Deloitte MarketPoint.

Analysis of Economic Impact of LNG Exports from the United States

Contents

Executive summary

Deloitte MarketPoint LLC ("DMP") has been engaged by Excelerate Energy L.P. ("Excelerate") to provide an independent and objective assessment of the potential economic impacts of LNG exports from the United States. We analyzed the impact of exports from Excelerate's Lavaca Bay terminal, located along the Gulf coast of Texas, by itself and also in combination with varying levels of LNG exports from other locations.

A fundamental question regarding LNG exports is: Are there sufficient domestic natural gas supplies for both domestic consumption and LNG exports. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas resources to supply both domestic consumption and exports? A more difficult question is: How much will U.S. natural gas prices increase as a result of LNG exports? To understand the possible answers to these questions, one must consider the full gamut of natural gas supply and demand in the U.S. and the rest of the world and how they are dynamically connected.

In our view, simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. The real issue is not one of volume, but of price impact. In a free market economy, price is one of the best measures of scarcity, and if price is not significantly affected, then scarcity and shortage of supply typically do not occur. In this report, we demonstrate that the magnitude of domestic price increase that results from exports of natural gas in the form of LNG is projected to be quite small.

However, other projections, including those developed by the DOE's Energy Information Administration (EIA), estimate substantially larger price impacts from LNG exports than derived from our analysis. We shall compare different projections and provide our assessment as to why the projections differ. A key determinant to the estimated price impact is the supply response to increased demand including LNG exports. To a large degree, North American gas producers' ability to increase productive capacity in anticipation of LNG export volumes will determine the price impact. After all, there is widespread agreement of the vast size of the North American natural gas resource base among the various studies and yet estimated price impacts vary widely. If one assumes that producers will fail to keep pace with demand growth, including LNG exports, then the price impact of LNG exports, especially in early years of operations, will be far greater than if they anticipate demand and make supplies available as they are needed. Hence, a proper model of market supply-demand dynamics is required to more accurately project price impacts.

DMP applied its integrated North American and World Gas Model (WGM or Model) to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects

[1] This report was prepared for Excelerate Energy L.P. ("Client") and should not be disclosed to, used or relied upon by any other person or entity. Deloitte Marketpoint LLC shall not be responsible for any loss sustained by any such use or reliance. Please note that the analysis set forth in this report is based on the application of economic logic and specific

monthly prices and quantities over a 30 year time horizon based on demonstrated economic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM solves for prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along each stage of the supply chain. It rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. More information about WGM is included in the Appendix.

Vital to this analysis, the WGM represents fundamental natural gas producer decisions regarding when and how much reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the price impact. Indeed, producers will anticipate the export volumes and make production decisions accordingly. LNG exporters might back up their multi-billion dollar projects with long-term supply contracts, but even if they do not, producers will anticipate future prices and demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to over-estimate the price impact of a demand change. Typically, users have to override this assumption by manually adjusting supply to meet demand. If insufficient supply volumes are added to meet the incremental demand, prices could shoot up until enough supply volumes are added to eventually catch up with demand.

Instead of a static approach, the WGM uses sophisticated depletable resource modeling to represent producer decisions. The model uses a "rational expectations" approach, which assumes that today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

It is well documented that shale gas production has grown tremendously over the past several years. According to the EIA, shale gas production climbed to over 35% of the total U.S. production in January of 2012[2]. By comparison, shale gas production was only about 5% of the total U.S. production in 2006, when improvements in shale gas production technologies (e.g., hydraulic fracturing combined with horizontal drilling) were starting to significantly reduce production costs. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, WGM projects production based resource volumes and costs, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

assumptions and the results are not intended to be predictions of events or future outcomes.

Notwithstanding the foregoing, Client may submit this report to the U.S. Department of Energy and the Federal Energy Regulatory Commission in support of Client's liquefied natural gas "(LNG") export application.

[2] Computed from the EIA's Natural Gas Weekly Update for week ending June 27, 2012.

Based on our existing model and assumptions, which we will call the "Reference Case", we developed five cases with different LNG export volumes to assess the impact of LNG exports. The five LNG export scenarios and their assumed export volumes by location are shown in Figure 1. Other Gulf in the figure refers to all other Gulf of Mexico terminals in Texas and Louisiana besides Lavaca Bay.

All cases are identical except for the assumed volume of LNG exports. The 1.33 Bcfd case assumed only exports from Lavaca Bay so that we could isolate the impact of the terminal. In the other LNG export cases, we assumed the Lavaca Bay terminal plus volumes from other locations so that the total exports volume equaled 3, 6, 9, and 12 Bcfd. The export volumes were assumed to be constant for twenty years from 2018 through 2037.

We represented LNG exports in the model as demands at various model locations generally corresponding to the locations of proposed export terminals (e.g., Gulf Texas, Gulf Louisiana, and Cove Point) that have applied for a DOE export license. The cases are not intended as forecasts of which export terminals will be built, but rather to test the potential impact given alternative levels of LNG exports. Furthermore, the export volumes are assumed to be constant over the entire 20 year period. Since our existing model already represented these import LNG terminals, we only had to represent exports by adding demands near each of the terminals. Comparing results of the five LNG export cases to the Reference Case, we projected how much the various levels of LNG exports could increase domestic prices and affect production and flows.

Given the model's assumptions and economic logic, the WGM projects prices and volumes for over 200 market hubs and represents every state in the United States. We can examine the impact at each location and also compute a volume-weighted average U.S. "citygate" price by weighting price impact by state using the state's demand. Impact on the U.S. prices increase along with the volume of exports.

As shown in Figure 2, the WGM's projected

Figure 1: LNG export scenarios

	Export Case				
Terminal	**1.33 Bcfd**	**3 Bcfd**	**6 Bcfd**	**9 Bcfd**	**12 Bcfd**
Lavaca Bay	1.33	1.33	1.33	1.33	1.33
Other Gulf		1.67	4.67	6.67	9.67
Cove Point (MD)				1.0	1.0
Total	1.33	3.0	6.0	9.0	12.0

Figure 2: Potential Impact of LNG export on U.S. prices (Average 2018-37)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	0.4%	0.4%	0.3%
3 Bcfd	1.0%	1.7%	0.9%
6 Bcfd	2.2%	4.0%	1.9%
9 Bcfd	3.2%	5.5%	3.2%
12 Bcfd	4.3%	7.7%	4.1%

impact on average U.S. citygate prices for the assumed years of operation (2018 to 2037) ranged from well under 1% in the 1.33 Bcfd (Lavaca Bay only) case to 4.3% in the 12 Bcfd case. However, the impacts vary significantly by location. Figure 2 shows the percentage change relative to the Reference Case to the projected average U.S. citygate price and at the Henry Hub and New York prices under various LNG export volumes.

As Figure 2 shows, the price impact is highly dependent on location. The impact on the price at Henry Hub, the world's most widely used benchmark for natural gas prices, is significantly higher than the national average. The reason is that the Henry Hub, located in Louisiana, is in close proximity to the prospective export terminals, which are primarily located in the U.S. Gulf of Mexico region. Since there are several cases analyzed, we will primarily describe results of the 6 Bcfd export case since it is the middle case. The impacts are roughly proportional to the export volumes. In the 6 Bcfd export case, the impact on the Henry Hub price is an increase of 4.0% over the Reference Case. Generally, the price impact in markets diminishes with distance away from export terminals as other supply basins besides those used to feed LNG exports are used to supply those markets. Distant market areas, such as New York and Chicago, experience only about half the price impact as at the Henry Hub. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total estimated impact on the U.S. consumers.

The results show that if exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

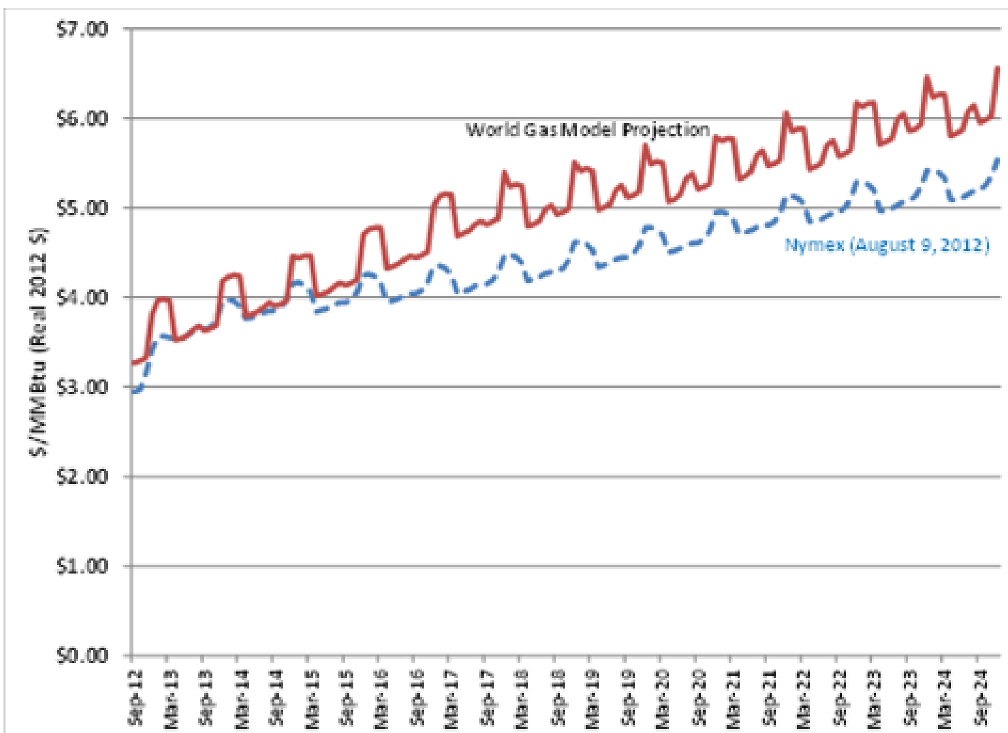
According to our projections, 12 Bcfd of LNG exports are projected to increase the average U.S. citygate gas price by 4.3% and Henry Hub price by 7.7% on average over a twenty year period (2018-37). This indicates that the projected level of exports is not likely to induce scarcity on domestic markets. The domestic resource base is expected to be large enough to absorb the incremental volumes required by LNG exports without a significant increase to future production costs. If the U.S. natural gas industry can make the supplies available by the time LNG export terminals are ready for operation, then the price impact will likely reflect the minimal change in production cost. As the industry has shown in the past several years, it is capable of responding to market signals and developing supplies as needed. Furthermore, the North American energy market is highly interconnected so any change in prices due to LNG exports from the U.S. will cause the entire market to re-equilibrate, including gas fuel burn for power generation and net imports from Canada and Mexico. Hence, the entire North American energy market would be expected to in effect work in tandem to mitigate the price impact of LNG exports from the U.S.

Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no LNG exports from the United States. U.S. gas demand growth rates for all sectors except for electricity were based on EIA's recently released Annual Energy Outlook (AEO) 2012 projection, which shows a significantly higher US gas demand than in the previous year's projection. Our gas demand for power generation is based on projections from DMP's electricity model, which is integrated with our WGM. (There is no intended advocacy or prediction of these events one way or the other. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall conclusion would be rather similar.)

In the WGM Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2012 dollars), benchmark U.S. Henry Hub spot prices are projected by the WGM to increase from currently depressed levels to \$5.34 per MMBtu in 2020, before rising to \$6.88 per MMBtu in

Figure 3: Projected Henry Hub prices from the WGM compared to Nymex futures prices



2030 in the Reference Case scenario.

The WGM Reference Case projection of Henry Hub prices is compared to the Nymex futures prices in Figure 3. (The Nymex prices, which are the dollars of the day, were deflated by 2.0%[3] per year to compare to our projections, which are in real 2012 dollars.) Our Henry Hub price projection is similar to the Nymex prices in the near-term but rises above it in the longer term. Bear in mind that our Reference Case by design assumes no LNG exports whereas there is possible there is some expectation of LNG exports from the U.S. built into the Nymex prices. Under similar assumptions, the difference between our price projection and Nymex likely would be even higher. Hence, our Reference Case would represent a fairly high price projection even without LNG exports.

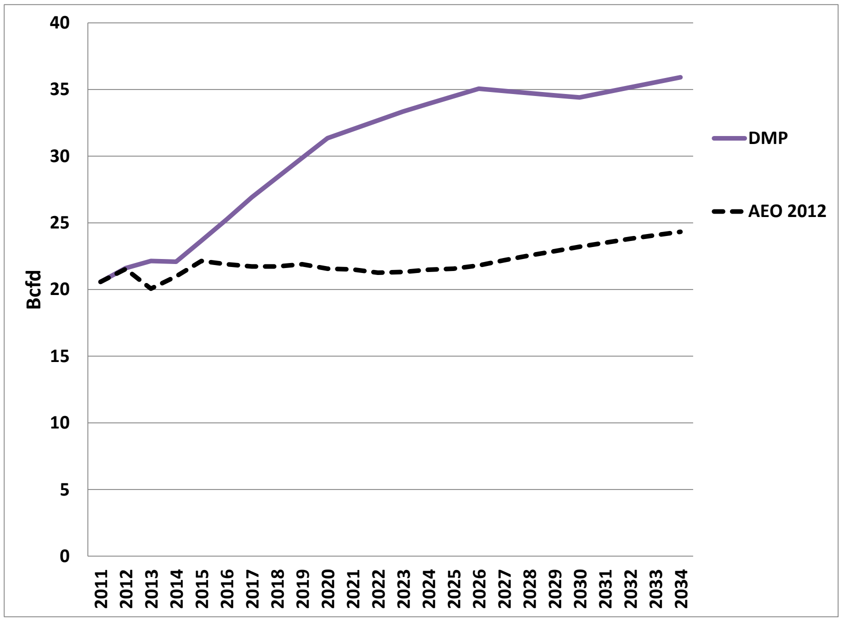
One possible reason why our price projection in the longer term is higher than market expectation, as reflected by the Nymex futures prices, is because of our projected rapid increase in gas demand for power generation. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 4, the DMP projected gas demand for U.S. power generation gas is far greater than the demand predicted by EIA's AEO 2012, which forecasts fairly flat demand for power generation. In the U.S., the power sector, which accounts for nearly all of the projected future growth, is projected to increase by about 50% (approximately 11 Bcfd) over the next decade. Our integrated electricity model projects that natural gas will become the fuel of choice for power generation due to a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; coal plant retirements; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO 2012 forecast, our Reference Case projection does not assume any new carbon legislation.

Our electricity model, fully integrated with our gas (WGM) and coal models, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO2, SOx, NOx, and mercury). The integrated structure of these models is shown in Figure 5. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a number of factors, including plant capacities, fuel prices, heat rates, variable costs, and environmental emissions costs. The model integration of North American natural gas with the rest of the world and the North American electricity market captures the global linkages and also the inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates.

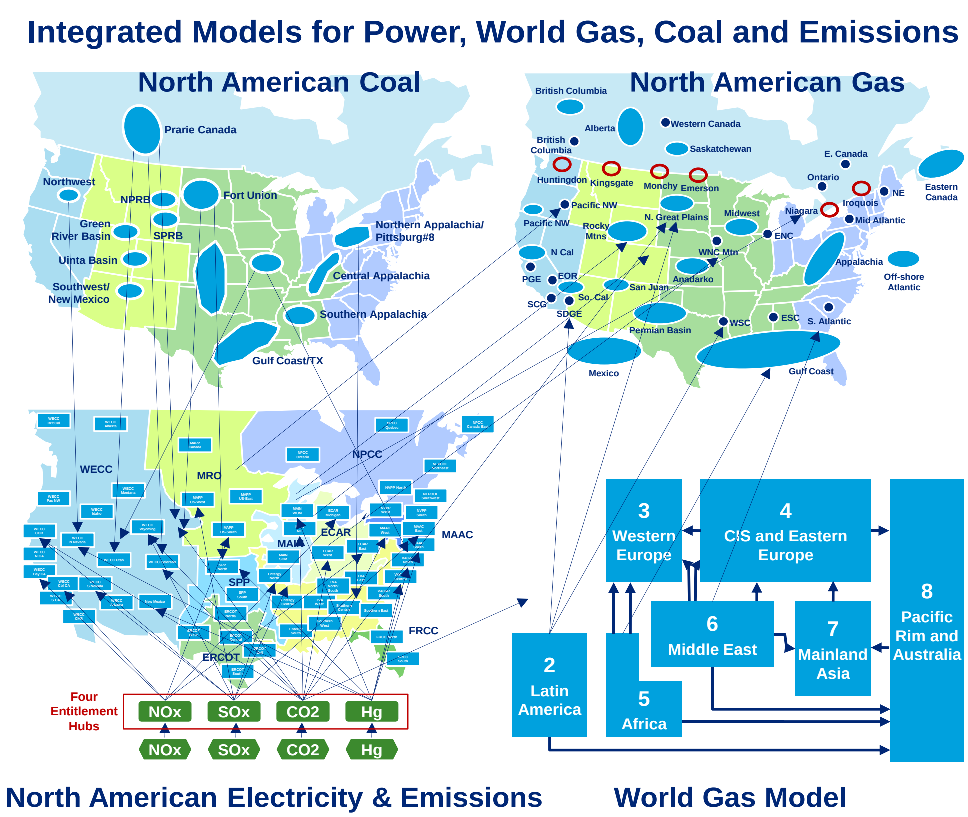
[3] Approximately the average consumer price index over the past 5 years according to the Bureau of Labor Statistics.

Figure 4: Comparison of projections of the U.S. gas demand for power generation



Furthermore, the electricity sector is projected to be far more responsive to natural gas price than any other sector. We model demand elasticity in the electricity sector directly rather than through elasticity estimates.

Figure 5: DMP North American Representation



Hence, the WGM projections include the impact of increased natural gas demand for electricity generation, which vies with LNG exports for domestic supplies. From the demand perspective, this is a conservative case in that the WGM would project a larger impact of LNG export than if we had assumed a lower US gas demand, which would likely make more supply available for LNG export and tend to lessen the price impact. Higher gas demand would tend to increase the projected prices impacts of LNG export. However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports. The absolute price of natural gas will be determined by a number of supply and demand factors in addition to the volume of LNG exports.

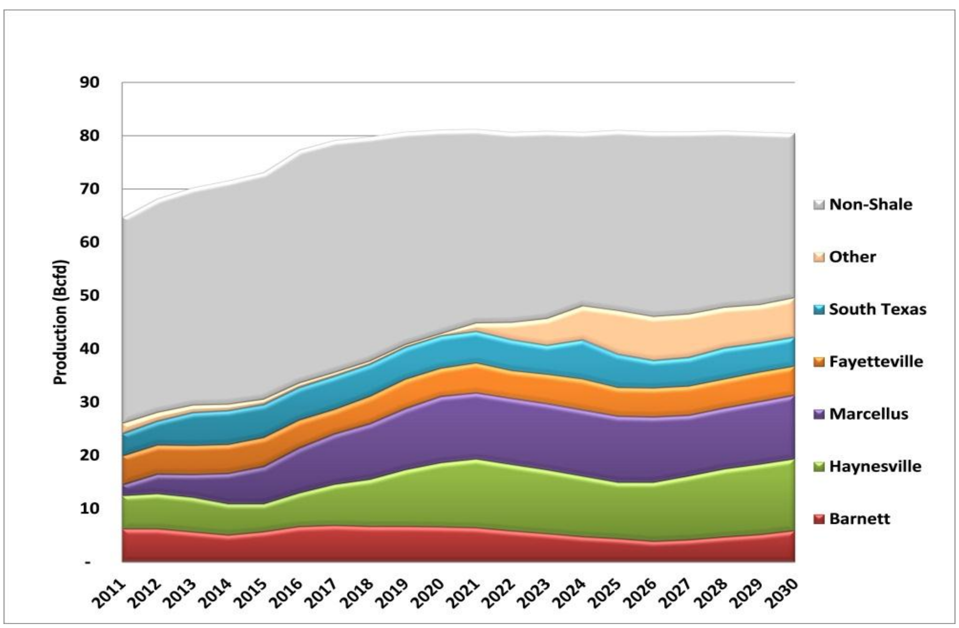
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas which we project to be an increasingly important component of domestic supply. As shown in Figure 6, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 66 Bcfd in 2011 to almost 79 Bcfd in 2018 before tapering off.

