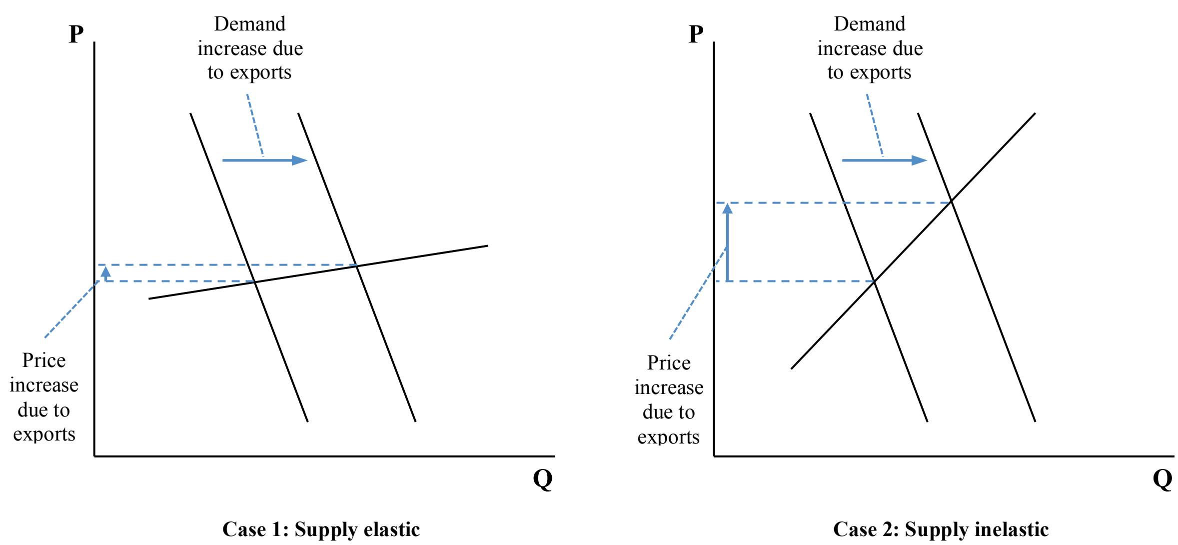
Finally, this paper will argue that the lens that has been offered to policymakers to address the question of U.S. LNG exports is inappropriate because it assumes a level of exports without accounting for the international market reaction. The question before policymakers is one of licensing a capability, not licensing a fixed volume. Therefore, this issue must be viewed in the context of international trade if informed policy decisions are to be made.

[4] In fact, the natural gas price could fall as we approach the end of the injection season. In particular, if summer electricity demands are not sufficient to offset production volumes, then inventories could approach capacity as October nears. This could result in the use of emergency balancing procedures, such as the issuance of operational flow orders, in which case price would likely fall dramatically. However, absent another warm winter, price should rise as the market rebalances going into 2013.

U.S. LNG Exports as a Simple Trade Problem: The Basic Paradigm

Generally, when analyzing this problem, an assumption is made that a certain quantity of exports will occur by a particular date. The resulting impact on domestic price is the centerpiece of the analysis, and the outcome is entirely driven by the responsiveness of domestic supply to the increase in "demand" implied by the export quantity. In other words, as indicated in Figure 1, we shift the demand curve out and the impact on price depends on the steepness of the supply curve. In short, the more *elastic* (flatter or price responsive) domestic supply is, the lower the impact on price for a given increase in exports.

Figure 1. The Elasticity of Domestic Supply and the Impact of Exports on Price



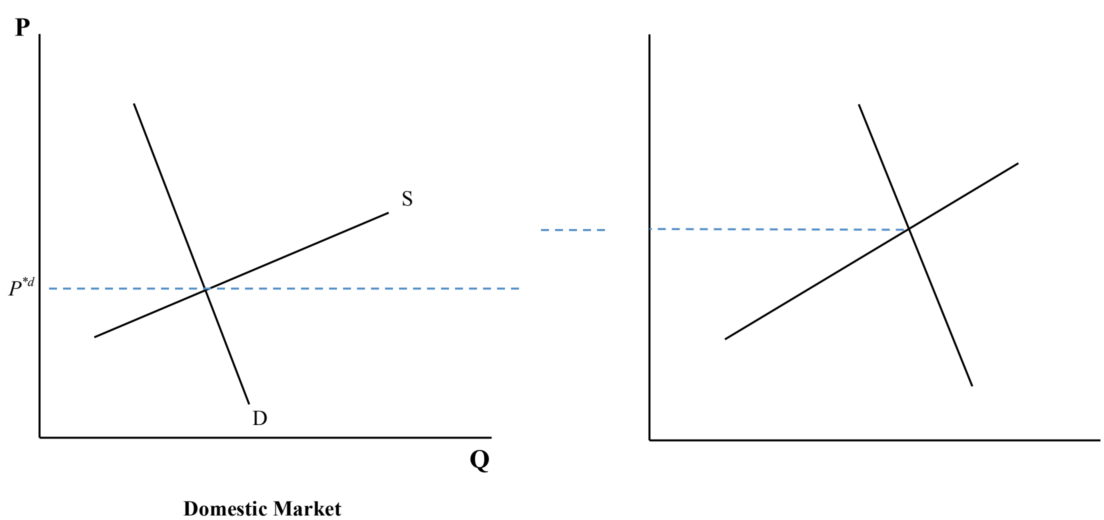
One fundamental flaw in this type of analysis is that it ignores the effects on price in the importing market and therefore any feedback that may occur. For example, consider Case 2 in Figure 1, where domestic price significantly increases for a given export volume. We then have to ask ourselves how likely it is that the assumed export volume (indicated by the increase in demand) would occur. The very reason the incentive to export exists is because there is a consumer in a foreign market that is willing to pay a certain margin (which covers the cost of the trade) above the domestic price. Will that price differential persist if the domestic price rises substantially? In addition, we have to ask, what if the price in foreign markets also falls as a result of the additional supply of exports from the U.S.? To answer these questions, we must assess both the domestic market *and* the foreign market in order to fully understand the implications of U.S. natural gas exports.

The answers to these questions are obviously very important for domestic export policy considerations. In particular, it could be that price adjustments both domestically and abroad render exports from the U.S. to be very small, in which case the subject of licensing firms to export would bear very little risk for higher domestic prices, but the exporting firms could bear a large commercial risk. In any case, it is important that the problem be analyzed in an appropriate manner so that policies are properly informed.

