NERA developed a set of world natural gas price projections based upon a number of data sources. The approach focuses on the wellhead price forecasts for net export regions and city gate price forecasts for net import regions.

U.S. wellhead natural gas prices are not precisely the same in the global natural gas model and the U.S. N_{ew}ERA model. Supply curves in both models were calibrated to the EIA implicit supply curves, but the GNGM has a more simplified representation of U.S. natural gas supply and demand than the more detailed N_{ew}ERA model so that the two models solve for slightly different prices with the same levels of LNG exports. The differences are not material to any of the results in the study.

In natural gas-abundant regions like the Middle East and Africa, the wellhead price is assumed to equal the natural gas development and lifting cost. City gate prices are estimated by adding a transportation cost to the wellhead prices. In the major Asian demand markets, natural gas prices are determined on a near oil-parity basis using crude oil price forecasts from IEA's WEO 2011. The resultant prices are highly consistent with the relevant historical pipeline import prices13 and LNG spot market prices as well as various oil and natural gas indices (*i.e.*, JCC, WTI, Henry Hub, AECO Hub indices, and UK National Balancing Point). U.S. wellhead and average city gate prices are adopted from AEO 2012 Early Release. Canadian wellhead prices are projected to initially be $0.35 less than the U.S. prices in the Reference case. The resulting city gate and wellhead prices are presented in Figure 16 and Figure 17.

[13] German BAFA natural gas import border price, Belgium Zeebrugge spot prices, TTF Natural Gas Futures contracts, *etc*.

Figure 16: Projected Wellhead Prices (2010$/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Canada	$3.39	$3.72	$4.25	$5.20	$5.64	$6.68
China/India	$12.29	$12.86	$13.00	$13.25	$13.57	$13.51
C&S America	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
Europe	$9.04	$9.97	$10.80	$11.95	$12.39	$13.23
FSU	$4.25	$4.60	$5.08	$5.61	$6.19	$6.84
Korea/Japan	$14.59	$15.30	$15.47	$15.79	$16.19	$16.11
Middle East	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Oceania	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Sakhalin	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Southeast Asia	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
U.S.	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36

Figure 17: Projected City Gate Prices (2010$/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$2.75	$2.89	$3.09	$3.31	$3.55	$3.81
Canada	$4.79	$5.12	$5.65	$6.60	$7.04	$8.08
China/India	$13.79	$14.36	$14.50	$14.75	$15.07	$15.01
C&S America	$4.50	$4.66	$4.89	$5.14	$5.41	$5.72
Europe	$10.04	$10.97	$11.80	$12.95	$13.39	$14.23
FSU	$5.25	$5.60	$6.08	$6.61	$7.19	$7.84
Korea/Japan	$15.09	$15.80	$15.97	$16.29	$16.69	$16.61
Middle East	$4.08	$4.18	$4.32	$4.48	$4.65	$4.84
Oceania	$3.25	$3.39	$3.59	$3.81	$4.05	$4.31
Sakhalin	$3.75	$3.85	$3.99	$4.15	$4.32	$4.51
Southeast Asia	$3.00	$3.16	$3.39	$3.64	$3.91	$4.22
U.S.	$4.72	$4.83	$5.28	$6.10	$6.48	$7.36

After calibrating the GNGM to the above prices and quantities, we allowed the model to solve for the least-cost method of transporting gas so that supplies and demands are met. Figure 18,

Figure 19, and Figure 20 display the pipeline flows between model regions, LNG exports, and LNG imports for all model years in the baseline.

Figure 18: Baseline Inter-Region Pipeline Flows (Tcf)

Origin	Destination	2010	2015	2020	2025	2030	2035
Africa	Europe	1.53	1.68	1.41	0.94	0.88	0.87
Canada	U.S.	2.33	2.33	1.40	0.74	0.64	0.04
FSU	China/India	0.07	0.34	1.18	1.55	1.59	1.83
FSU	Europe	4.55	5.88	7.21	9.22	10.38	10.84

Figure 19: Baseline LNG Exports (Tcf)

Exporter	2010	2015	2020	2025	2030	2035
Africa	2.38	3.46	4.02	4.45	4.12	3.77
C&S America	0.37	0.66	0.50	0.19	0.16	0.06
Sakhalin	0.44	0.48	0.49	0.52	0.55	0.59
Middle East	4.10	4.64	4.64	4.64	4.64	4.64
Oceania	0.74	1.28	1.63	2.02	2.60	3.04
Southeast Asia	1.64	1.42	0.85	-	-	-

Figure 20: Baseline LNG Imports (Tcf)

Importer	2010	2015	2020	2025	2030	2035
China/India	1.02	2.58	2.52	3.21	3.69	3.48
Europe	3.58	3.99	4.02	2.82	2.57	2.98
Korea/Japan	4.80	5.00	5.05	5.21	5.43	5.48
U.S.	0.37	0.37	0.50	0.36	0.16	0.06

B. Behavior of Market Participants

In a market in which existing suppliers are collecting profits, the potential entry of a new supplier creates an issue concerning how the existing suppliers should respond. Existing suppliers have three general strategy options:

1. Existing suppliers can voluntarily reduce their own production, conceding market share to the new entrant in order to maintain market prices.

2. Existing suppliers can act as price takers, adjusting their volume of sales until prices reach a new, lower equilibrium.

3. Existing suppliers can choose to produce at previously planned levels with the hope of discouraging the new potential supplier from entering the market by driving prices below levels acceptable to the new entrant.

How much the U.S. will be able to export, and at what price, depends critically on how other LNG producers like Qatar that are low cost producers but currently limiting exports would react to the appearance of a new competitor in the market. Our model of the world gas market is one of a single dominant supplier, which has the largest shares of LNG exports and is thought to be limiting output, and a competitive fringe whose production adjusts to market prices.[14] Our calculation of U.S. benefits from trade assumes that the dominant supplier would not change its plans for expanding production to counter U.S. entry into the market (strategy 3). Their continued production would leave no room for U.S. exports until prices were driven down far enough to stimulate sufficient additional demand to absorb economic exports from the U.S. Since the competitive fringe does reduce output (strategy 2) as prices fall due to U.S. LNG exports, there is an opportunity for the U.S. to enter the market but only by driving delivered LNG prices in key markets below what they are today. Should these countries respond instead by cutting production below planned levels to maintain prices, the U.S. could gain greater benefits and a larger market share. If the dominant supplier chooses to cut prices, then exporting LNG from the U.S. would become less attractive to investors.

Another consideration is the behavior of LNG consumers. At this point in time, countries like Japan and Korea appear to be paying a substantial premium over the price required to obtain supplies from regions that have not imposed limits on planned export capacity. At the same time, those countries are clearly looking into arrangements in the United States that would provide natural gas at a delivered cost substantially below prices they currently pay for LNG deliveries. This could be because they view the U.S. as a uniquely secure source of supply, or it could be that current high prices reported for imports into Japan and Korea are for contracts that will expire and be replaced by more competitively priced supplies. If countries like Japan and Korea became convinced that they could obtain secure supplies without long-term oil-based pricing contracts, and ceased paying a premium over marginal cost, the entire price structure could shift downward. Since the U.S. does not appear to be the world's lowest cost supplier, this could have serious consequences for the profitability of U.S. exports.

In this study, we address issues of exporter responses by assuming that there is a competitive market with exogenously determined export limits chosen by each exporting region and determined by their liquefaction capacity. This assumption allows us to explore different scenarios for supply from the rest of the world when the U.S. begins to export. This is a middle

[14] We consider the dominant supplier to be Qatar, with a 31% share of the market in 2011, while also exercising some production restraint.

ground between assuming that the dominant producer will limit exports sufficiently to maintain the current premium apparent in the prices paid in regions like Japan and Korea, or that dominant exporters will remove production constraints because with U.S. entry their market shares fall to levels that do not justify propping up prices for the entire market.

It is outside the scope of this study to analyze alternative responses by other LNG suppliers in order to determine what would be in their best economic interest or how they might behave strategically to maximize their gains. This would require a different kind of model that addresses imperfect competition in global LNG markets and could explain the apparent ability of some large exporters to set prices for some importing countries at prices higher than the cost of production plus transportation.

C. Available LNG Liquefaction and Shipping Capacity

This analysis did not investigate the technical feasibility of building new liquefaction capacity in a timely fashion to support the level of exports the model found optimal. In all cases, the GNGM assumed no limits on either LNG liquefaction capacity additions outside the U.S. or world LNG shipping capacity. The only LNG export capacity limits were placed on the U.S. and the Middle East.

D. The Effects of U.S. LNG Exports on Regional Natural Gas Markets

When the U.S. exports LNG, the worldwide and domestic natural gas markets are affected in the following ways:

- The additional supplies from U.S. LNG exports cause a drop in city gate prices in the importing regions;
- The lower prices lead to increased natural gas consumption in the importing regions;
- Relative to the baseline forecast, U.S. LNG exports displace some LNG exports from other regions, which leads to lower production levels in many of the other exporting regions;
- U.S. LNG exports displace FSU pipeline exports to Europe and China, which leads to lower FSU production;
- Exporting regions with lower LNG or pipeline exports and hence lower production levels experience a drop in wellhead and city gate prices because of the lower demand for their gas;
- Natural gas production rises in the U.S. because there is additional demand for its gas;

- Wellhead natural gas prices rise in the U.S. because of the increased demand, which leads to higher city gate prices; and

- Higher U.S. prices cause a reduction in U.S. natural gas consumption.

Whether or not a region's exports would be displaced by U.S. LNG exports depend on several factors:

- The difference in delivered costs between an exporting region and the U.S.;

- The magnitude of the demand shock or increased demand; and

- The magnitude of the supply shock or reduction in world supply.

Because Africa and the Middle East are the lowest cost producers, U.S. LNG exports have the smallest effect on their exports. Also, the Middle East's exports are limited by our assumption that Qatar continues to limit its exports of natural gas at its announced levels. Thus, there are pent-up LNG exports, which mean that the Middle East can still export its same level of LNG even with a decline in international gas prices.

Since the cost of exports is higher in some other regions, they are more vulnerable to having their exports displaced by U.S. LNG exports. In the International Reference case, U.S. LNG exports displace LNG exports from all regions to some extent in many of the years. U.S. exports also cause reductions in inter-regional pipeline exports: FSU to Europe and China, as well as Africa to Europe.

In comparing the International Reference case to the Demand Shock and Supply/Demand Shock cases, we find that global LNG exports increase because the world demand for natural gas is greater. Like other regions, U.S. LNG exports increase, which means that they displace a greater number of exports. However, those regions that have some of their exports displaced still export more natural gas under the Demand Shock and Supply/Demand Shock scenarios than under the equivalent International Reference scenarios.

In the Supply/Demand Shock scenarios, Oceania, Southeast Asia, and Africa have their LNG exports restricted. This restriction leads to these regions receiving a netback price in excess of their wellhead prices. Thus, these regions have a margin that buffers them when the U.S. LNG exports try to enter the market. These regions can lower their export price for LNG some while still ensuring their netback price is greater than or equal to their wellhead price and maintain their level of LNG exports at the level that existed before the U.S. entered the market. However, Southeast Asia has a much smaller buffer than Oceania and Africa so when the U.S. enters the market it effectively displaces much of Southeast Asia's supply.

By 2030, demand for LNG becomes greater so low-cost producing regions such as Sakhalin and the Middle East experience no decline in LNG exports when the U.S. LNG exports enter the market.

When the U.S. enters the global LNG market, each region's supply, demand, wellhead price, and city gate price for natural gas respond as expected. More precisely, importing regions increase their demand for natural gas, and exporting regions either reduce or maintain their supply of natural gas. The wellhead and city gate prices for natural gas decline in all importing regions and remain the same in exporting regions except for in the U.S. and Canada, which are now able to export LNG.

E. Under What Conditions Would the U.S. Export LNG?

In order to understand the economic impacts on the U.S. resulting from LNG exports, it is necessary to understand the circumstances under which U.S. natural gas producers will find it profitable to export LNG. To accomplish this, we used GNGM to run a series of scenarios for all combinations of the three U.S. scenarios (Reference, High Shale EUR, and Low Shale EUR) and three international scenarios (International Reference, Demand Shock, and Supply/Demand Shock). In these runs, we varied the constraints on LNG export levels across seven settings (No-Exports, Low/Slowest, Low/Slow, Low/Rapid, High/Slow, High/Rapid, and Unconstrained). Based upon these 63 runs, we found the following:

- For the scenarios which combined the International Reference and U.S. Reference cases, there were no U.S. LNG exports. In part, this is due to the fact that the EIA scenarios upon which they are based assume that global natural gas demand is met by global supplies without U.S. LNG exports. This outcome also implies that U.S. LNG exports under a U.S. Reference scenario would not be lower cost than existing or planned sources of LNG in other regions of the world and thus do not displace them.
- When there is additional growth in global natural gas demand beyond that of the International Reference scenario, then the U.S. exports LNG to help meet this incremental demand. The degree to which the U.S. exports LNG depends upon the abundance and quality of the U.S. resource base.
- When the U.S. gas supplies are more abundant and lower cost than in the U.S. Reference case, the U.S. can competitively export LNG either to meet incremental global demand or to displace planned LNG supplies in other regions.
- Should the U.S. shale gas resource prove less abundant or cost effective, then U.S. LNG exports will be minimal under the most optimistic global scenario (Supply/Demand Shock).

In the next sections, we present the modeling results for each of the three U.S. cases that served as the basis for arriving at these conclusions.

1. Findings for the U.S. Reference Scenario

This section reports the level of U.S. LNG exports under the 21 scenarios (includes no LNG export scenario) that assume the U.S. Reference scenario. These scenarios consider different international assumptions about international demand and supply of natural gas as well as different assumptions about the U.S.'s ability to export LNG. Figure 21 reports the U.S.'s maximum export capacity for each LNG export capacity scenario.

Figure 21: U.S. LNG Export Capacity Limits (Tcf)

LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
Low/Slowest	0.18	1.10	2.01	2.19	2.19
Low/Slow	0.37	2.19	2.19	2.19	2.19
Low/Rapid	1.10	2.19	2.19	2.19	2.19
High/Slow	0.37	2.19	4.02	4.38	4.38
High/Rapid	1.10	4.38	4.38	4.38	4.38
No Constraint	N/A	N/A	N/A	N/A	N/A

Figure 22 reports the level of U.S. LNG exports. Viewing Figure 21and Figure 22, one can see the effect of the LNG export capacity limits on restraining U.S. exports and the effect of these limits under different assumptions about the International scenarios.

Figure 22: U.S. LNG Exports –U.S. Reference (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
U.S. Reference	Demand Shock	Low/Slowest	**0.18**	0.98	1.43	1.19	1.37
		Low/Slow	**0.37**	0.98	1.43	1.19	1.37
		Low/Rapid	1.02	0.98	1.43	1.19	1.37
		High/Slow	**0.37**	0.98	1.43	1.19	1.37
		High/Rapid	1.02	0.98	1.43	1.19	1.37
		No Constraint	1.02	0.98	1.43	1.19	1.37
	Supply/ Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	3.93	**4.38**	**4.38**
		High/Rapid	**1.10**	2.92	3.93	**4.38**	**4.38**
		No Constraint	2.17	2.92	3.93	4.54	5.75

Figure 22 omits the International Reference Scenario because when there are no international shocks that either raise world demand or lower world supply from baseline levels, then the U.S. does not export LNG. However, the U.S. does export LNG when higher levels of world demand are assumed and exports even greater amounts of LNG when both world demand increases and non-U.S. supply planned expansions are not built (units denoted as "under construction" are still assumed to be built).

Under the Demand Shock scenario from 2020 onward, the economic level of U.S. LNG exports do not reach export capacity limits. Therefore, the level of exports in the years 2020 through 2035 is the same for all LNG export capacity levels. Under Supply/Demand Shock scenario, however, the LNG export capacity limits are often binding.[15] The low U.S. LNG capacity export limits are binding for all rates of expansion (Low/Slowest, Low/slow, and Low/Rapid) for all years. For the high LNG export levels, some years are binding and some are not. Under the Supply/Demand Shock scenarios, LNG exports are always greater than or equal to LNG exports in the Demand Shock cases.

The U.S. LNG export capacity binds when the optimal level of exports as determined by the model (see the rows denoted "No Constraint") exceeds the LNG export capacity level. The difference between the value of LNG exports in the "No Constraint" row and a particular case with a LNG export capacity defines the quantity of exports that LNG export capacity prohibits from coming onto the world market. The greater this number, the more binding the LNG export capacity and the more valuable an LNG terminal would be. In 2025 for example, the U.S. would choose to export almost 4 Tcf of LNG, but if its export capacity limit followed one of the low level cases (Low/Slowest, Low/Slow, or Low/Rapid), there would be a shortfall of almost 2 Tcf of export capacity. On the other hand, if the export capacity followed one of the high level cases (High/Slow or High/Rapid), the U.S. would have about 0.4 Tcf of spare capacity.

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15 The U.S. LNG export capacity binds when the market equilibrium level of exports as determined by the model exceeds the maximum LNG export capacity assumed in that scenario.

2. Findings for the U.S. High Shale EUR Scenario

Figure 23: U.S. LNG Export – High Shale EUR (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
High Shale EUR	International Reference	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	3.77	2.78	3.38
		High/Rapid	**1.10**	2.97	3.77	2.78	3.38
		No Constraint	2.23	2.97	3.77	2.78	3.38
	Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	**4.02**	**4.38**	**4.38**
		High/Rapid	**1.10**	3.94	**4.38**	**4.38**	**4.38**
		No Constraint	3.30	3.94	4.87	4.59	5.61
	Supply/ Demand Shock	Low/Slowest	**0.18**	**1.10**	**2.01**	**2.19**	**2.19**
		Low/Slow	**0.37**	**2.19**	**2.19**	**2.19**	**2.19**
		Low/Rapid	**1.10**	**2.19**	**2.19**	**2.19**	**2.19**
		High/Slow	**0.37**	**2.19**	**4.02**	**4.38**	**4.38**
		High/Rapid	**1.10**	**4.38**	**4.38**	**4.38**	**4.38**
		No Constraint	4.23	5.44	6.72	6.89	8.39

Analogous to Figure 22, Figure 23 shows LNG export levels for the U.S. High Shale EUR scenario and a combination of international and LNG export capacity scenarios. Under this highest level of U.S. natural gas supplies, it is cost-effective to export U.S. LNG with or without any international supply or demand shocks. In 2025, the LNG export capacity is binding in all but two cases: no international shock with either High/Slow or High/Rapid LNG export capacity limits. For all other scenarios, the export levels reflect the different U.S. LNG export capacity levels. The only exception is in the year 2020 for the High/Rapid scenario. Exports are even greater for the unconstrained cases with Demand Shocks and Supply/Demand Shocks.

The U.S. LNG export capacity limits become increasingly more binding as the international shocks lead to greater demand for U.S. LNG exports. Under the Supply/Demand shocks, the U.S. LNG export capacity limits bind in all years for the High Shale EUR case. By 2025, the capacity limits restrict between 2.3 and 4.5 Tcf of U.S. exports. Even with only a Demand shock, the U.S. LNG export capacity limits bind in all years for all limits except the High/Rapid case in 2020 in which U.S. LNG exports are only 0.4 Tcf below the U.S. LNG export capacity limit (Figure 21 and Figure 23) when the export capacity limit is 4.38 Tcf. Without any international shocks, the U.S. LNG export capacity limits bind in all years for the Low/Slowest, Low/Slow and Low/Rapid cases, and the U.S. LNG export capacity limits are non-binding for the High/Slow and High/Rapid cases after 2025.

3. Findings for the U.S. Low Shale EUR Scenario

Figure 24 shows all combinations of International scenarios and LNG export capacity scenarios in which the U.S. exports LNG for the U.S. Low Shale EUR scenario. With Low Shale EUR, U.S. supplies are more costly, and as a result, there are no U.S. LNG exports in either the International Reference or Demand Shock scenarios. For the Supply/Demand shock scenarios, U.S. LNG export capacity is binding only in some years in some cases.

Figure 24: U.S. LNG Export – Low Shale EUR (Tcf)

Bold numbers indicate that the U.S. LNG export limit is binding

U.S. Scenario	International Scenario	LNG Export Capacity Scenarios	2015	2020	2025	2030	2035
Low Shale EUR	Supply/ Demand Shock	Low/Slowest	0	0.78	0.90	0.27	0.52
		Low/Slow	0	0.78	0.90	0.27	0.52
		Low/Rapid	0	0.78	0.90	0.27	0.52
		High/Slow	0	0.78	0.90	0.27	0.52
		High/Rapid	0	0.78	0.90	0.27	0.52
		No Constraint	0	0.78	0.90	0.27	0.52

4. Netback Pricing and the Conditions for “Rents” or “Profits”

When LNG export capacity constrains exports, rents or profits are generated. These rents or profits are the difference in value between the netback and wellhead price. The netback price is the value of the LNG exports in the consuming market, less the costs incurred with transporting the natural gas from the wellhead to the consuming market. In the case of LNG, these costs consist of: pipeline transportation from the wellhead to the liquefaction plant, liquefaction costs, transportation costs by ship from the liquefaction plant to the regasification plant, regasification costs, and pipeline transportation from the regasification facility to the city gate.

The netback price can be either greater than or equal to the average wellhead price. It cannot be lower otherwise there would be no economic incentive to produce the natural gas. In cases where the U.S. LNG exports are below the LNG export capacity, the netback prices the U.S. receives for its exports equal the U.S. wellhead price. However, when the LNG export capacity binds so that LNG exports equal the LNG export capacity level, the U.S. market becomes disconnected from the world market, and the netback prices that the U.S. receives exceed its wellhead prices. In this event, the difference between the netback price and the wellhead price leads to a positive profit or rent.

5. LNG Exports: Relationship between Price and Volume

Figure 25 indicates the range of LNG exports and U.S. natural gas prices that were estimated across all 63 global scenarios, many of which had zero exports and therefore no price impacts.[16] Based on Figure 25, NERA selected 13 scenarios for detailed U.S. economic analysis. These 13 scenarios spanned the full range of potential impacts and provided discrete points within that range for discussion. In this section, we describe the analysis performed to select the 13 scenarios.

Because each of the 63 scenarios was characterized by both a U.S. and international dimension (as well as different U.S. LNG export capacity), shapes and colors were used to denote the different combinations:

- Shapes are used to differentiate among the different U.S. scenarios: U.S. Reference (diamond), High Shale EUR (triangle), and Low Shale EUR (square); and
- Colors are used to differentiate among the International cases: International Reference (red), Demand Shock (blue), and Supply/Demand Shock (yellow). In some instances, the same level of U.S. LNG exports and wellhead prices existed for multiple International cases. In these instances, the naturally combined color of the multiple cases is used (*e.g.*, a green symbol (combination of blue and yellow) if the Demand Shock and Supply/Demand Shock scenarios yield the same results.

Therefore, each point on Figure 25 conveys the U.S. and International scenarios, which may correspond to multiple LNG export capacity scenarios. For example, the northwest yellow square (0.9 Tcf of exports) corresponds to the High/Slow and High/Rapid LNG export capacity scenarios. In our detailed U.S. analysis, we only need to consider one of the multiple scenarios. Thus, we can greatly reduce the number of scenarios because Figure 25 suggests there are far fewer than 63 unique LNG export levels.

The yellow markers (scenarios that include the International Supply/Demand shock) yield the highest levels of LNG exports and U.S. natural gas prices and form the upper right hand boundary of impacts. The most northeast red, blue, and yellow markers for each shape represent the cases where LNG exports are unconstrained. For the scenarios where the LNG exports are below the export capacity limits, the marker represents multiple scenarios.

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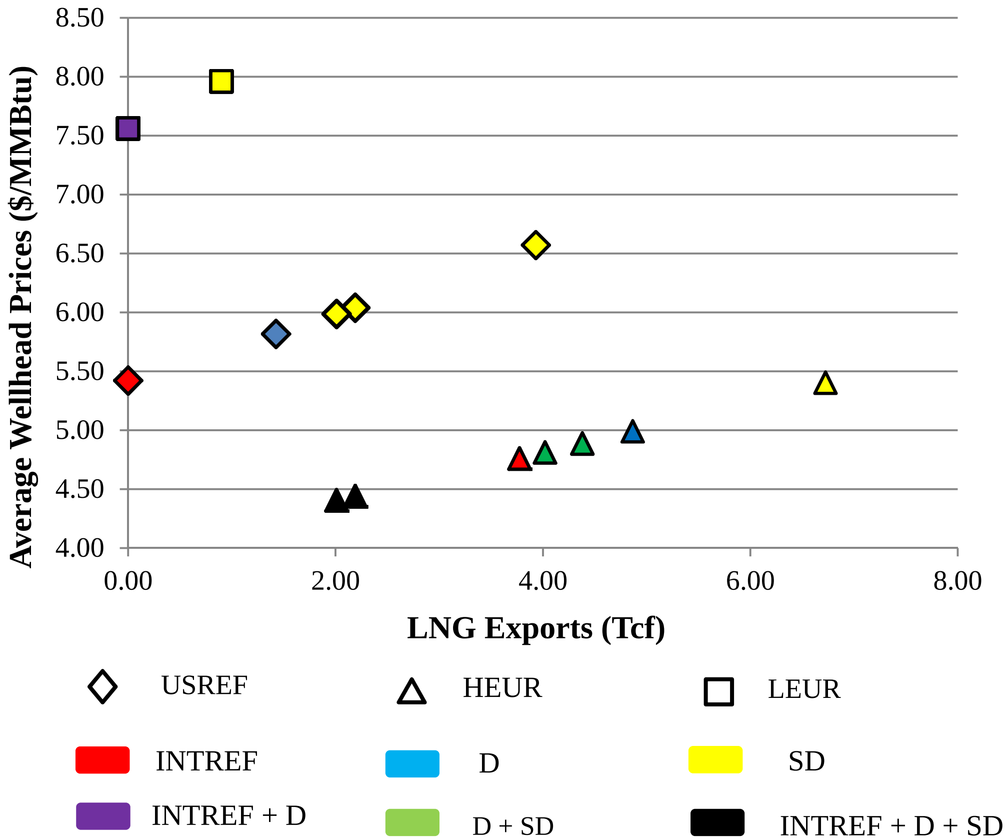
[16] In order to keep the discussion of macroeconomic impacts as concise as possible, this report does not discuss in detail all the scenarios that were run.

Figure 25: U.S. LNG Exports in 2025 Under Different Assumptions
(Note each point can correspond to multiple LNG export capacity scenarios.)



BCF/day = 2.74 * Tcf/Year

The triangles (scenarios that include the High EUR) form a line moving up and to the right, which essentially traces out the U.S. supply curve for LNG under the High EUR scenario. These scenarios combine the lowest U.S. natural gas prices with the highest levels of exports, as would be expected. With High EUR assumptions, U.S. natural gas supply can be increased at relatively low cost enabling larger levels of exports to be economic. For the detailed U.S. economic analysis, we used the High EUR cases to provide the high end of the range for U.S. LNG exports. Since the results are nearly identical between the Demand Shock and Supply and Demand Shock scenarios, we included the five export capacity scenarios under the Supply and Demand Shock because they yielded slightly higher exports.

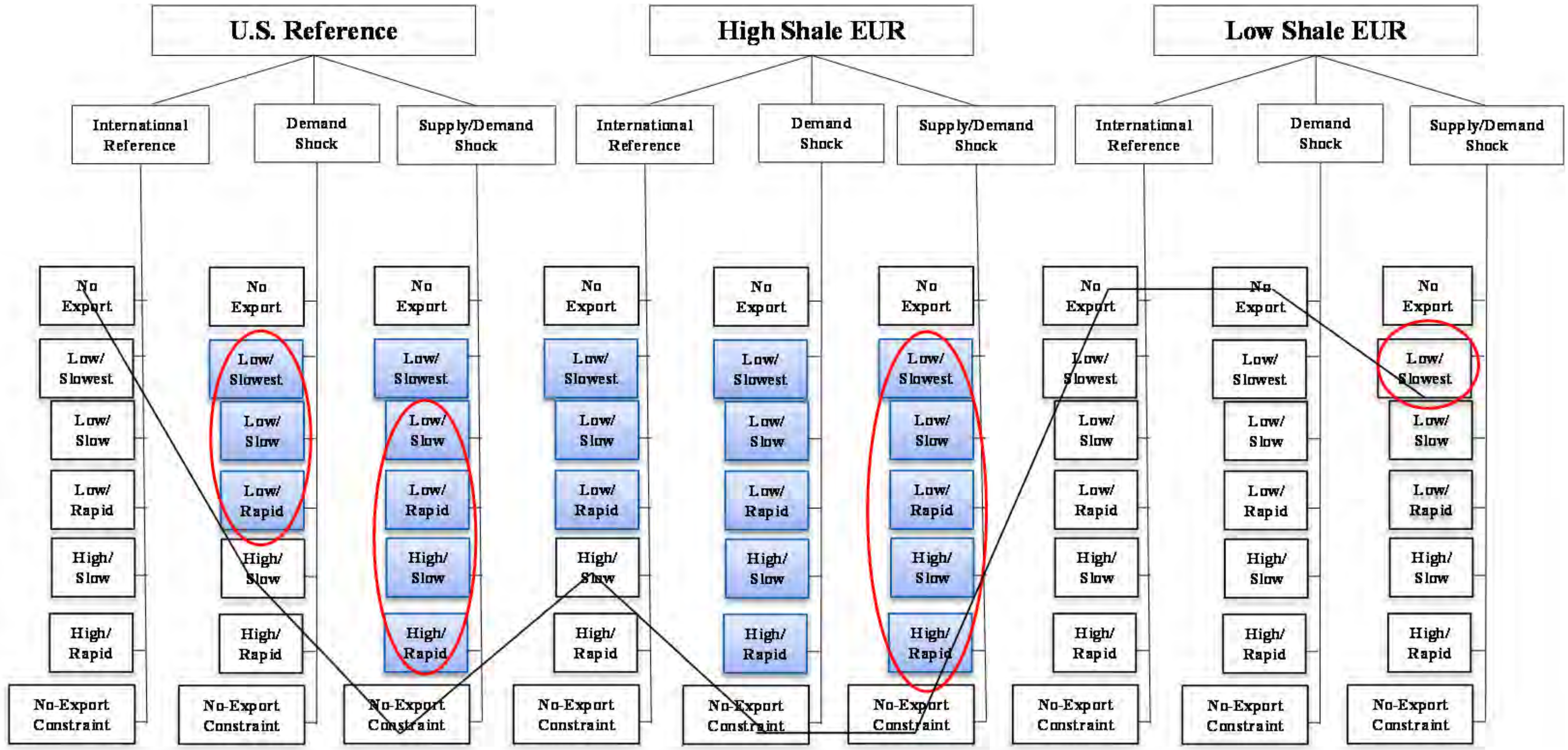
The supply curve traced out by the scenarios that include U.S. Reference case (represented by diamonds) are higher than in the High EUR cases because domestic gas is less plentiful. When only a Demand shock exists, the LNG export capacity limits are non-binding so the level of exports (the lone blue diamond) is the same for all six LNG export capacity scenarios under the U.S. Reference case. Raising the limits on LNG exports in the presence of the International

Demand Shock and Supply/Demand Shock, however, causes actual exports to increase and satisfy more of the higher world demand as exhibited by the series of yellow diamonds that move along a northeast line. In the U.S. Reference case, there are zero exports under International Reference assumptions as represented by the red diamond.

A line joining the squares in Figure 25 traces out the 2025 supply curve for the Low EUR case. The trajectory of the wellhead prices is the highest compared to other cases because of the high underlying baseline wellhead prices. Under the Low EUR baseline, the U.S. wellhead price is $7.56/Mcf in 2025, so that only with International Supply and Demand shocks is there sufficient global demand to bring about positive LNG exports at a price at least as high as the LEUR baseline. The combination of Low EUR and an international supply and demand shock leads to a combination of higher U.S. natural gas prices and lower exports than in the corresponding High EUR or U.S. Reference scenarios. Since exports are similar in the LEUR scenarios in which they exist, we only considered the most binding case (Low EUR with Supply/Demand Shock under the Low/Slowest LNG export capacity), in the detailed U.S. economic analysis. This scenario provides the low end of the export range.

F. Findings and Scenarios Chosen for N_{ew}ERA Model

Figure 26: Scenario Tree with Maximum Feasible Export Levels Highlighted in Blue and N_{ew}Era Scenarios Circled



The first use we made of the GNGM was to determine the level of exports in each of these scenarios that would be accepted by the world market at a price high enough to buy gas at the prevailing wellhead price in the United States, transport it to a liquefaction facility, and liquefy and load it onto a tanker. In some of the above cases, we found that there were no LNG exports because LNG exports would not be profitable. In many cases, we found that the amount of LNG exports that met this profitability test was below the LNG export capacity level assumed in that case. In others, we found that the assumed limit on exports would be binding. In a few cases, we found that the market if allowed would accept more than any of the export limits.

In Figure 26 under the U.S. Reference assumptions as well as in the International Reference case, we found that there would be no export volumes that could be sold profitably into the world market. In the case that combined High Shale EUR and International Reference, it was possible to achieve the Low/Rapid level of exports. After 2010, the exports approach the level of the High/Rapid constraint but never exceed it.

The line in Figure 26 designates the cases in which we observed the maximum level of exports for that combination of U.S. and International assumptions. Export levels and U.S. prices in any case falling below the line were identical to the case identified by the line. Thus, looking down the column for U.S. High EUR supply conditions combined with International Supply/Demand, we found that LNG exports and U.S. wellhead prices were the same with the High/Rapid export limits as with the more constraining High/Slow limits. We therefore did not analyze further any scenarios that fell below the line in Figure 26 and used the No-Export capacity cases to provide a benchmark to which the impacts of increased levels of exports could be compared.

Based on the results of these scenarios, we pared down the scenarios to analyze in the N_{ew}ERA macroeconomic model. Taking into account the possible world natural gas market dynamics, the GNGM model results suggest 21 scenarios in which there were some levels of LNG exports from the U.S. These scenarios were further reduced to 13 scenarios by taking the minimum level of exports across international outlooks. This was done because N_{ew}ERA model does not differentiate various international outlooks. For N_{ew}ERA, the critical issue is the level of U.S. LNG exports and U.S. natural gas production. Of the 13 N_{ew}ERA scenarios (circled in Figure 26), 7 scenarios reflected the U.S. Reference case, 5 reflected the High Shale EUR case with full U.S. LNG export capacity utilization and 1 from the Low EUR case with the lowest export expansion.