The growth in production from a large domestic resource base is a crucial point and consistent with fundamental economics. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. They believe, de facto, that natural gas supply is highly "elastic," i.e., the supply curve is very flat.

A flattening supply curve is consistent with the resource pyramid diagram that the United States Geological Survey and others have postulated. At the top of the pyramid are high quality gas supplies which are low cost but also are fairly scarce. As you move down the pyramid, the costs increase but the supplies are more plentiful. This is another interpretation of our supply curve which has relatively small amounts of low cost supplies but as the cost increases, the supplies become more abundant.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in

Figure 6: U.S. gas production by type



production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S.

Rather than basing our production projections solely on the physical decline rates of producing fields, the WGM considers economic displacement as new, lower cost supplies force their way into the market. The North American natural gas system is highly integrated so Canadian supplies can easily access U.S. markets when economic.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, has already started to transform historical basis relationships (the difference in prices between two markets) and the trend is projected to continue during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, although to a lesser degree.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. Indeed, the flattening of Eastern bases is already becoming evident. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Gas production from Marcellus Shale will help shield the Mid-Atlantic region from supply and demand changes in the Gulf region. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The result could be displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Understanding the dynamic nature of the natural gas market is paramount to understanding the impact of LNG exports. If LNG is exported from any particular location, the entire North American natural gas system will potentially reorient production, affecting basis differentials and flows. Basis differentials are not fixed and invariant to LNG exports or any other supply and demand changes. On the contrary, LNG exports will likely alter basis differentials, which lead to redirection of gas flows to highest value markets from each source given available capacity.

Potential impact of LNG exports

Impact on natural gas prices

We analyzed five LNG export cases within this report: one case with Lavaca Bay only (1.33 Bcfd) and four other cases with varying levels of total U.S. LNG export volumes (3 Bcfd, 6 Bcfd, 9 Bcfd and 12 Bcfd exports). Each case was run with the DMP's Integrated North American Power and Gas Models in order to capture the dynamic interactions across commodities.

For ease of reporting, we will focus on the results with 6 Bcfd of LNG exports, our middle case, without any implication that it is more likely than any other case. Given the model's assumptions, the WGM projects 6 Bcfd of LNG exports will result in a weighted-average price impact of $0.15/MMBtu on the average U.S. citygate price from 2018 to 2037. The $0.15/MMBtu increase represents a 2.2% increase in the projected average U.S. citygate gas price of $6.96/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.26/MMBtu during this period. It is important to note the variation in price impact by location. The impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

For all five export cases considered, the projected natural gas price impacts at the Henry Hub, New York, and average US citygate from 2018 through 2037 are shown in Figure 7.

To put the impact in perspective, Figure 8 shows the price impact of the midpoint 6 Bcfd case compared to projected Reference Case U.S. average citygate prices over a twenty year period. The height of the bars represents the projected price with LNG exports.

The small incremental price impact may not appear intuitive or expected to those familiar with market traded fluctuations in natural gas prices. For example, even a 1 Bcfd increase in demand due to sudden weather changes can cause near term traded gas prices to surge because in the short term, both supply and demand are highly inelastic (i.e., fixed quantities). However, in the long-term, producers can develop more reserves in anticipation of demand growth, e.g. due to LNG exports. Indeed, LNG export projects will likely be linked in the origination market to long-term supply contracts, as well as long-term contracts with LNG buyers. There will be ample notice and

Figure 7: Price impact by scenario for 2018-37 ($/MMBtu)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	$ 0.03	$ 0.03	$ 0.02
3 Bcfd	$ 0.07	$ 0.11	$ 0.06
6 Bcfd	$ 0.15	$ 0.26	$ 0.14
9 Bcfd	$ 0.22	$ 0.36	$ 0.23
12 Bcfd	$ 0.30	$ 0.50	$ 0.29

time in advance of the LNG exports for suppliers to be able to develop supplies so that they are available by the time export terminals come into operation. Therefore, under our long-term equilibrium modeling assumptions, long-term changes to demand may be anticipated and incorporated into supply decisions. The built-in market expectations allows for projected prices to come into equilibrium smoothly over time. Hence, our projected price impact primarily reflects the estimated change in the production cost of the marginal gas producing field with the assumed export volumes.

As previously stated, the model projected price impact varies by location as shown in Figure 9.

As previously described, the price impact diminishes with distance from export terminals. For all cases the impact is greatest at Henry Hub, situated near most export terminals. For the midpoint case of 6 Bcfd, the impact at the Houston Ship Channel is nearly as much as Henry Hub, at $0.26/MMBtu on average from 2018 to 2037. As distance from export terminals increases (i.e., distance to downstream markets such as Chicago, California and New York) the price impact is generally only about $0.12 to $0.14/MMBtu on average from 2018 to 2037.

Similarly, Figures 8 and 9 corresponding to the other export cases (1.33, 3.0, 9.0 and 12.0 Bcfd) are shown in the Appendix.

Figure 8: Projected Impact of LNG exports on average U.S. Citygate gas prices (Real 2012 $)

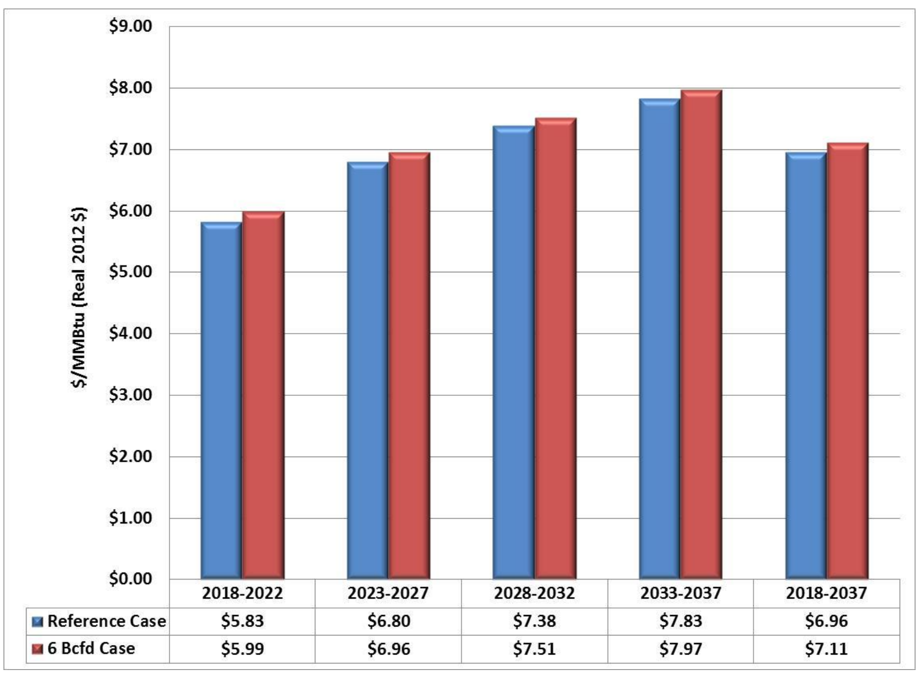
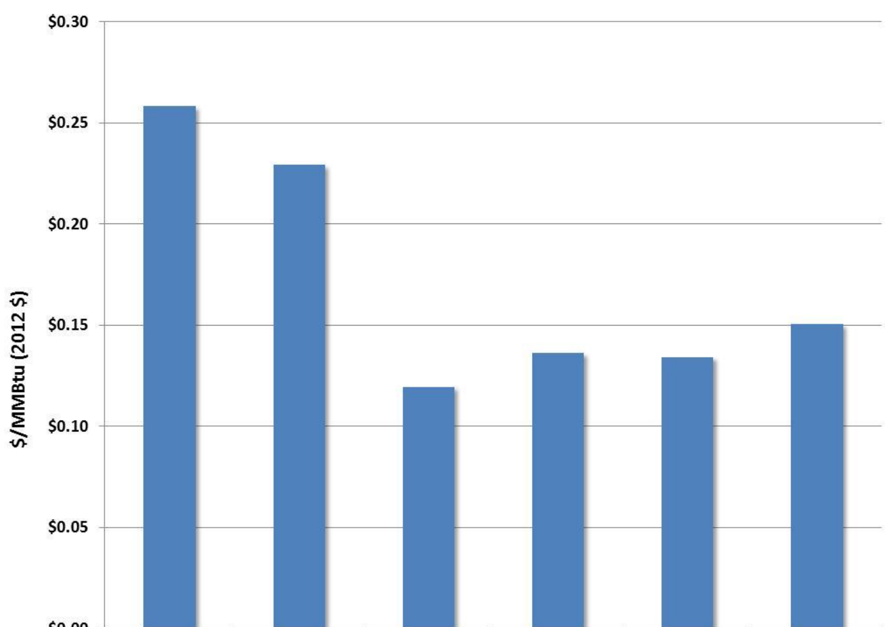


Figure 9: Price impact varies by location in 6 Bcfd export case (average 2018-37)



	Henry Hub	HSC	Chicago	New York	California	Average US
6 Bcfd Case	$0.26	$0.23	$0.12	$0.14	$0.13	$0.15

Impact on electricity prices

The projected impact on electricity prices is even smaller than the projected impact on gas prices. DMP's integrated power and gas model allows us to estimate incremental impact on electricity prices resulting from LNG export assumptions, as natural gas is also a fuel used for generating electricity. Since our integrated model represents the geographic linkages between the electricity and natural gas systems, we can compute the potential impact of LNG exports in local markets (local to LNG exports) where the impact would be the largest.