A Basic International Trade Model

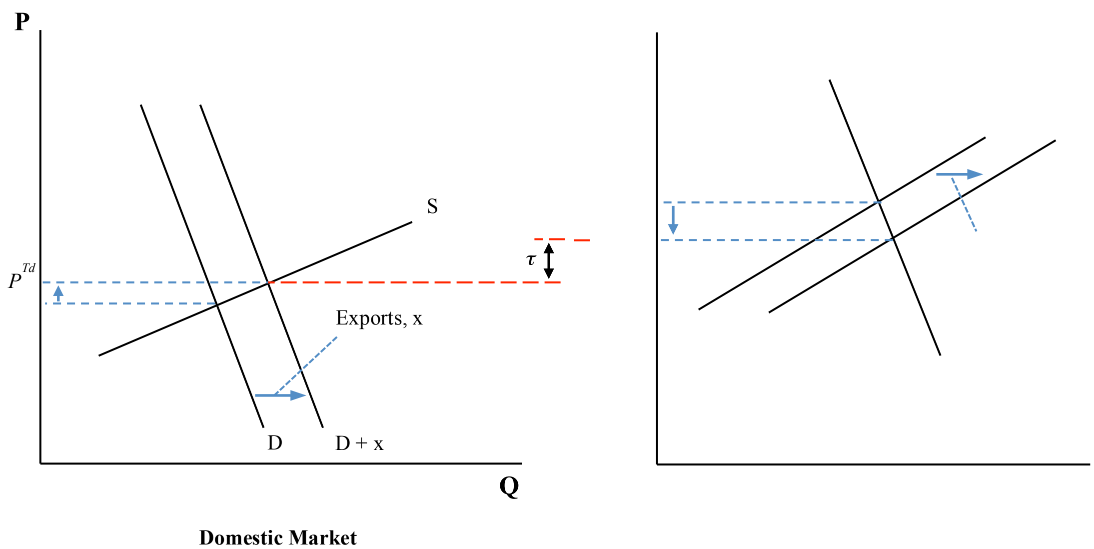
Let's consider our problem in the context of an international trade model. In Figure 2, we have a domestic and a foreign market. First consider an autarkic equilibrium, that is, one in which there is no trade. The supply-demand equilibrium in the domestic market yields a price below that of the supply-demand equilibrium in the foreign market. If the spread between the two prices, which is denoted as $P^{*f} - P^{*d}$ in Figure 2, exceeds the cost of liquefaction, shipping and regasification, it leads to an "arbitrage opportunity" that domestic suppliers would like to exploit.

Figure 2. Domestic and Foreign Market with No Trade



Once we establish there is indeed an arbitrage opportunity, we can now examine the impact of allowing trade between the domestic and foreign market. In Figure 3, we depict the effect of allowing exports from the domestic market to the foreign market.

Figure 3. Domestic and Foreign Market with Trade



Notice that price rises in the domestic market, as was indicated in Figure 1, but price also falls in the foreign market, a result not gleaned from the simple "domestic-only" analysis considered in Figure 1. If markets were left unconstrained by policy, an equilibrium would be reached in which price in the two markets only differs by the transport cost[5] associated with trade, indicated as τ in Figure 3. Importantly, if exports exceed x, the price difference will collapse such that $P^{Tf} - P^{Td} < \tau$, meaning trade will not be profitable because it will not cover transport costs. It is precisely this point that is explicitly not considered in the simple domestic-only analysis of the price impacts of LNG exports. Moreover, this point is extremely important from a policy perspective. If the price differential between the foreign and domestic markets is reasonably responsive to the introduction of trade, then licensing exports will not necessarily result in large export volumes.

[5] Henceforth, we refer to the sum of liquefaction, shipping, and regasification costs simply as "transport costs."

In general, trade theory tells us that in the long run, as market participants seize arbitrage opportunities, prices will adjust thereby eliminating additional trade. Thus, we must consider the possibility that not all of the export proposals that currently seek certification approval will move forward. Moreover, it is possible that at least some export capacity, once constructed, will remain underutilized. In the short run, however, demand shocks and other transitory factors may present profitable arbitrage opportunities that will see export volumes increase on occasion. But, these will generally be fleeting, and they certainly won't support large-scale capital investments in export capacity.[6]

The discussion above illustrates the importance of analyzing LNG exports from the U.S. in the context of *international* trade.[7] Importantly, the discussion around Figure 3 focuses on long-run equilibrium. As such, we will now refocus the discussion to include short-run factors so that we can expand on the framework introduced above to examine the current market environment and the implications for trade and domestic and international pricing.

U.S. LNG Exports: The Current Market Reality

To begin, we must comment on the shapes of the supply curves in the U.S. and abroad, in other words, what is the appropriate elasticity of supply to inform our analysis.[8] Without doubt, the elasticity of supply in the North American gas market is substantially larger since the emergence of shale. Using data from the recently completed Baker Institute study, "Shale Gas and U.S. National Security," we estimate that the elasticity of supply in the United States post-shale has

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[6] As an illustrative microcosm of the principles of trade theory in practice, we can consider what occurs in the U.S. domestic natural gas market. Arbitrage opportunities occasionally present themselves as large differences in regional prices. If pipeline capacity is sufficient between the two regions, marketers will quickly eliminate the pricing difference through trade by scheduling shipments across the pipeline. If pipeline capacity is not sufficient, pipeline developers will evaluate the opportunity to add capacity. In particular, if the regional price differences are due to short-term factors, capacity will not generally be added. But, if the regional price differences are due to more structural elements, then capacity will generally be added. In either case, the responsiveness of price to trade in both regional markets is a critical determinant to the capacity investment decision.

[7] The analysis uses a very basic construct in trade theory that can be complicated substantially if one wants to employ more modern tools of international trade theory. However, the basic lesson is the same, so for brevity and ease of exposition, we use a relatively basic analysis.

[8] Note that we do not focus on the elasticities of demand because in both the domestic and foreign markets, demand is being driven by growth in power generation requirements. Given the lack of technological differences, the availability of competing fuels and fact that demand for natural gas is relatively own-price inelastic in all major end-use markets—generally varying between 0.15 and 0.3 according to Baker Institute analysis—we focus instead here on the relative elasticities of supply. In fact, allowing for variable elasticities of demand will tend to reinforce the results herein.

risen over five-fold, from 0.29 to 1.52.[9] So, Case 1 from Figure 1 above is the most realistic representation of the supply picture in the U.S. In effect, additional shale resources can be exploited with only slightly increasing costs. This, in turn, has effectively stretched the domestic supply curve, rendering it relatively flat at a price between $4 and $6 per mcf.[10]

The aforementioned elasticity of supply in the U.S., so estimated using the RWGTM, is best characterized as a *long-run* elasticity. In other words, it is the elasticity that would apply if all actors in the market are able to fully respond to expected events. This contrasts to a *short-run* elasticity, which would be smaller and also more appropriate when gauging the price and supply response to an *unexpected* occurrence, such as a demand shock. When considering the price impact of *expected* events, such as the opening of an LNG export terminal, the long-run elasticity is a more appropriate representation of supply responsiveness. Producers know the additional market "demand" in the form of exports is coming as the development plans are common knowledge. Thus, the additional demand should not be treated as an unknown. This is an important and often misunderstood point when modeling the likely impacts of LNG exports from the U.S. In fact, using a short-run elasticity in this instance is akin to assuming LNG exports come as a surprise.

How do we characterize the current foreign market? Figure 4 indicates the effect of an increase in demand in the foreign market (a move from *D* to *D'*) in the face of a short-term constraint on the ability to deliver supplies (where the constraint is represented by the vertical portion of the supply curve, *S*). Deliverability constraints often arise in the short term, particularly when there is an *unexpected* increase in demand. The situation can be more pronounced when storage capacity is lacking and/or there is an inability to physically hedge against unexpected events. Basically, it takes time to develop new supply capacity and a sudden, unexpected increase in demand can result in short-term capacity constraints becoming binding.