VI. U.S. ECONOMIC IMPACTS FROM N$_{EW}$ERA

A. Organization of the Findings

There are many factors that influence the amount of LNG exports from the U.S. into the world markets. These factors include supply and demand conditions in the world markets and the availability of shale gas in the U.S. The GNGM analysis, discussed in the previous section, found 13 export volume cases under different world gas market dynamics and U.S. natural gas resource outlooks. These cases are implemented as 13 N$_{ew}$Era scenarios[17] and are grouped as:

- Low/Slow and Low/Rapid DOE/FE export expansion volumes for the Reference natural gas resource outlook referred to as USREF_SD_LS and USREF_SD_LR;

- Low/Slow, Low/Rapid, High/Slow, High/Rapid and Low/Slowest GNGM export expansion volumes for the Reference natural gas resource outlook referred to as USREF_D_LS, USREF_D_LR, USREF_SD_HS, USREF_SD_HR and USREF_D_LSS;

- Low/Slow, Low/Rapid, High/Slow, High/Rapid and Low/Slowest DOE/FE export expansion volumes for the High Shale EUR natural gas resource outlook referred to as HEUR_SD_LS, HEUR_SD_LR, HEUR_SD_HS, HEUR_SD_HR and HEUR_SD_LSS; and

- Low/Slowest GNGM export expansion volumes for the Low Shale EUR natural gas resource outlook referred to as LEUR_SD_LSS

The Reference natural gas outlook scenarios were run against its No-Export volume baseline consistent with AEO 2011 Reference case (Bau_REF). Similarly, the High Shale EUR and Low Shale EUR scenarios were run against its No-Export volume baseline consistent with AEO 2011 High Shale EUR (Bau_HEUR) and AEO 2011 Low Shale EUR (Bau_LEUR) respectively.

This section discusses the impacts on the U.S. natural gas markets and the overall macroeconomic impacts for these 13 scenarios. The impacts are a result of implementing the export expansion scenarios against a baseline without any LNG exports. The economic benefits of the scenarios, as measured by different economic measures, are cross compared. We used economic measures such as welfare, aggregate consumption, disposable income, GDP, and loss of wage income to estimate the impact of the scenarios. The scenario results provide a range of outcomes that capture key sources of uncertainties in the international and the U.S. natural gas markets.

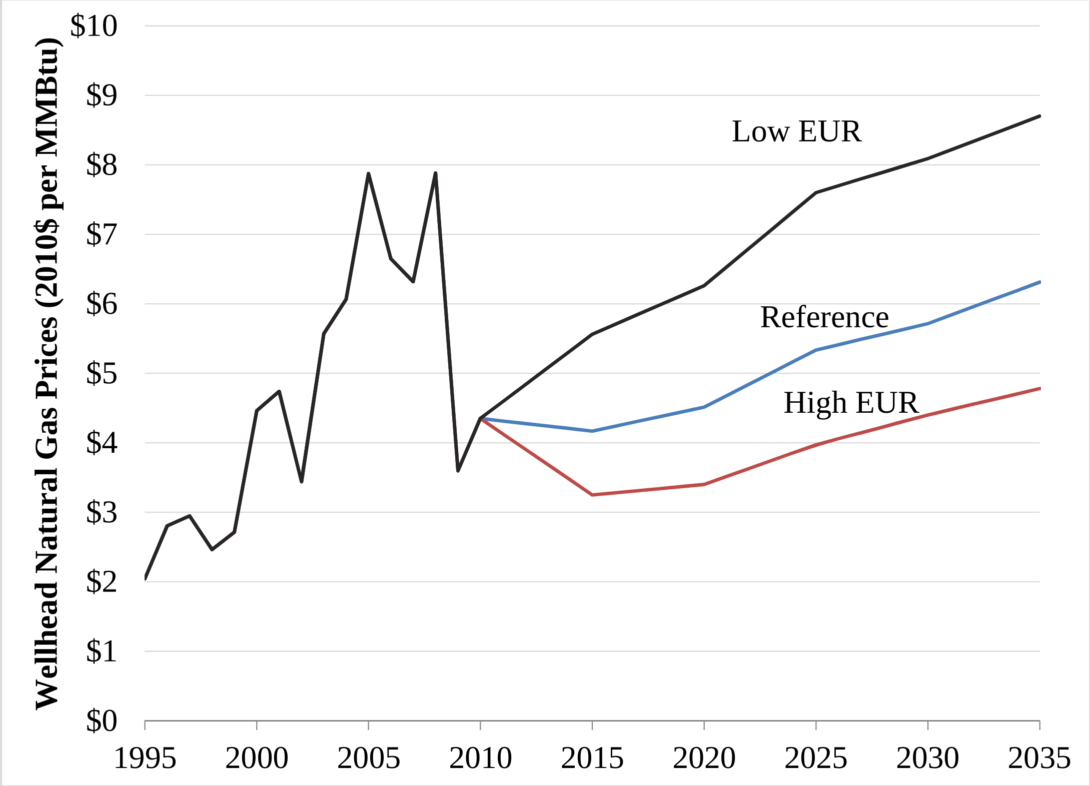
[17] NERA also ran 3 cases in which the LNG export capacity was assumed to be unlimited.

B. Natural Gas Market Impacts

1. Price, Production, and Demand

The wellhead natural gas price increases steadily in all three of the baseline cases (REF, High EUR and Low EUR). Under the REF case the wellhead price increases from $4.40/MMBtu in 2010 to $6.30/MMBtu while under the High EUR and the Low EUR cases the price increases to about $4.80/MMBtu (a 10% increase from the 2010 price) and $8.70/MMBtu (a 100% increase from 2010), respectively. Comparing the projected natural gas price under the three baseline cases with historical natural gas prices, we see that the prices exceed recent historical highs only under the Low EUR case beyond 2030 (see Figure 27). The natural gas price path and its response in the scenarios with LNG exports will depend on the availability and accessibility of natural gas resources. Additionally, the price changes will be influenced by the expansion rate of LNG exports. The lower level of supply under the Low EUR case results in a higher projected natural gas price while the High EUR case, with abundant shale gas, results in a lower projected natural gas price path.

Figure 27: Historical and Projected Wellhead Natural Gas Price Paths



Source: Energy Information Agency (EIA)

The extent of the natural gas price response to an expansion of LNG exports depends upon the supply and demand conditions and the corresponding baseline price. For a given baseline, the higher the level of LNG exports the greater the change in natural gas price. Similarly, the natural gas price rises much faster under a scenario that has a quicker rate of expansion of LNG exports.

From Figure 28 we can see that under the Low/Rapid expansion scenario, USREF_SD_LR, the price rises by 7.7% in 2015 while under the Low/Slow expansion scenario, USREF_SD_LS, the price rises by only 2.4% in 2015. The demand for LNG exports in the Low/Rapid scenario (1.1 Tcf) is much greater than in the Low/Slow scenarios (0.37 Tcf); hence, the pressure on the natural gas price in the Low/Rapid scenario is higher. However, post-2015 LNG export volumes are the same in both scenarios, thus leading to the same level of increase in the wellhead price. The wellhead price rises 14% by 2020 relative to the baseline and then tapers off to a 6.4% increase by 2035 under both scenarios.

For the same Reference case baseline, Bau_Ref, the wellhead natural gas price varies by export level scenarios. The NERA High/Rapid export scenario (USREF_SD_HR) leads to the largest price increases of about 20% in 2020 ($0.90/Mcf) and 14% in 2035 ($0.90/Mcf) relative to the Reference baseline. The increase in the wellhead price is the smallest for the NERA low export scenarios (USREF_D_LS, USREF_D_LR and USREF_D_LSS). The Low/Slowest export scenario, USREF_D_LSS, has a 2015 increase of about 1% ($0.05/Mcf) and a 2035 price increase of about 4% ($0.25/Mcf).

The price increase for the High EUR scenarios is similar to the increases in the EIA Study since the export volumes are the same.[18] The largest increase in price takes place under the High/Rapid scenario in 2020 (32% relative to the High EUR baseline). However, as quickly as the price rises in 2020 it only increases by 21% in 2025 and 13% in 2025 relative to the High EUR baseline.[19] To put the percentage change in context, Figure 29 shows the level value changes relative to the corresponding baseline. Given the lower baseline price under the High EUR case, the absolute increase in the natural gas prices is smaller under the High EUR scenarios than the Reference case scenarios. The price increase under the Low EUR scenario with the slowest export volume is only a 6% increase in price relative to the baseline, or about $0.40/Mcf.

A higher natural gas price in the scenarios has three primary impacts on the overall economy. First, it tends to increase the cost of producing goods and services that are dependent on natural gas, which leads to decreasing economic output. Second, the higher price of natural gas leads to an increase in export revenues, which improves the balance of payment position. Third, it provides wealth transfer in the form of take-or-pay tolling charges that support the income of the consumers. The overall macroeconomic impacts depend on the magnitudes of these three effects as discussed in the next section.

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[18] See Appendix D for comparison of natural gas prices.

[19] Since the results are shown for three baselines with three different prices, comparing percentage changes across these baseline cases can be misleading since they do not correspond to the same level value changes. In general, when comparing scenarios between Reference and High EUR cases, the level change would be smaller under the High EUR case for the same percentage increase in price.

Figure 28: Wellhead Natural Gas Price and Percentage Change for NERA Core Scenarios

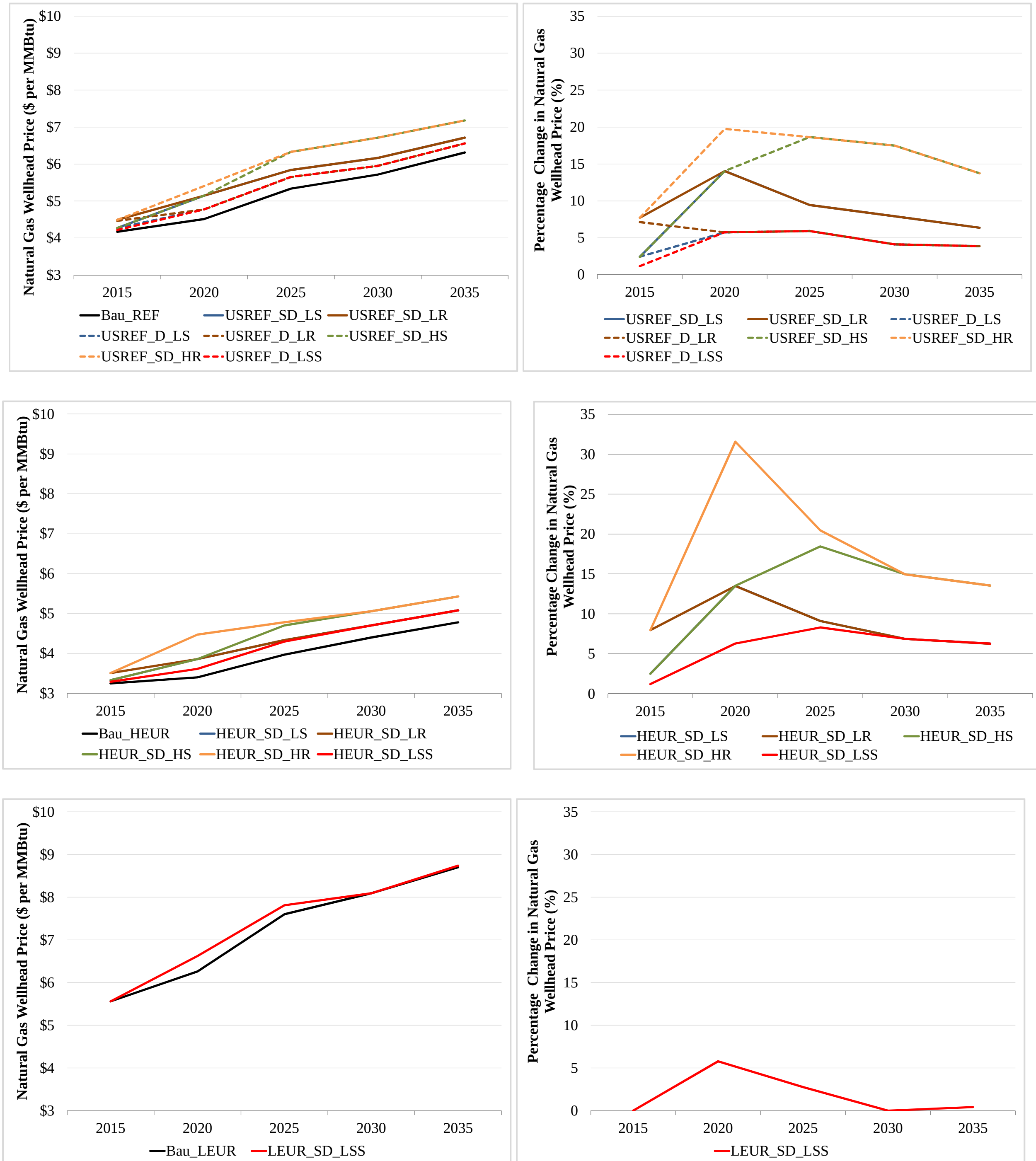


Figure 29: Change in Natural Gas Price Relative to the Corresponding Baseline of Zero LNG Exports (2010$/Mcf)

	2015	2020	2025	2030	2035
USREF_SD_LR	$0.33	$0.65	$0.52	$0.47	$0.41
USREF_SD_LS	$0.10	$0.65	$0.52	$0.47	$0.41
USREF_SD_HR	$0.33	$0.92	$1.02	$1.03	$0.89
USREF_SD_HS	$0.10	$0.65	$1.02	$1.03	$0.89
USREF_D_LR	$0.31	$0.27	$0.33	$0.24	$0.25
USREF_D_LS	$0.10	$0.27	$0.33	$0.24	$0.25
USREF_D_LSS	$0.05	$0.27	$0.33	$0.24	$0.25
HEUR_SD_HR	$0.27	$1.11	$0.84	$0.68	$0.67
HEUR_SD_HS	$0.08	$0.47	$0.75	$0.68	$0.67
HEUR_SD_LR	$0.27	$0.47	$0.37	$0.31	$0.31
HEUR_SD_LS	$0.08	$0.47	$0.37	$0.31	$0.31
HEUR_SD_LSS	$0.04	$0.22	$0.34	$0.31	$0.31
LEUR_SD_LSS	$0.00	$0.37	$0.22	$0.00	$0.04

Natural gas production increases under all three baseline cases to partially support the rise in export volumes in all of the scenarios. In the Reference case, the high scenarios (USREF_SD_HS and USREF_SD_HR) have production steadily increasing by about 10% in 2035 with production in the High/Slow scenario rising at a slower pace than in the High/Rapid scenario. In the low scenarios (USREF_SD_LS and USREF_SD_LR) and the slowest scenario (USREF_D_LSS), the production increases by about 5% and 3% in 2035, respectively (see the first two panels in Figure 30). The rise in production under the High EUR case scenarios is smaller than the corresponding Reference case scenarios.

The response in natural gas production depends upon the nature of the supply curve. Production is much more constrained in the short run as a result of drilling needs and other limitations. In the long run, gas producers are able to overcome these constraints. Hence there is more production response in the long run than in the short run.[20] Figure 30 shows that in 2015 the increase in production accounts for about 30% to 40% of the export volume, while in 2035 due to gas producers overcoming production constraints, the share of the increase in production in export volumes increases to about 60%.

[20] In the short run, the natural gas supply curve is much more inelastic than in the long run.

Figure 30: Natural Gas Production and Percentage Change for NERA Core Scenarios

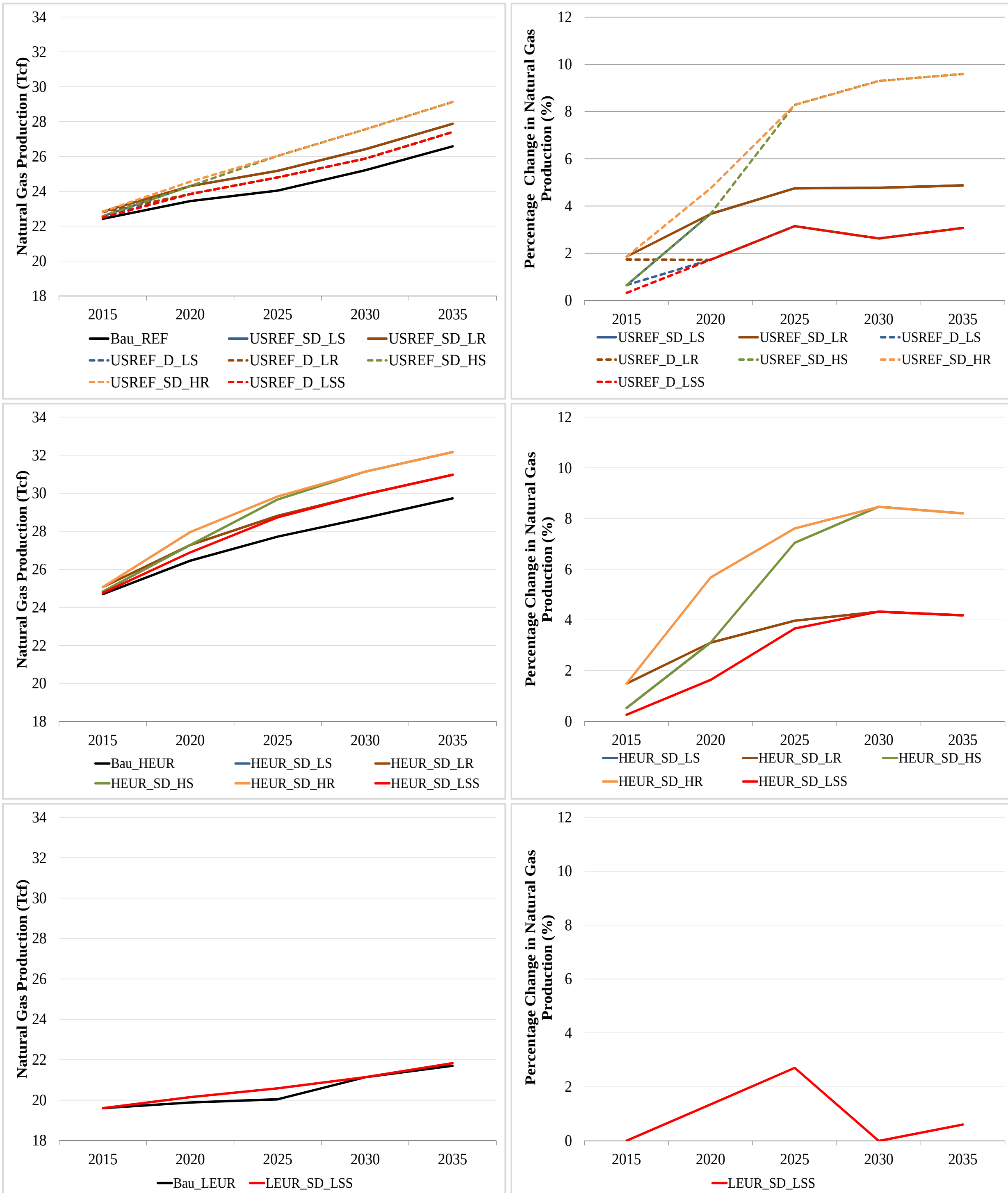


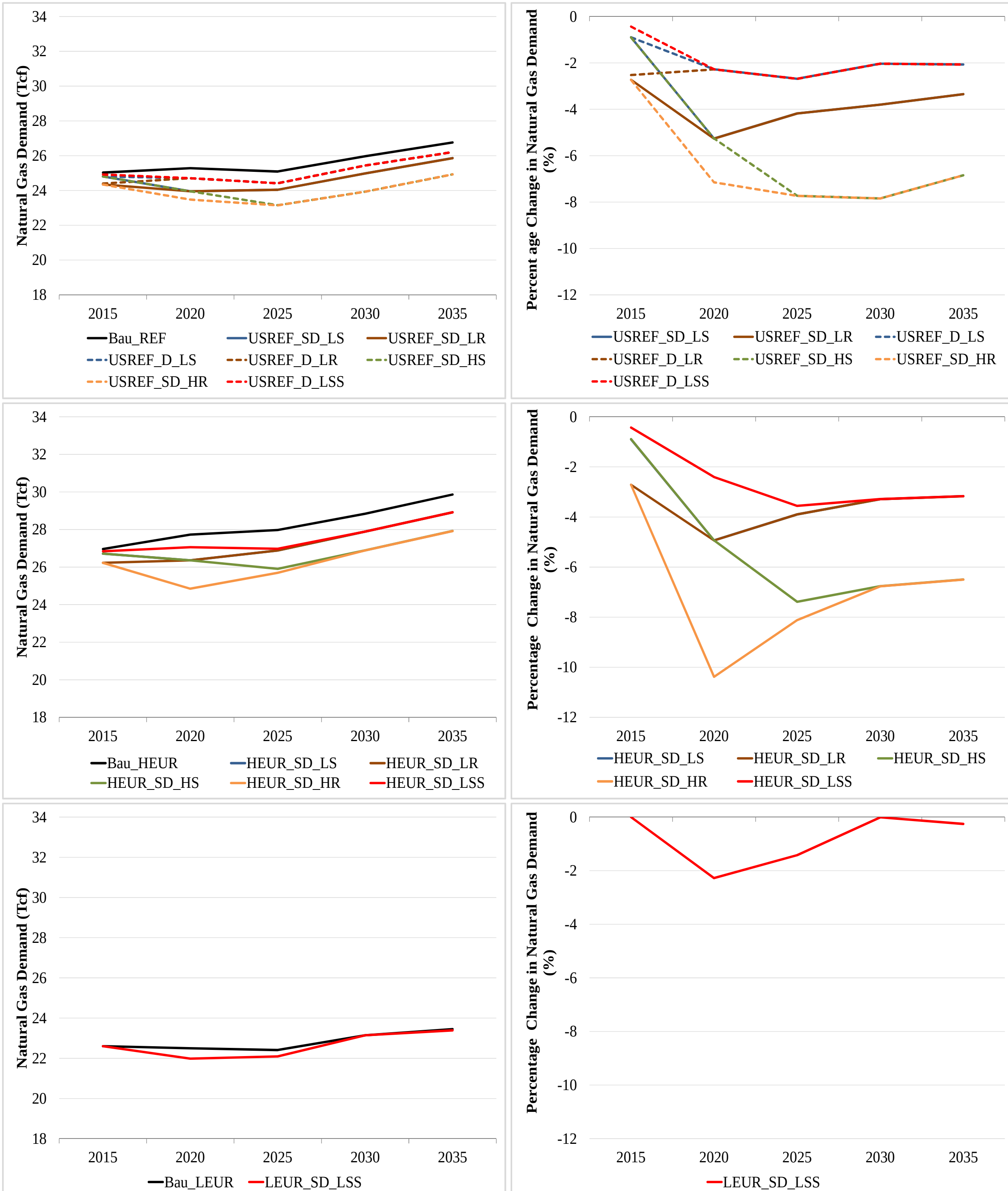
Figure 31: Change in Natural Gas Production Relative to the Corresponding Baseline (Tcf)

Scenario	Increase in Production (Tcf)					Ratio of Increase in Production to Export Volumes				
	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
USREF_SD_LR	0.42	0.86	1.14	1.20	1.29	38%	39%	52%	55%	59%
USREF_SD_LS	0.15	0.86	1.14	1.20	1.29	39%	39%	52%	55%	59%
USREF_SD_HR	0.42	1.11	1.99	2.34	2.55	38%	38%	51%	53%	58%
USREF_SD_HS	0.14	0.86	1.99	2.34	2.55	39%	39%	51%	54%	58%
USREF_D_LR	0.39	0.40	0.76	0.66	0.82	35%	41%	53%	56%	60%
USREF_D_LS	0.15	0.40	0.76	0.66	0.82	39%	41%	53%	56%	37%
USREF_D_LSS	0.07	0.40	0.76	0.66	0.82	40%	41%	53%	56%	60%
HEUR_SD_HR	0.37	1.50	2.11	2.43	2.44	34%	34%	48%	55%	56%
HEUR_SD_HS	0.13	0.82	1.95	2.43	2.44	35%	38%	49%	55%	56%
HEUR_SD_LR	0.37	0.82	1.10	1.24	1.24	34%	37%	50%	57%	57%
HEUR_SD_LS	0.13	0.82	1.10	1.24	1.24	35%	38%	50%	57%	57%
HEUR_SD_LSS	0.06	0.43	1.02	1.24	1.24	35%	39%	51%	57%	57%
LEUR_SD_LSS	0.00	0.27	0.54	0.00	0.13	0%	34%	63%	0%	69%

The increase in natural gas price has three main impacts on the production of goods and services that primarily depend upon natural gas as a fuel. First, the production processes would switch to fuels that are relatively cheaper. Second, the increase in fuel costs would result in a reduction in overall output. Lastly, the price increase would induce new technology that could more efficiently use natural gas. All of these impacts would reduce the demand for natural gas. The extent of this demand response depends on the ease of substituting away from natural gas in the production of goods and services. Pipeline imports into the U.S. are assumed to remain unchanged between scenarios within a given baseline case. Pipeline imports for the Reference, High EUR, and Low EUR cases are calibrated to the EIA's AEO 2011 projections. Figure 32 shows the natural gas demand changes for all cases and scenarios. The largest drop in natural gas demand occurs in 2020 when the natural gas price increases the most.

In the Reference and High EUR cases, the high scenarios are projected to have the largest demand response because overall prices are the highest. The largest drop in natural gas demand in 2020 for the Reference, High EUR, and Low EUR is about 8%, 10%, and 2%, respectively. In the long run (2035), natural gas demand drops by about 5% for the Reference and the High EUR cases while there is no response in demand under the Low EUR case. In general, the largest drop in natural gas demand corresponds to the year and scenario in which the price increase is the largest. For the High/Rapid scenario under the High EUR case, the largest drop occurs in 2020. Given that the implied price elasticity of demand is similar across all cases, the long-run demand impacts across cases tend to converge for the corresponding scenarios. Figure 32 shows the demand for all scenarios.

Figure 32: Natural Gas Demand and Percent Change for NERA Core Scenarios



C. Macroeconomic Impacts

1. Welfare

Expansion of natural gas exports changes the price of goods and services purchased by U.S. consumers. In addition, it also alters the income level of the consumers through increased wealth transfers in the form of tolling charges on LNG exports. These economic effects change the well-being of consumers as measured by equivalent variation in income. The equivalent variation measures the monetary impact that is equivalent to the change in consumers' utility from the price changes and provides an accurate measure of the impacts of a policy on consumers.[21]

We report the change in welfare relative to the baseline in Figure 33 for all the scenarios. A positive change in welfare means that the policy improves welfare from the perspective of the consumer. All export scenarios are welfare-improving for U.S. consumers. The welfare improvement is the largest under the high export scenarios even though the price impacts are also the largest. Under these export scenarios, the U.S. consumers[22] receive additional income from two sources. First, the LNG exports provide additional export revenues, and second, consumers who are owners of the liquefaction plants, receive take-or-pay tolling charges for the amount of LNG exports. These additional sources of income for U.S. consumers outweigh the loss associated with higher energy prices. Consequently, consumers, in aggregate, are better off as a result of opening up LNG exports.

Comparing welfare results across the scenarios, the change in welfare of the low export volume scenarios for the High EUR case is about half that of the corresponding scenarios for the Reference case (see Figure 33). The welfare impacts under the Reference case scenarios are higher than for corresponding High EUR case scenarios. Under the High EUR case, the wellhead price is much lower than the Reference case and therefore results in lower welfare impacts. Similarly in both the Reference and High EUR cases, the high export volume scenarios have much larger welfare impacts than the lower export volume scenarios. Again, the amount of wealth transfer under high export volume scenarios drives the higher welfare impacts. In fact, the U.S. consumers are better off in all of the export volume scenarios that were analyzed.

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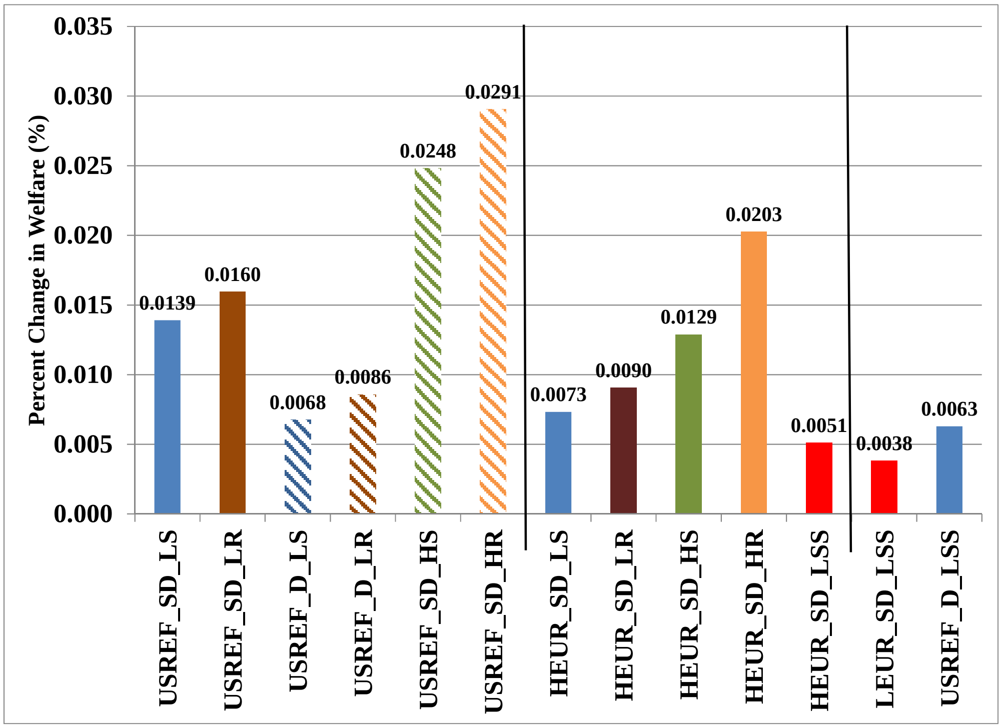
[21] *Intermediate Microeconomics: A Modern Approach*, Hal Varian, 7th Edition (December 2005), W.W. Norton & Company, pp. 255-256. "Another way to measure the impact of a price change in monetary terms is to ask how much money would have to be taken away from the consumer *before* the price change to leave him as well off as he would be *after* the price change. This is called the **equivalent variation** in income since it is the income change that is equivalent to the price change in terms of the change in utility." (emphasis in original).

[22] Consumers own all production processes and industries by virtue of owning stock in them.

Figure 33: Percentage Change in Welfare for NERA Core Scenarios[23]



2. GDP

GDP is another economic metric that is often used to evaluate the effectiveness of a policy by measuring the level of total economic activity in the economy. In the short run, the GDP impacts are positive as the economy benefits from investment in the liquefaction process, export revenues, resource income, and additional wealth transfer in the form of tolling charges. In the long run, GDP impacts are smaller but remain positive because of higher resource income.

A higher natural gas price does lead to higher energy costs and impacts industries that use natural gas extensively. However, the effects of higher price do not offset the positive impacts from wealth transfers and result in higher GDP over the model horizon in all scenarios. In the high scenarios and especially in periods with high natural gas prices, the export revenue stream increases while increasing the natural gas resource income as well. These effects combined with wealth transfer lead to the largest positive impacts on the GDP. In all scenarios, the impact on GDP is the largest in 2020 then drops as the export volumes stabilize. In a subsequent section, we discuss changes in different sources of household income.

Under the Reference case, the change in GDP in 2015 is between 0.01% for the Low/Slowest scenario to 0.05% in the High/Rapid scenario. The increase in GDP in the High EUR case is as large as 0.26% because resource income and LNG exports are the greatest. Overall, GDP

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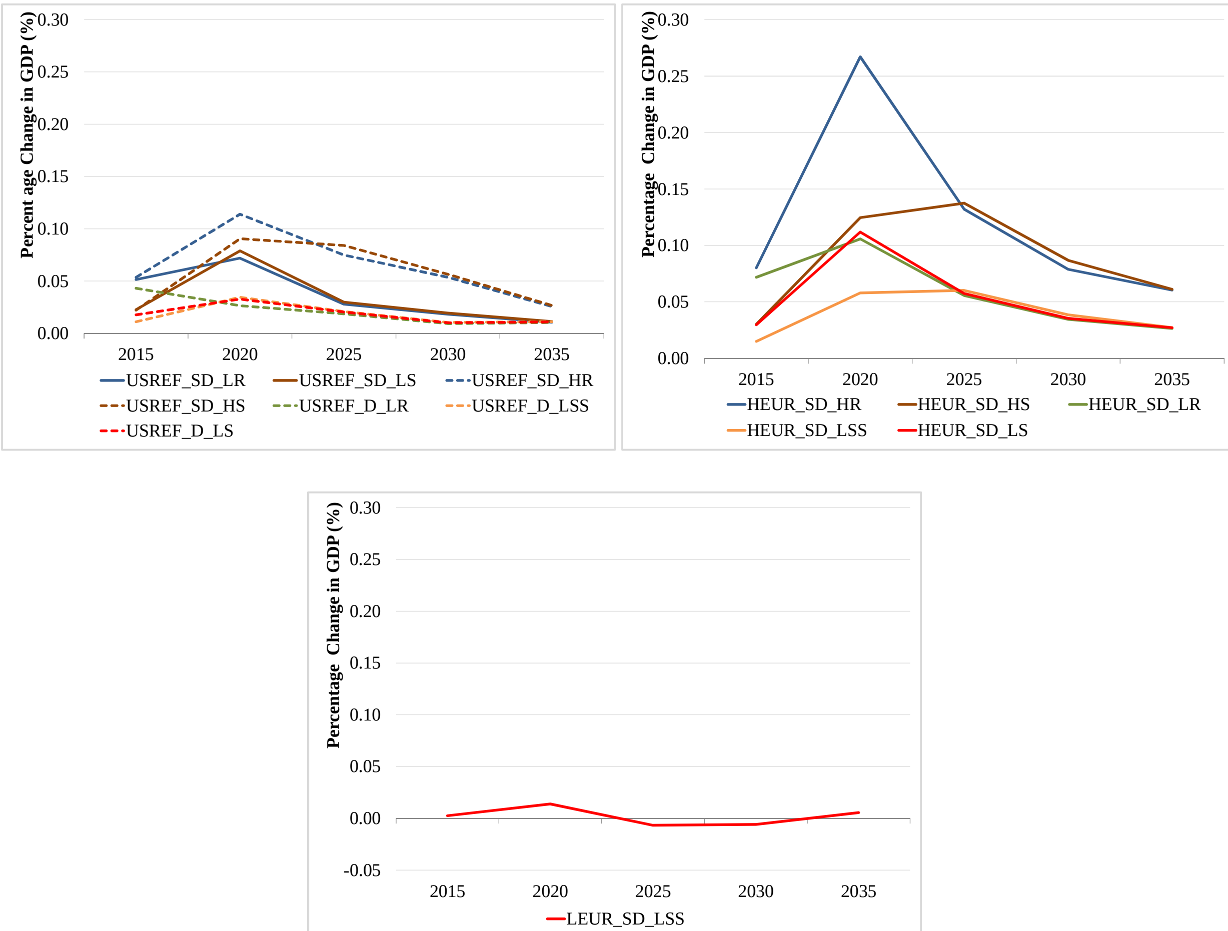
23 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

impacts are positive for all scenarios with higher impact in the short run and minimum impact in the long run.