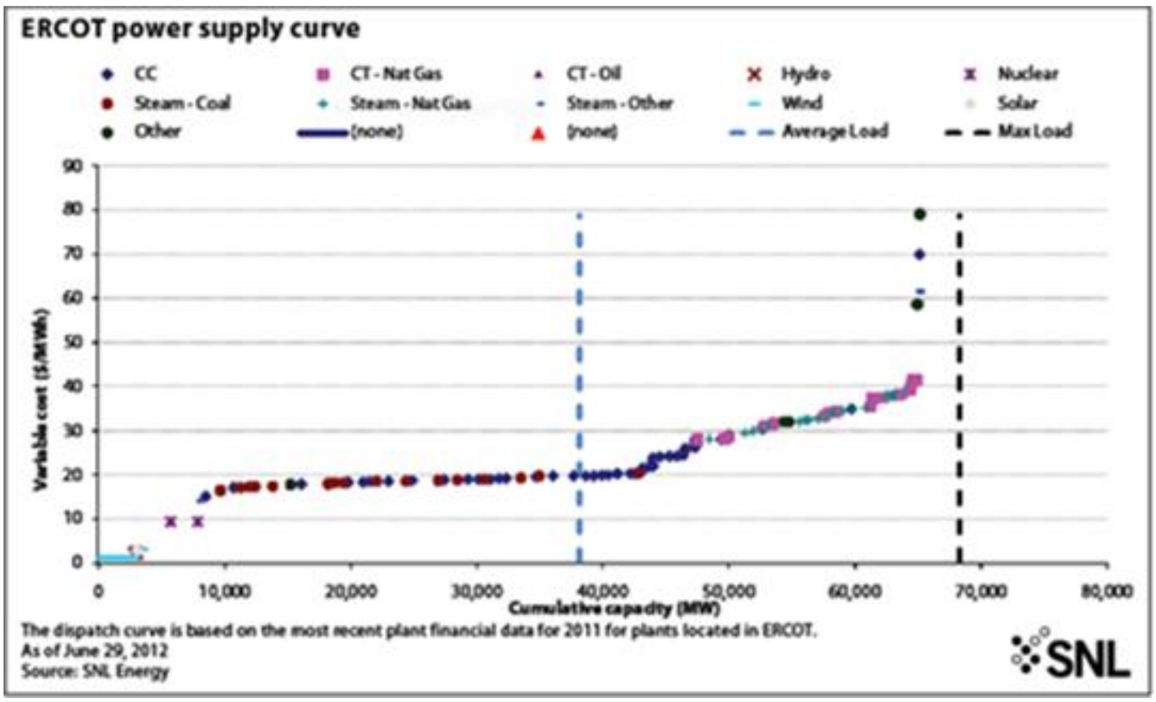
A similar comparison for electricity shows that the projected average (2018-2037) electricity prices increase by 0.8% in ERCOT (the Electric Reliability Council of Texas), under the 6 Bcfd export case. The impact on electricity prices is much less than the 4.0% Henry Hub gas price impact. For power markets in other regions, the electricity price impact is much lower, because the gas price impact is much lower.

A key reason why the price impact for electricity is less than that of gas is that electricity prices will only be directly affected by an increase in gas prices when gas-fired generation is the marginal source of power generation. That is, gas price only affects power price if it changes the marginal unit (i.e., the last unit in the generation stack needed to service the final amount of electricity load). When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive gas-fired generation to be the marginal source of generation. If gas-fired generation is already more expensive than the marginal source of generation, then an increase in gas price will not impact electricity price, since gas-fired generation is not being utilized because there is sufficient capacity from units with lower generation costs.

If gas-fired generation is the marginal source, then electricity price will increase with gas price, but only up to the point that some other source can displace it as marginal source. Every power region has numerous competing power generation plants burning different fuel types, which will mitigate the price impact of an increase in any one fuel type. Moreover, within DPM's integrated power and gas model, fuel switching among coal, nuclear, gas, hydro, wind and oil units is directly represented as part of the modeling.

Figure 10 shows the power supply curve for ERCOT. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a generating unit with a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized. Since the marginal source sets the price, a change in gas price under these conditions would not affect power prices.

Figure 10: Power supply curve for ERCOT region

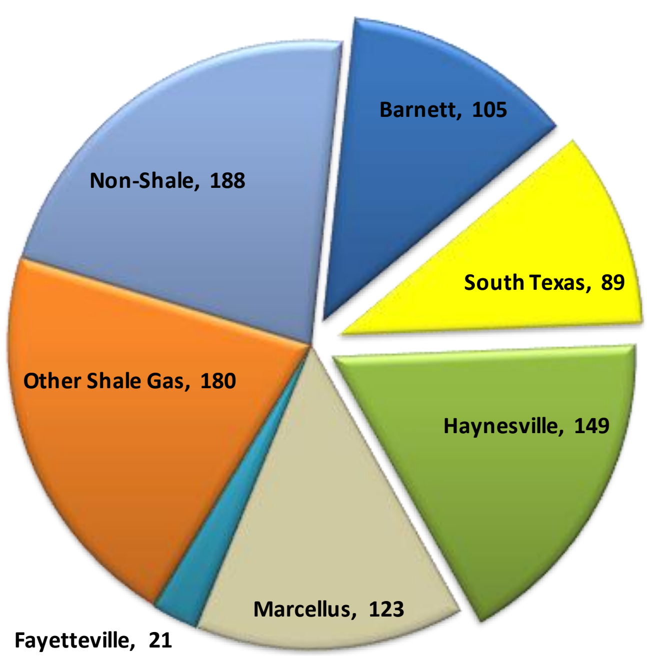


Incremental production impact in Texas from Lavaca Bay export

All of the gas used as feedstock for 1.33 Bcfd of LNG exports from Lavaca Bay is projected to come from Texas production. About one-third of the gas is incremental supplies from Texas production with the remaining two-thirds coming from Texas gas that would have otherwise been exported out of the state but instead is diverted to the terminal. The diverted volumes stimulate production in other supply basins outside Texas. Figure 11 shows the projected increase in production volume on average from 2018-2037.

The shale gas basins that are entirely or at least partially located in Texas are separated to highlight the impact on the State. One might expect South Texas, which includes Eagle Ford shales, to have a larger incremental impact. However, the region is rich in liquids and is projected to grow strongly even without boost from LNG exports. The incremental supplies indicate the marginal regions which would be stimulated with incremental demand.

Figure 11: Average incremental production with Lavaca Bay export, 2018-37 (MMcfd)

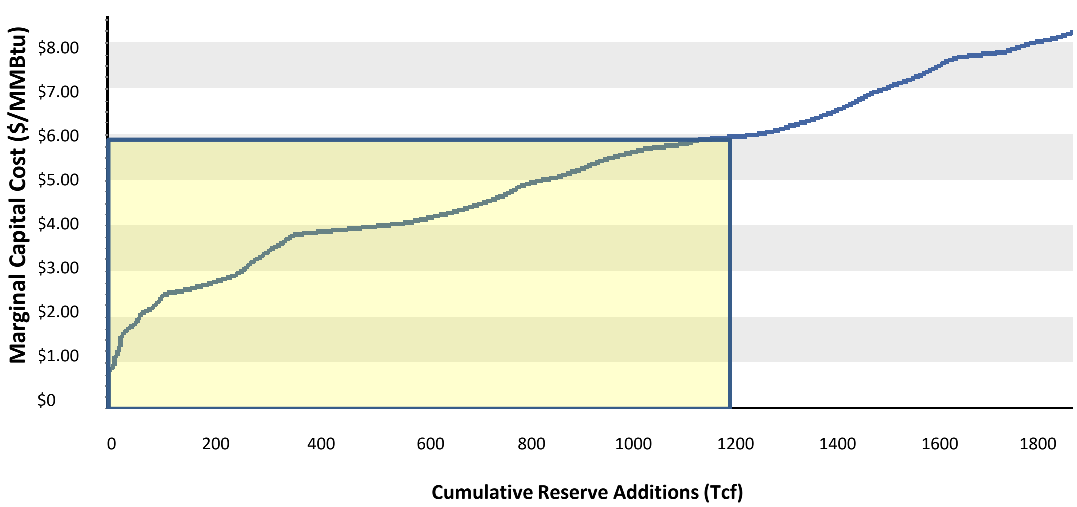


Large domestic supply buffers impact

Figure 12 shows the aggregate U.S. supply curve, including all types of gas formations. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The model includes over one hundred different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publically available documents and discussions with sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the DOE's Energy Information Administration.