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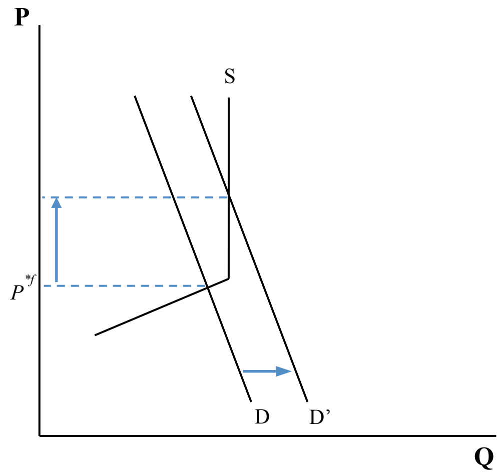
[9] "Shale Gas and U.S. National Security" was sponsored by the Office of International Policy and Affairs of the U.S. Department of Energy. The study was released in June 2011, and is available online at http://www.bakerinstitute.org/news/shale-gas-and-us-national-security.

[10] One might question the validity of this assertion given that the current price is below this range. However, as argued above, the current price environment is at least partly due to an unexpectedly below-normal winter heating demand coupled with continued growth in domestic supply; it does not reflect long-run marginal cost.

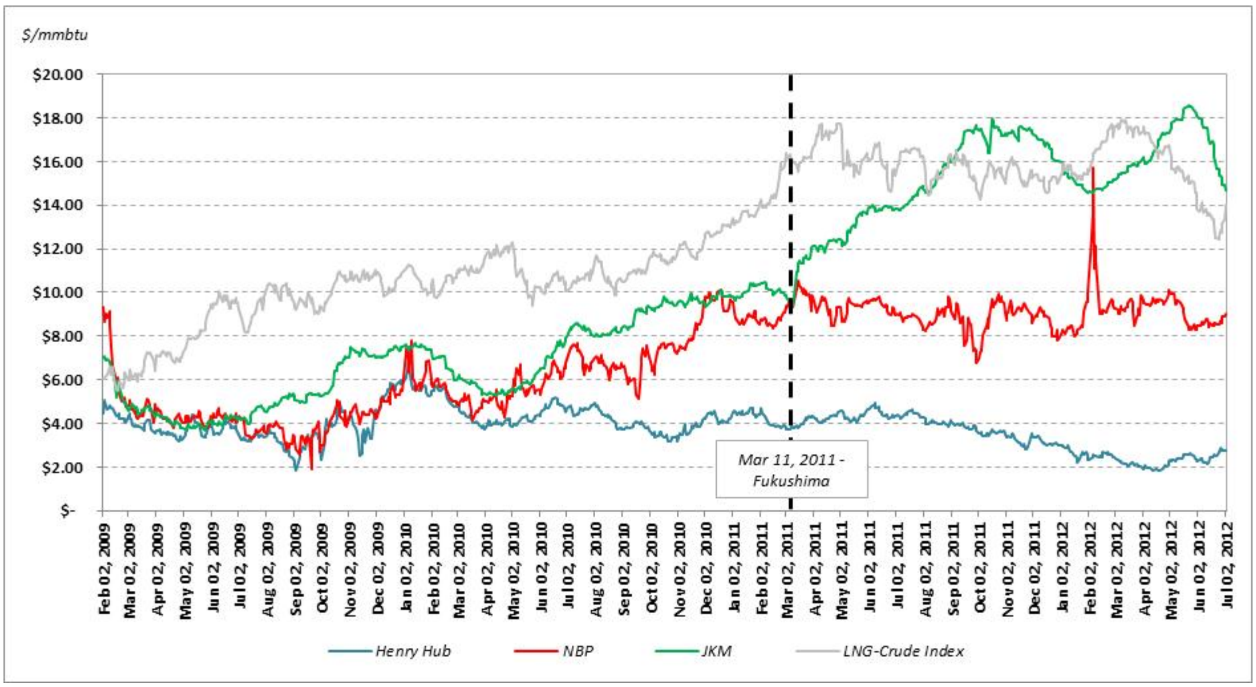
Figure 4. The "Foreign" Market for Natural Gas



This argument is illustrated by the aftermath of the disaster at Fukushima in Japan in March 2011. Following the tsunami, the resulting nuclear accident sparked safety concerns that ultimately led to the closure of all of Japan's nuclear power generating capacity by early 2012. This, in turn, dramatically increased Japanese utility demand for LNG. This is depicted in Figure 4 as a shift in the demand curve from *D* to *D'*. The subsequent increase in the price of LNG deliveries was substantial. In fact, the Platts Japan/Korea Marker price, which is the benchmark daily assessment of the spot price for cargoes of LNG delivered ex-ship to Japan or Korea, increased dramatically following the incident at Fukushima. Moreover, the price increase continued in the following months as the phased shutdown of all of Japan's nuclear plants commenced (see Figure 5).

Figure 5 indicates the prices of natural gas at the U.S. Henry Hub (HH), the UK National Balancing Point (NBP), the Platts Japan/Korea Marker (JKM), and a representative crude-indexed LNG price from 2009 to the present. Following the nuclear incident at Fukushima and the subsequent phased shutdown of all of Japan's nuclear reactors, the JKM price is markedly different. In fact, as can be seen in Figure 5, JKM jumps markedly relative to both NBP and HH after Fukushima, and, in fact, it approaches oil-indexed parity.[11] This is precisely what we would expect in the face of a constraint on deliverability of LNG to the Asian market.[12] The implication is that the price difference that currently exists between Asia and the rest of the world is at least partially the result of short-term constraints, or transitory factors, meaning they should not be expected to persist. In fact, the pre-Fukushima pricing relationship between JKM and NBP can be expected to re-emerge as both new LNG delivery capacity is brought online, new sources of supply are developed and, in particular, if Japan's nuclear reactors are restarted.

Figure 5. Global Marker Prices (Daily, Feb. 2, 2009–July 31, 2012)



Sources: Platts, U.S. Energy Information Administration, author's calculation

In general, dramatic increases in price will occur when demand increases unexpectedly in the presence of a supply constraint. This is consistent with *short-term* supply being highly *inelastic*. In other words, in the LNG market, supply was not capable of fully responding to the *unexpected* increase in demand, so price had to rise.

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[11] Note, the LNG-Crude Index is constructed using the formula $\mathit{LNG\text{-}Crude\ Index} = 0.14 \times \mathit{Brent}$, so it should be viewed only as an approximation. The terms of specific oil-linked contracts will vary, sometimes dramatically, from this formula. Moreover, the Index so constructed is provided only as a point of reference.

[12] It is also worth noting that the standard deviation of the spread of daily prices between NBP and JKM is 2.12 times higher post-Fukushima. This is also consistent with the emergence of a constraint on deliverability to Asia.

This raises another very important point about liquidity and the evolution of regional gas markets—an ability to arbitrage regional price differentials will force prices into relative ranges defined by transportation costs. A lack of capability to arbitrage current regional price differences allows prices to drift apart dramatically. If the U.S. develops export capability, an additional arbitrage mechanism will be introduced. All else equal, this will force a shift in the relative nominal prices of gas in markets around the world to a long-run equilibrium set of differentials that is defined by transportation costs and currency values.