Figure 34: Percentage Change in GDP for NERA Core Scenarios

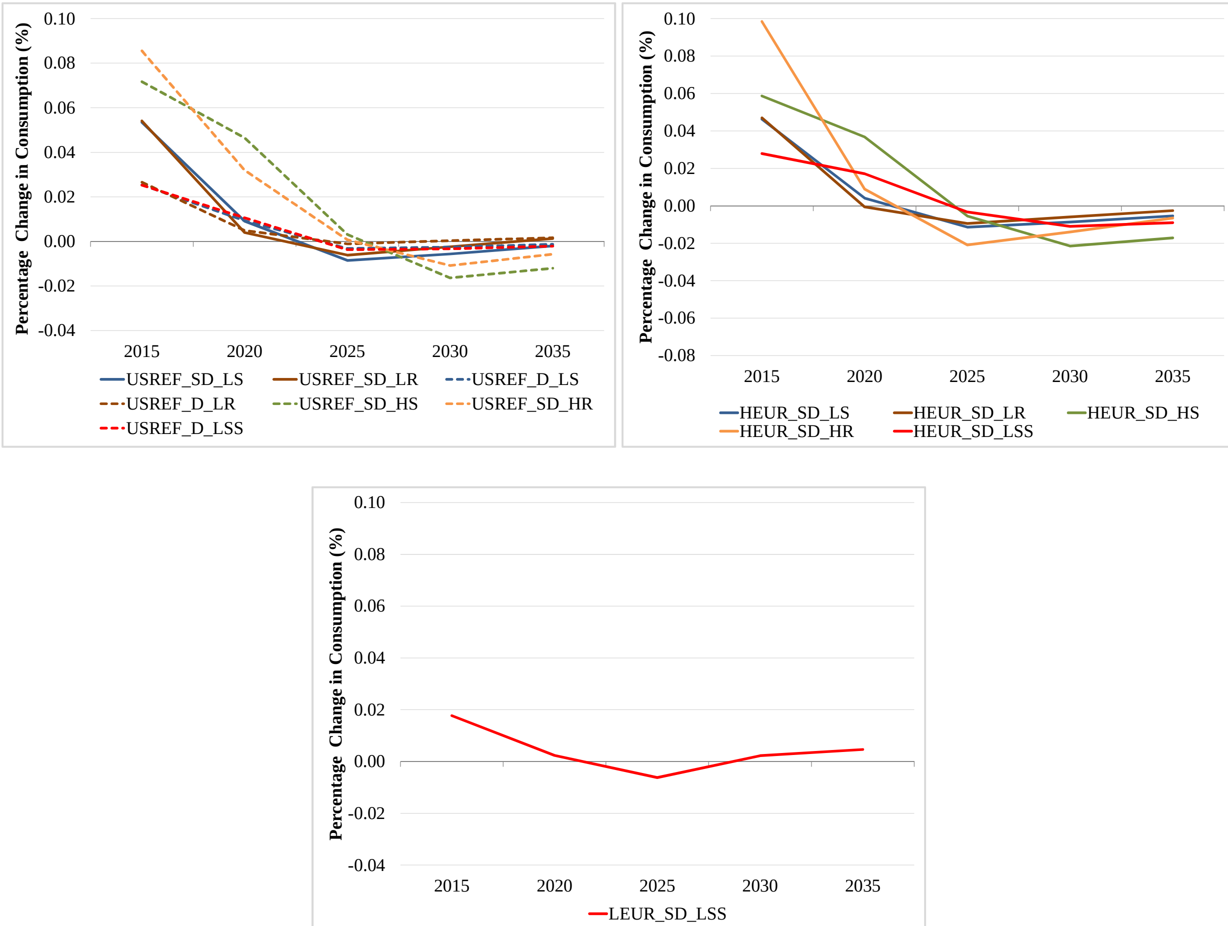


3. Aggregate Consumption

Aggregate consumption measures the total spending on goods and services in the economy. In 2015, consumption increases from the No-Export case between 0.02% for the low scenarios to 0.8% for the high scenarios. Consumption impacts for the High EUR scenarios also show similar impacts (Figure 35). Under the High/Rapid scenarios, the increase in consumption in 2015 is much greater (0.10%) because higher export volumes result in leading to much larger export revenue impacts. By 2035, consumption decreases by less than 0.02%.

Higher aggregate spending or consumption resulting from a policy suggests higher economic activity and more purchasing power for the consumers. The scenario results of the Reference case, seen in Figure 35, show that the consumption increases or remains unchanged until 2025 for almost all of the scenarios. These results suggest that the wealth transfer from exports of LNG provides net positive income for the consumers to spend after taking into account potential decreases in capital and wage income from reduced output.

Figure 35: Percentage Change in Consumption for NERA Core Scenarios



4. Aggregate Investment

Investment in the economy occurs to replace old capital and augment new capital formation. In this study, additional investment also takes place to convert current regasification plants to liquefaction plants and/or build new green-field liquefaction plants. The investment that is necessary to support the expansion of LNG exports is largest in 2015.[24] The investment outlay under each of the LNG export expansion scenarios is discussed in Appendix C. In 2015 and 2020, investment increases to support higher consumption (and production) of goods and services and investment in the liquefaction plants. As seen in Figure 36, investment increases for all scenarios, except for the Low/Rapid scenarios. Investment in 2015 could increase by as much as 0.10%. As the price of natural gas increases, the economy demands or produces fewer goods and services. This results in lower wages and capital income for consumers. Hence, under such economic conditions, consumers save less of their income for investment. The investment drop is the largest under the High EUR case for the High/Rapid scenario (-0.2%) where industrial

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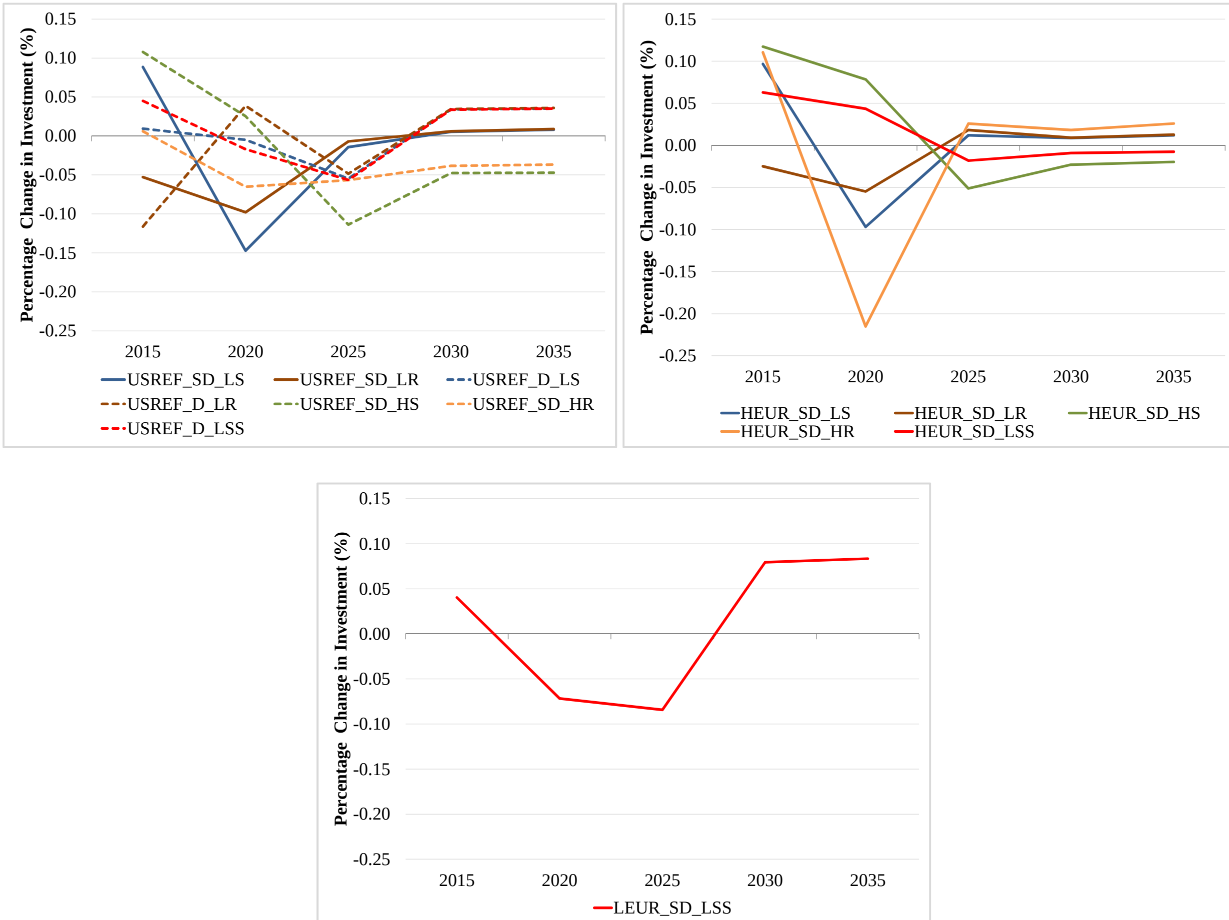
24 Each model year represents a span of five years, thus the investment in 2015 represents an average annual investment between 2015 and 2019.

decline is the largest because of the increases in energy prices in general and the natural gas price in particular. As with consumption, the results for the low scenarios under the Reference and High EUR cases (with the same level of LNG exports) show similar investment changes. The range of change in investment over the long run (2030 through 2035) for all scenarios is between -0.05% and 0.08%.

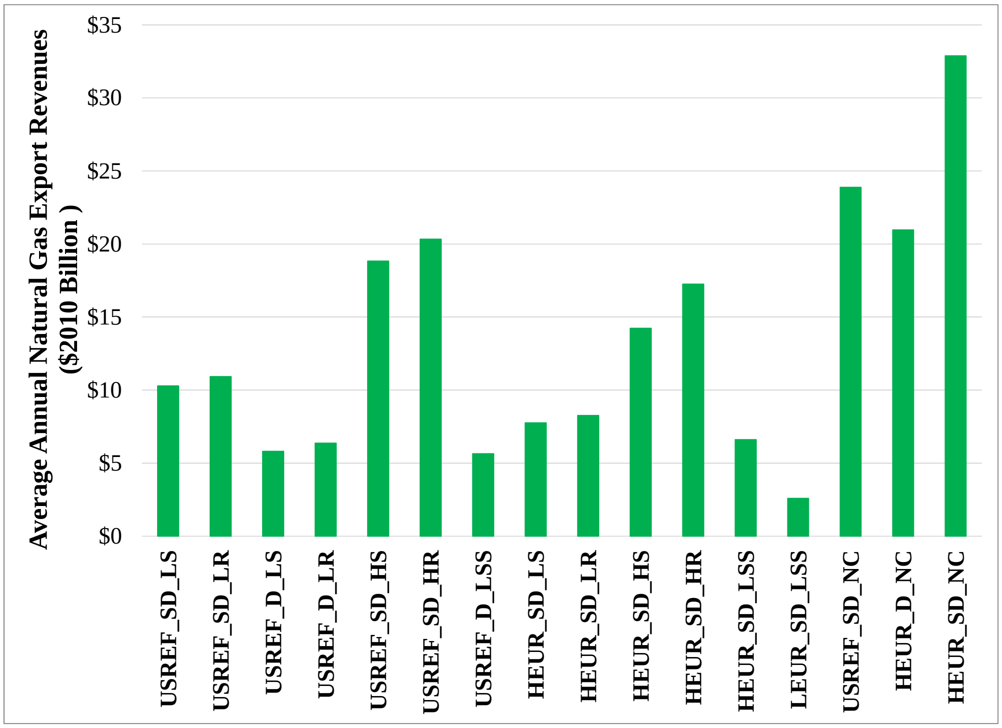
Figure 36: Percentage Change in Investment for NERA Core Scenarios



5. Natural Gas Export Revenues

As a result of higher levels of natural gas exports and increased natural gas prices, LNG export revenues offer an additional source of income. Depending on the baseline case and scenario used, the average annual increase in revenues from LNG exports ranges from about $2.6 billion (2010$) to almost $32.9 billion (2010$) as seen in Figure 37. Unsurprisingly, the high end of this range is from the unconstrained scenario, while the low end is the Low/Slowest scenario. The average revenue increase in all of the high scenarios for each baseline is roughly double the increase in the low scenarios. The difference in revenue increases between comparable rapid and slow scenarios is about 6% to 20%, with the low scenarios showing a smaller difference between their rapid and slow counterparts than the high scenarios.

Figure 37: Average Annual Increase in Natural Gas Export Revenues

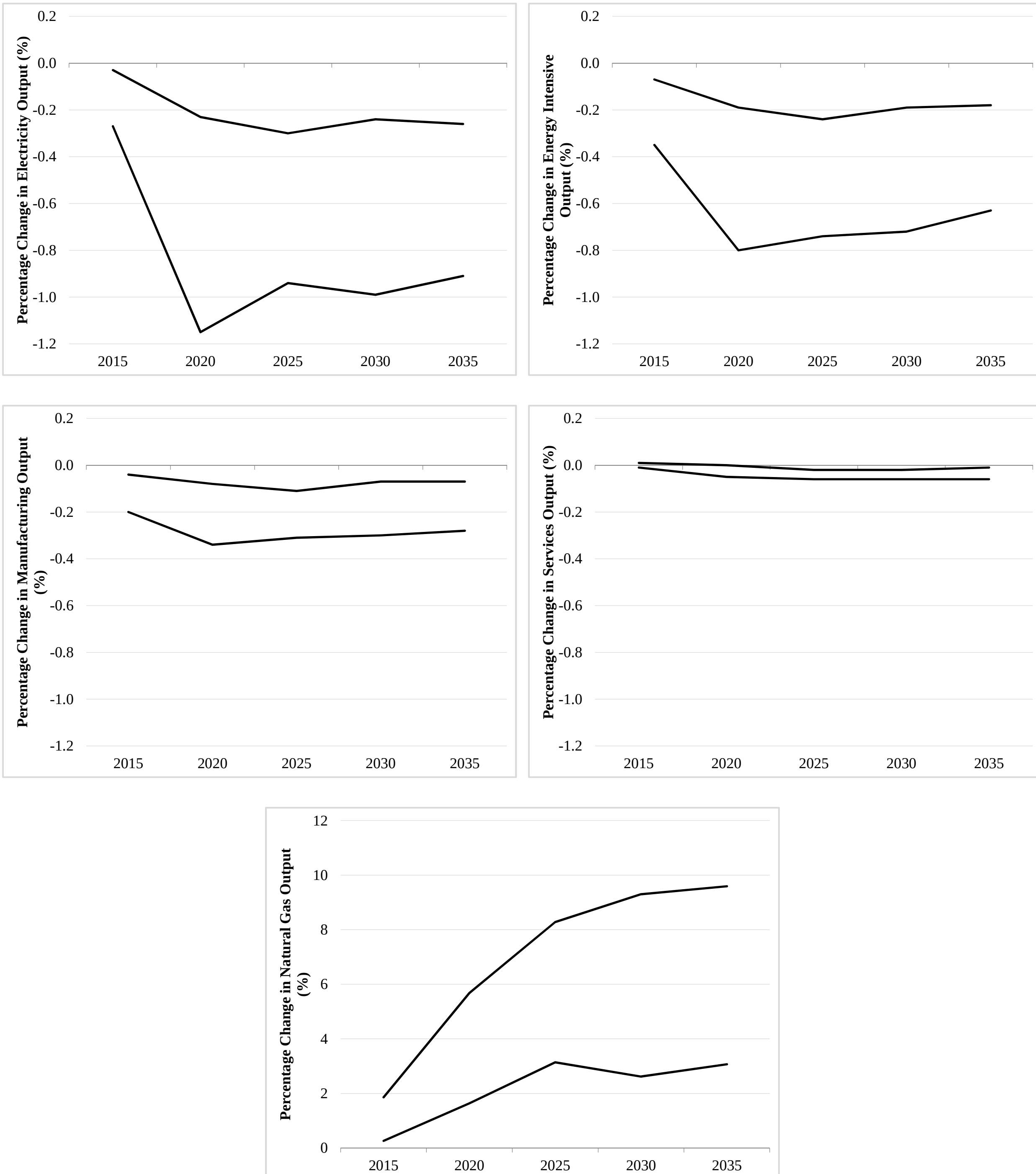


6. Range of Sectoral Output Changes for Some Key Economic Sectors

Changes in natural gas prices have real effects throughout the economy. Economic sectors such as the electricity sector, energy-intensive sectors ("EIS"), the manufacturing sector, and the services sector are dependent on natural gas as a fuel and are therefore vulnerable to natural gas price increases. These particular sectors will be disproportionately impacted leading to lower output. In contrast, natural gas producers and sellers will benefit from higher natural gas prices and output. These varying impacts will shift income patterns between economic sectors. The overall effect on the economy depends on the degree to which the economy adjusts by fuel switching, introducing new technologies, or mitigating costs by compensating parties that are disproportionately impacted.

Figure 38 illustrates the minimum and maximum range of changes in some economic sectors. The range of impacts on sectoral output varies considerably by sector. The electricity and EIS sectoral output changes are the largest across all scenarios. Maximum losses in electricity sector output could be between 0.2% and 1%, when compared across all scenarios while the decline in output of EIS could be between 0.2% and 0.8%. The manufacturing sector, being a modest consumer of natural gas, sees a fairly narrow range of plus or minus 0.5% loss in output around 0.2%. Since the services sector is not natural gas intensive (one-third of the natural gas is consumed by the commercial sector), the impact this sector's output is minimal.

Figure 38: Minimum and Maximum Output Changes for Some Key Economic Sectors

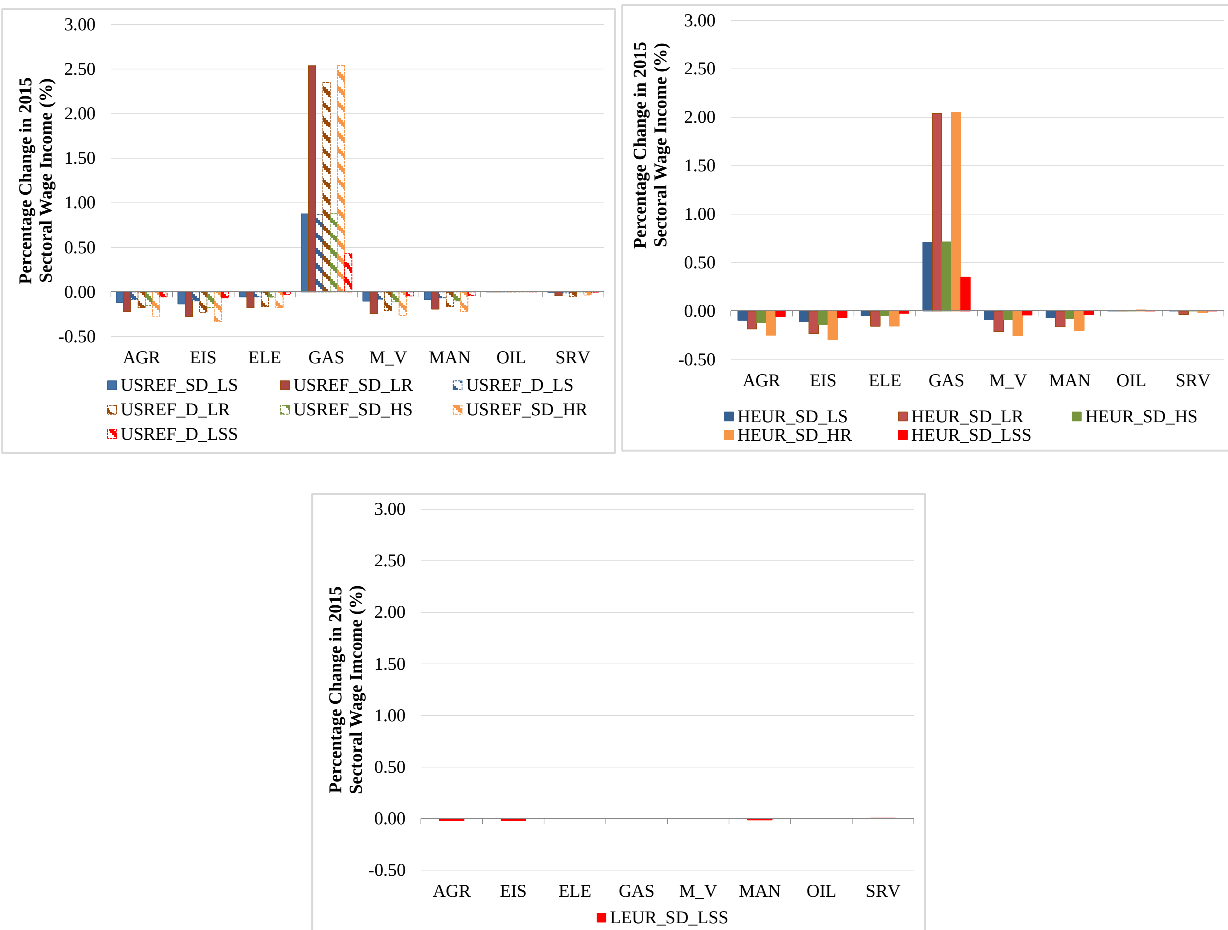


7. Wage Income and Other Components of Household Income

Sectoral output, discussed in the previous section, translates directly into changes in input levels for a given sector. In general, if the output of a sector increases so do the inputs associated with the production of this sector's goods and services. An increase in natural gas output leads to more wage income in the natural gas sector as domestic production increases. In the short run, industries are able to adjust to changes in demand for output by increasing employment if the sector expands or by reducing employment if the sector contracts.

Figure 39 shows the change in total wage income in 2015 for all scenarios. Wage income decreases in all industrial sectors except for the natural gas sector. Services and manufacturing sectors see the largest change in wage income in 2015 as these are sectors that are highly labor intensive.

Figure 39: Percentage Change in 2015 Sectoral Wage Income



As seen from the discussion above, the overall macroeconomic impacts are driven by the changes in the sources of household income. Households derive income from capital, labor, and resources. These value-added incomes also form a large share of GDP and aggregate consumption. Hence, to tie all the above impacts together, we illustrate the magnitude of each of the income subcomponents and how they relate to the overall macroeconomic impacts in Figure 40.

Figure 40: Changes in Subcomponents of GDP in 2020 and 2035

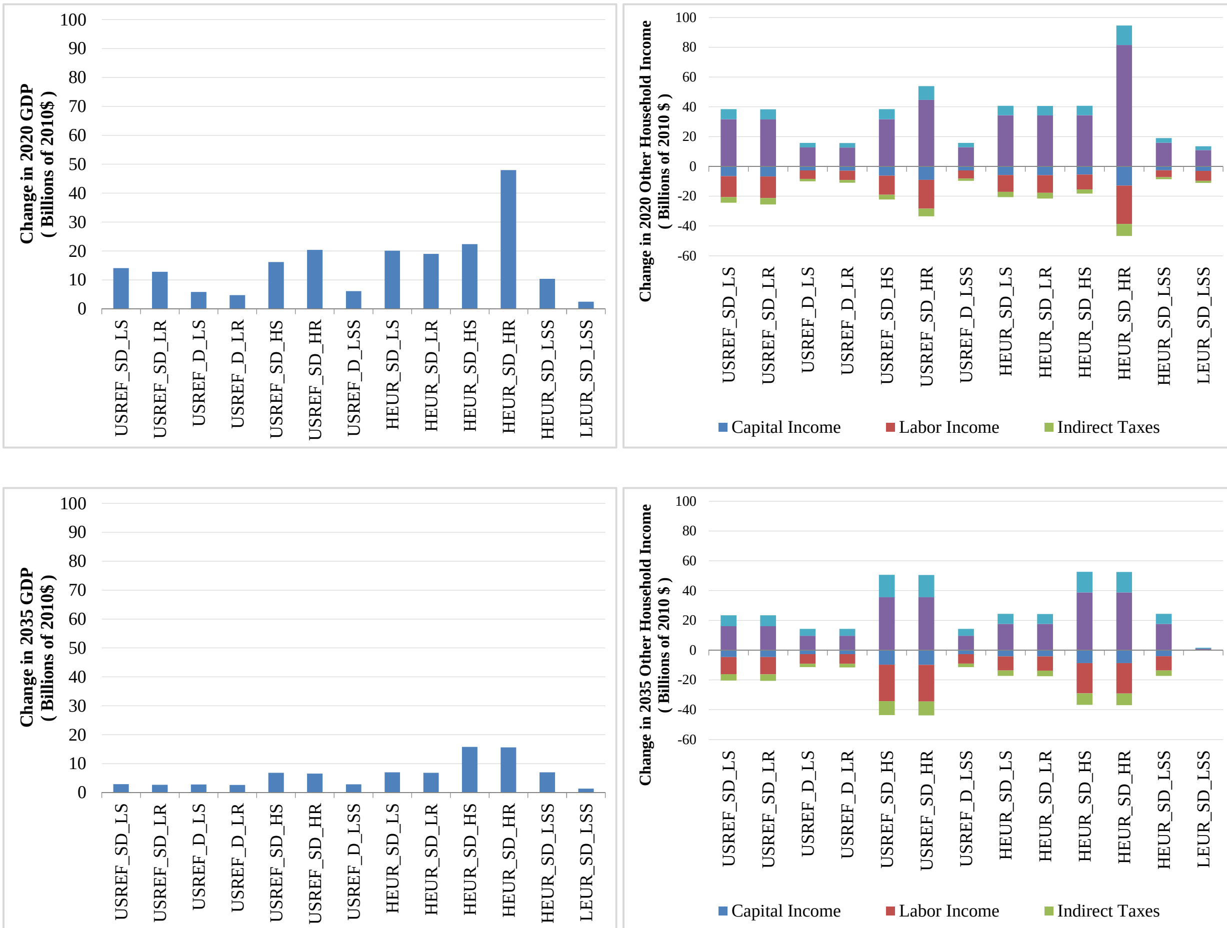


Figure 40 shows a snapshot of changes in GDP and household income components in 2020 and 2035. GDP impacts in 2020 provide the largest increase, while 2035 impacts provide a picture of the long run changes. Capital income, wage income, and indirect tax revenues drop in all scenarios, while resource income and net transfers associated with LNG export revenues increase in all scenarios. As previously discussed, capital and wage income declines are caused by high fuel prices leading to reductions in output and hence lower demand for input factors of production. However, there is positive income from higher resource value and net wealth transfer. This additional source of income is unique to the export expansion policy. This leads to the total increase in household income exceeding the total decrease. The net positive effect in real income translates into higher GDP and consumption.[25]

[25] The net transfer income increases even more in the case where the U.S. captures quota rents leading to a net benefit to the U.S. economy.

D. Impacts on Energy-Intensive Sectors

1. Output and Wage Income

The EIS sector includes the following 5 energy using subsectors identified in the IMPLAN[26] database:

1) Paper and pulp manufacturing (NAICS 322);

2) Chemical manufacturing (NAICS 326);

3) Glass manufacturing (NAICS 3272);

4) Cement manufacturing (NAICS 3273); and

5) Primary metal manufacturing (NAICS 331) that includes iron, steel and aluminum.[27]

As the name of this sector indicates, these industries are very energy intensive and are dependent on natural gas as a key input.[28]

The model results for EIS industrial output are shown in Figure 41 for all scenarios. Because of the heavy reliance on natural gas as input, the impact on the sector is driven by natural gas prices. Under the Reference case for the high scenarios, output declines by about 0.7% while under the High EUR case output declines by about 0.8% in 2020 and then settles at around 0.6%. The reduction in EIS output for the low scenarios is less than 0.4%. Under the Low EUR case and Low/Slowest export volume scenario EIS, output changes minimally. Overall, EIS reduction is less that 1.0%.

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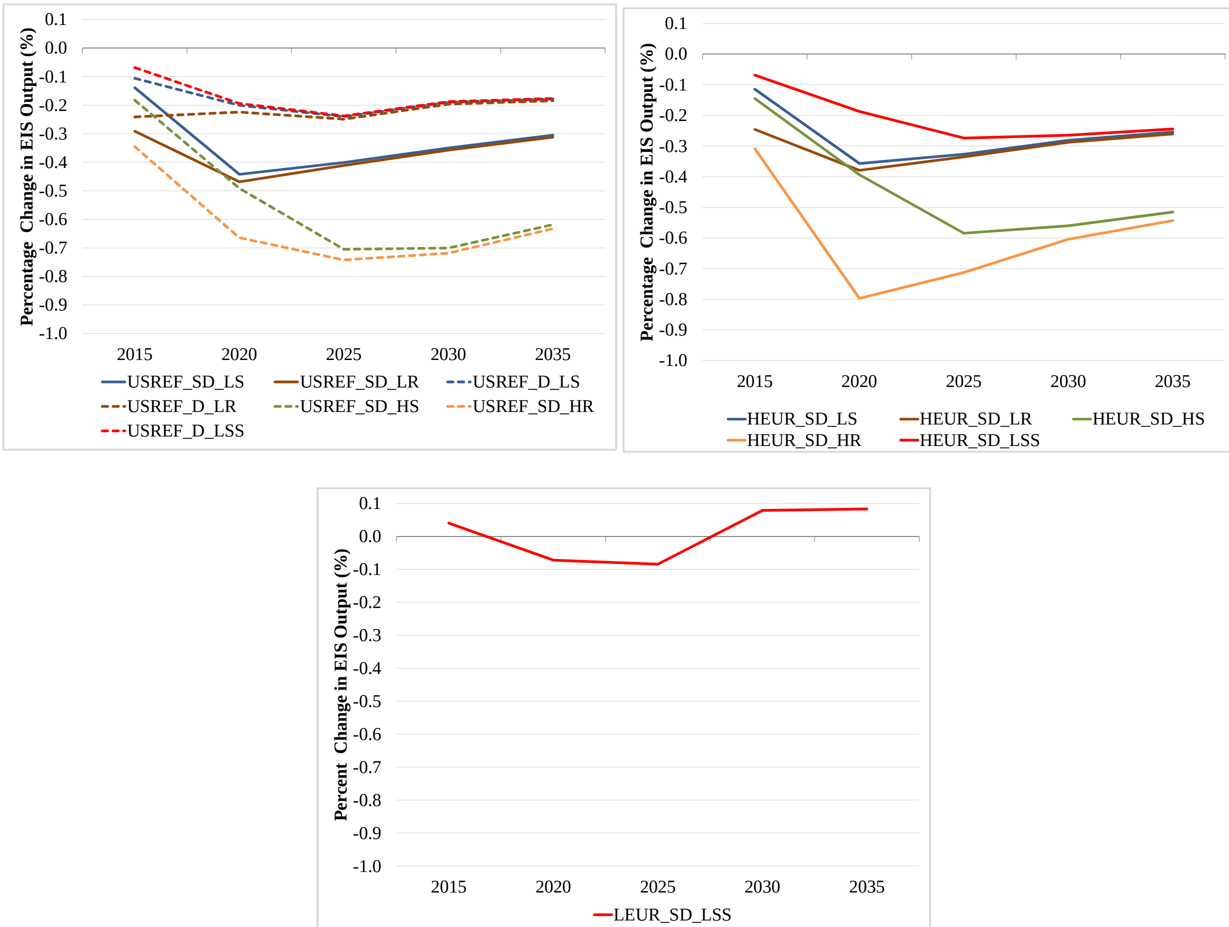
[26] IMPLAN dataset provides inter-industry production and financial transactions for all states of the U.S. (www.implan.com).

[27] The North American Industry Classification System ("NAICS") is the standard used to classify business establishments.

[28] For this study, we have represented the EIS sector based on a 3-digit classification that aggregates upstream and downstream industries within each class. Thus, in aggregating at this level the final energy intensity would be less than one would expect if only we were to aggregate only the downstream industries or at higher NAICS-digit levels.

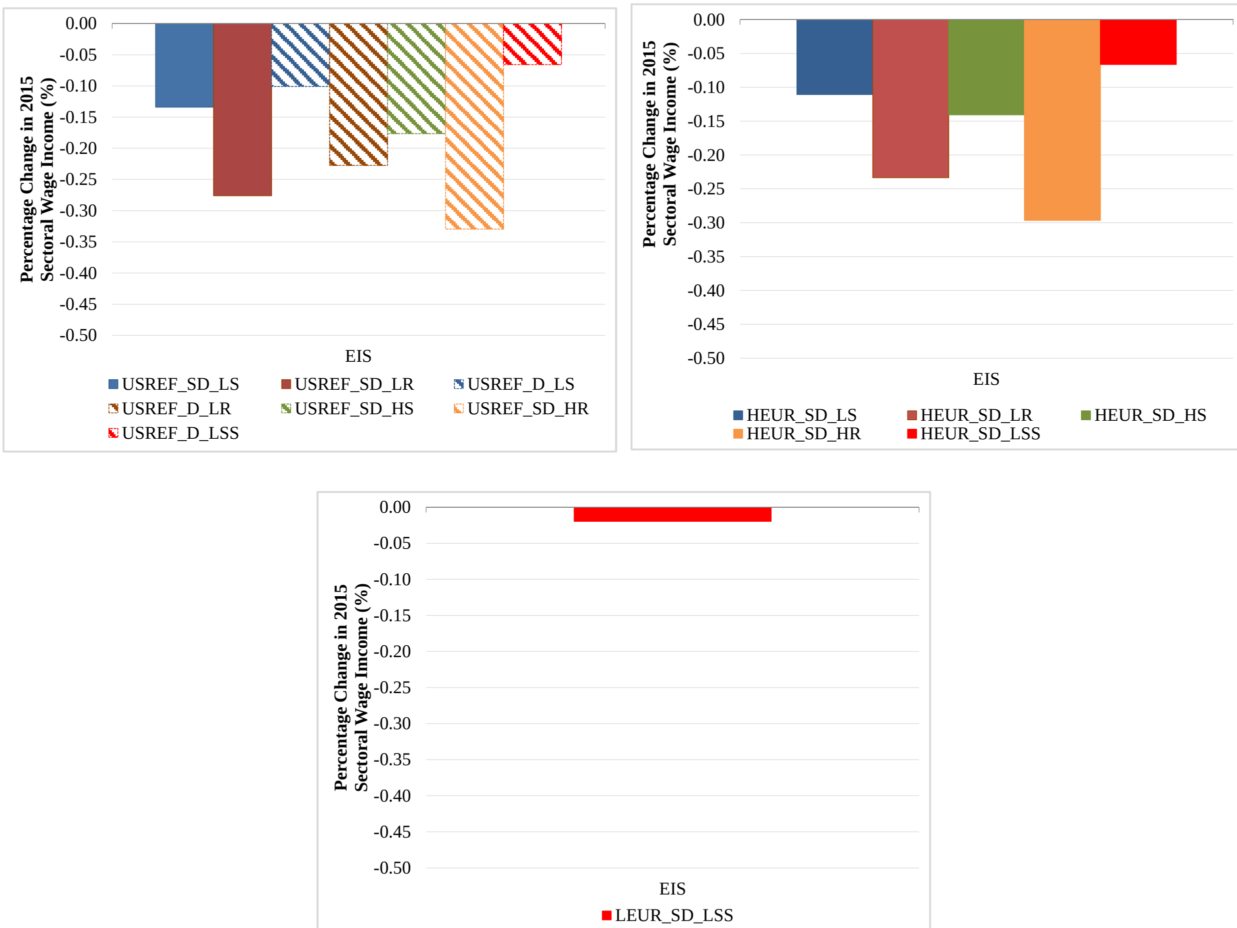
Figure 41: Percentage Change in EIS Output for NERA Core Scenarios



As mentioned in the previous sections, a reduction in sectoral output means intermediate input demand also is reduced. The EIS sector declines result in lower demand for labor, capital, energy, and other intermediate goods and services.