The area of the supply curve that matters most for the next couple decades is the section below $6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to get produced over the next couple decades. The Reference Case estimates about 1,200 Tcf available at wellhead prices below $6/MMBtu in current dollars. To put the LNG export volumes into perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below $6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to show the big picture. The magnitude of total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

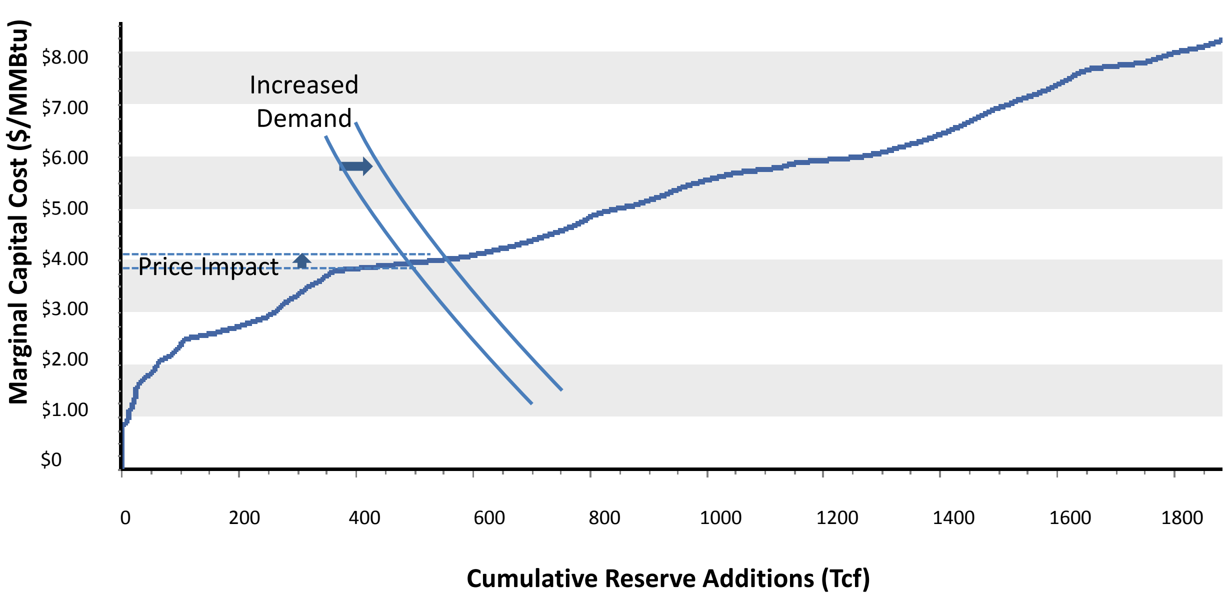
Figure 12: Aggregate U.S. natural gas supply curve (2012 $)



With regards to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 13 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters. Hence, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG would not increase the price of domestic gas very much because it would not increase the production cost of domestic gas very much.

The projected sources of incremental volumes used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. Figure 14 shows the sources of incremental volumes in the 6 Bcfd LNG export case on average from 2018 to 2037, the assumed years of LNG exports. (The source fractions are similar for other LNG export cases so we only show the 6 Bcfd case.) The bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 18%. Higher U.S. prices induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The net exports to Mexico declines slightly as higher cost of U.S. supplies will likely prompt more Mexican production and would reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 19% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Figure 13: Impact of higher demand on price (illustrative)

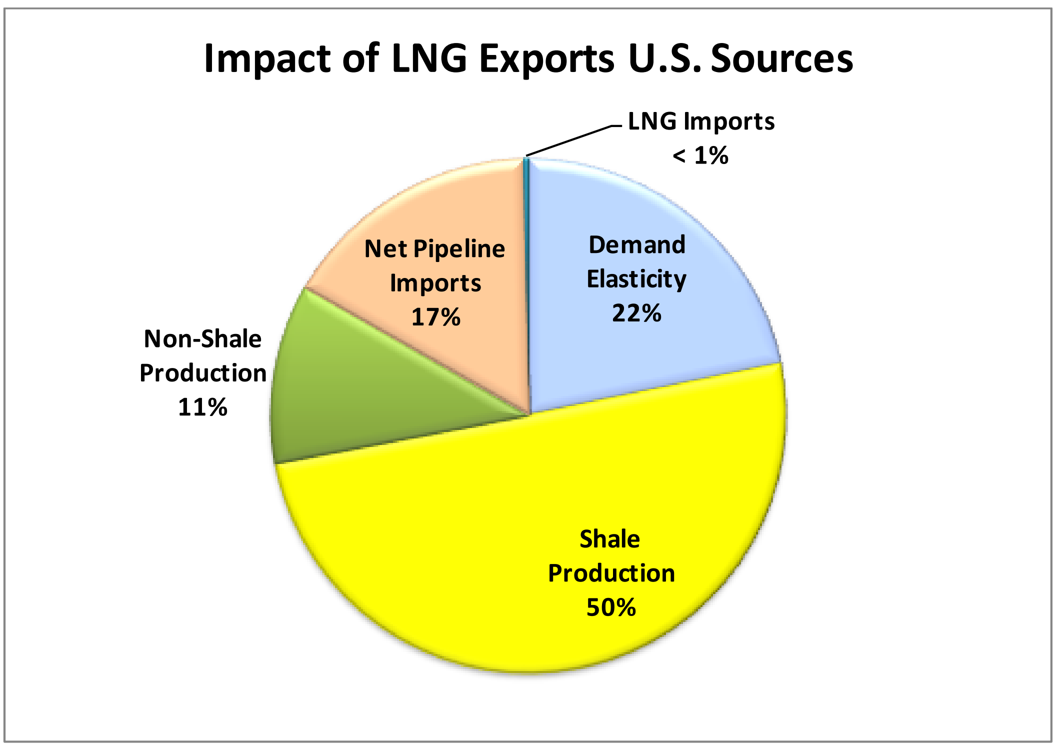


Finally, there is an insignificant increment, less than 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston will likely see higher prices than will Gulf terminals) and by time (e.g., LNG cargos will seek to arbitrage seasonal price).

These results underscore the fact that the North American natural gas market is highly integrated and the entire market works to mitigate price impacts of demand changes.

During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then it will be a simple calculation to see electricity price impact. At the projected Henry Hub gas price impact of \$0.26/MMBtu, a typical gas plant with a heat rate of 8,000 would cost an additional \$2.08/MWh (=\$0.26/MMBtu x 8000 Btu/MWh x 1 MMBtu/1000 Btu). We believe that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during mid-afternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 14: Projected sources of incremental volume in the 6 Bcfd Export Case (Average 2018-37)



Comparison of results to other studies

A number of studies, including others submitted to the DOE in association with LNG export applications, have estimated impacts of LNG exports from the U.S. The EIA also performed a study[4] at the request of the DOE. The various studies used different models and assumptions, but a comparison of their results might shed some light on the key factors and range of possible outcomes.

Figure 15 compares projections of estimated Henry Hub price impact from 2015 to 2035 with 6 Bcfd of LNG exports. The price impact ranges from 4% to 11%, with this study being on the low end and the ICF International being on the high end. The first observation is that, although the percentage differences are large on a relative basis, the range of estimated impacts is not so large. These studies consistently show that the price impact will not be that large relative to the change in demand. Bear in mind that 6 Bcfd is a fairly large incremental demand. In fact, it exceeds the combined gas demands in New York (3.3 Bcfd) and Pennsylvania (2.4 Bcfd) in 2011. These studies indicate that adding a sizeable incremental gas load on the U.S. energy system might result in a gas price increase of 11% or less.

Although we have limited data relating to specific assumptions and detailed output from the other studies, we can infer why the impacts differ so much. By most accounts, the resource base in the United States is plentiful, perhaps sufficient to last some 100 years at current production levels. All of the studies listed, including our own, had estimated natural gas resource volumes, including proved reserves and undiscovered gas of all types, of over 2,000 Tcf. Why then would the LNG export impacts vary as much as they do?

An important distinction between our analysis and the other studies is the representation of market dynamics, particularly for supply response to demand changes. That is, how do the studies represent how producers will respond to demand changes? The World Gas Model has a dynamic supply representation in which producers are assumed to anticipate demand and price changes. Producers do more than just respond to price that they see, but

Figure 15: Comparison of projected price impact from 2015-35 at the Henry Hub with 6 Bcfd of LNG exports

Study	Price without Exports ($/MMBtu)	Price with Exports ($/MMBtu)	Average Price Increase (%)
EIA	$ 5.28	$ 5.78	9%
Navigant (2010)	$ 4.75	$ 5.10	7%
Navigant (2012)	$ 5.67	$ 6.01	6%
ICF International	$ 5.81	$ 6.45	11%
Deloitte MarketPoint	$ 6.11	$ 6.37	4%

Source: Brookings Institute for all estimates besides Deloitte MarketPoint's

[4] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Howard Gruenspecht, EIA, January 2012.

rather anticipate events. Accordingly, prices will rise to induce producers to develop supplies in time to meet future demand.

Other models, primarily based on linear programming (LP)[5] or similar approaches, use static representation of supply in that supply does not anticipate price or demand growth. These static supply models require the user to input estimates of productive capacities in each future time period. The Brookings Institution completed a study assessing the impact of LNG exports and analyzing different economic approaches.[6] . As the Brookings study states:

"… static supply model, which, unlike dynamic supply models, does not fully take account of the effect that higher prices have on spurring additional production."

Since the supply volumes available in each time period is an input into LP models, the user must input how supply will respond to demand. In the case of LNG exports, the user must input how much supplies will increase and how quickly given the export volumes. Hence, the price impact is largely determined by how the user changes these inputs.

The purpose of this discussion is not to assert which approach is best, but rather to understand the differences so that the projections can be understood in their proper context. Assuming little or no price anticipation will tend to elevate the projected price impact while assuming price anticipation will tend to mitigate the projected price impact. Depending on the issue being analyzed, one approach may be more appropriate than the other. In the case of LNG export terminals, our belief is that the assumption of dynamic supply demand balance is appropriate. Given the long lead time, expected to be at least five years, required to permit, site, and construct an LNG export terminal, producers will have both ample time and plenty of notice to prepare for the export volumes. It would be a different matter if exports were to begin with little advanced notice.