Figure 6. The "Foreign" Market Price Impact of LNG Exports from the United States

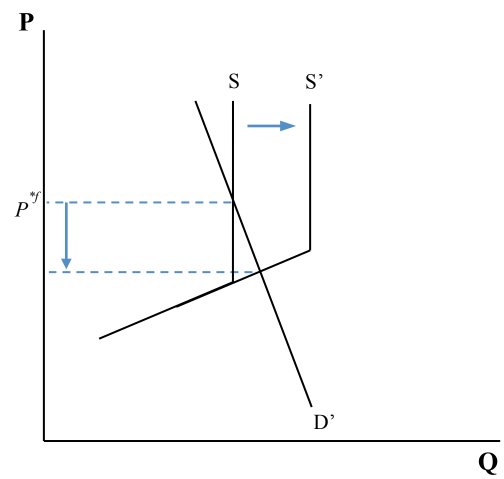


Figure 6 helps to illustrate this point. If one adds supply to a supply-constrained market, the price in that market will fall precipitously, all else equal. In the case of the Asian natural gas market, supply will almost certainly be added—whether it is as LNG exports from the U.S. or other sources of supply via pipeline or LNG to Asian consumers—precisely because the high near-term price encourages such a response. In Figure 6, we see that the price of natural gas paid by LNG importers in Asia will fall substantially when the current deliverability constraint on supply is relieved. Thus, to the extent that Figure 6 represents the Asian LNG market, the addition of, say, LNG supply from the U.S. will have a very large effect on prices paid by foreigners, as will the addition of any new incremental supplies. Moreover, the recommissioning of Japan's nuclear fleet, should it occur, will exacerbate the price decline by reducing demand.

The above becomes even more salient when one considers the volumes being discussed. Global LNG trade in 2011 totaled 32 bcfd, according to the *BP Statistical Review of World Energy, 2012*. Currently, in the U.S. alone there is over 17 bcfd of export capacity in various stages of proposal and development, which represents over 50 percent of current traded volume. If even one-third of this capacity is built and placed into operation, it will dramatically alter the ability to supply the Asian market with natural gas.

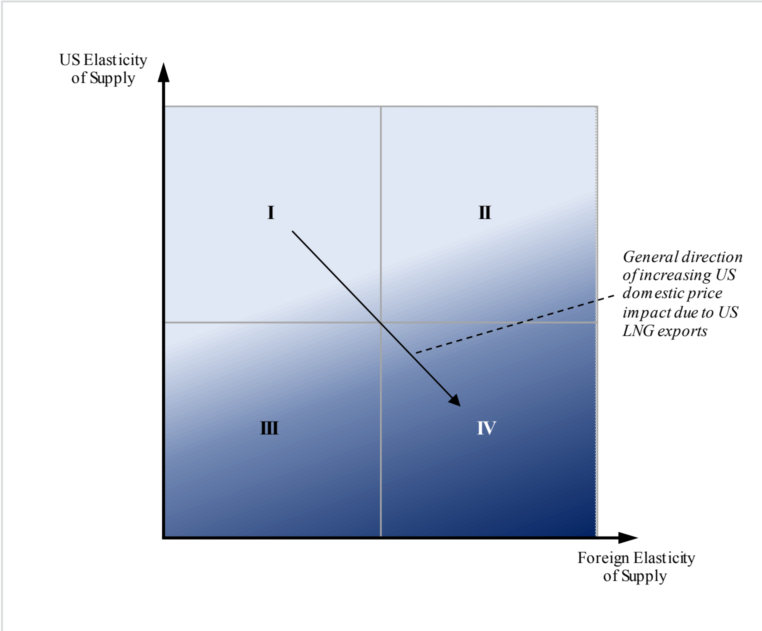
The preceding highlights a very important point when considering both the long- and short-run price effects of trade in domestic and foreign markets. The *relative* elasticities of supply will determine the extent to which prices rise (or do not rise) in the traded markets. This point is lost in a U.S.-centric analysis. Moreover, the point is of considerable importance when considering U.S. policy on exports. In particular, if the market abroad is short-term supply-constrained (meaning supply is inelastic) and the domestic market is supply elastic, then the majority of the price movement that will occur when trade is introduced will be abroad.

A Rule of Thumb Approach

A general approach to analyzing the effect of LNG exports on both foreign and domestic prices, and in fact the commercial viability of incremental export proposals, is illustrated in Figure 7. Figure 7 summarizes the incidence of U.S. exports on domestic price for a range of possible scenarios. Moving from the upper left-hand side of Figure 7 to the lower right-hand side (or moving from Quadrant I to Quadrant IV), we see an increasing impact of trade on U.S. price. So, the U.S. domestic price impact of U.S. LNG exports increases as the *relative* elasticity of supply in U.S. falls. In other words, if U.S. supply is highly elastic and foreign supply is highly inelastic, then the U.S. domestic price impact will be very small, but the price impact abroad would be substantial. Note that this situation would erode the current price difference that exists between the U.S. natural gas price and the price abroad quite substantially.

Figure 7, although it is only qualitatively illustrative, can also allow us to make some inference on the overall profitability of U.S. LNG exports. For example, if the elasticity of supply in the foreign market is very high *and* the elasticity of supply in the U.S. is very low, then the foreign price will not change much as a result of U.S. LNG exports, but the U.S. price would increase a lot. This is, of course, the scenario causing many policymakers concern, but it is the least likely outcome.

Figure 7. The Incidence of U.S. Exports on U.S. Price



To the discussion of Figure 7, as we move into Quadrant II, the price differential will remain the largest for a *given* volume of trade. Thus, if the elasticity of supply in both markets is large, the price in both markets should not change by a significant amount when trade commences, meaning there will be rents associated with export capacity. Importantly, this is not meant to represent that *any* trade is more profitable; rather, it is meant to indicate that the *marginal* trade is generally more profitable. The implication is that if Quadrant II describes the situation in the market, then a large volume of trade is possible with little effect on price in either market. This, in turn, means that owners of U.S. LNG export capacity will generally receive large rents.

An important point of caution is warranted here. A situation described by Quadrant II in Figure 7 can only persist in the long run if suppliers in the U.S. markets are willing to forego future LNG export capacity expansion in the face of large rents. In addition, it would be necessary for supply in the foreign market, given that it is highly elastic in this case, to be generally more costly than

U.S. supply. In other words, the foreign market must be characterized by a long, flat supply curve at a relatively high price.

However, neither of these conditions is likely to be true. For one, given the current push to license and ultimately construct LNG export terminals in the U.S., it is highly unlikely that developers would be willing to forego profits associated with LNG exports, unless of course they are unable to export due to a prohibitive act of a regulatory authority. Moreover, Baker Institute analysis of the quantity and cost of supply around the world indicates that there is a large amount of natural gas available outside of North America, assuming political and regulatory factors do not prohibit investment, and that the long-run development cost of that supply is certainly not substantially higher than supplies available in the U.S. This is particularly true in regions with high quantities of associated liquids, such as many currently producing regions in the Middle East and Africa.