Figure 42 shows the changes in wage income in 2015. Under the Reference outlook, wage income would be about 0.10% to about 0.40% below baseline levels, which still represents real wage growth over time. The largest slowdown in the growth of wage income occurs in periods where reductions in EIS industrial output relative to baseline are the largest. Since the increase in natural gas prices is highest under the high/Rapid scenarios with the HEUR Shale gas outlook, the largest total labor compensation decrease in EIS occurs in that scenario, a decrease of about 0.70% in 2020 relative to baseline. Wage income never falls short of baseline levels by more than 1% in any year or any industry in any scenario.

Figure 42: Percentage Change in 2015 Energy Intensive Sector Wage Income for NERA Core Scenarios



2. Rate of Change

Even if this entire change in wage income in EIA represented a shift of jobs out of the sector, the change in EIS employment would be relatively small compared to normal turnover in the industries concerned and, under normal economic conditions, would not necessarily result in any change in aggregate employment other than a temporary increase in the number of workers between jobs. This can be seen by comparing the average annual change in employment to annual turnover rates by industry. The annual Job Openings and Labor Turnover (JOLTS) survey done by the Bureau of Labor Statistics[29] shows that the lowest annual quits rate observed, representing voluntary termination of employment in the worst year of the recession, was 6.9% for durable goods manufacturing. The largest change in wage income in the peak year of a scenario, with the largest increases in natural gas prices, is a reduction of about 5% in a 5-year period, or less than 1% per year. This is less than 15% of the normal turnover rate in that industry.

[29] "Job Openings and Labor Turnover," Bureau of Labor Statistics, January 2012, Table 16.

3. Harm is Likely to be Confined to Very Narrow Segments of Industry

To identify where higher natural gas prices might cause severe impacts such as plant closings (due to an inability to compete with overseas suppliers not experiencing similar natural gas price increases), it is necessary to look at much smaller slices of U.S. manufacturing. Fortunately, this was done in a study by an Interagency Task Force in 2007 that analyzed the impacts of proposed climate legislation, the Waxman-Markey bill (H.R.2454), on energy-intensive, trade-exposed industries ("EITE") using data from the 2007 Economic Census.[30] The cap-and-trade program in the Waxman-Markey bill would have caused increases in energy costs and impacts on EITE even broader than would the allowing of LNG exports because the Waxman-Markey bill applied to all fuels and increased the costs of fuels used for about 70% of electricity generation. Thus, the Task Force's data and conclusions are directly relevant.

The Interagency Report defined an industry's energy intensity as "its energy expenditures as a share of the value of its domestic production."[31] The measure of energy intensity used in the Interagency Report included all sources of energy, including electricity, coal, fuel oil, and natural gas. Thus, natural gas intensity will be even less than energy intensity.

The Interagency Report further defined an energy-intensive, trade-exposed industry (those that were "presumptively eligible" for emission allowance allocations under the Waxman-Markey bill) as ones where the industry's "energy intensity or its greenhouse gas intensity is at least 5 percent, and its trade intensity is at least 15 percent."[32]

The Interagency Report found:

> *According to the preliminary assessment of the nearly 500 six-digit manufacturing industries, 44 would be deemed "presumptively eligible" for allowance rebates under H.R. 2454 ["presumptive eligibility" screened out industries that did not have a significant exposure to foreign competition]. Of these, 12 are in the chemicals sector, 4 are in the paper sector, 13 are in the nonmetallic minerals sector (e.g., cement and glass manufacturers), and 8 are in the primary metals sector (e.g., aluminum and steel manufacturers). Many of these sectors are at or near the beginning of the value chain, and provide the basic materials needed for manufacturing advanced technologies. In addition to these 44 industries, the processing subsectors of a few mineral industries are also likely to be deemed "presumptively eligible." In total, in 2007, the "presumptively eligible" industries accounted for 12 percent of total manufacturing output and*

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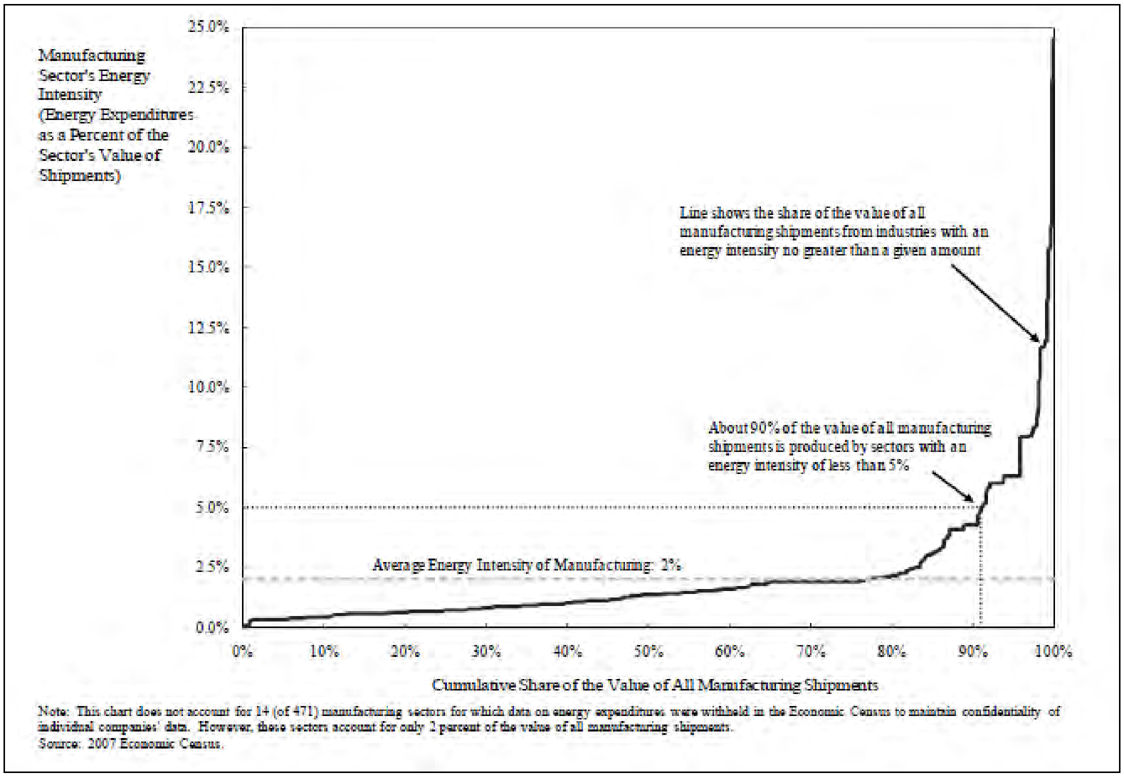
30 "The Effects of H.R.2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," An Interagency Report Responding to a Request from Senators Bayh, Specter, Stabenow, McCaskill, and Brown December 2, 2009.

31 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

32 "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 8.

employed about 780,000 workers, or about 6 percent of manufacturing employment and half a percent of total U.S. non-farm employment. [Figure 1 shows that] most industrial sectors have energy intensities of less than 5 percent, and will therefore have minimal direct exposure to a climate policy's economic impacts.[33]

Figure 43: Interagency Report (Figure 1)



Source: "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

If we were to use the same criterion for EITE for natural gas, it would imply that an energy-intensive industry was one that would have expenditures on natural gas at the projected industrial price for natural gas greater than 5% of its value of output.

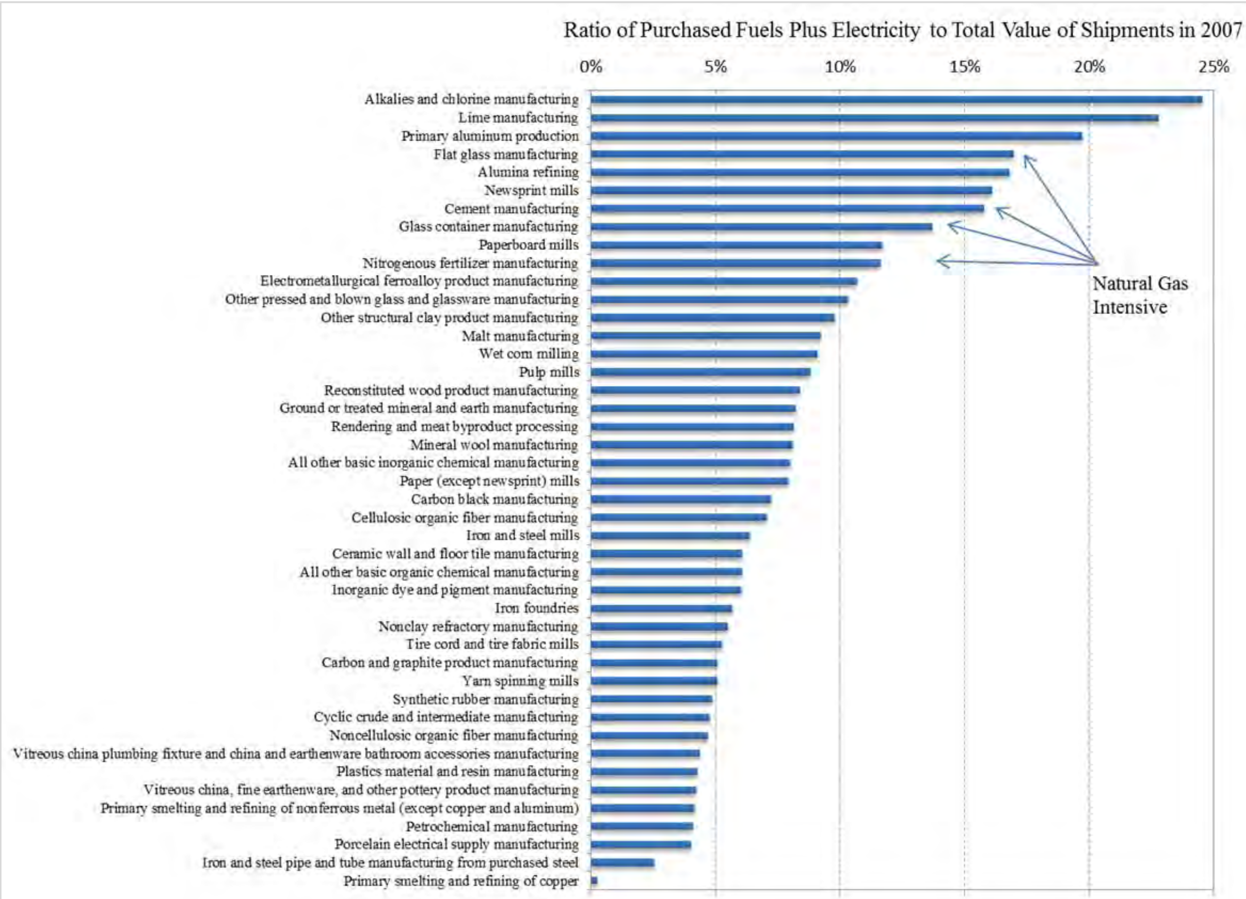
4. Vulnerable Industries are not High Value-Added Industries

A high value-added industry is one in which wage income and profits are a large share of revenues, implying that purchases of other material inputs and energy are a relatively small share. This implies that in a high value-added industry, increases in natural gas prices would have a relatively small impact on overall costs of production. Exactly that pattern is seen in Figure 44, which shows that the industries with the highest energy intensity are low margin

[33] "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 9.

industries that use high heats for refining, smelting, or beneficiation processes, or else they are bulk chemical processes with low value-to-weight ratios and large amounts of natural gas used as a feedstock.

Figure 44: Energy Intensity of Industries "Presumptively Eligible" for Assistance under Waxman-Markey



Source: Based on information from Census.gov. Energy intensity is measured as the value of purchased fuels plus electricity divided by the total value of shipments.

For manufacturing as a whole in 2007,[34] the ratio of value added to the total value of shipments was 78%. In the nitrogenous fertilizer industry, as an example of a natural gas-intensive, trade-exposed industry, the ratio of value added to value of shipments was only 44%. It is also a small industry with a total of 3,920 employees nationwide in 2007.[35] The ratio of value added to value of shipments for the industries that would be classified as EITE under the Waxman-Markey criteria was approximately 41%.[36] Thus there is little evidence that trade-exposed industries that

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[34] The date of the most recent Economic Census that provides these detailed data is the year 2007.

[35] http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

[36] Excludes two six-digit NAICS codes for which data was withheld to protect confidentiality, 331411 and 331419. Source: http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk.

would experience the largest cost increases due to higher natural gas prices are high value-added industries.

The Interagency Study similarly observed:

> *On the whole, energy expenditures equal only 2 percent of the value of U.S. manufacturing's output (see Figure 1) and three-quarters of all manufacturing output is from industries with energy expenditures below 2 percent of the value of their output. Thus, the vast majority of U.S. industry will be relatively unaffected by a greenhouse gas cap-and-trade program.*[37]

The same conclusion should apply to the effects of price increases attributable to LNG exports.

5. Impacts on Energy-Intensive Industries at the Plant or 5- to 6-Digit NAICS Level

The issue of EITE industries was investigated exhaustively during Congressional deliberations on climate legislation in the last Congress. In particular, H.R.2454 (the Waxman-Markey bill) set out specific criteria for classification as EITE. A broad consensus developed among analysts that at the 2 to 4-digit level of NAICS classification there were no industries that fit those criteria for EITE, and that only at the 5- to 6-digit level would there be severe impacts on any specific industry.[38] The phrase "deep but narrow" was frequently used to characterize the nature of competitive impacts. Some examples of industries that did fit the criteria for EITE were 311251 (nitrogenous fertilizer) within the 31 (2-digit chemicals) industry and 331111 (iron and steel mills) within the 3311 (4-digit iron and steel) industry. Analysis in this report strongly suggests that competitive impacts of higher natural gas prices attributable to LNG exports will be very narrow, but it was not possible to model impacts on each of the potentially affected sectors.

E. Sensitivities

1. Lost Values from Quota Rents

When scarcity is created there is value associated with supplying an additional unit. In economic terms, a quantity restriction to create this scarcity is called a quota. By enacting a quota, one creates a price difference between the world supply price (netback price) and the domestic price. This generates economic rent referred to as the "quota rent." Mathematically, a quota rent is the quota amount times the difference between the world net back price and the domestic price. A quota rent provides an additional source of revenue to the seller.

The quota levels for the13 scenarios analyzed and discussed in this study correspond to the export volumes assumed in the EIA Study. We assume that the quota rents are held by foreign

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[37] "The Effects of H.R. 2454 on International Competitiveness and Emission Leakage in Energy-Intensive Trade-Exposed Industries," p. 7.

[38] Richard Morgenstern, *et al.*, RFF Workshop Report.

parties. That is, the rents do not recycle back into the U.S. economy. In this section, we look at how the welfare results would change if the quota rents were recycled back to the U.S.

Figure 45 shows the quota price in 2010 dollars per Mcf for all 13 scenarios determined in the GNGM. The quota price is the marginal price of the quota, or the quota rents divided by the level of exports. The quota price is zero for scenarios that have a non-binding quota constraint. That is, export volumes are less than the quota levels. All of the scenarios under the High EUR and Low EUR cases have binding quota constraints leading to a positive quota price. The quota price is highest in the scenarios in which the domestic natural gas price is the lowest (*i.e.*, the low scenarios for the High EUR outlook). The largest quota price results in the High EUR case with the Low/Slowest export expansion scenario (HEUR_SD_LSS). For this scenario, the quota price is around $3/Mcf.

Figure 45: Quota Price (2010$/Mcf)

Scenario	Quota Price (2010$/Mcf)				
	2015	2020	2025	2030	2035
USREF_SD_LS	1.24	0.52	1.11	1.2	1.62
USREF_SD_LR	1.09	0.52	1.11	1.2	1.62
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	1.24	0.52	-	0.08	0.67
USREF_SD_HR	0.74	-	-	0.08	0.67
USREF_D_LSS	0.46	-	-	-	-
HEUR_SD_LS	2.23	1.88	2.71	2.69	3.28
HEUR_SD_LR	1.8	1.88	2.71	2.69	3.28
HEUR_SD_HS	2.23	1.88	1.73	1.73	2.47
HEUR_SD_HR	1.8	0.52	1.53	1.73	2.47
HEUR_SD_LSS	2.34	2.63	2.81	2.69	3.28
LEUR_SD_LSS	-	-	-	-	-

Figure 46: Quota Rents (Billions of 2010$)

Scenario	Quota Rents* (Billions of 2010$)				
	2015	2020	2025	2030	2035
USREF_SD_LS	0.41	1.02	2.19	2.37	3.19
USREF_SD_LR	1.08	1.02	2.19	2.37	3.19
USREF_D_LS	-	-	-	-	-
USREF_D_LR	-	-	-	-	-
USREF_SD_HS	0.41	1.02	-	0.32	2.64
USREF_SD_HR	0.73	-	-	0.32	2.64
USREF_D_LSS	0.07	-	-	-	-
HEUR_SD_LS	0.74	3.71	5.34	5.30	6.46
HEUR_SD_LR	1.78	3.71	5.34	5.30	6.46
HEUR_SD_HS	0.74	3.71	6.26	6.82	9.74
HEUR_SD_HR	1.78	2.05	6.03	6.82	9.74
HEUR_SD_LSS	0.38	2.60	5.08	5.30	6.46
LEUR_SD_LSS	-	-	-	-	-

** The quota rents are based on net export volumes.*

The quota rents on the other hand, depend on the price and quantity. Even though the price is the highest under the low export scenarios, as seen in Figure 45, quota rents are the largest for the high export expansion scenarios. Under the high quota rent scenario, HEUR_SD_HR, the average annual quota rents range from $1.8 billion to $9.7 billion. Over the model horizon, 2015 through 2035, maximum total quota rents amount to about $130 billion (Figure 47). This is an important source of additional income that would have potential benefits to the U.S. economy. However, in the event that U.S. companies are unable to capture these rents, this source of additional income would not accrue to the U.S. economy.

Figure 47: Total Lost Values

Scenario	Total Lost Value from 2015-2035 (Billions of 2010$)	Average Annual Lost Value (Billions of 2010$)
USREF_SD_LS	$45.92	$1.84
USREF_SD_LR	$49.25	$1.97
USREF_D_LS	$0.00	$0.00
USREF_D_LR	$0.00	$0.00
USREF_SD_HS	$21.97	$0.88
USREF_SD_HR	$18.45	$0.74
USREF_D_LSS	$0.37	$0.01
HEUR_SD_LS	$107.78	$4.31
HEUR_SD_LR	$112.98	$4.52
HEUR_SD_HS	$136.32	$5.45
HEUR_SD_HR	$132.10	$5.28
HEUR_SD_LSS	$99.16	$3.97
LEUR_SD_LSS	$0.00	$0.00

2. A Larger Share of Quota Rents Increases U.S. Net Benefits

To understand how the macroeconomic impacts (or U.S. net benefits) would change if the quota rents were retained by U.S. companies, we performed sensitivities on two different scenarios – one with high quota price, HEUR_SD_LSS, and the other with high quota rents, HEUR_SD_HR. The sensitivities put an upper bound on the potential range of improvement in the net benefits to the U.S. consumers.

In the sensitivity runs, we assume that quota rents are returned to the U.S. consumers as a lump-sum wealth transfer from foreign entities.

Figure 48 shows the range of welfare changes for the sensitivities of the two scenarios. Under both scenarios, the welfare improves because the quota rents provide additional income to the household in the form of a wealth transfer. Consumers have more to spend on goods and services leading to higher welfare. The welfare in the Low/Slowest scenario improves by more than threefold, while under the High/Rapid scenario the improvement in welfare increases by twofold. The ability to extract quota rents unequivocally benefits U.S. consumers.

Figure 48: Change in Welfare with Different Quota Rents[39]

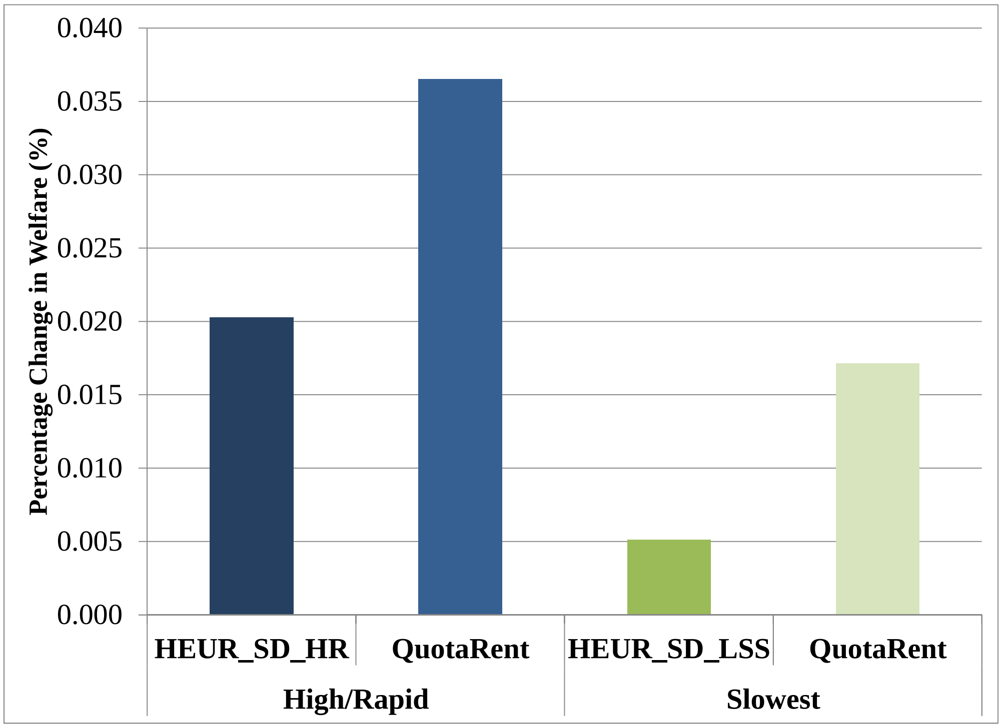
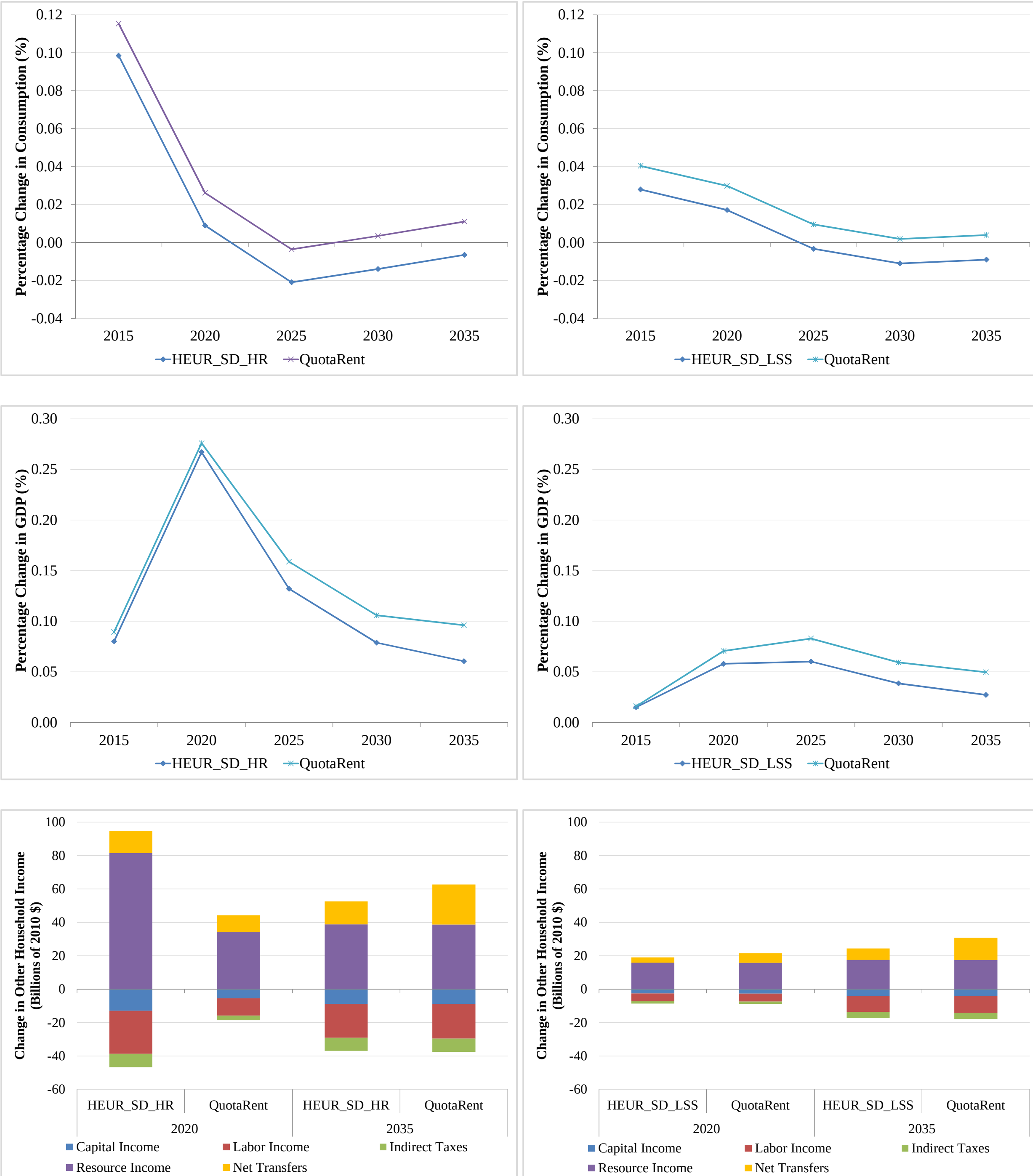


Figure 49 shows the change in impacts on aggregate consumption, GDP, and other household income for different quota rent sensitivities. The additional income from quota rents makes consumers wealthier, leading to increased expenditures on goods and services. This increase in economic activity leads to higher aggregate consumption and GDP. The impacts are highest when allowing for maximum quota rent transfer. The pattern of impacts is the same across the High/Rapid and Low/Slowest scenarios - the only difference is in the magnitude of the effect. The change under the Low/Slowest scenario is relatively smaller because of the smaller amount of transfers compared to the High/Rapid scenario. The consumption change under the maximum quota rent transfer scenario in 2015 is 50% higher than the scenario with no quota rent transfer. In this optimistic scenario, consumption changes are always positive throughout the model horizon for both scenarios. The charts below also highlight changes in other household incomes that add to GDP. While all other income source changes remain the same, only the net transfers change. As quota rents increase so does the change in net transfers leading to higher real income. As a result, higher quota rents lead to more imports, more consumption, higher GDP, and ultimately greater well-being of U.S. consumers.

39 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

Figure 49: Macroeconomic Impacts for the High EUR – High/Rapid and Low/Slowest Scenario Sensitivities



VII. CONCLUSIONS

NERA developed a Global Natural Gas Model ("GNGM") and a general equilibrium model of the U.S. economy ("N_{ew}ERA Model") to evaluate feasible levels of LNG exports and their impacts on the U.S. economy. These two models allowed us to determine feasible export levels, characterize the international gas market conditions, and evaluate overall macroeconomic effects. Given the wide range in export expansion outcomes, it is not surprising to find great variation in the macroeconomic impacts and natural gas market changes. Nevertheless, several observations may be distilled from the patterns that emerged.

A. LNG Exports Are Only Feasible under Scenarios with High International Demand and/or Low U.S. Costs of Production

Under status quo conditions in the world and the U.S. (U.S. Reference and International Reference cases) there is no feasible level of exports possible from the U.S. Under the low natural price case (High Shale EUR), LNG exports from the U.S. are feasible. However, under a low shale gas outlook (Low Shale EUR), international demand has to increase along with a tightening of international supply for the U.S. to be an LNG exporter.

B. U.S. Natural Gas Prices Do Not Rise to World Prices

LNG exports will not drive the price of domestic natural gas to levels observed in countries that are willing to pay oil parity-based prices for LNG imports. U.S. exports will drive prices down in regions where U.S. supplies are competitive so that even export prices will come down at the same time that U.S. prices will rise.

Moreover, basis differentials due to transportation costs from the U.S. to high-priced regions of the world will still exist, and U.S. prices will never get closer to those prices than the cost of liquefaction plus the cost of transportation to and regasification in the final destination. Thus even in the scenarios with no binding export levels, the wellhead price in the U.S. is below the import price in Japan, where the U.S. sends some of its exports.

The largest change in international natural gas prices in 2015 and 2025 is about \$0.33/MMBtu and \$1/MMBtu, respectively. These increases occur only in highly stressed conditions or when global markets are willing to take the full quantities of export volumes at prices above marginal production cost in the U.S. plus liquefaction, transportation, and regasification costs incurred to get the LNG to market.

C. Consumer Well-being Improves in All Scenarios

The macroeconomic analysis shows that there are consistent net economic benefits across all the scenarios examined and that the benefits generally become larger as the amount of exports increases. These benefits are measured most accurately in a comprehensive measure of economic welfare of U.S. households that takes into account changes in their income from all sources and the cost of goods and services they buy. This measure gives a single indicator of relative overall well-being of the U.S. population, and it consistently ranks all the scenarios with

LNG exports above the scenario with No-Exports. Welfare improvement is highest under the high export volume scenarios because U.S. consumers benefit from an increase in wealth transfer and export revenues.

D. There Are Net Benefits to the U.S.

A related measure that shows how economic impacts are distributed over time is GDP. Like welfare, GDP also increases as a result of LNG exports. The most dramatic changes are in the short term, when investment in liquefaction capacity adds to export revenues and tolling charges to grow GDP. Under the Reference case, GDP increases could range from $5 billion to $20 billion. Under the High Shale case, GDP in 2020 could increase by $10 billion to $47 billion. Under the Low Shale case, GDP in 2020 could increase by $4.4 billion. Every scenario shows improvement in GDP over the No-Exports cases although in the long run the impact on GDP is relatively smaller than in the short run.

Although the patterns are not perfectly consistent across all scenarios, the increase in investment for liquefaction facilities and increased natural gas drilling and production provides, in general, near-term stimulus to the economy. At the same time, higher energy costs do create a small drag on economic output in the U.S. so that total worker compensation declines.

E. There Is a Shift in Resource Income between Economic Sectors

The U.S. has experienced many changes in trade patterns as a result of changing patterns of comparative advantage in global trade. Each of these has had winners and losers. Grain exports raised the income of farmers and transferred income from U.S. consumers to farmers, steel imports lowered the income of U.S. steel companies and lowered costs of steel for U.S. manufacturing, etc.

The U.S. economy will experience some shifts in output by industrial sectors as a result of LNG exports. Compared to the No-Exports case, incomes of natural gas producers will be greater, labor compensation in the natural gas sector will increase while other industrial sector output and labor compensation decreases. The natural gas sector could experience an increase in production by 0.4 Tcf to 1.5 Tcf by 2020 and 0.3 Tcf to 2.6 Tcf by 2035 to support LNG exports. The LNG exports could lead to an average annual increase in natural export revenues of $10 billion to $30 billion. Impacts on sectoral output vary. Manufacturing sector output decreases by less than 0.4% while EIS and electric sector output impacts could be about 1% in 2020 when the natural gas price is the highest. Changes in industry output and labor compensation are very small. Even energy-intensive sectors experience changes of 1% or less in output and labor compensation during the period when U.S. natural gas prices are projected to rise more rapidly than in a No-Exports case.

Harm is likely to be confined to narrow segments of the industry, and vulnerable industries are not high value-added industries. The electricity sector, energy-intensive sector, and natural gas-dependent goods and services producers will all be impacted by price rises. Conversely, natural gas suppliers will benefit. Labor wages will likewise decrease or increase, respectively, depending on the sector of the economy. The overall impact on the economy depends on the tradeoff between these sectors.

In terms of natural gas-dependent production, producers switch to cheaper fuels or use natural gas more efficiently as natural gas prices rise and production overall is reduced. Reductions in tax revenues are directly related to changes in sectoral output. Industrial output declines the most in scenarios that have the highest increase in natural gas and fuel costs.

The costs and benefits of natural gas price increases are shifted in two ways. Costs and benefits experienced by industries do not remain with the companies paying the higher energy bills or receiving higher revenues. Part of the cost of higher energy bills will be shifted forward onto consumers, in the form of higher prices for goods being produced. The percentage of costs shifted forward depends on two main factors: first, how demand for those goods responds to increases in price, and second, whether there are competitors who experience smaller cost increases. The remainder of the cost of higher energy bills is shifted backwards onto suppliers of inputs to those industries, to their workers, and to owners of the companies. As each supplier in the chain experiences lower revenue, its losses are also shifted back onto workers and owners.

Gains from trade are shifted in the same way. Another part of the increased income of natural gas producers comes from foreign sources. This added revenue from overseas goes immediately to natural gas producers and exporters but does not come from U.S. consumers. Therefore, it is a net benefit to the U.S. economy and is also shifted back to the workers and owners of businesses involved directly and indirectly in natural gas production and exports.

In the end, all the costs and benefits of any change in trade patterns or prices are shifted back to labor and capital income and to the value of resources in the ground, including natural gas resources. One of the primary reasons for development of computable general equilibrium models like N_{ew}ERA is to allow analysts to estimate how impacts are shifted back to the different sources of income and their ultimate effects on the economy at large. In conclusion, the range of aggregate macroeconomic results from this study suggests that LNG export has net benefits to the U.S. economy.

APPENDIX A - TABLES OF ASSUMPTIONS AND NON-PROPRIETARY INPUT DATA FOR GLOBAL NATURAL GAS MODEL

A. Region Assignment

Figure 50: Global Natural Gas Model Region Assignments

Region	Countries
Africa	Algeria, Angola, Egypt, Equatorial Guinea, Ghana, Libya, Morocco, Mozambique, Nigeria, Tunisia
Canada	Canada
China/India	China, Hong Kong, India
Central and South America	Andes, Argentina, Bolivia, Brazil, Central America and Caribbean, Chile, Dominican Republic, Mexico, Peru, Southern Cone, Trinidad & Tobago, Uruguay, Venezuela
Europe	Albania, Austria, Belgium, Croatia, Denmark, Estonia, France, Germany, Greece, Ireland, Italy, Netherlands, North Sea, Norway, Poland, Portugal, Romania, Spain, Sweden, Switzerland, Ukraine, United Kingdom
Former Soviet Union	Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
Korea/Japan	South Korea, Japan
Middle East	Abu Dhabi, Cyprus, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, Turkey, United Arab Emirates, Yemen
Oceania	Australia, New Zealand, Papua New Guinea
Sakhalin	Sakhalin Island
Southeast Asia	Brunei, Indonesia, Malaysia, Myanmar, Singapore, Taiwan, Thailand
U.S.	Puerto Rico, United States

B. EIA IEO 2011 Natural Gas Production and Consumption

Figure 51: EIA IEO 2011 Natural Gas Production (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	7.80	9.70	11.10	12.20	13.30	14.10
Canada	6.10	7.00	7.70	8.30	8.70	9.00
China/India	4.60	5.60	6.70	8.00	9.60	9.70
C&S America	6.80	7.90	8.30	9.20	10.50	11.70
Europe	9.50	8.10	7.40	7.50	7.90	8.30
FSU	28.87	30.05	32.12	34.89	37.77	39.94
Korea/Japan	0.20	0.20	0.20	0.20	0.20	0.20
Middle East	16.30	19.70	22.40	24.60	26.70	28.80
Oceania	2.10	2.60	3.10	3.80	4.80	5.70
Sakhalin	0.43	0.45	0.48	0.51	0.53	0.56
Southeast Asia	9.30	10.00	10.70	11.60	12.60	13.40
U.S.	21.10	22.40	23.40	24.00	25.10	26.40
World	113.10	123.70	133.60	144.80	157.70	167.80

Figure 52: EIA IEO 2011 Natural Gas Consumption (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	3.90	4.70	5.90	7.10	8.30	9.10
Canada	3.30	3.50	3.70	4.20	4.60	5.00
China/India	5.70	8.60	10.70	13.10	15.10	16.60
C&S America	6.60	7.40	8.90	10.50	12.20	14.40
Europe	19.20	19.80	20.40	20.90	22.00	23.20
FSU	24.30	24.30	24.50	24.90	25.80	26.50
Korea/Japan	5.00	5.20	5.30	5.70	5.90	5.90
Middle East	12.50	14.70	17.00	19.10	21.30	24.00
Oceania	1.20	1.30	1.50	1.80	2.00	2.20
Sakhalin	0.00	0.00	0.00	0.00	0.00	0.00
Southeast Asia	7.40	8.50	10.00	12.00	13.90	15.30
U.S.	23.80	25.10	25.30	25.10	25.90	26.50
Total World	112.90	123.10	133.20	144.40	157.00	168.70

C. Pricing Mechanisms in Each Region

1. Korea/Japan

Korea/Japan was assumed to continue to rely upon LNG to meet its natural gas demand. LNG was assumed to continue to be supplied under long-term contracts with index pricing tied to crude oil prices. It was assumed that with time, supplier competition would result in some softening in the LNG pricing relative to crude.[40] This Reference case assumes some growth in Korea/Japan demand but does not incorporate significant shifts away from nuclear energy to natural gas-fired generation.