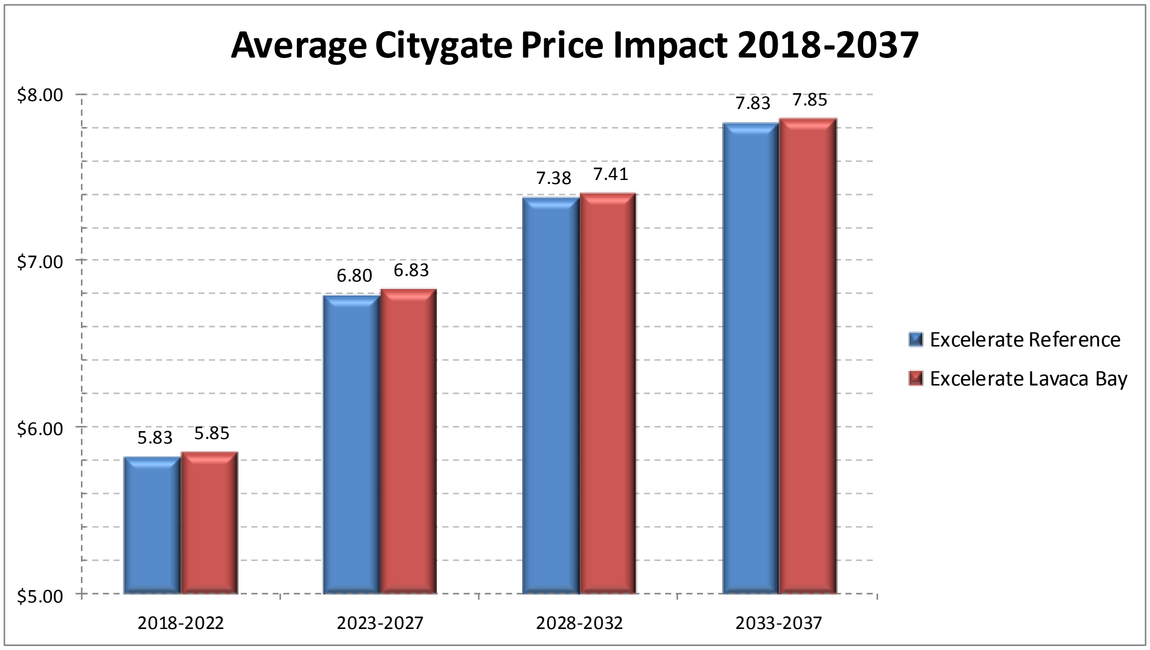
The importance of timing is evident in EIA's projections. The projected price impact is highly dependent on how quickly export volumes are assumed to ramp up. Furthermore, in all cases, the impacts are the greatest in the early years of exports. The impacts dissipate over time as supplies are assumed to eventually catch up with the demand growth.

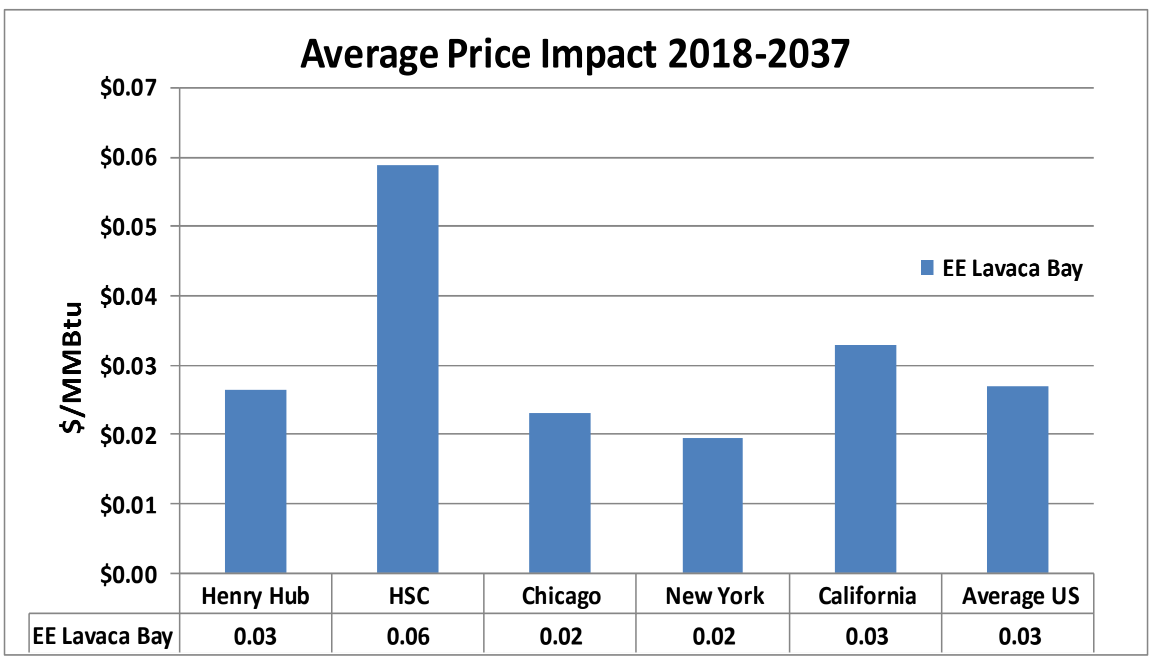
Natural gas producers are highly sophisticated companies with analytical teams monitoring and forecasting market conditions. Producers, well aware of the potential LNG export projects, are looking forward to the opportunity to supply these projects.

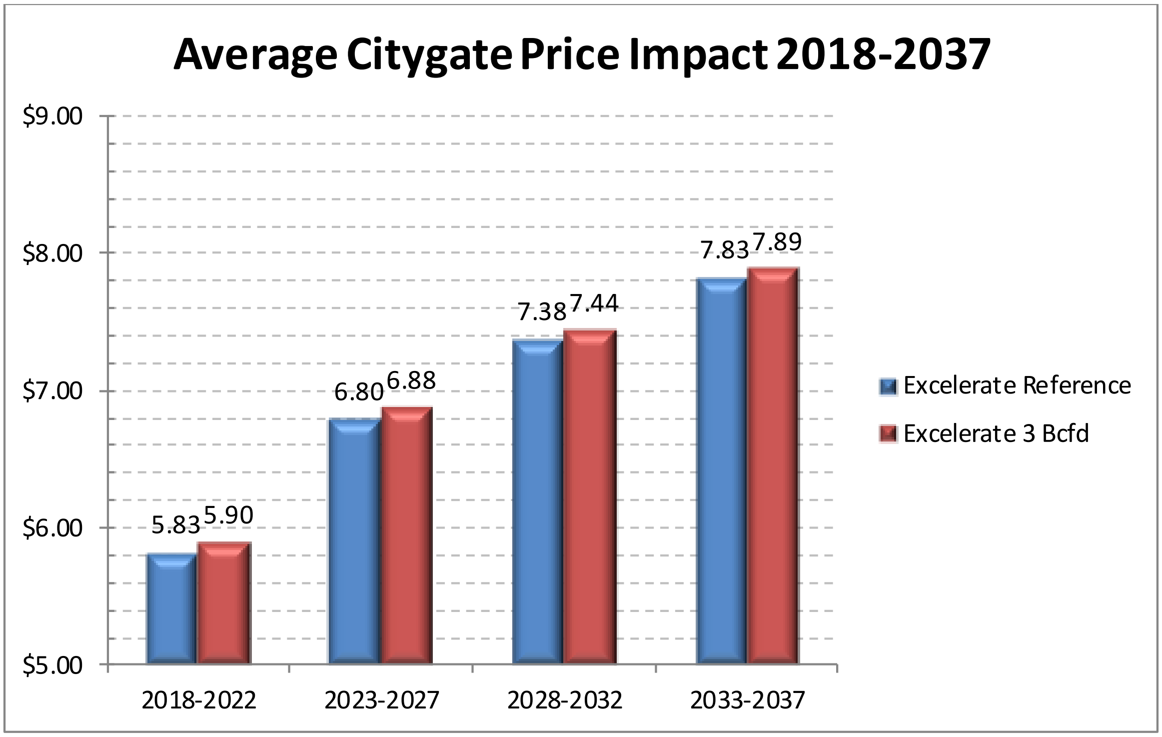
[5] Linear programming ("LP") is a mathematical technique for solving a global objective function subject to a series of linear constraints

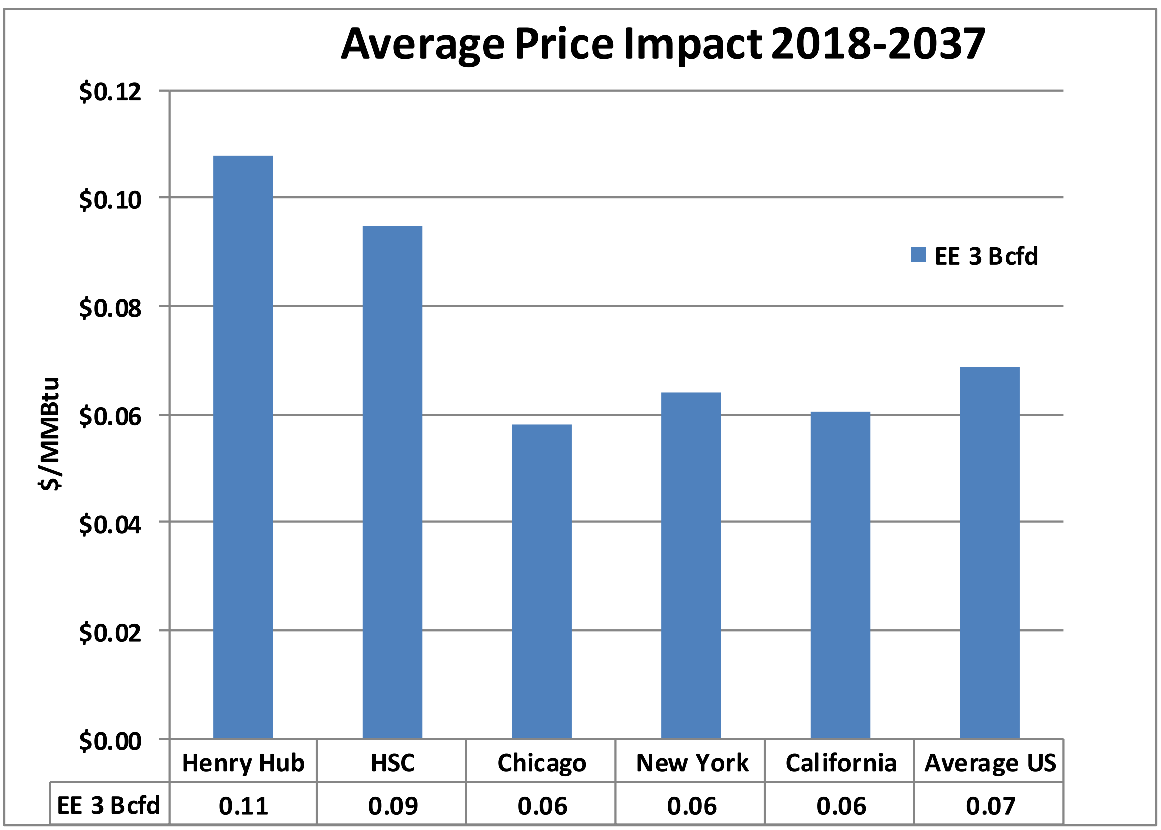
[6] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (2012).