As alluded to above, the scenario of most concern to policymakers is one where the U.S. spot price will rise to the *current* international price. This outcome can only be true if U.S. domestic supply is perfectly inelastic (meaning production is *absolutely* unresponsive to an increase in demand), and rest of world supply is perfectly elastic (meaning additional supply from the U.S. will not alter the price of the marginal supply abroad). If this is the case, then indeed the U.S. price would rise dramatically, and Quadrant IV in Figure 7 is the best descriptor of the market. Moreover, if this were the case, then the increase in domestic price would eliminate the profitability of trade, meaning that although price rises domestically, very little (if any) export would actually occur. Finally, if one adheres to the view that U.S. supply is perfectly inelastic, then it must also be true that any source of additional demand will cause price to rise, whether it is from the introduction of LNG exports or increased domestic use.

The Viability of U.S. LNG Exports

The prospect of exporting LNG from the U.S. to consumers in Asia and Europe arises from the fact that spot prices for natural gas in both Europe and Asia are well above the current spot price at Henry Hub, as indicated in Figure 5, so much so that any trade evaluated at current market conditions looks very profitable. However, *current* market conditions do not define long-term commerciality of a trade; *future* market conditions do. Therefore, we must develop an assessment of the future given our state of knowledge today. To evaluate the likelihood of long-term profitable LNG exports from the U.S., we used the latest Reference Case of Rice World Gas Trade Model (RWGTM). In short, the Baker Institute projects that the next three decades do not indicate a future in which exports from the U.S. Gulf Coast are profitable in the long term, at least not if developers are seeking a competitive rate of return to capital.[13]

As outlined above, we know from international trade theory that upon the introduction of U.S. LNG exports, the degree to which the price in the U.S. increases and the degree to which the price abroad decreases will be dependent on the relative elasticities in the two markets. So, we simply need to assess the relative elasticities in the two markets to determine what is likely to happen in practice.

In the U.S. market, domestic production has risen dramatically in the past few years resulting in prices being driven down from double-digit highs in 2008 to the current environment in the low $3 per mcf range. Aside from the lack of heating demand this past winter, the softening of price in North America since 2008 is the result of innovations that have made recovery of natural gas from shale a commercial reality, and is indicative, more generally, of a domestic supply curve that has become relatively elastic. Notice, when evaluating the domestic price impacts of LNG exports, this should push our focus into the upper half of the diagram in Figure 7.

An important point is worth emphasis here. We mention above that the long-term equilibrium price is likely to be in the $4 to $6 per mcf range. The current price environment is at least partly the result of an unexpected negative shock to demand in the U.S. In other words, we had a warm winter, which means demand is unexpectedly below normal, even with the current weakness in the U.S. economy. Being unexpected, producers can only respond after the fact. This is another example of a short-term constraint (on demand in this case) that has exacerbated the current price spread between North America and the rest of the world. It also means that the correct point of

[13] The Rice World Gas Trade Model (RWGTM) has been developed by Peter Hartley and Kenneth Medlock III of Rice University using the *MarketBuilder* software program available from Deloitte MarketPoint, Inc. More information on the RWGTM is available from the author upon request.

reference when considering the impact of LNG exports from the U.S. on domestic prices is the long-run equilibrium, since that is where prices will settle even without exports.

Also in the last couple of years, increases in demand in Asia have tended to push price up. Moreover, given the lack of alternatives/competition for Asian consumers in particular, large rents are being earned in the short run by LNG suppliers to the Asian market. This all stems from the realization of a short-run capacity constraint, or a situation where supply is highly inelastic. Again referring to Figure 7, this will tend to push us into Quadrant I, meaning the introduction of LNG exports from the U.S. will likely see most of the price response in the foreign market as the short-run capacity constraint abroad is relieved.

Under virtually every condition described by Figure 7, the current price differential that exists between the U.S. natural gas price and prices overseas will fall with the introduction of U.S. LNG exports. Of course the volumes associated with a particular decline in the price spread will depend on the relative elasticities. In particular, if we move to the far upper right corner of Quadrant II, a large volume would be needed to erode the price differential. However, moving toward virtually any other corner on the diagram will require very little traded volume to see the price difference collapse.

Given the short-run nature of the supply constraint in Asia, one should also expect that competing potential opportunities to provide natural gas supplies to the Asian market will be evaluated and perhaps even taken. Examples of competing projects could include development of unconventional resources in Asia, pipeline import options from Russia, Central Asia, and/or South Asia, and/or competing LNG supplies from Australia, East Africa, the Middle East, and/or North America. In other words, the current arbitrage opportunity is being aided by short-run *in*elasticity of supply in and to Asia. In the long run, this cannot be expected to persist, and the development of new supplies from outside the U.S. will only serve to further erode regional price differentials, all else equal.

Indeed, modeling at the Baker Institute indicates that prices outside of North America will likely soften relative to their current levels. This reflects several factors:

- For one, longer term shale developments in places such as China, India, Australia, and several countries in Europe will become commercially attractive in price environments in excess of $7 per mcf. Thus, foreign shale supplies effectively serves as a sort of backstop on long-term prices.
- Secondly, the development of pipeline supplies from Russia, Central Asia, and South Asia to China will displace the need for LNG. This frees up those supplies for consumers in Korea and Japan. So, pipes serve as another point of competition for LNG longer term, particularly in developing continental markets.
- Third, exchange rate movements will affect dollar-denominated supplies abroad. In particular, if the U.S. dollar strengthens relative to its recent historical lows against major traded currencies, the evaluation of dollar-denominated arbitrage opportunities will change. This will tend to lower the current spreads between the U.S. and Asia and the U.S. and Europe, but importantly, this will not be due to any fundamental shift in the physical value of the commodity. Effectively, a stronger dollar makes dollar-denominated commodities more expensive.
- Fourth, growth in competition will foster increased liquidity, and a movement away from the traditional pricing paradigm of long-term oil-linked contracts. Importantly, there is no guarantee that movement away from oil-indexation will result in natural gas prices falling longer term relative to crude oil; rather, a lack of oil-indexation should only mean that gas will be priced according to marginal cost.

Each of these points has implications for U.S. LNG exports to Asia and Europe.

Global Shale Gas Opportunities and Foreign Supply Developments

Relatively high prices in Europe and Asia have already encouraged supply responses from shale and other resources in those markets. While the initial forays into shale in Europe and other regions have proven to be more costly than the experience in the U.S., much of that is due to lack of equipment and personnel and will likely prove transitory as high quality opportunities are identified. The prospects for shale developments longer term in China, in Australia, and in Argentina (which could serve the Pacific basin via LNG) all look promising. With the Chinese natural gas market expected to be the primary source of growth for LNG suppliers in the coming decades, the large assessments for recoverable shale gas in China is certainly something to be considered.[14]

Aside from unconventional natural gas resources, recent finds in offshore basins in the Eastern Mediterranean and East Africa may prove to be highly competitive resources that can serve demands in both Europe and Asia. While these sources of supply in particular would have to be transported as LNG, there are also viable sources of supply in both Western Siberia and Eastern Russia that could be transported by pipeline to Asia. In addition, Iraqi supplies by pipeline to Europe also remain a potential. To make matters more complex, supplies from Central and South Asia already or soon will enjoy pipeline links to China, and discussions continue regarding alternatives for Central Asian supply routes to Europe.