2. China/India

LNG pricing for China/India is also assumed to be linked to crude oil prices but at a discount to Korea/Japan. The discount was intended to reflect that China/India, although short of natural gas supplies, have other sources of natural gas that LNG complements. As a result, we assumed that China/India would have some additional market leverage in negotiating contracting terms.

3. Europe

Europe receives natural gas from a variety of sources. The prices of some supplies are indexed to petroleum prices. Other sources are priced based upon regional gas-on-gas competition. In our analysis, we assumed that European natural gas prices would reflect a middle point with prices not tied directly either to petroleum or to local natural gas competition. We assumed that European prices would remain above the pricing levels forecast for North America but not as high as in Asia. Europe was also assumed to remain dependent upon imported supplies of natural gas to meet its moderately growing demand.

4. United States

The United States was assumed to follow the forecast for supply and demand and pricing as presented in the EIA's AEO 2011 Reference case.

5. Canada

The analysis assumed that Canada is part of an integrated North American natural gas market. As a consequence, Canadian pricing is linked to U.S. prices, and Canadian prices relate by a basis differential to U.S. prices. We assumed that Canadian production was sufficient to meet Canadian demand plus exports to the United States as forecast in the EIA AEO 2011. We did not allow for Canadian exports of LNG in the Reference case. Also, we held exports to the United States constant across different scenarios so as to be able to eliminate the secondary impacts of changing imports on the economic impacts of U.S. LNG on the U.S. economy.

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[40] This is consistent with the IEO WEO 2011, which forecasts the LNG to Crude index will decline from 82% to 63% between now and 2035.

6. Africa, Oceania, and Southeast Asia

These three regions were assumed to produce natural gas from remote locations. The analysis assumed that these natural gas supplies could be produced economically today at a price between $1 and $2/MMBtu. The EIA's IEO 2011 was used as the basis for forecasting production volumes.

7. Middle East

Qatar is assumed to be the low-cost producer of LNG in the world. It is assumed that although Qatar has vast natural gas resources, it decides to continue to limit its annual LNG exports to 4.6 Tcf during the forecast horizon.

8. Former Soviet Union

The FSU was assumed to grow its natural gas supply at rates that far exceed its domestic demand. The resulting excess supplies were assumed to be exported mostly to Europe and, to a lesser degree, to China/India.

9. Central and South America

Central and South America was assumed to produce sufficient natural gas to meet its growing demand in every year during the forecast horizon. The region also has the potential for LNG exports that the model considered in determining worldwide LNG flows.

Figure 53: Projected Wellhead Prices ($/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Canada	$3.39	$3.72	$4.25	$5.20	$5.64	$6.68
China/India	$12.29	$12.86	$13.00	$13.25	$13.57	$13.51
C&S America	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
Europe	$9.04	$9.97	$10.80	$11.95	$12.39	$13.23
FSU	$4.25	$4.60	$5.08	$5.61	$6.19	$6.84
Korea/Japan	$14.59	$15.30	$15.47	$15.79	$16.19	$16.11
Middle East	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Oceania	$1.75	$1.89	$2.09	$2.31	$2.55	$2.81
Sakhalin	$1.25	$1.35	$1.49	$1.65	$1.82	$2.01
Southeast Asia	$2.00	$2.16	$2.39	$2.64	$2.91	$3.22
U.S.	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36

Source: U.S. wellhead prices are from EIA AEO 2012 Early Release.

Figure 54: Projected City Gate Prices ($/MMBtu)

	2010	2015	2020	2025	2030	2035
Africa	$2.75	$2.89	$3.09	$3.31	$3.55	$3.81
Canada	$4.79	$5.12	$5.65	$6.60	$7.04	$8.08
China/India	$13.79	$14.36	$14.50	$14.75	$15.07	$15.01
C&S America	$4.50	$4.66	$4.89	$5.14	$5.41	$5.72
Europe	$10.04	$10.97	$11.80	$12.95	$13.39	$14.23
FSU	$5.25	$5.60	$6.08	$6.61	$7.19	$7.84
Korea/Japan	$15.09	$15.80	$15.97	$16.29	$16.69	$16.61
Middle East	$4.08	$4.18	$4.32	$4.48	$4.65	$4.84
Oceania	$3.25	$3.39	$3.59	$3.81	$4.05	$4.31
Sakhalin	$3.75	$3.85	$3.99	$4.15	$4.32	$4.51
Southeast Asia	$3.00	$3.16	$3.39	$3.64	$3.91	$4.22
U.S.	$4.72	$4.83	$5.28	$6.10	$6.48	$7.36

D. Cost to Move Natural Gas via Pipelines

Figure 55: Cost to Move Natural Gas through Intra- or Inter-Regional Pipelines ($/MMBtu)

From	To	Cost
Africa	Africa	$1.00
Africa	Europe	$1.00
Canada	Canada	$1.20
Canada	U.S.	$1.20
China/India	China/India	$1.50
FSU	FSU	$1.00
FSU	Europe	$1.00
FSU	China-India	$1.00
U.S.	U.S.	$1.00
U.S.	Canada	$1.00
C&S America	C&S America	$2.50
Middle East	Middle East	$2.83
Oceania	Oceania	$1.50
Korea/Japan	Korea/Japan	$0.50
Europe	Europe	$1.00
Sakhalin	Sakhalin	$0.50
Southeast Asia	Southeast Asia	$1.00

E. LNG Infrastructures and Associated Costs

1. Liquefaction

The world liquefaction plants data is based upon the International Group of LNG Importers' ("GIIGNL") 2010 LNG Industry report. The dataset includes 48 existing liquefaction facilities worldwide, totaling 13.58 Tcf of export capacity. The future liquefaction facility dataset, based upon *LNG Journal* (October 2011),[41] includes 32 LNG export projects and totals 10.59 Tcf of planned export capacity. This dataset covers worldwide liquefaction projects from 2011 to 2017. Beyond 2017, each region's liquefaction capacity is assumed to grow at the average annual growth rate of its natural gas supply.[42]

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41 LNG Journal, Oct 2011. Available at: http://lngjournal.com/lng/.

42 Rates are adopted from IEO 2011.

The liquefaction cost per MMBtu can be broken down into three components:

1. An operation and maintenance cost of $0.16;
2. A capital cost that depends on the location of the facility; and
3. A fuel use cost that varies with natural gas prices over time.

To derive the capital cost per MMBtu, we obtained a set of investment costs per million metric tons per annum ("MMTPA") by region (Figure 56).[43] The U.S.'s investment cost per MMTPA is competitive because most domestic projects convert existing idle regasification facilities to liquefaction facilities. This implies a 30% to 40% cost savings relative to greenfield projects. Offshore LNG export projects are more costly, raising the investment costs per unit of capacity in Southeast Asia and Oceania.

Figure 56: Liquefaction Plants Investment Cost by Region ($millions/ MMTPA Capacity)

	$Millions/MMTPA	Capital Cost ($/MMBtu produced)
Africa	$1,031	$3.05
Canada	$1,145	$3.39
C&S America	$802	$2.37
Europe	$802	$2.37
FSU	$802	$2.37
Middle East	$859	$2.54
Oceania	$1,317	$3.90
Sakhalin	$802	$2.37
Southeast Asia	$1,145	$3.39
U.S.	$544	$1.61

The total investment cost is then annualized assuming an average plant life of 25 years and a discount rate of 10%. The capital cost per MMBtu of LNG produced is obtained after applying a 72% capacity utilization factor to the capital cost per MMBtu of LNG capacity. Figure 57 shows the liquefaction fixed cost component in $/MMBtu LNG produced.

$$\text{Equivalent Annual Cost} = \frac{\text{Asset Price} \times \text{Discount Rate}}{1-(1+\text{Discount Rate})^{-\text{Number of Periods}}}$$

[43] From Paul Nicholson, a Marsh & McLennan company colleague (NERA is a subsidiary of Marsh & McClennan).

In the liquefaction process, 9% of the LNG is burned off. This fuel use cost is priced at the wellhead and included in the total liquefaction costs.

Figure 57: Liquefaction Costs per MMBtu by Region, 2010-2035

	2010	2015	2020	2025	2030	2035
Africa	$3.37	$3.38	$3.40	$3.42	$3.44	$3.46
Canada	$3.85	$3.88	$3.93	$4.02	$4.06	$4.15
C & S America	$2.71	$2.73	$2.75	$2.77	$2.79	$2.82
Europe	$3.35	$3.43	$3.50	$3.61	$3.65	$3.72
FSU	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Middle East	$2.81	$2.82	$2.84	$2.85	$2.87	$2.88
Oceania	$4.22	$4.23	$4.25	$4.27	$4.29	$4.31
Sakhalin	$2.65	$2.65	$2.67	$2.68	$2.70	$2.71
Southeast Asia	$3.73	$3.74	$3.76	$3.79	$3.81	$3.84
U.S.	$2.13	$2.14	$2.18	$2.25	$2.28	$2.34

2. Regasification

The world regasification plants data is based upon the GIIGNL's annual LNG Industry report, 2010. The dataset includes 84 existing regasification facilities worldwide, totaling to a 28.41 Tcf annual import capacity. Korea and Japan together own 12.58 Tcf or 44% of today's world regasification capacities. The GNGM future regasification facility database includes data collected from multiple sources: the GLE Investment Database September 2011, LNG journal Oct 2011, and GIIGNL's 2010 LNG Industry report. It includes 46 LNG import projects, totaling to 12.12 Tcf of planned import capacity, and covers regasification projects from 2011 to 2020 worldwide. Beyond 2020, each region's regasification capacity is assumed to grow at the average annual growth rate of its natural gas demand.[44]

LNG regasification cost can also be broken down into three components: an operation and maintenance cost of $0.20/MMBtu, a fixed capital cost of $0.46/MMBtu, and a fuel use cost that varies with natural gas demand prices by region and time. The capital cost assumes a 40% capacity utilization factor, and the fuel use component assumes a 1.5% LNG loss in regasification. LNG regasification cost in GNGM is shown in Figure 58.

[44] Rates adopted from IEO 2011.

Figure 58: Regasification Costs per MMBtu by Region 2010-2035

	2010	2015	2020	2025	2030	2035
C&S America	$0.73	$0.73	$0.73	$0.74	$0.74	$0.75
Canada	$0.73	$0.74	$0.75	$0.76	$0.77	$0.78
China/India	$0.87	$0.88	$0.88	$0.88	$0.89	$0.89
Europe	$0.81	$0.83	$0.84	$0.86	$0.86	$0.87
FSU	$0.74	$0.75	$0.75	$0.76	$0.77	$0.78
Korea/Japan	$0.89	$0.90	$0.90	$0.91	$0.91	$0.91
Middle East	$0.72	$0.72	$0.73	$0.73	$0.73	$0.73
Southeast Asia	$0.71	$0.71	$0.71	$0.72	$0.72	$0.72
U.S.	$0.73	$0.73	$0.74	$0.75	$0.76	$0.77

3. Shipping Cost

GNGM assumes that the shipping capacity constraint is non-binding. There are sufficient LNG carriers to service any potential future route in addition to existing routes.

Shipping cost consists of a tanker cost and a LNG boil-off cost, both of which are a function of the distance between the export and import regions. An extra Panama Canal toll of 13 cents roundtrip is applied to gulf-Asia Pacific shipments.[45] Tanker costs are based on a $65,000 rent per day and average tanker speed of 19.4 knots. Fuel use costs assume a 0.15% per day boil off rate and an average tanker capacity of 149,000 cubic meters of LNG. LNG boil-off cost is valued at city gate prices in importing regions. Shipping distances for existing routes are based upon the GIIGNL's 2010 LNG Industry report while distances for potential routes are calculated with the Sea Rates online widget.[46]

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45 $0.13 roundtrip toll calculated based upon a 148,500 cubic meter tanker using approved 2011 rates published at http://www.pancanal.com/eng/maritime/tolls.html.

46 http://www.searates.com/reference/portdistance/.

Figure 59: 2010 Shipping Rates ($/MMBtu)

	Canada	China/ India	C&S America	Europe	Korea/ Japan	Oceania	SE Asia	U.S.
Africa		$1.76	$1.44	$0.46	$2.60		$1.70	$2.60
Canada		$1.51	$1.53		$1.23		$1.55	
China/ India								$2.81
C&S America	$1.53	$2.22	$1.26	$1.39	$2.73			$1.54
Europe								$1.27
FSU			$2.15			$2.39	$2.44	$1.17
Korea/ Japan								$2.54
Middle East		$0.96	$2.36	$1.30	$1.61		$1.15	$2.16
Oceania		$0.74	$2.38		$0.90		$0.63	$2.41
Sakhalin		$0.48			$0.26		$0.84	$2.50
Southeast Asia		$0.52			$0.66		$0.32	$2.63
U.S.		$2.81	$1.53	$1.27	$2.54		$2.61	

The Gulf Coast has a comparative disadvantage in accessing the Asia pacific market due to the long shipping distances and Panama Canal tolls.

4. LNG Pipeline Costs

A pair of pipeline transport costs is also included in LNG delivery process to account for the fact that pipelines are necessary to transport gas from wellheads to liquefaction facilities in supply regions and from regasification facilities to city gates in demand regions.

Figure 60: Costs to Move Natural Gas from Wellheads to Liquefaction Plants through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.70
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$1.00
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

Figure 61: Costs to Move Natural Gas from Regasification Plants to City Gates through Pipelines ($/MMBtu)

Region	Cost
Africa	$1.00
Canada	$0.50
China/India	$1.50
C&S America	$0.50
Europe	$1.00
FSU	$1.00
Korea/Japan	$0.50
Middle East	$1.42
Oceania	$0.50
Sakhalin	$0.50
Southeast Asia	$1.00
U.S.	$1.00

5. Total LNG Costs

Costs involved in exporting LNG from the Gulf Coast to demand regions are aggregated in Figure 62. The largest cost components are liquefaction and shipping.

Figure 62: Total LNG Transport Cost, 2015 ($/MMBtu)

	China/India	Europe	Korea/Japan
Regas to city gate pipeline cost	$1.50	$1.00	$0.50
Regas cost	$0.88	$0.83	$0.90
Shipping cost	$2.87	$1.33	$2.60
Liquefaction cost	$2.14	$2.14	$2.14
Wellhead to liquefaction pipeline cost	$1.00	$1.00	$1.00
Total LNG transport cost	$8.39	$6.30	$7.14

F. Elasticity

1. Supply Elasticity

All regions are assumed to have a short-run supply elasticity of 0.2 in 2010 and a long-run elasticity of 0.4 in 2035. Elasticities in the intermediate years are interpolated with a straight line method. There are two exceptions to this rule.

The U.S. supply elasticity is computed based upon the price and production fluctuations under different scenarios in the EIA Study. The median elasticity in 2015 and 2035 is recorded and elasticities for the other years are extrapolated with a straight line method.

After numerous test runs, we found that African supply elasticity is appropriately set at 0.1 for all years. Supply elasticity in GNGM is:

Figure 63: Regional Supply Elasticity

	2010	2015	2020	2025	2030	2035
Africa	0.10	0.10	0.10	0.10	0.10	0.10
U.S.	0.17	0.24	0.33	0.46	0.65	0.90
All other regions	0.20	0.23	0.26	0.30	0.35	0.40

2. Demand Elasticity

All regions are assumed to have a short run demand elasticity of -0.10 in 2010 and a long run demand elasticity of -0.20 in 2035 except the U.S. The U.S. demand elasticity is derived based on average delivered price and consumption fluctuations reported in the EIA Study.

Figure 64: Regional Demand Elasticity

	2010	2015	2020	2025	2030	2035
U.S.	-0.33	-0.36	-0.39	-0.42	-0.46	-0.50
All other regions	-0.10	-0.11	-0.13	-0.15	-0.17	-0.20

G. Adders from Model Calibration[47]

Figure 65: Pipeline Cost Adders ($/MMBtu)

Exporters	Importers	2010	2015	2020	2025	2030	2035
Africa	Europe	$7.43	$8.23	$8.88	$9.83	$10.03	$10.62
Canada	Canada	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Canada	U.S.	$0.30	$0.12				
FSU	China/India	$8.71	$8.93	$8.58	$8.30	$8.03	$7.31
FSU	Europe	$4.88	$5.47	$5.83	$6.46	$6.32	$6.52
Sakhalin	Sakhalin	$2.04	$2.04	$2.04	$2.04	$2.04	$2.04

[47] Appendix B provides details on the generation of cost adders in GNGM.

Figure 66: LNG Cost Adders Applied to Shipping Routes ($/MMBtu)

Exporter	Importer	2010	2015	2020	2025	2030	2035
Africa	China/India	$3.59	$3.97	$3.89	$3.89	$3.93	$3.57
Africa	Europe	$1.73	$2.50	$3.11	$4.01	$4.18	$4.73
Africa	Korea/Japan	$5.09	$5.60	$5.54	$5.59	$5.70	$5.33
Canada	China/India	$5.91	$2.16	$1.71	$0.90	$0.72	-
Canada	Korea/Japan	$8.54	$4.93	$4.52	$3.77	$3.67	$2.44
C&S America	China/India	$4.06	$4.41	$4.29	$4.25	$4.24	$3.85
C&S America	Europe	$1.73	$2.43	$2.97	$3.78	$3.90	$4.36
C&S America	Korea/Japan	$5.89	$6.37	$6.28	$6.30	$6.37	$5.96
Sakhalin	China/India	$6.64	$7.09	$7.07	$7.16	$7.29	$7.01
Sakhalin	Korea/Japan	$9.19	$9.79	$9.81	$9.96	$10.17	$9.89
Middle East	China/India	$5.05	$5.49	$5.47	$5.55	$5.67	$5.40
Middle East	Europe	$1.55	$2.32	$2.96	$3.88	$4.11	$4.70
Middle East	Korea/Japan	$6.74	$7.31	$7.32	$7.46	$7.65	$7.37
U.S.	China/India	$1.51	$1.86	$1.60	$0.92	$0.80	$0.08
U.S.	Europe	-	$0.61	$1.02	$1.21	$1.21	$1.35
U.S.	Korea/Japan	$4.13	$4.62	$4.40	$3.78	$3.74	$3.00
Oceania	China/India	$4.26	$4.66	$4.58	$4.59	$4.64	$4.29
Oceania	Korea/Japan	$6.44	$6.99	$6.94	$7.01	$7.14	$6.77
Southeast Asia	China/India	$4.21	$4.59	$4.48	$4.46	$4.47	$4.08
Southeast Asia	Korea/Japan	$6.42	$6.94	$6.86	$6.91	$7.00	$6.58

H. Scenario Specifications

Figure 67: Domestic Scenario Conditions

	2010	2015	2020	2025	2030	2035
Reference Case						
Production (Tcf)	21.10	22.40	23.40	24.00	25.10	26.40
Wellhead price ($/MMBtu)	$3.72	$3.83	$4.28	$5.10	$5.48	$6.36
Pipeline imports from Canada (Tcf)	2.33	2.33	1.4	0.74	0.64	0.04
High EUR						
Production (Tcf)	21.21	24.68	26.37	27.52	28.61	30.19
Wellhead price ($/MMBtu)	$3.23	$2.90	$3.15	$3.72	$4.14	$4.80
Pipeline imports from Canada (Tcf)	2.18	2.01	0.87	0.01	-0.18	-0.68
Low EUR						
Production (Tcf)	20.93	19.61	19.88	20.06	21.13	21.67
Wellhead price ($/MMBtu)	$4.54	$5.65	$6.37	$7.72	$8.23	$8.85
Pipeline imports from Canada (Tcf)	2.45	2.66	2.06	1.96	1.93	1.66

Figure 68: Incremental Worldwide Natural Gas Demand under Two International Scenarios (in Tcf of Natural Gas Equivalents)

	2010	2015	2020	2025	2030	2035
Demand Shock						
Japan converts nuclear to gas	2.41	3.18	3.41	3.56	3.86	4.19
Supply& Demand Shock						
Japan and Korea convert nuclear to gas and limited international supply expansion	3.82	5.00	5.59	5.88	6.37	6.86

Sources: EIA IEO 2011 Nuclear energy consumption, reference case.

Figure 69: Scenario Export Capacity (Tcf)

	2010	2015	2020	2025	2030	2035
No Export	0	0	0	0	0	0
Low Slow	0	0.37	2.19	2.19	2.19	2.19
High Slow	0	0.37	2.19	4.02	4.38	4.38
Low Rapid	0	1.10	2.19	2.19	2.19	2.19
High Rapid	0	1.10	4.38	4.38	4.38	4.38
Low/Slowest	0	0.18	1.10	2.01	2.19	2.19
No Constraint	∞	∞	∞	∞	∞	∞

Source: EIA Study.

APPENDIX B – DESCRIPTION OF MODELS

A. Global Natural Gas Model

The GNGM is a partial-equilibrium model designed to estimate the amount of natural gas production, consumption, and trade by major world natural gas consuming and/or producing regions. The model maximizes the sum of consumers' and producers' surplus less transportation costs, subject to mass balancing constraints and regasification, liquefaction, and pipeline capacity constraints.

1. Model Calibration

The model is calibrated to match the EIA's IEO and AEO 2011 Reference Case natural gas production, consumption, wellhead, and delivered price forecasts, after adjusting the AEO and IEO production and consumption forecasts so that:

- World supply equaled world demand
- U.S. imports from Canada equaled total U.S. imports as defined by the AEO Reference case, less U.S. LNG imports as defined by the AEO Reference case
- Middle East LNG exports were capped at 4.64 Tcf, which meant that for the Middle East
  - Production ≤ Demand + Min(Liquefaction capacity, LNG export cap)
- FSU pipeline capacity satisfied the expression
  - Production ≤ Demand + pipeline export capacity
- Regasification capacity satisfied the expression for LNG importing regions:
  - Production ≤ Supply + Regasification Capacity
- Sufficient liquefaction capacity exists in LNG exporting regions
  - Production ≤ Demand + liquefaction capacity + pipeline export capacity

The GNGM assumes that the world natural gas market is composed of a perfectly competitive group of countries with a dominant supplier that limits exports. Therefore, if we simply added the competitive transportation costs to transport gas among regions, the model would not find the market values and would be unable to match the EIA's forecasts because the world natural gas market is not perfectly competitive and at its current scale includes important risks and transaction costs. For example, the city gate prices in the Korea/Japan region represent not only the cost of delivering LNG to this region but also this region's willingness to pay a premium above the market price to ensure a stable supply of imports.

Therefore to calibrate the GNGM to the EIA's price and volume forecasts, we had to introduce cost adders that represented the real world cost differentials, including these transaction costs. To derive these cost adders, we developed a least-squares algorithm that solved for these adders. The least-squares algorithm minimized the sum of the inter-region pipeline and LNG shipping cost adders subject to matching the EIA natural gas production, consumption, wellhead, and city gate prices for each region (see Appendix A for the resulting cost adders).

These pipeline and LNG shipping cost adders were added to the original pipeline and LNG shipping costs, respectively, to develop adjusted pipeline and LNG shipping costs. The GNGM made use of these adjusted transportation costs in all the model runs.

These adders can be interpreted in several ways consistent with their function in the GNGM:

- As transaction costs that could disappear as the world market became larger and more liquid, in the process shifting downward the demand curve for assured supplies in the regions where such a premium now exists
- As a leftover from long term contracts and therefore a rent to producers that will disappear as contracts expire and are renegotiated
- As a rent taken by natural gas utilities and traders within the consuming regions, that would either continue to be taken within importing countries or competed away if there were more potential suppliers

Under all of these interpretations, the amount of the adder would not be available to U.S. exporters, nor would it be translated into potentially higher netback prices to the U.S.

2. Input Data Assumptions for the Model Baseline

a. GNGM Regions

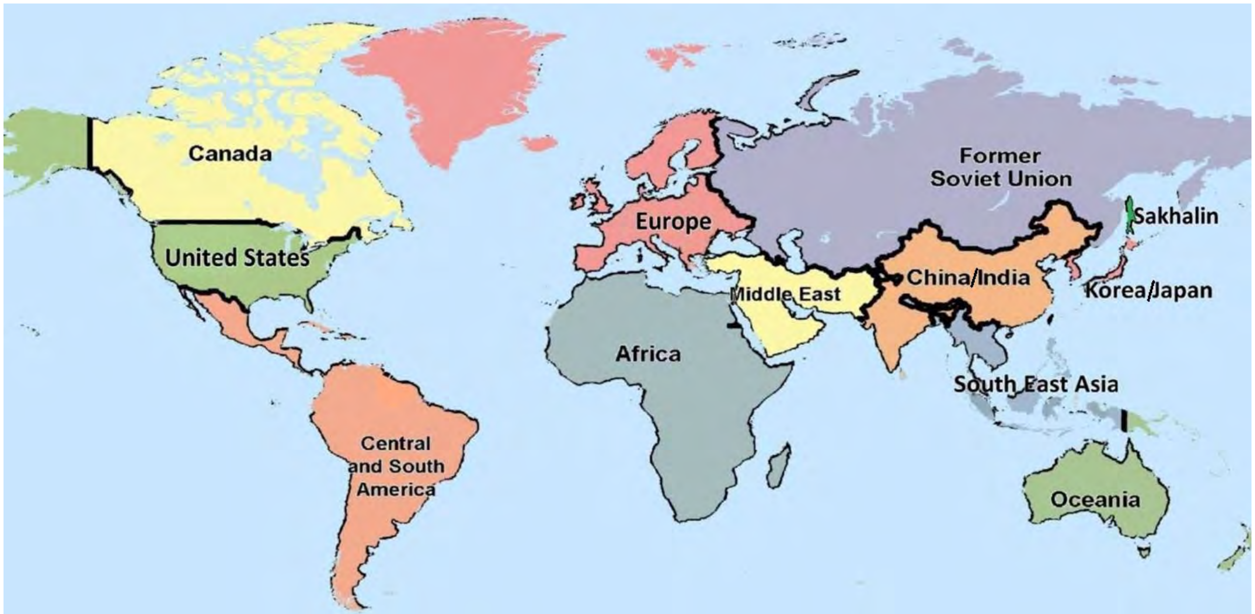
The GNGM regional mapping scheme is largely adapted from the EIA IEO regional definitions with modifications to address the LNG-intensive regions.

- OECD Regions: the OECD region of Americas maps to GNGM regions U.S., Canada and Central and South America; OECD Europe maps to GNGM Europe; OECD Asia maps to GNGM Korea-Japan and Oceania.
- Non-OECD Regions: the non-OECD regions of Eurasia and Europe map to GNGM regions Former Soviet Union and Sakhalin; Non-OECD Asia maps to China-India and Southeast Asia; Middle East maps to GNGM Middle East; Africa to GNGM Africa; Non-OECD Central and South America maps to GNGM Central and South America.
- Sakhalin is a Russian island just north of Japan. All Russian or FSU LNG exports in 2010 were produced in Sakhalin.[48] This island is characterized as a pure supply region with zero demand and adopted as a separate GNGM region from the rest of the FSU for its proximity to the demand regions. Its LNG production in 2010 is set equal to the

48 "The LNG Industry 2010," GIIGNL. Available at: www.giignl.org/fr/home-page/publications.

FSU's LNG exports in 2010 and grows at a rate of 1.1% per annum for the subsequent years.[49]

Figure 70: Map of the Twelve Regions in the GNGM



b. Time Horizon

GNGM reads in forecast data from each year and outputs the optimized gas trade flows. The model's input data currently covers years 2010 through 2035, but can be readily extended given data availability. For this analysis, we solved the model in five-year time steps starting with 2010.

c. Projected World Natural Gas Production and Consumption

The model's international natural gas consumption and production projections are based upon the IEO 2011 reference case. GNGM assumes four different future U.S. natural gas markets: the AEO 2011 reference case is adopted as the baseline and three other U.S. futures are obtained with the following modifications.

- High Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 High Shale EUR projections. All other regions are held constant.
- Low Shale EUR: U.S. natural gas production and wellhead prices are replaced by AEO 2011 Low Shale EUR projections. All other regions are held constant.
- High Economic Growth: U.S. natural gas consumption is replaced by AEO 2011 High Economic Growth projections. All other regions are held constant.

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49 The 1.1% per annum rate corresponds to IEO 2011 projected Russian natural gas production average annual growth rate for 2008 through 2035.

d. Gas Production and Consumption Prices

NERA has developed a set of world natural gas price projections based upon a number of data sources. The approach focuses on the wellhead price forecasts for net export regions and city gate price forecasts for net import regions. In naturally gas-abundant regions like the Middle East and Africa, the wellhead price is assumed to equal the natural gas extraction cost or lifting cost. City gate prices are estimated by adding a transportation cost to the wellhead prices.

In the major demand markets, natural gas prices are determined on an oil-parity basis using crude oil price forecasts from IEA's WEO 2011. The resultant prices are highly consistent with the relevant historical pipeline import prices[50] and LNG spot market prices as well as various oil and natural gas indices (*i.e.*, JCC, WTI, Henry Hub, AECO Hub indices, and UK National Balancing Point). U.S. wellhead and average city gate prices are adopted from AEO 2011. Canadian wellhead and city gate prices are projected to be $0.35 less than the U.S. prices in the reference case. A region-by-region price forecast description is presented in Section II.

e. Natural Gas Transport Options

Pipelines

GNGM assumes that all intra-regional pipeline capacity constraints are non-binding. Each region is able to transport its indigenously-produced natural gas freely within itself at an appropriate cost.

Four inter-regional pipeline routes are acknowledged in GNGM. The Africa-to-Europe route, including the Greenstream Pipeline, Trans-Mediterranean Pipeline, and Maghreb–Europe Gas Pipeline, is assigned a total capacity of 1.9 Tcf/year (connecting Northern Africa to Spain, Portugal, and Italy). The Turkmenistan–China Gas Pipeline, connecting FSU to China/India, has a maximum discharge of 1.41 Tcf/year. The FSU-Europe pipeline route has a total capacity of 8.3 Tcf/year in 2010 and grows to 10.8 Tcf/year in 2025. Lastly, the U.S.-Canada pipeline route is open and assumed to have unlimited capacity.

LNG Routes

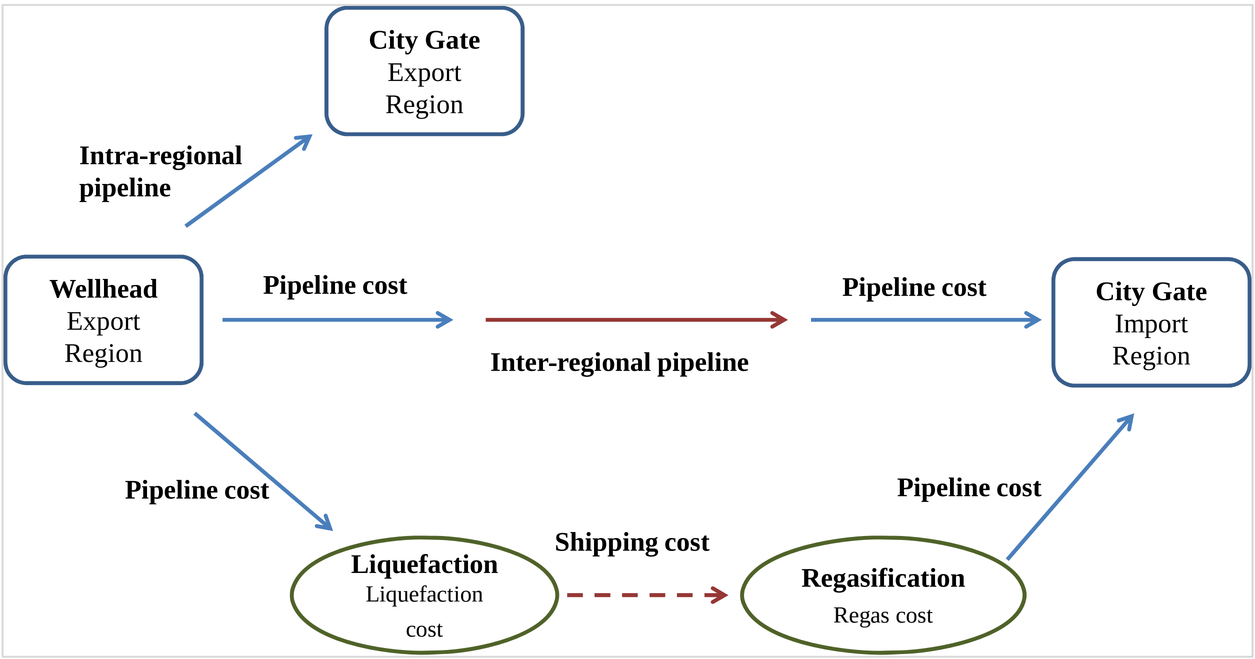
GNGM sets two constraints on LNG transportation. Each export region is subjected to a liquefaction capacity constraint and each import region to a regasification capacity constraint. There are five components in transporting LNG (Figure 71), and capacity constraints on the wellhead to liquefaction pipeline, LNG tankers, and regasification to city gate pipeline are assumed to be non-binding.

LNG transportation costs are generally four to seven times higher than the pipeline alternative since, to satisfy natural gas demand with LNG, shipments incur five segments of costs: 1) pipeline shipping cost to move gas from the wellhead to the liquefaction facility, 2) liquefaction

[50] German BAFA natural gas import border price, Belgium Zeebrugge spot prices, TTF Natural Gas Futures contracts, *etc*.

cost, 3) shipping cost between the liquefaction to regasification facilities, 4) regasification cost and 5) the pipeline shipping cost to move gas from the regasification facility to the city gate terminal in the demand region. A detailed cost breakdown for each leg of this process is presented in Appendix A.