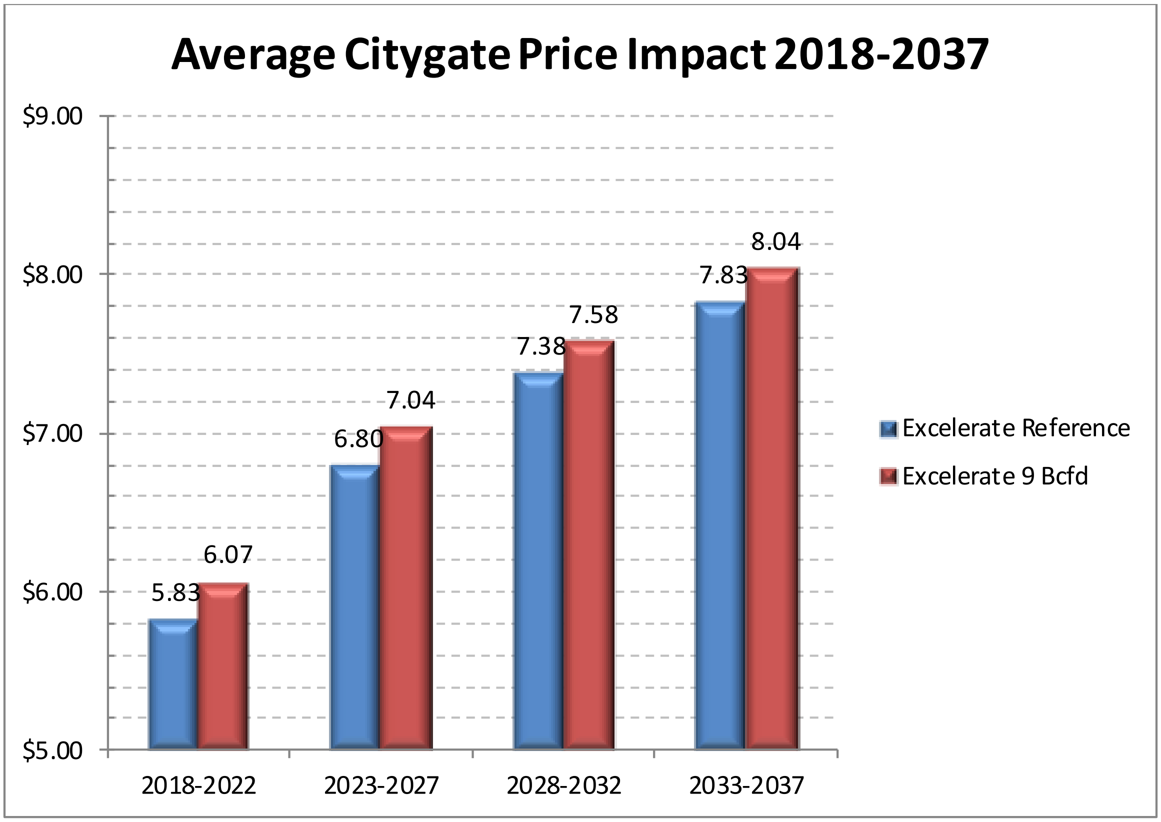
Appendix A: Price Impact Charts for other Export Cases