Altogether, the evidence is substantial that the long-run supply curve outside of North America is much more elastic than the current market might indicate, and development of these supplies will ultimately bring prices down. In fact, this is a major point of competition for U.S. LNG export projects currently under consideration. Specifically, if shale opportunities in Europe and Asia, and other sources of imported pipeline and LNG supply can be brought to market, then growth in global production will put downward pressure on prices everywhere. Of course, geopolitical and regulatory uncertainties and constraints could overwhelm commercial considerations, but even if these "above-ground" constraints do exist, they would have to be substantial, widespread and persistent given the number of competing supply opportunities that exist in the longer term.

In sum, U.S. LNG exports face risk from foreign supply developments. This is eerily reminiscent of the rush to build LNG import capacity in the U.S. in the early 2000s, which ultimately turned out to be *ex post* ill-conceived investments due to U.S. domestic supply response.

[14] In fact, the Baker Institute paper authored by Kenneth B. Medlock III and Peter Hartley entitled "Quantitative Analysis of Scenarios for Chinese Domestic Unconventional Natural Gas Resources and Their Role in Global LNG Markets" revealed that shale gas developments in China could be every bit as game-changing over the next couple of decades as shale gas developments in North America have been in the last decade. The study is available online at http://www.bakerinstitute.org/publications/EF-pub-RiseOfChinaMedlockHartley-120211-WEB.pdf.

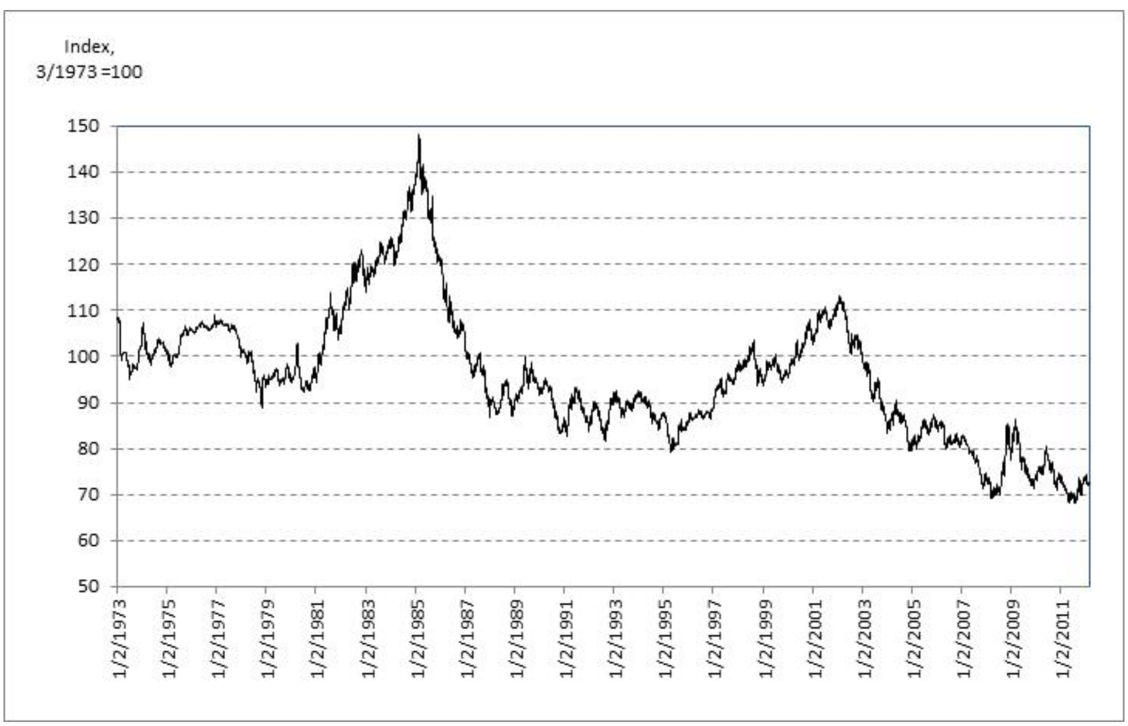
The Exchange Rate and Arbitrage Value

Another important factor to consider when evaluating arbitrage opportunities presented by current market conditions is the role the exchange rate plays. As a simple example, consider the potential for arbitrage between the U.S. and UK. Natural gas is traded in pence per therm in the UK and dollars per mmbtu in the U.S. In order to evaluate the benefits of trans-Atlantic arbitrage, one must first apply an exchange rate between the £UK and $US. In particular, we can represent the value of the trade as

$$P_{US} - P_{UK} \cdot XR \cdot HR = arb\ value$$

where *XR* is the exchange rate denominated as £/$ and *HR* is the heating conversion from therm to mmbtu. All else equal, if the dollar weakens against the pound, *XR* will decrease. In turn, the *arb value* will rise for no reason related to the physical gas market conditions in either location. Thus, the risk of exchange rate movements is very real for potential LNG exporters.

Figure 8. Trade-Weighted Value of U.S. $, Major Currencies (Daily, Jan. 1973–July 2012)



Source: U.S. Federal Reserve Bank

This issue is made more salient when one considers the value of the U.S. dollar against internationally traded currencies at the present time. Figure 8 indicates the U.S. dollar value against major currencies as reported by the U.S. Federal Reserve Bank. This indicates that, on a trade-weighted basis, the value of the U.S. dollar is lower than it has been in the last 40 years. Any reversion toward even a historical average will ultimately shrink calculated arbitrage returns, *ceteris paribus*.

The argument above, it turns out, holds even if LNG exporters can secure oil-indexed contracts for their supplies. In a recent paper, Hartley and Medlock (2012) show that exchange rates are important in determining the crude oil-natural gas price differential when (i) there is limited capability for direct international arbitrage of natural gas but not oil prices and (ii) fuel-switching capabilities are limited.[15] Thus, currently in the U.S. where both conditions are met, the exchange rate is a very important determinant of the relative price of natural gas to crude oil. This means that a strengthening of the U.S. dollar will erode the current oil-gas spread, leaving even oil-indexed flows potentially exposed to exchange rate risk.

Contract versus Spot Prices

Brito and Hartley[16] show that growth in physical liquidity also limits the ability of a single supplier to price above marginal cost. The relative abundance of LNG, prompted by the dramatic growth in shale, also puts downward pressure on demand for pipeline gas supplies, meaning Europe and Asia see increased competition. Importantly, this has implications for the pricing terms at which existing and future supplies are negotiated. In fact, as the natural gas supply curve becomes more elastic, as is the case with an increasing abundance of shale gas, it will become increasingly difficult to price natural gas above marginal cost, meaning oil-indexation is likely to lose some of its prominence.