Figure 71: Natural Gas Transport Options



f. Fuel Supply Curves

The supply of natural gas in each region is represented by a CES supply curve (see Equation 1). The supply curve provides a relationship between the supply of gas (Q) and the wellhead price of gas (P). The elasticity of the supply curves dictates how the price of natural gas changes with changes in production.

Equation 1: CES Supply Curve

$$Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of supply}}$$

Each supply curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA's adjusted forecasts.[51] $Q_{0.t}$ represents the EIA's adjusted forecasted quantity of natural gas production for year t, and $P_{0.t}$ represents the EIA's forecasted wellhead price of gas for year t. The elasticity of supply for all regions is included in Figure 63.

[51] See Section IV.B for a discussion of how the EIA's forecasts are adjusted before the GNGM model is calibrated. Note, only quantities are adjusted.

g. Fuel Demand Curves

The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function (see Equation 2). The demand curve provides a relationship between the demand for gas (Q) and the city gate price of gas (P). The demand curves dictate how the price of natural gas changes with changes in demand in each region.

Equation 2: CES Demand Curve

$$Q(t) / Q_{0,t} = (P(t) / P_{0,t})^{\text{elasticity of demand}}$$

Each demand curve is calibrated to the benchmark data points ($Q_{0.t}$, $P_{0.t}$) for each year t, where the benchmark data points represent those of the EIA's adjusted forecasts. $Q_{0.t}$ represents the EIA's adjusted forecasted demand for natural gas for year t and $P_{0.t}$ represents the EIA's forecasted city gate price of gas for year t. The elasticity of demand for all regions except the U.S. is based on the elasticities used in MIT's Emissions Prediction and Policy Analysis ("EPPA") model.[52] For the U.S., the demand elasticity was estimated by using the percentage changes in natural gas demand and city gate prices between the EIA's AEO 2011 Reference scenario and the different shale gas scenarios.

3. Model Formulation

The GNGM is formulated as a non-linear program. The following text describes at a high level the GNGM's non-linear objective function and linear constraints.

Maximize: Consumer Surplus + Producer Surplus – Transportation Costs

Subject to:

$$Supply(s) = \sum_d PipeGas(s,d) + LNG(s,d)$$

$$Demand(d) = \sum_s PipeGas(s,d) + LNG(s,d)$$

$$\sum_d LNG(s,d) \leq LiquefactionCapacity(s)$$

$$\sum_s LNG(s,d) \leq RegasificationCapacity(d)$$

52 "The MIT Emissions Prediction and Policy Analysis ("EPPA") Model: Version 4," Sergey Paltsev, John M. Reilly, Henry D. Jacoby, Richard S. Eckaus, James McFarland, Marcus Sarofim, Malcolm Asadoorian and Mustafa Babiker, August 2004.

$$PipeGas(s,d) \leq PipelineCapacity(s,d)$$

$$PipeGas('Canada','USA') = BaselinePipeGas('Canada',' USA')$$

Scenario Constraints

* Quota Constraint

$$\sum_{d} LNG('USA',d) \leq Quota$$

* Supply Shock

$$\sum_{d} LNG(\text{'Oceania'}, \text{d}) + LNG('Africa',d) + LNG('SouthEastAsia',d) \leq MaxExports$$

Consumer Surplus = $\int CityGatePrice(d)\ x\ (\frac{Demand(d)}{Demand0(d)})^{(\frac{1}{ElasOfDemand(d)})}$

Producer Surplus= $\int WellheadPrice(s)\ x\ (\frac{Supply(s)}{Supply0(s)})^{(\frac{1}{ElasOfSupply(s)})}$

Transportation Costs =

$$\sum_{s,d} ShipCost(s,d)\ x\ LNG(s,d) + \sum_{s,d} PipeLineCost(s,d)\ x\ PipeGas(s,d) + \sum_{s,d} RegasCost(d)\ x\ LNG(s,d) + \sum_{s,d} LiquefactionCost(s)\ x\ LNG(s,d)$$

where,

LiquefactionCost(s) = Cost to liquefy natural gas in region s + transport the gas from the wellhead to the liquefaction facility within region s.

RegasCost(d) = Cost to re-gasify natural gas in region d + transport the gas from the regasification facility to the city gate within region d.

PipelineCost(s,d) = Cost to transport natural gas along a pipeline from supply region s to demand region d.

ShipCost(s,d) = Cost to ship natural gas from supply region s to demand region d.

Quota = Maximum allowable amount of U.S. LNG exports. This varies by time period and scenario.

The supply curves capture the technological issues (penetration rate, availability and cost) for natural gas in each region. The demand curves for natural gas capture the change in utility from consuming natural gas.

The main constraints are applied to all cases while scenario constraints are case specific. The demand shocks are modeled by changing the baseline level of natural gas demand ($Demand_0(d)$).

B. N_{ew}ERA Model

1. Overview of the N_{ew}ERA Macroeconomic Model

The N_{ew}ERA macro model is a forward-looking, dynamic, computable general equilibrium model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. The economic interactions are based on the IMPLAN[53] 2008 database for a benchmark year, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to the most recent AEO produced by the Energy Information Administration (EIA). Because the model is calibrated to an internally-consistent energy forecast, the use of the model is particularly well-suited to analyze economic and energy policies and environmental regulations.

2. Model Data (IMPLAN and EIA)

The economic data is taken from the IMPLAN 2008 database which includes balanced Social Accounting Matrices for all states in 2008. These inter-industry matrices provide a snapshot of the economy. Since the IMPLAN database contains only economic values, we benchmark energy supply, demand, trade, and prices to EIA historical statistics to capture the physical energy flows. The integration of the EIA energy quantities and prices into the IMPLAN economic database results in a balanced energy-economy dataset.

Future economic growth is calibrated to macroeconomic (GDP), energy supply, energy demand, and energy price forecasts from the EIA's AEO 2011. Labor productivity, labor growth, and population forecasts from the Census Bureau are used to project labor endowments along the baseline and ultimately employment by industry.

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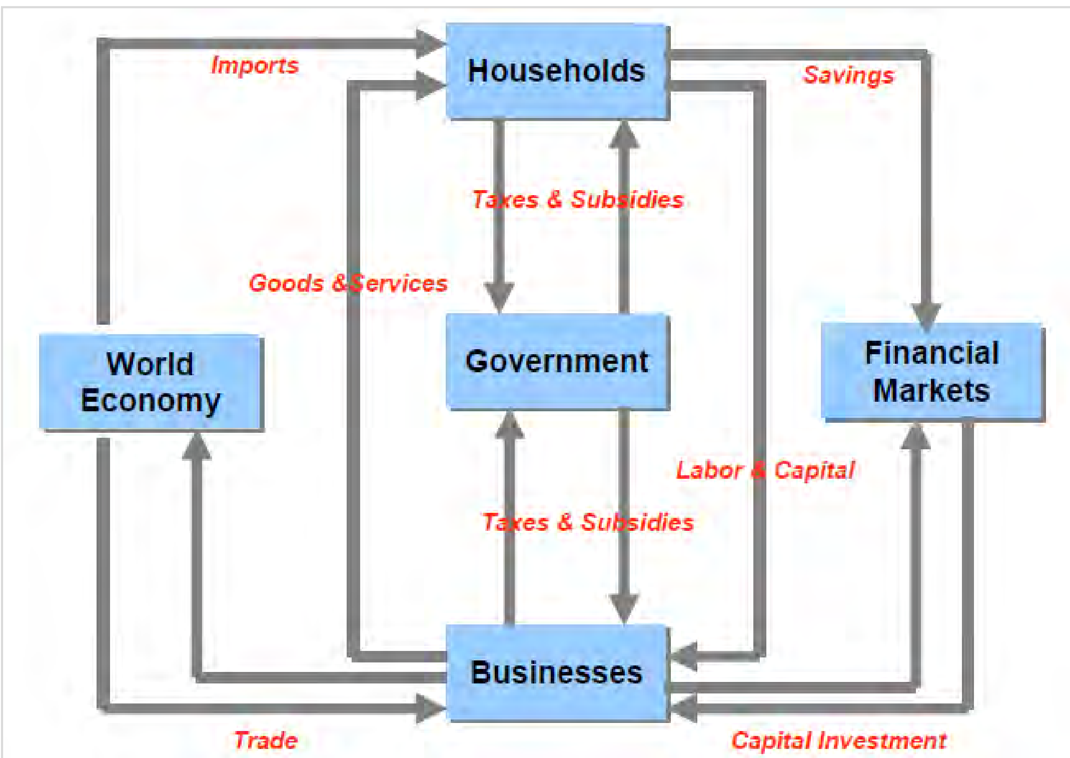
53 IMPLAN produces unique set of national structural matrices. The structural matrices form the bais for the inter-industry flows which we use to characterize the production, household, and government transactions, see www.implan.com.

3. Brief Discussion of Model Structure

The theoretical construct behind the N$_{ew}$ERA model is based on the circular flow of goods, services, and payments in the economy (every economic transaction has a buyer and a seller whereby goods/service go from a seller to a buyer and payment goes from the seller to the buyer). As shown in Figure 72, the model includes households, businesses, government, financial markets, and the rest of the world economy as they interact economically in the global economy. Households provide labor and capital to businesses, taxes to the government, and savings to financial markets, while also consuming goods and services and receiving government subsidies. Businesses produce goods and services, pay taxes to the government and use labor and capital. Businesses are both consumers and producers of capital for investment in the rest of the economy. Within the circular flow, equilibrium is found whereby goods and services consumed is equal to those produced and investments are optimized for the long term. Thus, supply is equal to demand in all markets.

The model assumes a perfect foresight, zero profit condition in production of goods and services, no changes in monetary policy, and full employment within the U.S. economy.

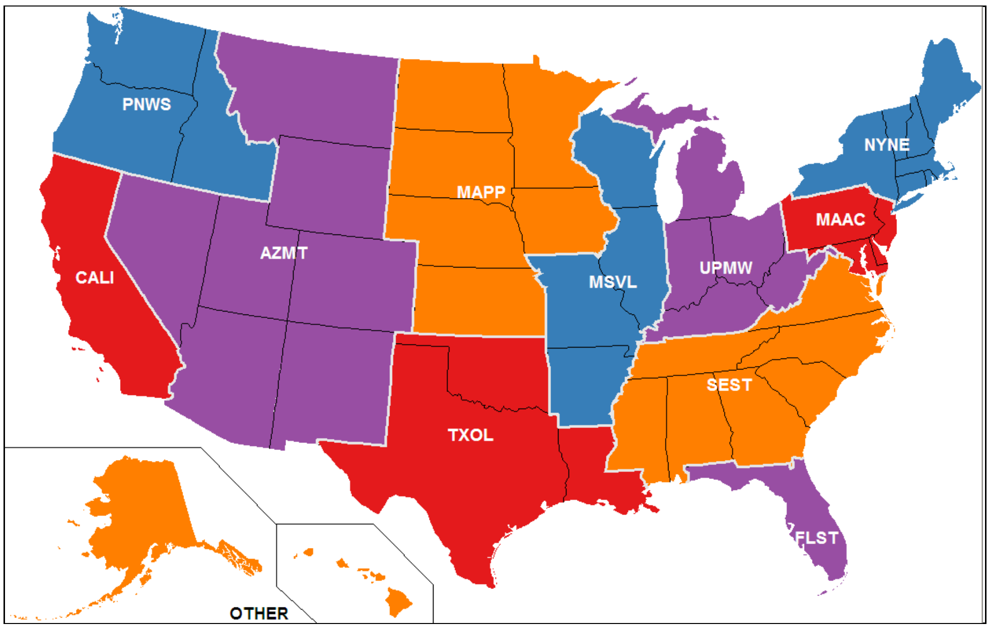
Figure 72: Circular Flow of Income



a. Regional Aggregation

The N$_{ew}$ERA macro model includes 11 regions: NYNE-New York and New England; MAAC-Mid-Atlantic Coast; UPMW-Upper Mid-West; SEST-South East; FLST-Florida; MSVL-Mississippi Valley; MAPP-Mid America; TXOL-Texas, Oklahoma, and Louisiana; AZMT-Arizona and Mountain states; CALI-California; and PNWS-Pacific Northwest.54 The aggregate model regions are built up from the 50 U.S. states' and the District of Columbia's economic data. The model is flexible enough to create other regional specifications, depending upon the need of the project. The 11 N$_{ew}$ERA regions and the States within each N$_{ew}$ERA region are shown in the following figure. For this Study we aggregate the 11 N$_{ew}$ERA regions into a single U.S. region.

Figure 73: N$_{ew}$ERA Macroeconomic Regions



b. Sectoral Aggregation

The N$_{ew}$ERA model includes 12 sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and seven non-energy sectors (services, manufacturing, energy-intensive, agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors to 28 sectors, defined as the AEO sector in Figure 74. These 28 sectors' economic and energy data are consistent with IMPLAN and EIA, respectively. For this study, we further aggregate these 28 production sectors into 12 sectors. The mapping of the sectors is show below in Figure 72. The model has the flexibility to represent sectors at any level of aggregation.

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[54] Hawaii and Alaska are included in the PNWS region.

Figure 74: N$_{ew}$ERA Sectoral Representation

	NewERA	AEO	
Final Demand	C	C	Household consumption
	G	G	Government consumption
	I	I	Investment demand
Energy Sectors	COL	COL	Coal
	GAS	GAS	Natural gas
	OIL	OIL	Refined Petroleum Products
	CRU	CRU	Crude oil
	ELE	ELE	Electricity
Non-Energy Sectors	AGR	AGR	Agriculture
	TRN	TRN	Transportation
	TRK	TRK	Trucking
	M_V	M_V	Motor vehicle
	SRV	SRV	Services
	SRV	DWE	Dwellings
	EIS	PAP	Paper and Pulp
	EIS	CHM	Chemicals
	EIS	GLS	Glass Industry
	EIS	CMT	Cement Industry
	EIS	I_S	Primary Metals
	EIS	ALU	Alumina and Aluminum
	MAN	CNS	Construction
	MAN	MIN	Mining
	MAN	FOO	Food, Beverage and Tobacco Products
	MAN	FAB	Fabricated Metal Products
	MAN	MAC	Machinery
	MAN	CMP	Computer and Electronic Products
	MAN	TRQ	Transportation Equipment
	MAN	ELQ	Electrical Equip., Appliances, and Components
	MAN	WOO	Wood and furniture
	MAN	PLA	Plastics
	MAN	OMA	Other Manufacturing sectors

c. Production and Consumption Characterization

Behavior of households, industries, investment, and government is characterized by nested constant elasticity of substitution production or utility functions. Under such a CES structure, inputs substitute against each other in a nested form. The ease of substitutability is determined by the value of the elasticity of substitution between the inputs. The higher the value of the substitution elasticity between the inputs, the greater the possibility of tradeoffs.

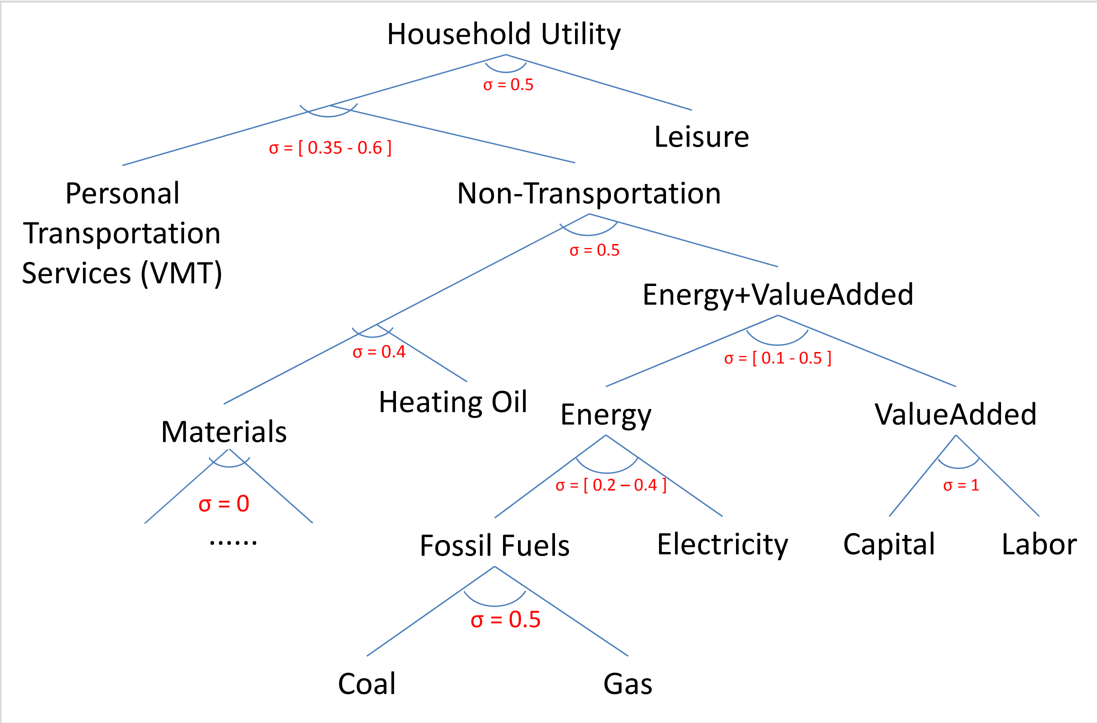
The CES nesting structure defines how inputs to a production activity compete with each other. In the generic production structure, intermediate inputs are aggregated in fixed proportion with a composite of energy and value-added inputs. The energy input aggregates fossil and non-fossil energy sources, and the value-added input combines capital and labor. Sectors with distinctive production characteristics are represented with structures different from the generic form. For alternative transportation fuels, such as ethanol and bio-diesel, inputs are demanded in fixed proportion. The characterization of nonrenewable resource supply adds a fixed resource that is calibrated to a declining resource base over time, so that it implies decreasing returns to scale.

This also implies rising marginal costs of production over time for exhaustible resources. The detailed nesting structure of the households and production sectors, with assumed elasticity of substitution parameters, are shown in figures below.

i. Households

Consumers are represented by a single representative household. The representative household derives utility from both consumption of goods and services, transportation services, and leisure. The utility is represented by a nested CES utility function. The elasticity of substitution parameters between goods are shown in Figure 75.

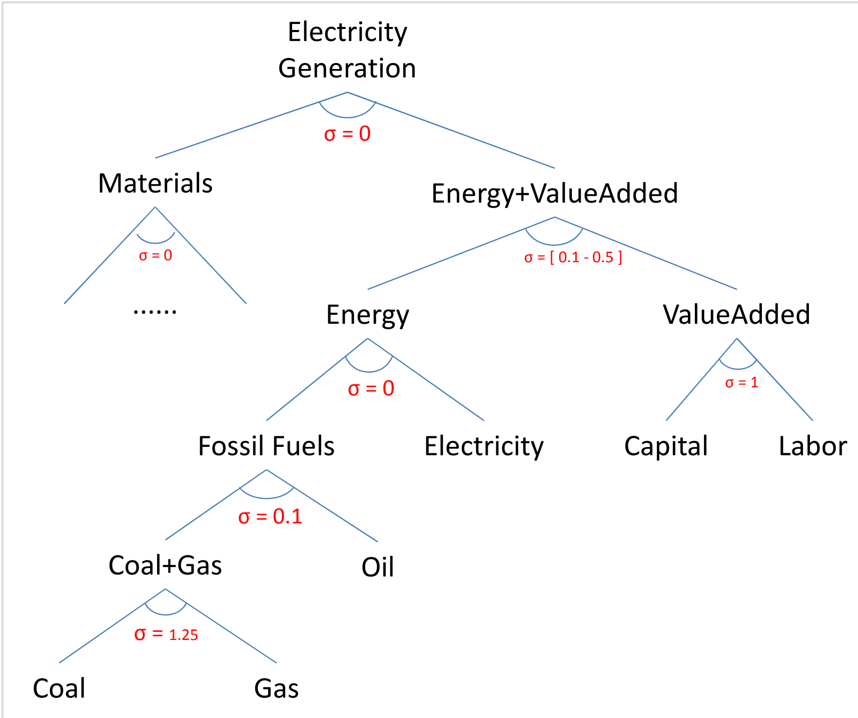
Figure 75: N$_{ew}$ERA Household Representation



ii. Electric Sector

We assume a simple representation of the electric sector. The electric sector models natural gas, coal, and oil-fired generation. The representation of the production is shown below.

Figure 76: N_{ew}ERA Electricity Sector Representation



iii. Other Sectors

The trucking and commercial transportation sector production structure is shown in Figure 77. The trucking sector uses diesel as transportation fuel. This sector has limited ability to substitute other fossil fuels. The other industrial sectors (agriculture, manufacturing, energy-intensive, motor vehicles) and the services sector production structure, with assumed elasticity of substitution, are shown in Figure 78.

Figure 77: N$_{ew}$ERA Trucking and Commercial Transportation Sector Representation

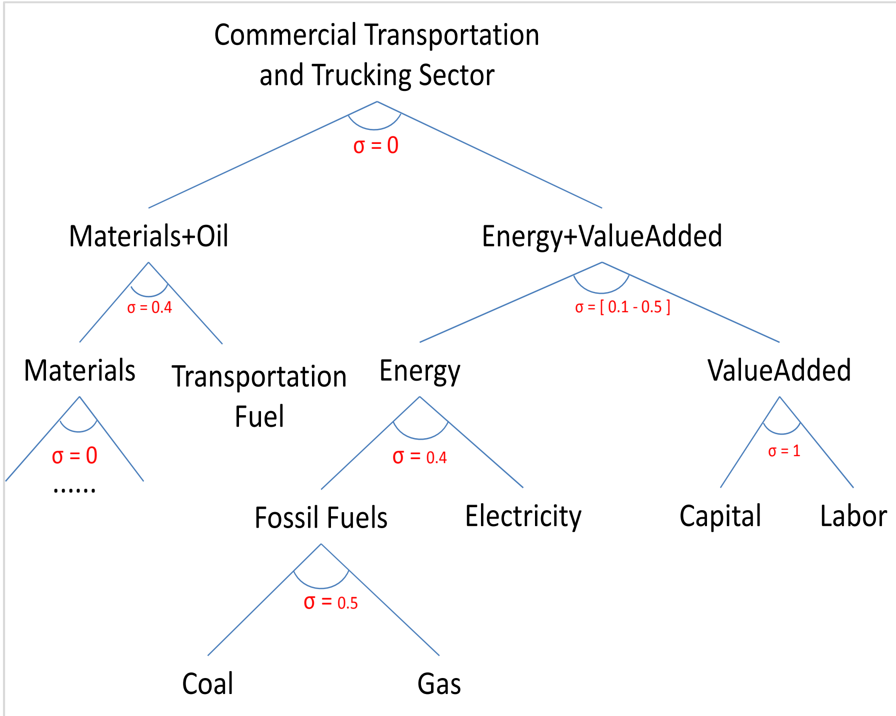
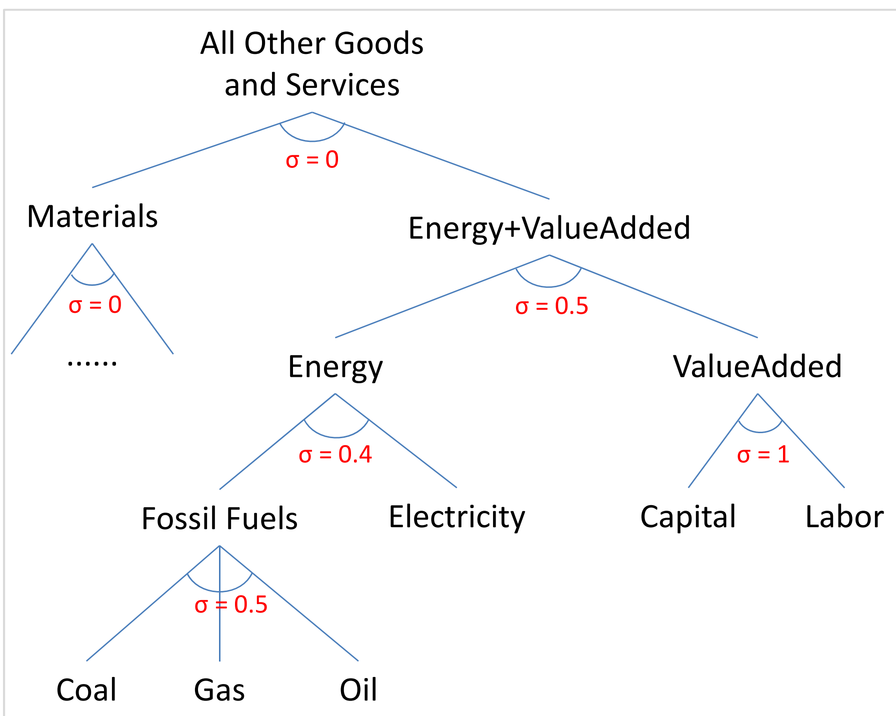


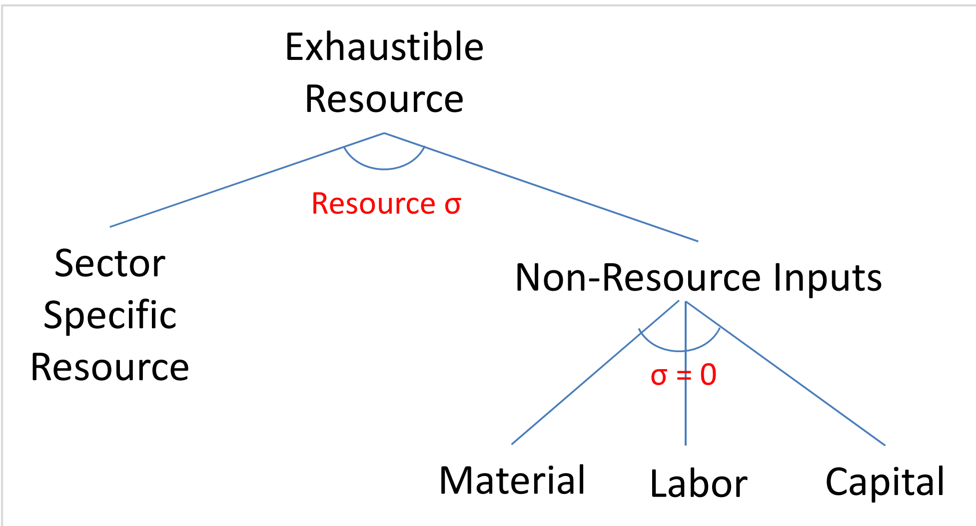
Figure 78: N$_{ew}$ERA Other Production Sector Representation



iv. Exhaustible Resource Sector

The simplest characterization of non-renewable resource supply adds a fixed resource that is calibrated to decline over time, so that the decreasing returns to scale implied for the non-resource inputs lead to rising marginal costs of production over time. The top level elasticity of substitution parameter is calibrated to be consistent with resource supply elasticity. We assume natural gas resource supply elasticity to be 0.25 in the short run (2010) and 1.5 in the long run (2050). Similarly, crude oil supply elasticity is assumed to be 0.3 in 2010 and 1.0 in 2050. Coal supply elasticity is assumed to be 0.4 in 2010 and 1.5 in 2050. The production structure of natural gas, crude oil, and coal is shown below.

Figure 79: N$_{ew}$ERA Resource Sector Representation



d. Trade Structure

All goods and services, except crude oil, are treated as Armington goods, which assumes that domestic and foreign goods are differentiated and thus, are imperfect substitutes. The level of imports depends upon the elasticity of substitution between the imported and domestic goods. The Armington elasticity among imported goods is assumed to be twice as large as the elasticity between domestic and aggregate imported goods, characterizing greater substitutability among imported goods.

We balance the international trade account in the N$_{ew}$ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. This prevents distortions in economic effects that would result from perpetual increases in borrowing, but does not overly constrain the model by requiring current account balances in each year.

This treatment of the current account deficit does not mean that there cannot be trade benefits from LNG exports. Although trade will be in balance over time, the terms of trade shift in favor of the U.S. because of LNG exports. That is, by exporting goods of greater value to overseas customers, the U.S. is able to import larger quantities of goods than it would able to if the same domestic resources were devoted to producing exports of lesser value. Allowing high value exports to proceed has a similar effect on terms of trade as would an increase in the world price of existing exports or an increase in productivity in export industries. In all these cases, the U.S. gains more imported goods in exchange for the same amount of effort being devoted to production of goods for export. The opposite is also possible, in that a fall in the world price of U.S. exports or a subsidy that promoted exports of lesser value would move the terms of trade against the U.S., in that with the same effort put into producing exports the U.S. would receive less imports in exchange and terms of trade would move against the U.S. The fact that LNG will be exported only if there is sufficient market demand ensures that terms of trade will improve if LNG exports take place.

e. Investment Dynamics

Periods in the model are linked by capital and investment dynamics. Capital turnover in the model is represented by the standard process that capital at time t+1 equals capital at time t plus investment at time t minus depreciation. The model optimizes consumption and savings decisions in each period, taking account of changes in the economy over the entire model horizon with perfect foresight. The consumers forego consumption to save for current and future investment.

f. Model Assumptions

The underlying assumptions of labor growth and initial capital stock drive the economy over time in the model.

The model assumes full employment in the labor market. This assumption means total labor demand in a policy scenario would be the same as the baseline labor projection. The baseline labor projections are based on population growth and labor productivity forecasts over time. Hence, the labor projection can be thought to be a forecast of efficient labor units. The model assumes that labor is fungible across sectors. That is, labor can move freely out of a production sector into another sector without any adjustment costs or loss of productivity. Capital, on the other hand, is vintaged in the model. We assume two types of capital stock to portray the current technology and more advanced technologies that develop over time. A non-malleable capital (the clay) is used in fixed proportion in the existing production activity. The clay portion of the capital decays over time as new capital replaces it. A malleable capital (the putty) is used in new production activity. The putty capital in the new production activity can substitute against other inputs. The replacement of the clay capital depends upon the extent of use of new capital. This gradual capital turnover of the fixed capital stock and costs associated with it is represented by the putty-clay formulation.

Energy intensities are calibrated to the EIA projections. The differentiated energy intensities across regions result in different responses in energy supply and demand as energy price changes.

The $\mathrm{N_{ew}}$ERA macroeconomic model includes a simple tax representation. The model includes only two types of input taxes: marginal tax rates on capital and labor. The tax rates are based on the NBER TAXSIM model. Other indirect taxes such as excise and sales are included in the output values and not explicitly modeled.

The N_{ew}ERA macro model is solved through 2050, starting from 2010 in five-year time intervals.

g. Some Key Model Features

There are great uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA model is designed explicitly to address the key factors affecting future natural gas demand supply, and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on the domestic markets, the N_{ew}ERA model includes resource supply curves for U.S. natural gas. The model also accounts for foreign imports, in particular pipeline imports from Canada, and the potential build-up of liquefaction plants for LNG exports. N_{ew}ERA also has a supply (demand) curve for U.S. imports (exports) that represents how the global LNG market price would react to changes in U.S. imports or exports. On a practical level, there are also other important uncertainties about the ownership of LNG plants and how the LNG contracts will be formulated. These have important consequences on how much revenue can be earned by the U.S. and hence overall macroeconomic impacts. In the N_{ew}ERA model it is possible to represent these variations in domestic versus foreign ownership of assets and capture of export revenues to better understand the issues.

In addition, we assume that natural gas is a homogenous good, similar to crude oil price. Hence, if there was a no-export constraint on LNG exports, domestic natural gas price will converge with the world net-back price.

Consumption of electricity as a transportation fuel could also affect the natural gas market. The N_{ew}ERA model is able to simulate impacts on the supply and disposition of transportation fuels (petroleum-based, biofuels, and electricity), along with responses to the personal driving behavior of the consumer. The personal driving or personal transportation services in the model is represented by Vehicle Miles Traveled (“VMT”), which takes vehicles’ capital, transportation fuels, and other driving expenditures as inputs. The model chooses among changes in consumption of transportation fuels, changes in vehicle fuel efficiency, and changes in the overall level of travel in response to changes in the transportation fuel prices.

h. Advantages of the Macro Model Framework

The N_{ew}ERA model incorporates EIA energy quantities and energy prices into the IMPLAN Social Accounting Matrices. This in-house developed approach results in a balanced energy-economy dataset that has internally consistent energy benchmark data, as well as IMPLAN consistent economic values.

The macro model incorporates all production sectors and final demanders of the economy and is linked through terms of trade. The effects of policies are transmitted throughout the economy as all sectors and agents in the economy respond until the economy reaches equilibrium. The ability of the model to track these effects and substitution possibilities across sectors and regions makes it a unique tool for analyzing policies, such as those involving energy and environmental regulations. These general equilibrium substitution effects, however, are not fully captured in a partial equilibrium framework or within an input-output modeling framework. The smooth production and consumption functions employed in this general equilibrium model enable gradual substitution of inputs in response to relative price changes, thus, avoiding all or nothing solutions.

Business investment decisions are informed by future policies and outlook. The forward looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment while anticipating future policies with perfect foresight. The alternative approach on savings and investment decisions is to assume agents in the model are myopic, thus, have no expectations for the future. Though both approaches are equally unrealistic to a certain extent, the latter approach can lead the model to produce inconsistent or incorrect impacts from an announced future policy.

The CGE modeling tool such as the N$_{ew}$ERA macro model can analyze scenarios or policies that call for large shocks outside historical observation. Econometric models are unsuitable for policies that impose large impacts because these models' production and consumption functions remain invariant under the policy. In addition, econometric models assume that the future path depends on the past experience and therefore fail to capture how the economy might respond under a different and new environment. For example, an econometric model cannot represent changes in fuel efficiency in response to increases in energy prices. However, the N$_{ew}$ERA macro model can consistently capture future policy changes that envisage having large effects.

The N$_{ew}$ERA macro model is also a unique tool that can iterate over sequential policies to generate consistent equilibrium solutions starting from an internally consistent equilibrium baseline forecast (such as the AEO reference case). This ability of the model is particularly helpful to decompose macroeconomic effects of individual policies. For example, if one desires to perform economic analysis of a policy that includes multiple regulations, the N$_{ew}$ERA modeling framework can be used as a tool to layer in one regulation at a time to determine the incremental effects of each policy.

i. Model Outputs

The N$_{ew}$ERA model outputs include supply and demand of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, disposable income, and changes in income from labor, capital, and resources.

APPENDIX C – TABLES AND MODEL RESULTS

In this section, we present the numerical results from both the Global Natural Gas Model and the U.S. macroeconomic model ("N_{ew}ERA") for all the scenarios that were run as part of the study.

A. Global Natural Gas Model

We evaluated a total of 63 cases with all possible combinations of the following:

- Three domestic outlooks: Reference ("USREF"), High Shale EUR ("HEUR"), Low Shale EUR ("LEUR"),
- Three international outlooks: Reference ("INTREF"), Demand Shock ("D"), Supply/Demand Shock ("SD"), and
- Seven quota schedules: No-Export Capacity ("NX"), Low/Slowest ("LSS"), Low/Slow ('LS"), Low/Rapid ("LR"), High/Slow ("HS"), High/Rapid ("HR"), No-Export Constraint ("NC").