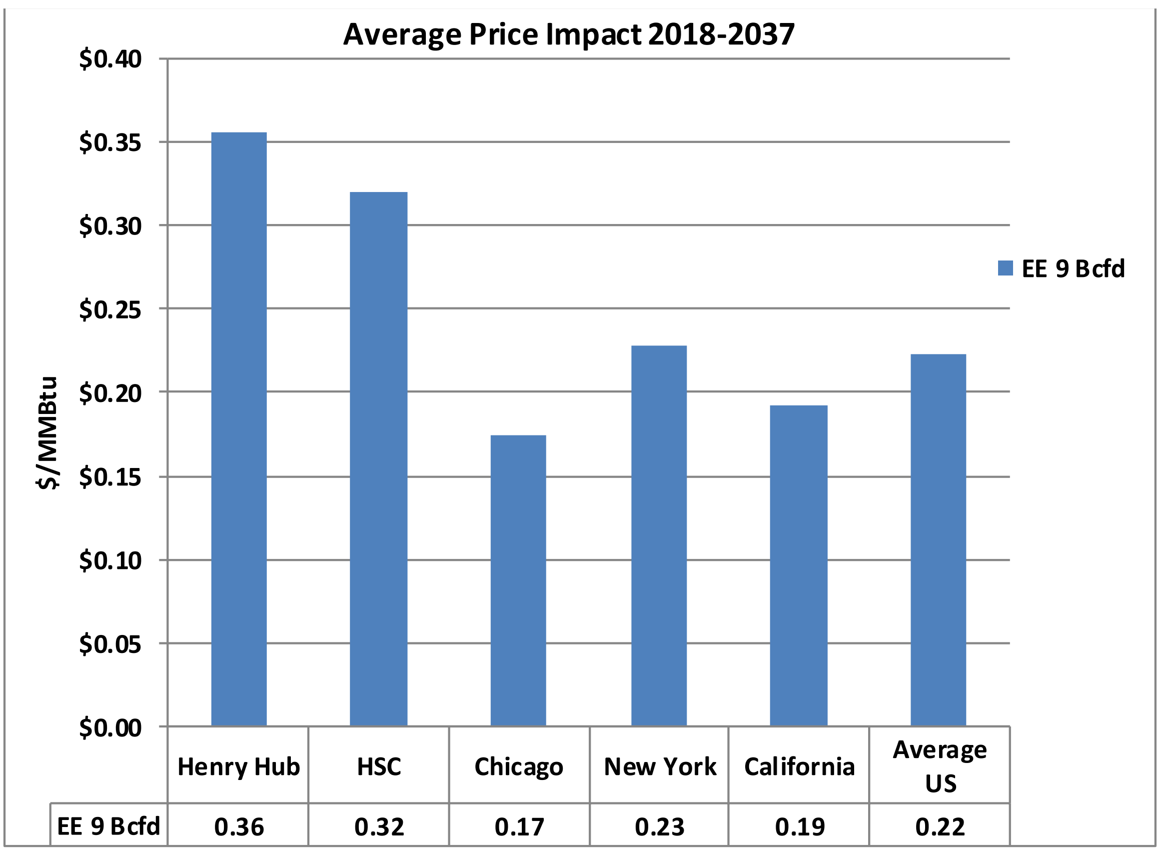


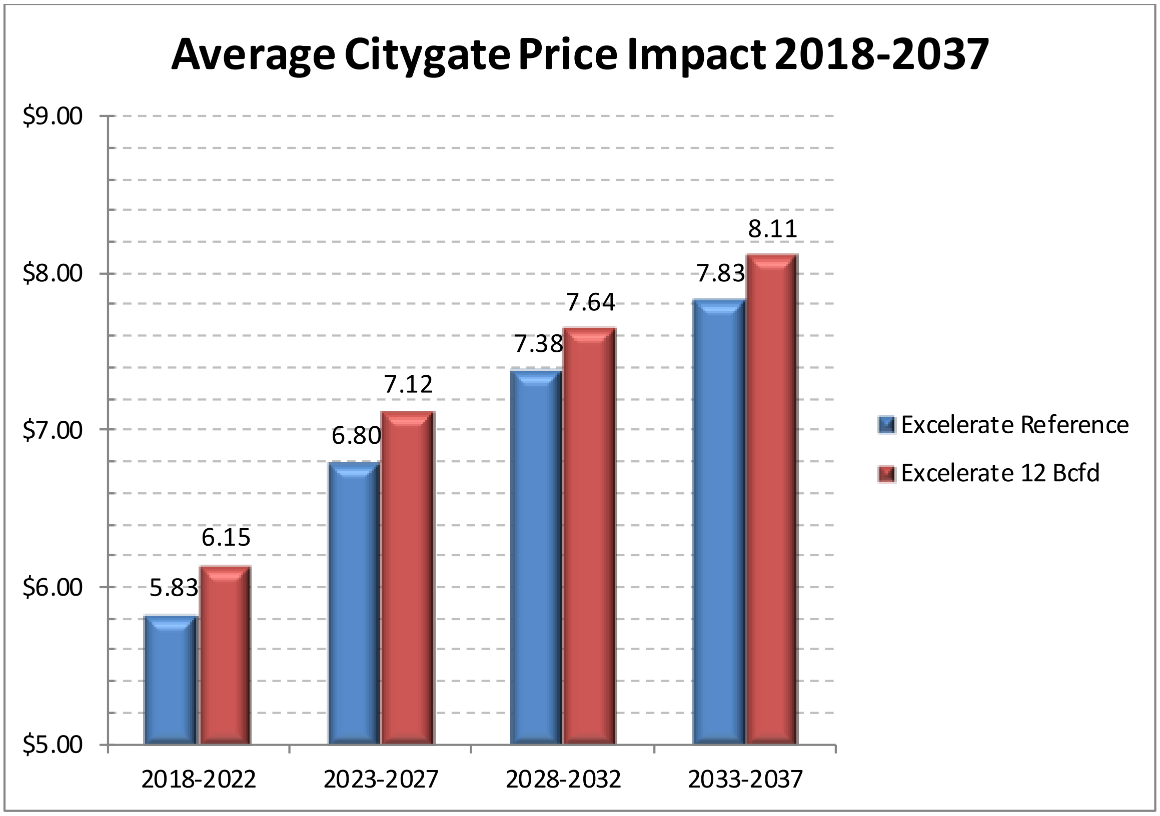


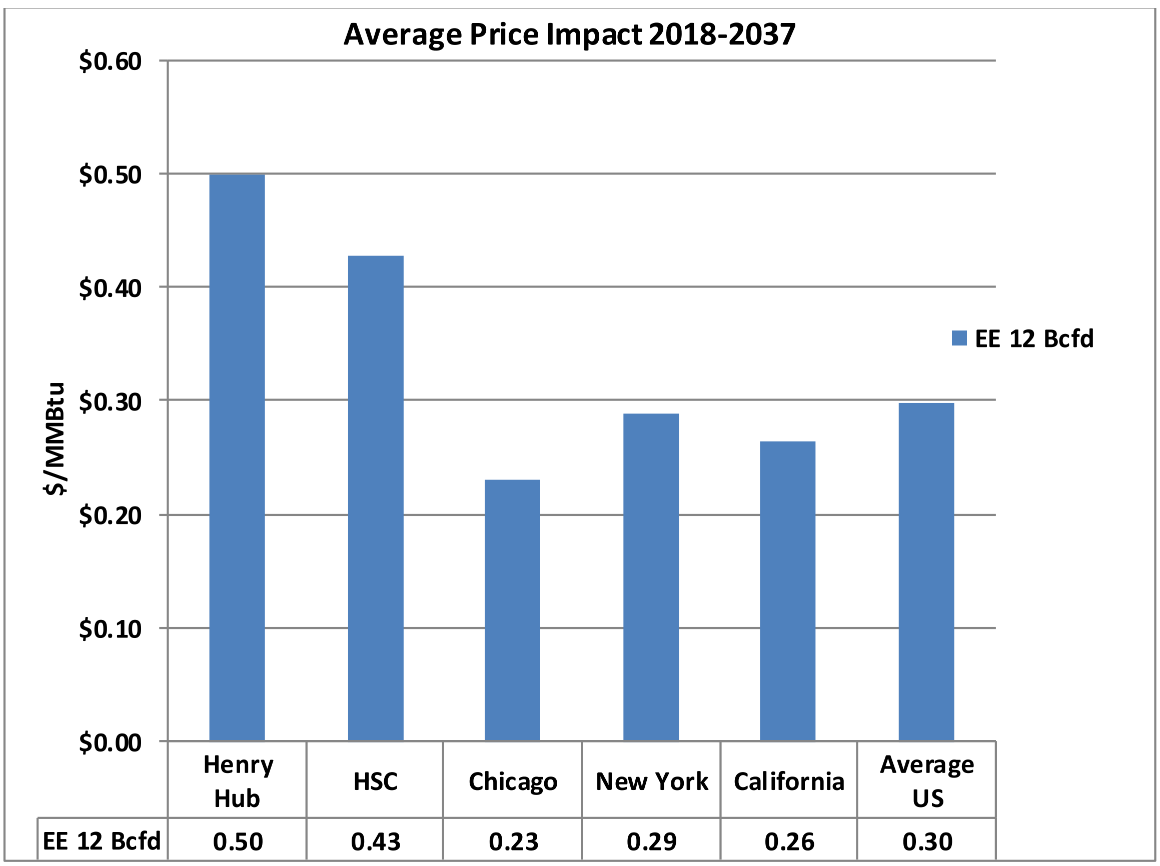

Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83 5.90
6.80 6.88
7.38 7.44
7.83 7.89
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 3 Bcfd


Average Price Impact 2018-2037
$/MMBtu
$0.12
$0.10
$0.08
$0.06
$0.04
$0.02
$0.00
EE 3 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 3 Bcfd
0.11
0.09
0.06
0.06
0.06
0.07


Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83
6.07
6.80
7.04
7.38
7.58
7.83
8.04
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 9 Bcfd


Average Price Impact 2018-2037
$/MMBtu
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
EE 9 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 9 Bcfd 0.36 0.32 0.17 0.23 0.19 0.22


Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83
6.15
6.80
7.12
7.38
7.64
7.83
8.11
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 12 Bcfd


Average Price Impact 2018-2037
$/MMBtu
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
EE 12 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 12 Bcfd
0.50
0.43
0.23
0.29
0.26
0.30

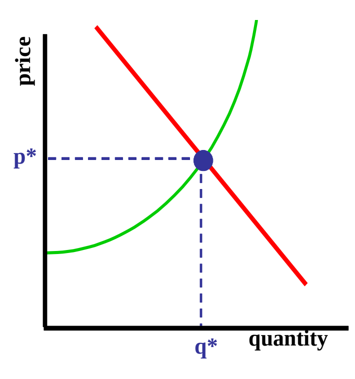
Appendix B: DMP's World Gas Model and data

To help understand the complexities and dynamics of global natural gas markets, DMP uses its World Gas Model ("WGM") developed in our proprietary MarketBuilder software. The WGM, based on sound economic theories and detailed representations of global gas demand, supply basins, and infrastructure, projects market clearing prices and quantities over a long time horizon on a monthly basis. The projections are based on market fundamentals rather than historical trends or statistical extrapolations.

WGM represents fundamental producer decisions regarding the timing and quantity of reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the market value of gas supply in remote parts of the world. The WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

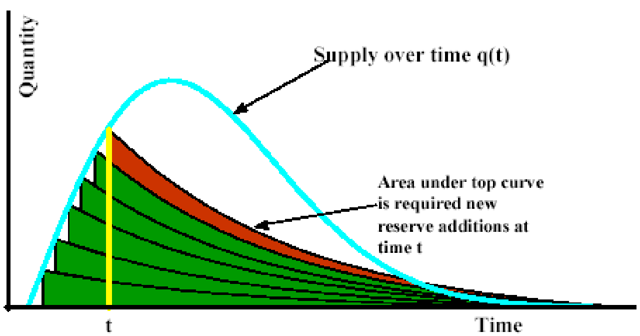
WGM simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2046. The WGM divides the world into major geographic regions that are connected by marine freight. Within each major region are very detailed representations of many market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area. All known significant existing and prospective trade routes, LNG liquefaction plants, LNG regasification plants and LNG terminals are represented. Competition with oil and coal is modeled in each region. The capability to model the related markets for emission credits and how these may impact LNG markets is included. The model includes detailed representation of LNG liquefaction, shipping, and regasification; pipelines; supply basins; and demand by sector. Each regional diagram describes how market elements interact internally and with other regions.

Agent based economic methodology. MarketBuilder rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. To understand the benefits of the agent based approach, suppose you have a market comprised of 1000 agents, i.e., producers, pipelines, refineries, ships, distributors, and consumers. If your model of that market is to be correct, how many optimization



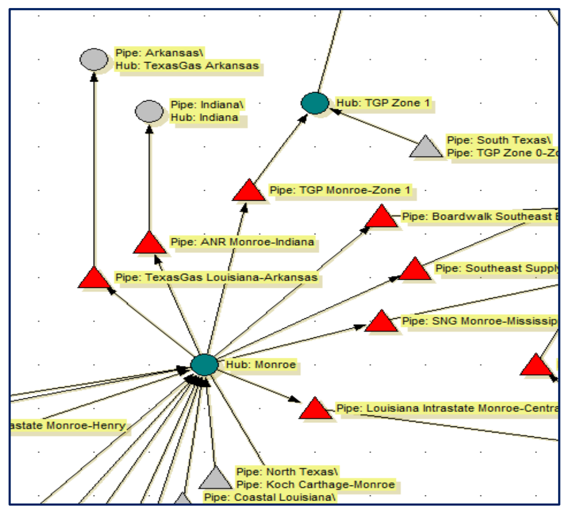
problems must there be in your model of that 1000 agent market? The answer is clear—there must be 1000 distinct, independent optimization problems. Every individual agent must be represented as simultaneously solving and pursuing his or her own maximization problem, vying for market share and trying to maximize his or her own individual profits. Market prices arise from the competition among these 1000 disparate, profit-seeking agents. This is the essence of microeconomic theory and competitive markets — people vying in markets for profits — and MarketBuilder rigorously approaches the problem from this perspective. In contrast, LP models postulate a single optimization problem no matter how many agents there are in the market; they only allow one, overall, global optimization problem. With LP, all 1000 agents are assumed to be manipulated by a "central authority" who forces them to act in lockstep to minimize the worldwide cost of production, shipment, and consumption of oil, i.e., to minimize the total cost of gas added up over the entire world.

Supply methodology and data. Working with data from agencies such as the United States Geological Survey (USGS), Energy Information Administration (EIA), and International Energy Agency (IEA), we have compiled a full and credible database of global supplies. In



particular, we relied on USGS' world oil and gas supply data including proved reserves, conventional undiscovered resources, growth of reserves in existing fields, continuous and unconventional deposits, deep water potential, and exotic sources. Derived from detailed probabilistic analysis of the world oil and gas resource base (575 plays in the US alone), the USGS data lies at the heart of DMP' reference case resource database. Only the USGS does a worldwide, "bottom up" resource assessment. Customers can easily substitute their own proprietary view where they believe they have better information. MarketBuilder allows the use of sophisticated depletable resource modeling to represent production of primary oil and gas (an extended Hotelling model). The DMP Hotelling depletable resource model uses a "rational expectations" approach, which assumes that today's drilling affects tomorrow's price and tomorrow's price affects today's drilling. Thus MarketBuilder combines a resource model that approaches resource development the same way real producers do given the available data.

Transportation data. DMP maintains a global pipeline and transportation database. DMP and our clients regularly revise and update the transportation data including capacity, tariffs, embedded cost, discounting behavior, dates of entry of prospective new pipelines, and costs of those new pipelines.



Non-linear demand methodology. MarketBuilder allows the use of multi-variate nonlinear representations of demand by sector, without limit on the number of demand sectors. DMP is skilled at performing regression analyses on historical data to evaluate the effect of price, weather, GNP, etc. on demand. Using our methodology, DMP systematically models the impact of price change on demand (demand price feedback) to provide realistic results.