It should be noted that *spot* prices are the primary focus of this discussion. In point of fact, *contract* prices can be substantially different from spot market prices. This is particularly true

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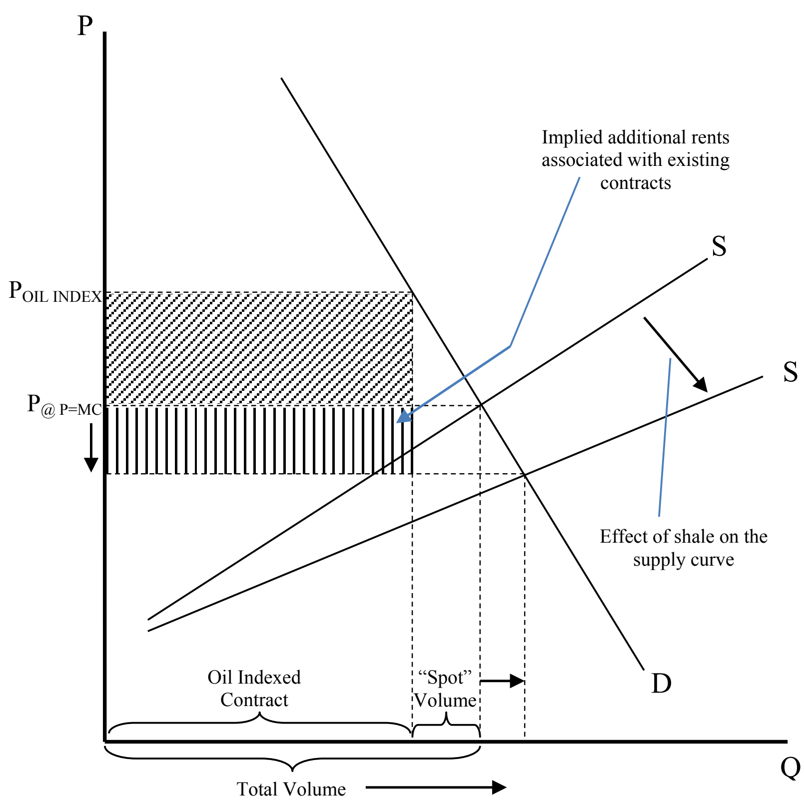
[15] See Peter R. Hartley and Kenneth B. Medlock III, "The Relationship between Crude Oil and Natural Gas Prices: The Role of the Exchange Rate," submitted to the *Energy Journal.* Manuscript available upon request.

[16] Peter Hartley with Dagobert Brito, "Expectations and the Evolving World Gas Market," *Energy Journal* 28, no. 1 (2007): 1-24.

when contracted supplies represent deliveries at prices that are not at the margin, meaning that they are infra-marginal. One can think of contracted deliveries, in this instance, as being the result of price discrimination.

Absent storage and physical liquidity, oil-indexation provides an element of price certainty. But, to be sure, oil-indexation can be viewed as a form of price discrimination. Figure 9 provides an illustration of price discrimination. Note that oil-indexation does not preclude the existence of spot transactions, but market structures that do not easily allow resale can severely limit them. In Figure 9, about 15 percent of the marketed volumes are sold on a spot basis, with the remaining 85 percent contracted above marginal cost.

Figure 9. The Supply Curve Effect of Shale and Implications for Price



In general, for a firm to be able to price discriminate, (1) it must be able to distinguish consumers and prevent resale, and (2) its consumers must have different elasticities of demand. Both of these conditions are met in Europe and Asia. However, an increased ability to trade between suppliers and consumers (i.e., increased physical liquidity) leads to a violation of condition (1). This is more likely to happen as the supply curve in Figure 9 becomes more elastic (flatter).[17]

Even now, evidence of a diminished ability to price discriminate is emerging in Europe as there have been multiple announcements of changes in contractual terms, with a propensity to index at least a portion of sales to spot prices. Thus, by displacement, the increase in shale production in North America has begun to have impacts on traditional pricing mechanisms in other markets. If shale resources are proven to be commercially viable in Europe and Asia, this will accelerate, and the "new normal" could very well be characterized by more intense competition.[18]

This shifting dynamic can be explained by the fact that shale gas has effectively made supply more elastic, the effect of which is indicated in Figure 9. As the elasticity of supply increases, the rents associated with contracts that are priced above marginal cost also increase. This, in turn, triggers calls for renegotiations of contracts between suppliers and demanders.

Of course, a critical element of this argument is that the increased elasticity of supply is directly related to new entrants to the global gas market. If the new supply from shale gas was in the hands of a single large producer, then that producer could continue to price discriminate effectively. It is critical that the increased elasticity be associated with multiple new market entrants so that liquidity is indeed enhanced. In the case of shale gas, there is considerable emergence of new suppliers to the global market as shale gas production increases.

The LNG Arbitrage Opportunity

Although the North American market remains one of the lowest priced regions globally, according to Baker Institute analysis using the Rice World Gas Trade Model (RWGTM), the

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[17] This will also happen in a liberalized market where trading of capacity rights is allowed, insomuch as the arbitrage allows price signals to clearly transmit. This promotes entry and, to the extent that hubs develop, financial liquidity. Once that occurs, the means to use capital markets to underwrite physical transactions increases and liquidity grows, thus making it difficult to price discriminate.

[18] For more detailed discussion of the competition of fuels and greenhouse gas implications, see "Energy Market Consequences of an Emerging U.S. Carbon Management Policy," published by the James A. Baker III Institute for Public Policy at http://bakerinstitute.org/programs/energy-forum/publications/energy-studies/energy-market-consequences-of-an-emerging-u.s.-carbon-management-policy. Baker Institute analysis showed that the United States was likely to make a major shift away from carbon-intensive coal use to a higher proportion of consumption of domestic natural gas, easing the increase in greenhouse gases that would come about from rising U.S. energy use.

differences between the JKM price and Henry Hub and the price at NBP and Henry Hub are not sufficient to support long-term baseload LNG exports from the U.S. Gulf Coast to these regions. Table 1 summarizes this point.

Table 1 indicates the cost of the gas at inlet to a generic terminal in the U.S. Gulf Coast for 2011 and then on a decadal annual average basis for the next three decades. To be sure, the inlet price can vary depending on location, but for this example we assumed a $0.20 discount to Henry Hub. Next, we add the cost of liquefaction, which is derived assuming a 10 percent real return on an $8 billion investment in liquefaction capacity with a 20-year plant life. Then, we add the cost of transporting the gas via LNG tanker to the market of destination, which for the purpose of this example is assumed to be either Tokyo or the UK. This yields a "Landed Cost" for LNG sourced from the U.S. Gulf Coast to each market. We then compare this cost to the spot market price, as simulated by the RWGTM, in both potential destinations to examine the margin on exports. Interestingly, the only time in which the export margin is positive, indicating a profitable trade including a return to capital, is in the very near term. The simulation results indicate that as current capacity constraints are alleviated, the export margin turns negative, indicating trade that becomes unprofitable.