Out of the 45 cases where a quota is enforced, 21 are feasible (*i.e.*, projected U.S. LNG exports are at a level comparable to the quota allotted for each year), as shown in Figure 80. Detailed results for each case are shown in Figure 81 through Figure 143.

The U.S. Reference, International Reference, and the No-Export Capacity cases (Figure 81) are the ultimate baselines to which all other GNGM cases are compared. It assumes no U.S. and Canadian export capacities. After allowing for North American exports in the baseline scenario (Figure 87), our model determines that the U.S. does not export LNG, despite unlimited liquefaction capacities. Running the International Reference outlook with all three domestic outlooks, GNGM found that the U.S. is only able to export under the High Shale EUR scenario (Figure 87, Figure 108, and Figure 129). The projected level of exports is short of the high quotas specified by the EIA, even in the High Shale EUR case. We have thus developed two international shocks that favor U.S. LNG export.

The No-Export Constraint series shows the optimal amounts of U.S. exports under each domestic and international outlook as determined in GNGM. Since GNGM assumes a perfectly-competitive natural gas market, all quota rents are zero if the No-Export Constraint is in effect. A positive rent is collected, however, when the country supplies less than its perfectly-competitive volumes – Figure 105 is one example. When the number of export licenses available is greater than the optimal export level as determined by the natural gas market, the remaining licenses are unutilized and export rent drops to zero (Figure 93). The quota rent per MMBtu reaches the maximum under the High Shale EUR, Supply/Demand Shock, Low/Slowest quota scenario, where the conditions for U.S. exports are most favorable. However, the quota is highly restrictive (Figure 117). A high marginal price on an additional unit of export quota is thus generated.

Figure 80: Scenario Tree with Feasible Cases Highlighted

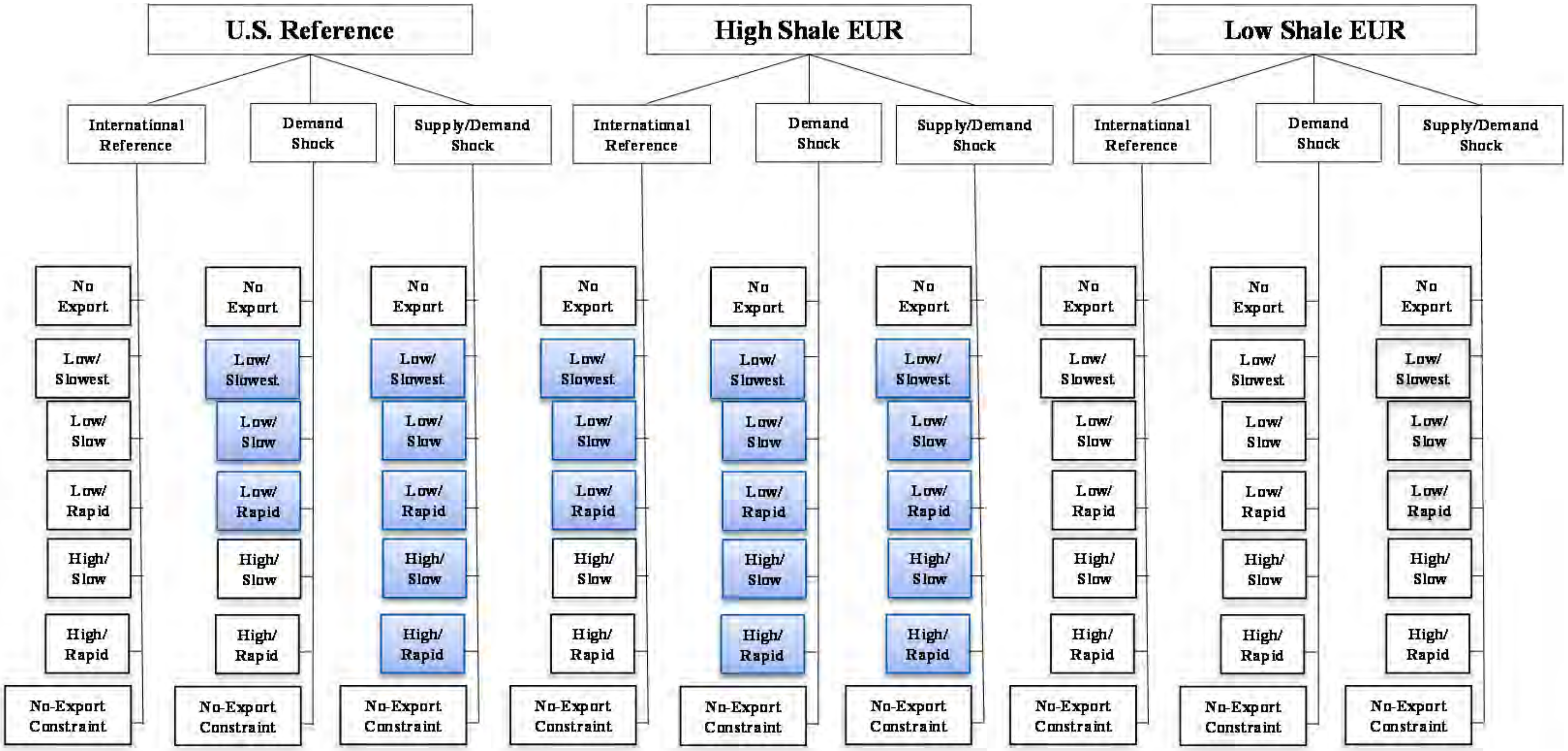


Figure 81: Detailed Results from Global Natural Gas Model, USREF_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$0.07**	**-**	**-**	**-**	**-**

Figure 82: Detailed Results from Global Natural Gas Model, USREF_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 83: Detailed Results from Global Natural Gas Model, USREF_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$//Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$//Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 84: Detailed Results from Global Natural Gas Model, USREF_INTREF_LR

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$//Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 85: Detailed Results from Global Natural Gas Model, USREF_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 86: Detailed Results from Global Natural Gas Model, USREF_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 87: Detailed Results from Global Natural Gas Model, USREF_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.00	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.14	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	0.14	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.15**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.10	22.45	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.28**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.28**	**$4.33**	**$5.11**	**$5.13**	**$5.45**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 88: Detailed Results from Global Natural Gas Model, USREF_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.11**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$0.62**	**$0.53**	**$0.81**	**$0.68**	**$0.77**

Figure 89: Detailed Results from Global Natural Gas Model, USREF_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.98	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	0.96	1.30	1.19	1.37
China/India	-	0.06	0.26	0.40	0.38	0.41
Europe	-	0.07	0.25	0.47	0.39	0.50
Korea/Japan	-	0.06	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.16**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.46	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.46**	**-**	**-**	**-**	**-**

Figure 90: Detailed Results from Global Natural Gas Model, USREF_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 91: Detailed Results from Global Natural Gas Model, USREF_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 92: Detailed Results from Global Natural Gas Model, USREF_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.87	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	0.96	1.30	1.19	1.37
China/India	-	0.11	0.26	0.40	0.38	0.41
Europe	-	0.15	0.24	0.47	0.39	0.50
Korea/Japan	-	0.11	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.24**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.1	22.54	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**$0.35**	**-**	**-**	**-**	**-**

Figure 93: Detailed Results from Global Natural Gas Model, USREF_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.25	0.47	0.39	0.50
Korea/Japan	-	0.25	0.45	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 94: Detailed Results from Global Natural Gas Model, USREF_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Demand	23.86	24.50	24.80	24.51	25.43	26.04
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.02	0.96	1.30	1.19	1.37
China/India	-	0.22	0.26	0.40	0.38	0.41
Europe	-	0.55	0.24	0.47	0.39	0.50
Korea/Japan	-	0.25	0.46	0.43	0.41	0.46
Total Supply (Tcf)	**23.86**	**25.52**	**25.76**	**25.81**	**26.61**	**27.40**
Domestic Production	21.10	22.82	23.86	24.71	25.81	27.30
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Netback Price (2010$/Mcf)	**-**	**$4.58**	**$4.86**	**$5.78**	**$6.07**	**$6.66**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 95: Detailed Results from Global Natural Gas Model, USREF_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Demand	23.86	25.09	25.28	25.08	25.88	26.48
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**25.09**	**25.28**	**25.08**	**25.88**	**26.48**
Domestic Production	21.1	22.39	23.38	23.98	25.08	26.38
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.23**	**$4.58**	**$5.42**	**$5.80**	**$6.41**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$1.60**	**$4.62**	**$4.61**	**$2.83**	**$2.92**

Figure 96: Detailed Results from Global Natural Gas Model, USREF_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Demand	23.86	24.98	24.73	24.20	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.24	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.62	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.16**	**25.83**	**26.21**	**27.25**	**27.97**
Domestic Production	21.1	22.46	23.93	25.11	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.29**	**$4.91**	**$5.99**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.36**	**$1.38**	**$1.23**	**$1.20**	**$1.62**

Figure 97: Detailed Results from Global Natural Gas Model, USREF_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.87	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.54	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 98: Detailed Results from Global Natural Gas Model, USREF_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Demand	23.86	24.46	24.19	24.13	25.06	25.78
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**25.56**	**26.38**	**26.32**	**27.25**	**27.97**
Domestic Production	21.1	22.86	24.48	25.22	26.45	27.87
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.25**	**$6.04**	**$6.30**	**$6.82**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**$0.52**	**$1.11**	**$1.20**	**$1.62**

Figure 99: Detailed Results from Global Natural Gas Model, USREF_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.87	24.19	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	0.37	2.19	3.93	4.38	4.38
China/India	-	0.11	0.33	0.83	0.93	0.75
Europe	-	0.13	0.35	0.77	0.27	0.59
Korea/Japan	-	0.13	1.51	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.24**	**26.38**	**27.32**	**28.65**	**29.50**
Domestic Production	21.1	22.54	24.48	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.35**	**$5.25**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.24**	**$0.52**	**-**	**$0.08**	**$0.67**

Figure 100: Detailed Results from Global Natural Gas Model, USREF_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Demand	23.86	24.46	23.83	23.39	24.27	25.12
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	1.10	2.92	3.93	4.38	4.38
China/India	-	0.26	0.46	0.83	0.93	0.75
Europe	-	0.43	0.74	0.77	0.27	0.59
Korea/Japan	-	0.40	1.72	2.34	3.17	3.03
Total Supply (Tcf)	**23.86**	**25.56**	**26.75**	**27.32**	**28.65**	**29.50**
Domestic Production	21.10	22.86	24.85	26.22	27.85	29.40
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.61**	**$5.49**	**$6.57**	**$6.82**	**$7.24**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.49**	**$6.57**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$0.74**	**-**	**-**	**$0.08**	**$0.67**

Figure 101: Detailed Results from Global Natural Gas Model, USREF_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Demand	23.86	23.85	23.83	23.39	24.21	24.73
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	2.17	2.92	3.93	4.54	5.75
China/India	-	0.39	0.39	0.83	0.97	1.04
Europe	-	0.99	0.41	0.77	0.29	0.74
Korea/Japan	-	0.80	2.12	2.34	3.28	3.97
Total Supply (Tcf)	**23.86**	**26.02**	**26.75**	**27.32**	**28.76**	**30.47**
Domestic Production	21.10	23.32	24.85	26.22	27.96	30.37
Pipeline Imports from Canada	2.33	2.33	1.40	0.74	0.64	0.04
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Netback Price (2010$/Mcf)	**-**	**$5.02**	**$5.49**	**$6.57**	**$6.86**	**$7.50**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 102: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent (2010$/Mcf)	**-**	**$1.03**	**$1.02**	**$1.21**	**$0.91**	**$0.92**

Figure 103: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	-	0.11	0.65	0.74	0.69
Europe	-	0.18	0.99	1.02	1.30	1.35
Korea/Japan	-	-	0.00	0.34	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.49	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.01	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.24**	**$4.23**	**$4.94**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.93**	**$0.57**	**$0.53**	**$0.18**	**$0.32**

Figure 104: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	0.37	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 105: Detailed Results from Global Natural Gas Model, HEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	-	0.38	0.70	0.74	0.69
Europe	-	1.10	1.71	1.12	1.30	1.35
Korea/Japan	-	-	0.10	0.37	0.14	0.15
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.10	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.13**	**$4.92**	**$5.00**	**$5.48**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**$0.24**	**$0.48**	**$0.18**	**$0.32**

Figure 106: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.78	26.61	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	3.77	2.78	3.38
China/India	-	-	0.38	1.06	0.89	1.01
Europe	-	0.37	1.71	1.99	1.73	2.22
Korea/Japan	-	-	0.10	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	24.77	27.43	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.41	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.09	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.21**	**$4.13**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.85**	**$0.24**	**-**	**-**	**-**

Figure 107: Detailed Results from Global Natural Gas Model, HEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	26.37	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.97	3.77	2.78	3.38
China/India	-	-	0.72	1.06	0.89	1.01
Europe	-	1.10	1.96	1.99	1.73	2.22
Korea/Japan	-	-	0.28	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.47**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.1	25.09	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$4.08**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**$0.53**	**-**	**-**	**-**	**-**

Figure 108: Detailed Results from Global Natural Gas Model, HEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Demand	23.86	25.76	26.24	26.26	27.60	28.69
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	2.23	2.97	3.77	2.78	3.38
China/India	-	0.08	0.71	1.06	0.89	1.01
Europe	-	2.14	1.99	1.99	1.73	2.22
Korea/Japan	-	0.00	0.27	0.72	0.16	0.16
Total Supply (Tcf)	**23.86**	**27.98**	**29.21**	**30.04**	**30.56**	**32.75**
Domestic Production	21.10	25.60	27.84	29.67	30.40	32.69
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.35	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.15	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Netback Price (2010$/Mcf)	**-**	**$3.86**	**$4.07**	**$4.76**	**$4.91**	**$5.31**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 109: Detailed Results from Global Natural Gas Model, HEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	0.00	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent (2010$/Mcf)	**-**	**$1.58**	**$1.67**	**$2.20**	**$2.01**	**$2.30**

Figure 110: Detailed Results from Global Natural Gas Model, HEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	**2015**	**2020**	**2025**	**2030**	**2035**
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.28	0.59	0.68	0.63
Europe	-	0.07	0.28	0.75	0.72	0.84
Korea/Japan	-	0.06	0.54	0.67	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.1	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.75**	**$4.80**	**$5.55**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.44**	**$1.15**	**$1.15**	**$0.80**	**$1.15**

Figure 111: Detailed Results from Global Natural Gas Model, HEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.47	0.64	0.68	0.63
Europe	-	0.15	0.63	0.81	0.72	0.84
Korea/Japan	-	0.11	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 112: Detailed Results from Global Natural Gas Model, HEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.23	0.47	0.64	0.68	0.63
Europe	-	0.61	0.63	0.81	0.72	0.84
Korea/Japan	-	0.26	1.10	0.73	0.79	0.72
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.60**	**$5.51**	**$5.61**	**$6.31**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**$0.71**	**$1.07**	**$0.80**	**$1.15**

Figure 113: Detailed Results from Global Natural Gas Model, HEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.47	1.08	1.28	1.18
Europe	-	0.15	0.63	1.54	1.61	1.67
Korea/Japan	-	0.11	1.10	1.41	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.01	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.35	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.71**	**$4.60**	**$5.08**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.35**	**$0.71**	**$0.27**	**$0.07**	**$0.33**

Figure 114: Detailed Results from Global Natural Gas Model, HEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.79	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	3.94	4.38	4.38	4.38
China/India	-	0.23	0.71	1.13	1.28	1.18
Europe	-	0.61	1.57	1.69	1.61	1.67
Korea/Japan	-	0.26	1.66	1.56	1.49	1.52
Total Supply (Tcf)	**23.86**	**27.47**	**29.73**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.36	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.00	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.30**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$4.56**	**$4.30**	**$5.04**	**$5.24**	**$5.77**
Quota Rent (2010$/Mcf)	**-**	**$1.01**	**-**	**$0.15**	**$0.07**	**$0.33**

Figure 115: Detailed Results from Global Natural Gas Model, HEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Demand	23.86	25.18	25.79	25.83	26.98	28.06
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	3.30	3.94	4.87	4.59	5.61
China/India	-	0.43	0.70	1.20	1.33	1.52
Europe	-	2.30	1.79	1.88	1.71	2.19
Korea/Japan	-	0.58	1.45	1.79	1.55	1.90
Total Supply (Tcf)	**23.86**	**28.47**	**29.73**	**30.69**	**31.75**	**34.35**
Domestic Production	21.10	26.09	28.36	30.32	31.59	34.29
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	0.06
C & S America	0.21	0.37	0.50	-	0.16	-
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.36	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Netback Price (2010$/Mcf)	**-**	**$4.18**	**$4.30**	**$4.99**	**$5.21**	**$5.60**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 116: Detailed Results from Global Natural Gas Model, HEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Demand	23.86	26.98	27.66	27.82	28.60	29.71
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**26.98**	**27.66**	**27.82**	**28.78**	**30.39**
Domestic Production	21.1	24.60	26.29	27.45	28.62	30.33
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.27**	**$3.43**	**$4.03**	**$4.47**	**$4.88**
Netback Price (2010$/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent (2010$/Mcf)	**-**	**$2.56**	**$5.77**	**$6.01**	**$4.16**	**$4.45**

Figure 117: Detailed Results from Global Natural Gas Model, HEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Demand	23.86	26.88	27.13	26.98	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.18	1.10	2.01	2.19	2.19
China/India	-	0.06	0.23	0.51	0.55	0.46
Europe	-	0.06	0.24	0.48	0.14	0.37
Korea/Japan	-	0.06	0.63	1.02	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.06**	**28.23**	**28.99**	**30.18**	**31.91**
Domestic Production	21.10	24.68	26.86	28.62	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.31**	**$3.66**	**$4.41**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.65**	**$6.29**	**$7.22**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.34**	**$2.63**	**$2.81**	**$2.69**	**$3.28**

Figure 118: Detailed Results from Global Natural Gas Model, HEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.78	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	2.19	2.19	2.19
China/India	-	0.11	0.33	0.54	0.55	0.46
Europe	-	0.13	0.35	0.51	0.14	0.37
Korea/Japan	-	0.13	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	24.77	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 119: Detailed Results from Global Natural Gas Model, HEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Demand	23.86	26.37	26.61	26.90	27.81	29.04
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	2.19	2.19	2.19	2.19
China/India	-	0.26	0.33	0.54	0.55	0.46
Europe	-	0.43	0.35	0.51	0.14	0.37
Korea/Japan	-	0.40	1.51	1.14	1.50	1.36
Total Supply (Tcf)	**23.86**	**27.47**	**28.80**	**29.09**	**30.18**	**31.91**
Domestic Production	21.1	25.09	27.43	28.72	30.02	31.85
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$3.89**	**$4.44**	**$4.82**	**$5.16**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$5.77**	**$7.15**	**$7.50**	**$8.43**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$1.88**	**$2.71**	**$2.69**	**$3.28**

Figure 120: Detailed Results from Global Natural Gas Model, HEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Demand	23.86	26.78	26.61	26.16	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	0.37	2.19	4.02	4.38	4.38
China/India	-	0.11	0.33	0.84	0.93	0.75
Europe	-	0.13	0.35	0.78	0.27	0.59
Korea/Japan	-	0.13	1.51	2.39	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.15**	**28.80**	**30.18**	**31.61**	**33.46**
Domestic Production	21.1	24.77	27.43	29.81	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.36**	**$3.89**	**$4.81**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.59**	**$5.77**	**$6.54**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$2.23**	**$1.88**	**$1.73**	**$1.73**	**$2.47**

Figure 121: Detailed Results from Global Natural Gas Model, HEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Demand	23.86	26.37	25.59	26.02	27.05	28.40
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	1.10	4.38	4.38	4.38	4.38
China/India	-	0.26	0.55	0.91	0.93	0.75
Europe	-	0.43	0.65	0.83	0.27	0.59
Korea/Japan	-	0.40	3.18	2.63	3.17	3.03
Total Supply (Tcf)	**23.86**	**27.47**	**29.97**	**30.40**	**31.61**	**33.46**
Domestic Production	21.1	25.09	28.60	30.03	31.45	33.40
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$3.55**	**$4.41**	**$4.89**	**$5.18**	**$5.44**
Netback Price (2010$/Mcf)	**-**	**$5.35**	**$4.93**	**$6.41**	**$6.91**	**$7.91**
Quota Rent (2010$/Mcf)	**-**	**$1.80**	**$0.52**	**$1.53**	**$1.73**	**$2.47**

Figure 122: Detailed Results from Global Natural Gas Model, HEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Demand	23.86	24.68	25.10	25.11	26.22	27.31
Pipeline Exports to Canada	-	-	-	-	0.18	0.68
Total LNG Exports	-	4.23	5.44	6.72	6.89	8.39
China/India	-	0.51	0.69	1.60	1.75	2.00
Europe	-	2.23	1.04	1.09	0.57	1.18
Korea/Japan	-	1.49	3.71	4.03	4.57	5.21
Total Supply (Tcf)	**23.86**	**28.91**	**30.54**	**31.84**	**33.29**	**36.38**
Domestic Production	21.10	26.53	29.17	31.47	33.13	36.32
Pipeline Imports from Canada	2.33	2.01	0.87	0.01	-	-
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.00	-	-
Wellhead Price (2010$/Mcf)	**$4.08**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Netback Price (2010$/Mcf)	**-**	**$4.47**	**$4.68**	**$5.40**	**$5.61**	**$5.97**
Quota Rent (2010$/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 123: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 124: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 125: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 126: Detailed Results from Global Natural Gas Model, LEUR_INTREF_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 127: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 128: Detailed Results from Global Natural Gas Model, LEUR_INTREF_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 129: Detailed Results from Global Natural Gas Model, LEUR_INTREF_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.19	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	0.17	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.30**	**$4.45**	**$5.23**	**$5.38**	**$5.80**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 130: Detailed Results from Global Natural Gas Model, LEUR_D_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 131: Detailed Results from Global Natural Gas Model, LEUR_D_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 132: Detailed Results from Global Natural Gas Model, LEUR_D_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 133: Detailed Results from Global Natural Gas Model, LEUR_D_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 134: Detailed Results from Global Natural Gas Model, LEUR_D_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 135: Detailed Results from Global Natural Gas Model, LEUR_D_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 136: Detailed Results from Global Natural Gas Model, LEUR_D_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$4.85**	**$5.10**	**$6.23**	**$6.48**	**$7.18**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 137: Detailed Results from Global Natural Gas Model, LEUR_SD_NX

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Demand	23.86	22.77	22.54	22.21	22.79	23.15
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	-	-	-	-
China/India	-	-	-	-	-	-
Europe	-	-	-	-	-	-
Korea/Japan	-	-	-	-	-	-
Total Supply (Tcf)	**23.86**	**22.77**	**22.54**	**22.21**	**22.79**	**23.15**
Domestic Production	21.1	19.74	19.98	19.89	20.70	21.43
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.49**	**$7.56**	**$7.97**	**$8.70**
Netback Price ($2010/Mcf)	**-**	**$5.83**	**$9.20**	**$10.04**	**$8.63**	**$9.33**
Quota Rent ($2010/Mcf)	**-**	**-**	**$2.70**	**$2.47**	**$0.66**	**$0.63**

Figure 138: Detailed Results from Global Natural Gas Model, LEUR_SD_LSS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 139: Detailed Results from Global Natural Gas Model, LEUR_SD_LS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 140: Detailed Results from Global Natural Gas Model, LEUR_SD_LR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 141: Detailed Results from Global Natural Gas Model, LEUR_SD_HS

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 142: Detailed Results from Global Natural Gas Model, LEUR_SD_HR

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

Figure 143: Detailed Results from Global Natural Gas Model, LEUR_SD_NC

	EIA Ref	NERA Projections				
	2010	2015	2020	2025	2030	2035
Total Demand (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Demand	23.86	22.77	22.12	21.78	22.68	22.97
Pipeline Exports to Canada	-	-	-	-	-	-
Total LNG Exports	-	-	0.78	0.90	0.27	0.52
China/India	-	-	-	-	0.13	-
Europe	-	-	-	0.46	0.01	0.14
Korea/Japan	-	-	0.78	0.44	0.13	0.37
Total Supply (Tcf)	**23.86**	**22.77**	**22.91**	**22.69**	**22.95**	**23.49**
Domestic Production	21.1	19.74	20.35	20.37	20.86	21.77
Pipeline Imports from Canada	2.33	2.66	2.06	1.96	1.93	1.66
Total LNG Imports	0.43	0.37	0.50	0.36	0.16	0.06
Africa	0.11	-	-	-	-	-
C & S America	0.21	0.37	0.50	0.36	0.16	0.06
Europe	0.03	-	-	-	-	-
Middle East	0.08	-	-	-	-	-
Wellhead Price ($2010/Mcf)	**$4.08**	**$5.85**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Netback Price ($2010/Mcf)	**-**	**$5.71**	**$6.86**	**$7.96**	**$8.07**	**$8.86**
Quota Rent ($2010/Mcf)	**-**	**-**	**-**	**-**	**-**	**-**

B. N_{ew}ERA Model Results

The following figures (Figure 144 through Figure 164) contain detailed macroeconomic outputs for all modeled baselines, scenarios, and sensitivities. For each figure, the "Level Values" section depicts the numerical results from the scenario or baseline, and the "Percentage Change" section shows the percentage change in the Level Values for a given scenario relative to its baseline case. Figure 144 through Figure 162 contain detailed results for the scenarios. Figure 163 through Figure 164 contain results for the sensitivity tests. All tables use the following acronyms defined in the following list:

AGR – agriculture sector
COL – coal sector
CRU – crude oil sector
EIS – energy-intensive sector
ELE – electricity sector
GAS – natural gas sector
M_V – motor vehicle manufacturing sector
MAN – other manufacturing sector
OIL – refining sector
SRV – commercial sector
TRK – commercial trucking sector
TRN – other commercial transportation sector
C – household sector
G – government sector

Figure 144: Detailed Results for U.S. Reference Baseline Case

Reference Baseline Case (USREF)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,883	$17,862	$20,277	$22,880	$25,756
	Consumption		Billion 2010$	$12,404	$13,969	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,467	$2,791	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.29	$4.65	$5.49	$5.89	$6.50
	Production		Tcf	22.42	23.44	24.04	25.21	26.58
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	25.03	25.28	25.09	25.97	26.76
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.35	3.27	3.16	3.08
		ELE	Tcf	6.94	6.82	6.65	7.35	7.93
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.23	4.32	4.34	4.41	4.54
		OIL	Tcf	1.32	1.41	1.36	1.40	1.38
		SRV	Tcf	2.44	2.53	2.58	2.67	2.79
		TRK	Tcf	0.47	0.48	0.49	0.53	0.56
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.80	4.84	4.84	4.84	4.82
		G	Tcf	0.93	0.96	0.99	1.02	1.06
	Export Revenues [1]		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 145: Detailed Results for High Shale EUR Baseline Case

High Shale EUR Baseline Case (HEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,960	$17,964	$20,411	$23,002	$25,902
	Consumption		Billion 2010$	$12,429	$13,999	$16,013	$18,184	$20,565
	Investment		Billion 2010$	$2,483	$2,811	$3,177	$3,532	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.35	$3.50	$4.09	$4.53	$4.92
	Production		Tcf	24.69	26.46	27.72	28.70	29.73
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.96	27.73	27.97	28.84	29.86
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.17	0.17
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.47	3.58	3.55	3.48	3.39
		ELE	Tcf	8.27	8.38	8.35	8.90	9.69
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.20	0.19	0.19	0.20
		MAN	Tcf	4.44	4.64	4.75	4.87	5.01
		OIL	Tcf	1.32	1.40	1.37	1.44	1.40
		SRV	Tcf	2.53	2.65	2.75	2.85	2.97
		TRK	Tcf	0.48	0.51	0.55	0.60	0.65
		TRN	Tcf	0.23	0.24	0.26	0.28	0.30
		C	Tcf	4.89	4.96	5.00	4.99	4.95
		G	Tcf	0.97	1.01	1.05	1.09	1.13
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 146: Detailed Results for Low Shale EUR Baseline Case

Low Shale EUR Baseline Case (LEUR)								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,790	$17,716	$20,061	$22,693	$25,567
	Consumption		Billion 2010$	$12,379	$13,920	$15,862	$18,093	$20,476
	Investment		Billion 2010$	$2,442	$2,759	$3,138	$3,493	$3,953
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.45	$7.83	$8.33	$8.96
	Production		Tcf	19.60	19.88	20.04	21.13	21.70
	Exports		Tcf	-	-	-	-	-
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	22.50	22.41	23.14	23.45
	Sectoral Demand	AGR	Tcf	0.16	0.16	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.15	3.02	2.86	2.76
		ELE	Tcf	5.23	5.00	5.16	5.91	6.12
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.16
		MAN	Tcf	3.99	3.99	3.92	3.95	4.00
		OIL	Tcf	1.32	1.41	1.39	1.36	1.39
		SRV	Tcf	2.32	2.37	2.38	2.45	2.55
		TRK	Tcf	0.45	0.46	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.68	4.64	4.63	4.59
		G	Tcf	0.89	0.90	0.91	0.94	0.97
	Export Revenues 1		Billion 2010$	$0.00	$0.00	$0.00	$0.00	$0.00
Percentage Change								
Macro	Gross Domestic Product		%					
	Gross Capital Income		%					
	Gross Labor Income		%					
	Gross Resource Income		%					
	Consumption		%					
	Investment		%					
Natural Gas	Wellhead Price		%					
	Production		%					
	Pipeline Imports		%					
	Total Demand		%					
	Sectoral Demand	AGR	%					
		COL	%					
		CRU	%					
		EIS	%					
		ELE	%					
		GAS	%					
		M_V	%					
		MAN	%					
		OIL	%					
		SRV	%					
		TRK	%					
		TRN	%					
		C	%					
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 147: Detailed Results for USREF_D_LSS

Scenario: USREF_D_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,884	$17,868	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,971	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,468	$2,790	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.34	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.49	23.84	24.80	25.87	27.40
	Exports		Tcf	0.18	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.92	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.30	3.24	3.16	3.09	3.00
		ELE	Tcf	6.91	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.21	4.20	4.20	4.31	4.43
		OIL	Tcf	1.31	1.37	1.32	1.37	1.35
		SRV	Tcf	2.43	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.79	4.77	4.76	4.77	4.75
		G	Tcf	0.93	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$0.72	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.01	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.01)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	2.37	8.70	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.05	(0.02)	(0.06)	0.03	0.04
Natural Gas	Wellhead Price		%	1.17	5.75	5.93	4.12	3.88
	Production		%	0.32	1.73	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.28)	(2.68)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(0.66)	(3.11)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(0.65)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.43)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.42)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(0.58)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(0.59)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.28)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.17)	(1.03)	(1.45)	(1.16)	(1.26)
		TRN	%	(0.18)	(1.06)	(1.49)	(1.20)	(1.29)
		C	%	(0.23)	(1.38)	(1.76)	(1.36)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 148: Detailed Results for USREF_D_LS

			Scenario: USREF_D_LS					
	Description		Units	2015	2020	2025	2030	2035
			Level Values					
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,867	$20,281	$22,883	$25,759
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,152	$20,520
	Investment		Billion 2010$	$2,467	$2,791	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.56	23.84	24.80	25.87	27.40
	Exports		Tcf	0.37	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.24	3.16	3.09	3.00
		ELE	Tcf	6.88	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.17	0.18
		MAN	Tcf	4.18	4.20	4.20	4.31	4.43
		OIL	Tcf	1.30	1.37	1.32	1.37	1.35
		SRV	Tcf	2.42	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.77	4.77	4.76	4.77	4.75
		G	Tcf	0.92	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$1.51	$4.47	$7.72	$6.76	$8.58
			Percentage Change					
Macro	Gross Domestic Product		%	0.02	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.03)	(0.07)	(0.08)	(0.06)	(0.05)
	Gross Labor Income		%	(0.02)	(0.05)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	5.00	8.68	7.64	4.95	4.62
	Consumption		%	0.03	0.01	(0.00)	(0.00)	(0.00)
	Investment		%	0.01	(0.00)	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	2.44	5.75	5.93	4.12	3.88
	Production		%	0.65	1.72	3.15	2.63	3.07
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(1.34)	(3.12)	(3.44)	(2.51)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(1.31)	(3.07)	(3.41)	(2.50)	(2.45)
		ELE	%	(0.91)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(0.85)	(2.23)	(2.70)	(2.06)	(2.10)
		MAN	%	(1.19)	(2.83)	(3.18)	(2.33)	(2.30)
		OIL	%	(1.21)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(0.59)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.35)	(1.03)	(1.45)	(1.17)	(1.26)
		TRN	%	(0.36)	(1.07)	(1.49)	(1.20)	(1.29)
		C	%	(0.50)	(1.38)	(1.76)	(1.36)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 149: Detailed Results for USREF_D_LR

Scenario: USREF_D_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,890	$17,866	$20,280	$22,882	$25,758
	Consumption		Billion 2010$	$12,408	$13,970	$15,972	$18,153	$20,521
	Investment		Billion 2010$	$2,464	$2,792	$3,160	$3,518	$3,978
Natural Gas	Wellhead Price		2010$ per Mcf	$4.60	$4.92	$5.82	$6.13	$6.75
	Production		Tcf	22.81	23.84	24.80	25.87	27.40
	Exports		Tcf	1.02	0.98	1.43	1.19	1.37
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.40	24.71	24.41	25.44	26.20
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.21	3.24	3.16	3.09	3.00
		ELE	Tcf	6.77	6.65	6.45	7.18	7.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.17	0.18
		MAN	Tcf	4.09	4.20	4.20	4.31	4.43
		OIL	Tcf	1.27	1.37	1.32	1.37	1.35
		SRV	Tcf	2.40	2.48	2.53	2.63	2.74
		TRK	Tcf	0.47	0.47	0.49	0.52	0.55
		TRN	Tcf	0.22	0.22	0.23	0.24	0.26
		C	Tcf	4.73	4.77	4.76	4.77	4.75
		G	Tcf	0.91	0.95	0.96	1.00	1.04
	Export Revenues [1]		Billion 2010$	$4.35	$4.47	$7.72	$6.76	$8.58
Percentage Change								
Macro	Gross Domestic Product		%	0.04	0.03	0.02	0.01	0.01
	Gross Capital Income		%	(0.09)	(0.08)	(0.09)	(0.06)	(0.05)
	Gross Labor Income		%	(0.07)	(0.06)	(0.07)	(0.05)	(0.04)
	Gross Resource Income		%	14.69	8.61	7.62	4.94	4.62
	Consumption		%	0.03	0.00	(0.00)	0.00	0.00
	Investment		%	(0.12)	0.04	(0.05)	0.03	0.04
Natural Gas	Wellhead Price		%	7.13	5.74	5.93	4.12	3.88
	Production		%	1.73	1.72	3.14	2.62	3.07
	Pipeline Imports		%					
	Total Demand		%	(2.52)	(2.28)	(2.69)	(2.03)	(2.07)
	Sectoral Demand	AGR	%	(3.72)	(3.13)	(3.45)	(2.52)	(2.46)
		COL	%					
		CRU	%					
		EIS	%	(3.62)	(3.09)	(3.42)	(2.51)	(2.46)
		ELE	%	(2.57)	(2.46)	(3.00)	(2.34)	(2.43)
		GAS	%					
		M_V	%	(2.37)	(2.24)	(2.70)	(2.07)	(2.10)
		MAN	%	(3.30)	(2.83)	(3.18)	(2.34)	(2.31)
		OIL	%	(3.42)	(2.89)	(3.21)	(2.34)	(2.30)
		SRV	%	(1.70)	(1.61)	(2.02)	(1.56)	(1.61)
		TRK	%	(0.99)	(1.04)	(1.45)	(1.17)	(1.26)
		TRN	%	(1.01)	(1.08)	(1.49)	(1.20)	(1.30)
		C	%	(1.46)	(1.38)	(1.76)	(1.35)	(1.42)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 150: Detailed Results for USREF_SD_LS

Scenario: USREF_SD_LS								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,876	$20,283	$22,885	$25,759
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,520
	Investment		Billion 2010$	$2,469	$2,787	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.56	24.30	25.18	26.41	27.88
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.81	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	3.10	3.02	2.95
		ELE	Tcf	6.88	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.17	0.18
		MAN	Tcf	4.18	4.04	4.12	4.22	4.37
		OIL	Tcf	1.30	1.32	1.29	1.34	1.33
		SRV	Tcf	2.42	2.43	2.50	2.59	2.71
		TRK	Tcf	0.47	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.78	4.68	4.71	4.72	4.71
		G	Tcf	0.92	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.08	0.03	0.02	0.01
	Gross Capital Income		%	(0.02)	(0.17)	(0.14)	(0.11)	(0.09)
	Gross Labor Income		%	(0.02)	(0.13)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	4.97	21.48	12.23	9.64	7.64
	Consumption		%	0.05	0.01	(0.01)	(0.01)	(0.00)
	Investment		%	0.09	(0.15)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	2.44	14.04	9.45	7.92	6.37
	Production		%	0.65	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(1.37)	(7.14)	(5.35)	(4.68)	(3.97)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(7.03)	(5.31)	(4.65)	(3.96)
		ELE	%	(0.90)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(0.88)	(5.15)	(4.19)	(3.86)	(3.40)
		MAN	%	(1.21)	(6.51)	(4.92)	(4.35)	(3.73)
		OIL	%	(1.21)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(0.59)	(3.76)	(3.16)	(2.92)	(2.61)
		TRK	%	(0.35)	(2.42)	(2.27)	(2.19)	(2.05)
		TRN	%	(0.38)	(2.49)	(2.34)	(2.26)	(2.10)
		C	%	(0.47)	(3.24)	(2.76)	(2.55)	(2.30)

[1] Export revenues are based on LNG exports net of liquefaction loss.