Table 1. The Prospect of U.S. LNG Exports (LNG Export Margin – Averages)

	2011	2011-2020	2021-2030	2031-2040
Feed gas cost ($/mcf)	$ 3.80	$ 3.98	$ 4.69	$ 5.26
Liquefaction ($/mcf)	$ 2.92	$ 2.92	$ 2.92	$ 2.92
Transport cost ($/mcf)				
UK	$ 1.07	$ 1.07	$ 1.07	$ 1.07
Japan	$ 2.15	$ 2.15	$ 2.15	$ 2.15
Landed cost ($/mcf)				
UK	$ 7.79	$ 7.97	$ 8.67	$ 9.25
Japan	$ 8.87	$ 9.05	$ 9.75	$ 10.33
Market price ($/mcf)				
NBP	$ 8.84	$ 7.47	$ 7.44	$ 8.09
JKM	$ 11.73	$ 8.08	$ 7.98	$ 8.46
Export margin ($/mcf)				
UK	$ 1.06	$ (0.49)	$ (1.23)	$ (1.16)
Japan	$ 2.86	$ (0.96)	$ (1.77)	$ (1.87)

It is important to note that the focus in Table 1 is on the U.S. Gulf Coast. This is done due to the fact that installing liquefaction trains at existing regasification terminal locations generally bears a lower incremental fixed cost. In effect, developers seek to turn around terminals that were built initially as import locations. If we were to analyze other export opportunities, such as proposals at Jordan Cove on the West Coast, at Kitimat in Canada or from Cove Point on the East Coast, the fixed costs would be considerably higher. In fact, public statements indicate the fixed cost for the terminals in Canada are as much as twice the amount indicated in Table 1. This would, however, be offset somewhat by lower feed gas costs (in the case of Canada in particular the cost of gas sourced from shale in British Columbia), and lower transport costs to Asia in the case of West Coast terminals or to Europe in the case of East Coast terminals.

Importantly, even with wide variations in the various costs in Table 1, the trades do not appear profitable in the long term. In fact, it would appear that multiple factors must change in the analysis to render the U.S. Gulf Coast LNG export option commercially viable long term. This is, in fact, what drives the result in the RWGTM that no exports from the U.S. Gulf Coast occur. The RWGTM is considering *future* market conditions, not just *current* market conditions, in determining whether or not to add export capability. So, it is factoring in the full dynamic responsiveness of supply and demand in domestic *and* foreign locations.

Of course, this analysis is not considering a customer that may contract for natural gas supply at above marginal cost (in other words, “pay a premium”). This would mean, for example, that if a buyer in Japan is willing to pay upwards of $2.00 per mcf above full marginal cost, he could secure supplies from the U.S. Gulf Coast and the supplier would earn a sufficient rate of return. While most suppliers would be willing to agree to such terms, any buyer who did so would likely be holding a contract that is distinctly out-of-the-money over time.

It is entirely plausible that export capacity will be built on the expectation that current rents from arbitrage will persist long enough to “pay” for the upfront fixed cost. Moreover, once the fixed cost of a new export facility is sunk, the operating decision no longer hinges on the payment to capital; it only depends on whether or not operating costs are covered. In this case, it is likely that any terminal constructed will operate, but, according to the latest Reference Case of the

RWGTM, operation will not be at full capacity and the profit margin will not likely be sufficient to earn the *ex-ante* required rate of return, unless of course the off-take agreement includes a premium to cost.

Another possibility is that U.S. Gulf Coast LNG export capability could be intended to be used for seasonal delivery. While the annual facility load factor would be lower in this circumstance, thus raising the per unit cost, if seasonal price differences among the regional markets are sufficient, U.S. exports could in this case be profitable. Nevertheless, this does not represent a *baseload* arrangement, and would likely only be maintained as part of a portfolio arrangement for a large LNG supplier.

Finally, the opening LNG exports from the U.S. will inevitably link global markets to storage opportunities in the U.S. The U.S. has the most well-developed storage market in the world, and this is, in fact, a key factor that contributes to market liquidity. By providing a link for the rest of the world to U.S. storage capacity, the liquidity benefits could easily spill over to European and Asian markets. In fact, it would not be surprising to see Asian utilities taking storage positions in the U.S. to hedge seasonal price fluctuations. This could, in fact, accelerate the dissolution of current regional pricing paradigms, and provide more opportunities for seasonal arbitrage opportunities. But, again, this is a distinctly different type of arrangement from a baseload LNG supply deal.

Concluding Remarks

The global gas market has experienced many significant changes in the past decade. We have witnessed the emergence of shale in North America, a development that dramatically altered the global outlook for LNG markets. In fact, we have moved from a consensus view that the U.S. would be increasingly reliant on imported LNG, to one in which the prospect of U.S. LNG exports is now being discussed. In addition, most future LNG profit opportunities appear to be focused on the Asian market. But, this “all eggs in one basket” approach is not without risk, as future demands, policy-motivated fuel choices, supply-responsiveness, and unconventional gas development will each play competing roles to LNG imports in Asia.

However, it is important to recognize that the *prospect* of LNG exports from the U.S. does not equate to large scale reality. In general, regardless of the number of export licenses granted, U.S. LNG exporters face risks associated with exchange rate movements, the development of alternative foreign supplies, and the relative price impacts of introducing U.S. LNG volumes into a currently tight international LNG market. In fact, we have presented evidence above that the apparent profitable export option from the U.S. market based on *current* market conditions is transitory, as current market conditions beget a supply response abroad that erodes current price differentials. Moreover, data on regional spot prices are supportive of this notion.

Aside from the apparent commercial risks associated with LNG exports, the more salient question for U.S. policymakers regards the U.S. price response to U.S. LNG exports. This question is best answered in understanding the elasticity of the domestic supply curve. In particular, we estimate that domestic elasticity of supply is roughly 1.52 between a price of $4 and $6 per mcf, which represents a five-fold increase since the emergence of shale gas. In other words, a one percent increase in price will result in a one-and-a-half percent increase in domestic production. This means that the export of LNG in any reasonable volume from the U.S. should not have a significant impact on price at the margin. Rather, the analysis herein indicates that international market response will ultimately limit the amount of LNG that the U.S. exports as a matter of commercial rationing.

Finally, even with exports, the price in the U.S. will not likely increase dramatically. While the projected price is above today's price, this reflects a long-run sustainable price in line with the marginal cost of supply, not the impact of LNG exports. The current low price in North America reflects an oversupply that resulted partly from the abnormally warm winter of 2011-12 coupled with ill-timed domestic production growth. The marginal cost of supply is above the current price, as is evidenced by an increasing number of producers ramping down their domestic rig activities, so the price should be expected to rise before LNG exports ever eventuate. Our own simulations indicate a long-run equilibrium price in the $4 to $6 per mcf range is likely for many years to come.

The implication for policy is simple: market responses will ultimately limit export volumes. The hand-wringing about domestic price impacts is based largely on an incomplete assessment of what should be addressed as an international trade question. Even if ex-post unprofitable investments are made in LNG liquefaction capacity in the U.S., the establishment of a link from U.S. supplies to foreign markets will intensify pressure on traditional pricing paradigms, thus having potentially dramatic implications. Moreover, a direct link between the U.S. and abroad will invite foreign market players to consider taking positions in the U.S. storage market to hedge their physical positions. This will only serve to accelerate market liquidity thus lowering liquidity risk. In turn, this could alter the financing risk of LNG projects, reducing the importance of oil-linked bilateral relationships. As the story plays out, the international gas market will evolve into something dramatically different from what it is today.