Figure 151: Detailed Results for USREF_SD_LR

Scenario: USREF_SD_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,874	$20,282	$22,885	$25,758
	Consumption		Billion 2010$	$12,411	$13,970	$15,971	$18,152	$20,521
	Investment		Billion 2010$	$2,465	$2,788	$3,161	$3,517	$3,977
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.30	$6.01	$6.35	$6.92
	Production		Tcf	22.83	24.30	25.18	26.41	27.88
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.95	24.04	24.98	25.86
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.11	3.10	3.02	2.95
		ELE	Tcf	6.75	6.43	6.34	7.03	7.62
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.18
		MAN	Tcf	4.08	4.04	4.12	4.22	4.37
		OIL	Tcf	1.27	1.32	1.29	1.34	1.33
		SRV	Tcf	2.39	2.43	2.50	2.59	2.71
		TRK	Tcf	0.46	0.47	0.48	0.51	0.55
		TRN	Tcf	0.22	0.22	0.22	0.24	0.25
		C	Tcf	4.72	4.68	4.71	4.72	4.71
		G	Tcf	0.91	0.92	0.95	0.99	1.03
	Export Revenues [1]		Billion 2010$	$4.72	$10.76	$12.21	$12.90	$14.04
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.07	0.03	0.02	0.01
	Gross Capital Income		%	(0.09)	(0.18)	(0.14)	(0.12)	(0.09)
	Gross Labor Income		%	(0.08)	(0.14)	(0.11)	(0.09)	(0.08)
	Gross Resource Income		%	15.94	21.40	12.22	9.63	7.64
	Consumption		%	0.05	0.00	(0.01)	(0.00)	0.00
	Investment		%	(0.05)	(0.10)	(0.01)	0.01	0.01
Natural Gas	Wellhead Price		%	7.73	14.03	9.44	7.92	6.37
	Production		%	1.86	3.67	4.75	4.77	4.87
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(5.26)	(4.18)	(3.80)	(3.35)
	Sectoral Demand	AGR	%	(4.04)	(7.15)	(5.36)	(4.68)	(3.98)
		COL	%					
		CRU	%					
		EIS	%	(3.94)	(7.05)	(5.32)	(4.66)	(3.97)
		ELE	%	(2.77)	(5.67)	(4.66)	(4.36)	(3.91)
		GAS	%					
		M_V	%	(2.58)	(5.15)	(4.20)	(3.86)	(3.40)
		MAN	%	(3.59)	(6.50)	(4.93)	(4.36)	(3.73)
		OIL	%	(3.69)	(6.64)	(4.98)	(4.36)	(3.71)
		SRV	%	(1.83)	(3.77)	(3.16)	(2.92)	(2.61)
		TRK	%	(1.07)	(2.43)	(2.27)	(2.20)	(2.05)
		TRN	%	(1.10)	(2.50)	(2.34)	(2.26)	(2.11)
		C	%	(1.55)	(3.25)	(2.76)	(2.55)	(2.29)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 152: Detailed Results for USREF_SD_HS

Scenario: USREF_SD_HS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,886	$17,878	$20,294	$22,893	$25,763
	Consumption		Billion 2010$	$12,413	$13,976	$15,973	$18,150	$20,518
	Investment		Billion 2010$	$2,469	$2,792	$3,158	$3,515	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.40	$5.30	$6.52	$6.92	$7.40
	Production		Tcf	22.56	24.30	26.03	27.55	29.13
	Exports		Tcf	0.37	2.19	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.80	23.95	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.28	3.11	2.95	2.86	2.83
		ELE	Tcf	6.88	6.44	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.17	0.16	0.16	0.17
		MAN	Tcf	4.18	4.04	3.94	4.01	4.19
		OIL	Tcf	1.30	1.32	1.24	1.28	1.28
		SRV	Tcf	2.42	2.43	2.43	2.51	2.64
		TRK	Tcf	0.47	0.47	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.78	4.68	4.59	4.58	4.59
		G	Tcf	0.92	0.92	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$1.51	$10.76	$23.75	$28.08	$30.03
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.09	0.08	0.06	0.03
	Gross Capital Income		%	(0.02)	(0.16)	(0.24)	(0.24)	(0.20)
	Gross Labor Income		%	(0.02)	(0.12)	(0.19)	(0.19)	(0.16)
	Gross Resource Income		%	4.89	21.45	24.76	21.89	16.93
	Consumption		%	0.07	0.05	0.00	(0.02)	(0.01)
	Investment		%	0.11	0.03	(0.11)	(0.05)	(0.05)
Natural Gas	Wellhead Price		%	2.42	14.04	18.65	17.49	13.75
	Production		%	0.65	3.67	8.28	9.30	9.59
	Pipeline Imports		%					
	Total Demand		%	(0.90)	(5.26)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(1.41)	(7.17)	(9.83)	(9.58)	(8.08)
		COL	%					
		CRU	%					
		EIS	%	(1.39)	(7.08)	(9.73)	(9.52)	(8.05)
		ELE	%	(0.89)	(5.66)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(0.89)	(5.17)	(7.76)	(7.94)	(6.95)
		MAN	%	(1.22)	(6.52)	(9.09)	(8.95)	(7.60)
		OIL	%	(1.21)	(6.64)	(9.17)	(8.97)	(7.56)
		SRV	%	(0.58)	(3.75)	(5.91)	(6.09)	(5.38)
		TRK	%	(0.36)	(2.42)	(4.26)	(4.61)	(4.25)
		TRN	%	(0.40)	(2.50)	(4.37)	(4.72)	(4.36)
		C	%	(0.45)	(3.21)	(5.18)	(5.36)	(4.76)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 153: Detailed Results for USREF_SD_HR

Scenario: USREF_SD_HR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,891	$17,882	$20,292	$22,893	$25,762
	Consumption		Billion 2010$	$12,415	$13,974	$15,972	$18,151	$20,519
	Investment		Billion 2010$	$2,467	$2,789	$3,160	$3,516	$3,975
Natural Gas	Wellhead Price		2010$ per Mcf	$4.62	$5.57	$6.52	$6.91	$7.40
	Production		Tcf	22.83	24.55	26.03	27.55	29.13
	Exports		Tcf	1.10	2.92	3.93	4.38	4.38
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	24.35	23.48	23.15	23.93	24.93
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.19	3.03	2.95	2.86	2.83
		ELE	Tcf	6.75	6.30	6.08	6.69	7.30
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	4.08	3.94	3.94	4.01	4.19
		OIL	Tcf	1.27	1.29	1.24	1.28	1.28
		SRV	Tcf	2.39	2.40	2.43	2.51	2.64
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.22	0.22	0.22	0.23	0.25
		C	Tcf	4.73	4.63	4.59	4.58	4.59
		G	Tcf	0.91	0.91	0.92	0.95	1.00
	Export Revenues [1]		Billion 2010$	$4.71	$15.07	$23.75	$28.08	$30.03
Percentage Change								
Macro	Gross Domestic Product		%	0.05	0.11	0.07	0.05	0.03
	Gross Capital Income		%	(0.09)	(0.24)	(0.25)	(0.24)	(0.20)
	Gross Labor Income		%	(0.07)	(0.19)	(0.20)	(0.19)	(0.16)
	Gross Resource Income		%	15.86	30.34	24.68	21.87	16.92
	Consumption		%	0.09	0.03	0.00	(0.01)	(0.01)
	Investment		%	0.01	(0.07)	(0.06)	(0.04)	(0.04)
Natural Gas	Wellhead Price		%	7.71	19.75	18.64	17.48	13.75
	Production		%	1.86	4.75	8.28	9.29	9.59
	Pipeline Imports		%					
	Total Demand		%	(2.73)	(7.15)	(7.73)	(7.84)	(6.84)
	Sectoral Demand	AGR	%	(4.09)	(9.69)	(9.85)	(9.59)	(8.09)
		COL	%					
		CRU	%					
		EIS	%	(3.99)	(9.55)	(9.76)	(9.53)	(8.06)
		ELE	%	(2.76)	(7.69)	(8.61)	(8.97)	(7.97)
		GAS	%					
		M_V	%	(2.60)	(7.00)	(7.76)	(7.95)	(6.95)
		MAN	%	(3.61)	(8.81)	(9.09)	(8.95)	(7.60)
		OIL	%	(3.69)	(8.99)	(9.18)	(8.97)	(7.56)
		SRV	%	(1.82)	(5.15)	(5.91)	(6.09)	(5.38)
		TRK	%	(1.08)	(3.34)	(4.27)	(4.61)	(4.26)
		TRN	%	(1.13)	(3.44)	(4.39)	(4.73)	(4.37)
		C	%	(1.52)	(4.43)	(5.18)	(5.35)	(4.76)

1 Export revenues are based on LNG exports net of liquefaction loss.

Figure 154: Detailed Results for USREF_SD_NC

Scenario: USREF_SD_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,900	$17,880	$20,292	$22,896	$25,773
	Consumption		Billion 2010$	$12,415	$13,973	$15,973	$18,153	$20,520
	Investment		Billion 2010$	$2,461	$2,791	$3,161	$3,520	$3,980
Natural Gas	Wellhead Price		2010$ per Mcf	$5.01	$5.57	$6.52	$6.96	$7.73
	Production		Tcf	23.19	24.55	26.03	27.63	29.90
	Exports		Tcf	2.17	2.92	3.93	4.54	5.75
	Pipeline Imports		Tcf	2.61	1.84	1.05	0.76	0.17
	Total Demand		Tcf	23.64	23.47	23.15	23.85	24.33
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.06	3.03	2.95	2.85	2.75
		ELE	Tcf	6.55	6.30	6.08	6.67	7.09
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.16	0.17
		MAN	Tcf	3.93	3.94	3.94	4.00	4.08
		OIL	Tcf	1.22	1.29	1.24	1.27	1.25
		SRV	Tcf	2.34	2.40	2.43	2.50	2.59
		TRK	Tcf	0.46	0.46	0.47	0.50	0.53
		TRN	Tcf	0.21	0.22	0.22	0.23	0.24
		C	Tcf	4.64	4.63	4.59	4.57	4.51
		G	Tcf	0.89	0.91	0.92	0.95	0.98
	Export Revenues [1]		Billion 2010$	$10.08	$15.06	$23.75	$29.29	$41.23
Percentage Change								
Macro	Gross Domestic Product		%	0.11	0.10	0.07	0.07	0.07
	Gross Capital Income		%	(0.20)	(0.25)	(0.25)	(0.24)	(0.24)
	Gross Labor Income		%	(0.17)	(0.19)	(0.20)	(0.19)	(0.20)
	Gross Resource Income		%	34.72	30.19	24.65	22.89	23.81
	Consumption		%	0.09	0.03	0.01	0.00	(0.00)
	Investment		%	(0.21)	0.02	(0.01)	0.10	0.09
Natural Gas	Wellhead Price		%	16.69	19.72	18.63	18.26	18.97
	Production		%	3.46	4.74	8.27	9.62	12.48
	Pipeline Imports		%					
	Total Demand		%	0.00	0.00	0.00	(0.00)	0.00
	Sectoral Demand	AGR	%	(5.57)	(7.15)	(7.74)	(8.14)	(9.09)
		COL	%	(8.17)	(9.71)	(9.86)	(9.96)	(10.69)
		CRU	%					
		EIS	%					
		ELE	%	(7.97)	(9.59)	(9.78)	(9.91)	(10.65)
		GAS	%	(5.64)	(7.69)	(8.61)	(9.31)	(10.56)
		M_V	%					
		MAN	%	(5.24)	(7.00)	(7.76)	(8.24)	(9.19)
		OIL	%	(7.25)	(8.81)	(9.09)	(9.29)	(10.06)
		SRV	%	(7.48)	(8.99)	(9.18)	(9.31)	(10.04)
		TRK	%	(3.78)	(5.15)	(5.91)	(6.33)	(7.19)
		TRN	%	(2.22)	(3.35)	(4.27)	(4.79)	(5.69)
		C	%	(2.28)	(3.47)	(4.40)	(4.92)	(5.83)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 155: Detailed Results for HEUR_D_NC

Scenario: HEUR_D_NC								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,000	$18,002	$20,442	$23,023	$25,929
	Consumption		Billion 2010$	$12,441	$14,000	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,475	$2,812	$3,176	$3,537	$4,001
Natural Gas	Wellhead Price		2010$ per Mcf	$4.31	$4.46	$5.04	$5.25	$5.82
	Production		Tcf	25.66	27.83	30.04	31.24	32.82
	Exports		Tcf	3.30	3.94	4.87	4.59	5.61
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	24.63	25.16	25.42	26.79	27.35
	Sectoral Demand	AGR	Tcf	0.14	0.14	0.15	0.15	0.15
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.04	3.13	3.14	3.18	3.05
		ELE	Tcf	7.54	7.54	7.50	8.17	8.74
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.18	0.17	0.18	0.18
		MAN	Tcf	3.93	4.10	4.23	4.47	4.53
		OIL	Tcf	1.16	1.23	1.22	1.32	1.27
		SRV	Tcf	2.39	2.48	2.57	2.70	2.78
		TRK	Tcf	0.47	0.49	0.52	0.57	0.62
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.65	4.70	4.71	4.77	4.68
		G	Tcf	0.90	0.94	0.97	1.02	1.05
	Export Revenues [1]		Billion 2010$	$13.18	$16.30	$22.77	$22.33	$30.25
Percentage Change								
Macro	Gross Domestic Product		%	0.25	0.21	0.15	0.09	0.10
	Gross Capital Income		%	(0.31)	(0.32)	(0.29)	(0.20)	(0.21)
	Gross Labor Income		%	(0.24)	(0.23)	(0.22)	(0.15)	(0.16)
	Gross Resource Income		%	63.40	45.34	33.90	21.40	24.37
	Consumption		%	0.10	0.01	(0.01)	0.00	0.00
	Investment		%	(0.31)	0.06	(0.03)	0.14	0.15
Natural Gas	Wellhead Price		%	28.73	27.46	23.37	15.80	18.15
	Production		%	3.93	5.19	8.38	8.85	10.41
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(8.64)	(9.26)	(9.10)	(7.11)	(8.42)
		COL	%	(12.74)	(12.66)	(11.72)	(8.79)	(10.02)
		CRU	%					
		EIS	%					
		ELE	%	(12.44)	(12.52)	(11.63)	(8.77)	(9.99)
		GAS	%	(8.80)	(9.99)	(10.17)	(8.15)	(9.86)
		M_V	%					
		MAN	%	(8.20)	(9.14)	(9.19)	(7.25)	(8.53)
		OIL	%	(11.47)	(11.61)	(10.89)	(8.22)	(9.45)
		SRV	%	(11.88)	(11.91)	(11.04)	(8.26)	(9.48)
		TRK	%	(5.65)	(6.35)	(6.61)	(5.27)	(6.32)
		TRN	%	(3.18)	(3.96)	(4.57)	(3.88)	(4.78)
		C	%	(3.24)	(4.10)	(4.70)	(4.00)	(4.91)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 156: Detailed Results for HEUR_SD_LSS

Scenario: HEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,974	$20,423	$23,011	$25,909
	Consumption		Billion 2010$	$12,433	$14,001	$16,013	$18,182	$20,563
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.95	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.98	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.06	0.06	0.04	0.03
	Gross Capital Income		%	(0.01)	(0.06)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.04)	(0.07)	(0.07)	(0.06)
	Gross Resource Income		%	2.58	10.21	11.75	9.10	8.13
	Consumption		%	0.03	0.02	(0.00)	(0.01)	(0.01)
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.20	6.29	8.29	6.87	6.27
	Production		%	0.26	1.64	3.66	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.68)	(3.35)	(4.61)	(4.07)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(0.67)	(3.30)	(4.57)	(4.05)	(3.77)
		ELE	%	(0.43)	(2.61)	(4.00)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.43)	(2.40)	(3.60)	(3.35)	(3.22)
		MAN	%	(0.60)	(3.07)	(4.29)	(3.81)	(3.57)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.15)	(0.98)	(1.73)	(1.76)	(1.76)
		TRN	%	(0.17)	(1.01)	(1.77)	(1.80)	(1.80)
		C	%	(0.20)	(1.32)	(2.15)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 157: Detailed Results for HEUR_SD_LS

Scenario: HEUR_SD_LS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,984	$20,422	$23,011	$25,909
	Consumption		Billion 2010$	$12,435	$14,000	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,485	$2,808	$3,177	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.46	$4.84	$5.23
	Production		Tcf	24.82	27.28	28.82	29.95	30.97
	Exports		Tcf	0.37	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.38	3.34	3.26
		ELE	Tcf	8.20	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.38	4.35	4.53	4.68	4.83
		OIL	Tcf	1.30	1.31	1.30	1.38	1.35
		SRV	Tcf	2.52	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.87	4.82	4.88	4.89	4.85
		G	Tcf	0.96	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.11	0.06	0.04	0.03
	Gross Capital Income		%	(0.02)	(0.15)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	5.44	22.13	12.88	9.08	8.12
	Consumption		%	0.05	0.00	(0.01)	(0.01)	(0.01)
	Investment		%	0.10	(0.10)	0.01	0.01	0.01
Natural Gas	Wellhead Price		%	2.52	13.51	9.11	6.86	6.27
	Production		%	0.53	3.11	3.97	4.33	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(3.89)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(1.38)	(6.79)	(5.05)	(4.08)	(3.79)
		COL	%					
		CRU	%					
		EIS	%	(1.35)	(6.70)	(5.02)	(4.06)	(3.78)
		ELE	%	(0.90)	(5.34)	(4.37)	(3.79)	(3.73)
		GAS	%					
		M_V	%	(0.88)	(4.88)	(3.94)	(3.35)	(3.22)
		MAN	%	(1.23)	(6.25)	(4.69)	(3.82)	(3.57)
		OIL	%	(1.24)	(6.41)	(4.77)	(3.84)	(3.58)
		SRV	%	(0.55)	(3.31)	(2.77)	(2.41)	(2.34)
		TRK	%	(0.32)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.33)	(2.09)	(1.96)	(1.81)	(1.81)
		C	%	(0.43)	(2.78)	(2.37)	(2.08)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 158: Detailed Results for HEUR_SD_LR

Scenario: HEUR_SD_LR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,972	$17,983	$20,422	$23,010	$25,909
	Consumption		Billion 2010$	$12,435	$13,999	$16,012	$18,182	$20,564
	Investment		Billion 2010$	$2,482	$2,809	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$3.97	$4.46	$4.84	$5.23
	Production		Tcf	25.06	27.28	28.82	29.94	30.97
	Exports		Tcf	1.10	2.19	2.19	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	26.36	26.88	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.34	3.37	3.34	3.26
		ELE	Tcf	8.04	7.93	7.99	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.19	0.18	0.18	0.19
		MAN	Tcf	4.27	4.35	4.53	4.68	4.83
		OIL	Tcf	1.27	1.31	1.30	1.38	1.35
		SRV	Tcf	2.49	2.56	2.67	2.78	2.90
		TRK	Tcf	0.48	0.50	0.54	0.59	0.64
		TRN	Tcf	0.22	0.23	0.25	0.27	0.30
		C	Tcf	4.82	4.82	4.88	4.89	4.85
		G	Tcf	0.95	0.97	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$3.69	$8.07	$9.06	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.07	0.11	0.06	0.03	0.03
	Gross Capital Income		%	(0.09)	(0.16)	(0.12)	(0.09)	(0.08)
	Gross Labor Income		%	(0.07)	(0.11)	(0.09)	(0.07)	(0.06)
	Gross Resource Income		%	17.33	22.05	12.86	9.07	8.11
	Consumption		%	0.05	(0.00)	(0.01)	(0.01)	(0.00)
	Investment		%	(0.02)	(0.05)	0.02	0.01	0.01
Natural Gas	Wellhead Price		%	7.97	13.49	9.11	6.86	6.27
	Production		%	1.49	3.10	3.97	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(4.94)	(3.90)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(4.08)	(6.80)	(5.06)	(4.08)	(3.80)
		COL	%					
		CRU	%					
		EIS	%	(3.98)	(6.71)	(5.03)	(4.07)	(3.79)
		ELE	%	(2.76)	(5.35)	(4.37)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(2.60)	(4.88)	(3.94)	(3.36)	(3.22)
		MAN	%	(3.67)	(6.25)	(4.69)	(3.82)	(3.58)
		OIL	%	(3.78)	(6.41)	(4.76)	(3.84)	(3.58)
		SRV	%	(1.71)	(3.32)	(2.78)	(2.41)	(2.34)
		TRK	%	(0.96)	(2.05)	(1.90)	(1.76)	(1.76)
		TRN	%	(0.98)	(2.11)	(1.96)	(1.81)	(1.81)
		C	%	(1.42)	(2.78)	(2.36)	(2.07)	(2.02)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 159: Detailed Results for HEUR_SD_HS

Scenario: HEUR_SD_HS								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,965	$17,986	$20,439	$23,022	$25,918
	Consumption		Billion 2010$	$12,437	$14,004	$16,013	$18,180	$20,561
	Investment		Billion 2010$	$2,486	$2,813	$3,175	$3,531	$3,994
Natural Gas	Wellhead Price		2010$ per Mcf	$3.43	$3.98	$4.84	$5.21	$5.59
	Production		Tcf	24.82	27.28	29.67	31.13	32.17
	Exports		Tcf	0.37	2.19	4.02	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.72	26.36	25.90	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.15	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.42	3.34	3.22	3.20	3.13
		ELE	Tcf	8.20	7.93	7.66	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.17	0.18	0.18
		MAN	Tcf	4.38	4.35	4.33	4.49	4.64
		OIL	Tcf	1.30	1.31	1.24	1.32	1.30
		SRV	Tcf	2.52	2.56	2.60	2.70	2.82
		TRK	Tcf	0.48	0.50	0.53	0.58	0.63
		TRN	Tcf	0.22	0.23	0.25	0.27	0.29
		C	Tcf	4.87	4.82	4.77	4.78	4.75
		G	Tcf	0.96	0.97	0.99	1.03	1.07
	Export Revenues [1]		Billion 2010$	$1.18	$8.07	$18.05	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.03	0.12	0.14	0.09	0.06
	Gross Capital Income		%	(0.02)	(0.14)	(0.21)	(0.19)	(0.17)
	Gross Labor Income		%	(0.01)	(0.10)	(0.16)	(0.14)	(0.13)
	Gross Resource Income		%	5.38	22.12	26.64	20.29	17.95
	Consumption		%	0.06	0.04	(0.01)	(0.02)	(0.02)
	Investment		%	0.12	0.08	(0.05)	(0.02)	(0.02)
Natural Gas	Wellhead Price		%	2.51	13.51	18.45	14.96	13.55
	Production		%	0.52	3.11	7.05	8.47	8.21
	Pipeline Imports		%					
	Total Demand		%	(0.89)	(4.93)	(7.39)	(6.76)	(6.50)
	Sectoral Demand	AGR	%	(1.40)	(6.82)	(9.52)	(8.33)	(7.73)
		COL	%					
		CRU	%					
		EIS	%	(1.38)	(6.74)	(9.44)	(8.29)	(7.70)
		ELE	%	(0.89)	(5.33)	(8.28)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(0.88)	(4.90)	(7.47)	(6.88)	(6.60)
		MAN	%	(1.24)	(6.26)	(8.87)	(7.82)	(7.31)
		OIL	%	(1.24)	(6.41)	(9.00)	(7.86)	(7.32)
		SRV	%	(0.55)	(3.30)	(5.33)	(5.01)	(4.85)
		TRK	%	(0.32)	(2.04)	(3.66)	(3.68)	(3.66)
		TRN	%	(0.35)	(2.11)	(3.75)	(3.77)	(3.75)
		C	%	(0.41)	(2.75)	(4.55)	(4.34)	(4.20)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 160: Detailed Results for HEUR_SD_HR

Scenario: HEUR_SD_HR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,973	$18,012	$20,438	$23,021	$25,918
	Consumption		Billion 2010$	$12,442	$14,000	$16,010	$18,181	$20,564
	Investment		Billion 2010$	$2,486	$2,805	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.23	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.49	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.74	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.69	$18.71	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.08	0.27	0.13	0.08	0.06
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.17)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.13)
	Gross Resource Income		%	17.27	52.53	29.53	20.22	17.92
	Consumption		%	0.10	0.01	(0.02)	(0.01)	(0.01)
	Investment		%	0.11	(0.22)	0.03	0.02	0.03
Natural Gas	Wellhead Price		%	7.96	31.57	20.46	14.95	13.54
	Production		%	1.49	5.68	7.61	8.46	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.71)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.14)	(14.12)	(10.46)	(8.36)	(7.75)
		COL	%					
		CRU	%					
		EIS	%	(4.05)	(13.92)	(10.39)	(8.32)	(7.73)
		ELE	%	(2.75)	(11.20)	(9.08)	(7.76)	(7.62)
		GAS	%					
		M_V	%	(2.64)	(10.24)	(8.20)	(6.90)	(6.60)
		MAN	%	(3.71)	(13.02)	(9.71)	(7.83)	(7.31)
		OIL	%	(3.77)	(13.34)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.70)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.97)	(4.47)	(4.05)	(3.69)	(3.66)
		TRN	%	(1.01)	(4.57)	(4.18)	(3.79)	(3.76)
		C	%	(1.36)	(6.06)	(5.03)	(4.33)	(4.19)
[1]	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 161: Detailed Results for HEUR_SD_NC

Scenario: HEUR_SD_NC								
	Description		Units	2015	2020	2025	2030	2035
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$16,017	$18,025	$20,462	$23,039	$25,948
	Consumption		Billion 2010$	$12,447	$14,002	$16,012	$18,184	$20,565
	Investment		Billion 2010$	$2,473	$2,812	$3,177	$3,538	$4,002
Natural Gas	Wellhead Price		2010$ per Mcf	$4.68	$4.98	$5.55	$5.71	$6.41
	Production		Tcf	25.87	28.24	30.81	32.43	34.24
	Exports		Tcf	4.23	5.44	6.72	6.89	8.39
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	23.91	24.07	24.34	25.67	25.99
	Sectoral Demand	AGR	Tcf	0.13	0.13	0.14	0.14	0.14
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	2.91	2.95	2.97	3.02	2.87
		ELE	Tcf	7.32	7.19	7.15	7.78	8.23
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.17	0.16	0.17	0.17
		MAN	Tcf	3.77	3.88	4.02	4.25	4.28
		OIL	Tcf	1.11	1.17	1.15	1.25	1.20
		SRV	Tcf	2.34	2.41	2.49	2.61	2.67
		TRK	Tcf	0.46	0.48	0.51	0.56	0.60
		TRN	Tcf	0.22	0.22	0.24	0.26	0.28
		C	Tcf	4.58	4.57	4.59	4.64	4.53
		G	Tcf	0.88	0.90	0.94	0.99	1.01
	Export Revenues [1]		Billion 2010$	$18.35	$25.13	$34.58	$36.49	$49.83
Percentage Change								
Macro	Gross Domestic Product		%	0.35	0.34	0.25	0.16	0.18
	Gross Capital Income		%	(0.42)	(0.47)	(0.42)	(0.32)	(0.33)
	Gross Labor Income		%	(0.33)	(0.34)	(0.32)	(0.25)	(0.26)
	Gross Resource Income		%	88.35	70.57	52.78	36.18	41.62
	Consumption		%	0.14	0.02	(0.01)	0.00	0.00
	Investment		%	(0.41)	0.04	0.01	0.18	0.18
Natural Gas	Wellhead Price		%	39.81	42.27	35.75	26.06	30.14
	Production		%	4.78	6.75	11.16	12.97	15.18
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	Sectoral Demand	AGR	%	(11.32)	(13.18)	(12.97)	(10.98)	(12.98)
		COL	%	(16.58)	(17.87)	(16.58)	(13.50)	(15.34)
		CRU	%					
		EIS	%					
		ELE	%	(16.19)	(17.66)	(16.46)	(13.45)	(15.30)
		GAS	%	(11.50)	(14.17)	(14.43)	(12.54)	(15.11)
		M_V	%					
		MAN	%	(10.73)	(13.00)	(13.07)	(11.18)	(13.14)
		OIL	%	(14.93)	(16.41)	(15.42)	(12.64)	(14.50)
		SRV	%	(15.45)	(16.82)	(15.63)	(12.69)	(14.54)
		TRK	%	(7.51)	(9.21)	(9.55)	(8.24)	(9.89)
		TRN	%	(4.25)	(5.81)	(6.66)	(6.10)	(7.55)
		C	%	(4.35)	(6.01)	(6.86)	(6.29)	(7.74)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 162: Detailed Results for LEUR_SD_LSS

Scenario: LEUR_SD_LSS								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,791	$17,719	$20,060	$22,691	$25,568
	Consumption		Billion 2010$	$12,382	$13,920	$15,861	$18,093	$20,477
	Investment		Billion 2010$	$2,443	$2,757	$3,135	$3,495	$3,956
Natural Gas	Wellhead Price		2010$ per Mcf	$5.73	$6.82	$8.04	$8.33	$9.00
	Production		Tcf	19.60	20.15	20.58	21.13	21.83
	Exports		Tcf	-	0.78	0.86	-	0.19
	Pipeline Imports		Tcf	3.00	2.61	2.37	2.01	1.75
	Total Demand		Tcf	22.60	21.98	22.09	23.14	23.39
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.18	3.05	2.96	2.86	2.75
		ELE	Tcf	5.23	4.88	5.08	5.91	6.10
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.19	0.16	0.15	0.16	0.16
		MAN	Tcf	3.99	3.88	3.86	3.95	3.99
		OIL	Tcf	1.32	1.37	1.37	1.36	1.38
		SRV	Tcf	2.32	2.33	2.35	2.45	2.54
		TRK	Tcf	0.45	0.45	0.47	0.49	0.51
		TRN	Tcf	0.21	0.21	0.22	0.23	0.24
		C	Tcf	4.68	4.61	4.59	4.63	4.58
		G	Tcf	0.88	0.89	0.90	0.94	0.97
	Export Revenues [1]		Billion 2010$	$0.00	$4.93	$6.41	$0.00	$1.58
Percentage Change								
Macro	Gross Domestic Product		%	0.00	0.01	(0.01)	(0.01)	0.01
	Gross Capital Income		%	0.00	(0.08)	(0.06)	(0.01)	(0.00)
	Gross Labor Income		%	0.00	(0.06)	(0.05)	(0.00)	(0.00)
	Gross Resource Income		%	(0.02)	7.82	3.12	(0.06)	0.43
	Consumption		%	0.02	0.00	(0.01)	0.00	0.00
	Investment		%	0.04	(0.07)	(0.08)	0.08	0.08
Natural Gas	Wellhead Price		%	(0.00)	5.78	2.75	(0.00)	0.42
	Production		%	(0.00)	1.35	2.70	(0.01)	0.60
	Pipeline Imports		%					
	Total Demand		%	(0.00)	(2.28)	(1.42)	(0.01)	(0.25)
	Sectoral Demand	AGR	%	(0.02)	(3.06)	(1.78)	(0.03)	(0.30)
		COL	%					
		CRU	%					
		EIS	%	(0.02)	(3.01)	(1.76)	(0.04)	(0.31)
		ELE	%	0.01	(2.46)	(1.56)	(0.00)	(0.29)
		GAS	%					
		M_V	%	(0.00)	(2.19)	(1.44)	(0.01)	(0.25)
		MAN	%	(0.02)	(2.76)	(1.64)	(0.00)	(0.27)
		OIL	%	0.00	(2.81)	(1.62)	(0.00)	(0.28)
		SRV	%	0.00	(1.70)	(1.14)	(0.01)	(0.21)
		TRK	%	(0.00)	(1.11)	(0.89)	(0.01)	(0.17)
		TRN	%	(0.01)	(1.14)	(0.91)	(0.02)	(0.19)
		C	%	0.02	(1.50)	(1.04)	0.00	(0.19)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 163: Detailed Results for HEUR_SD_LSS_QR

Scenario: HEUR_SD_LSS_QR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,963	$17,976	$20,428	$23,016	$25,915
	Consumption		Billion 2010$	$12,434	$14,003	$16,015	$18,184	$20,566
	Investment		Billion 2010$	$2,484	$2,812	$3,176	$3,531	$3,995
Natural Gas	Wellhead Price		2010$ per Mcf	$3.39	$3.72	$4.43	$4.84	$5.23
	Production		Tcf	24.76	26.89	28.73	29.94	30.97
	Exports		Tcf	0.18	1.10	2.01	2.19	2.19
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.84	27.06	26.97	27.89	28.92
	Sectoral Demand	AGR	Tcf	0.16	0.15	0.16	0.16	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.45	3.46	3.39	3.34	3.26
		ELE	Tcf	8.23	8.16	8.02	8.56	9.33
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.21	0.19	0.18	0.18	0.19
		MAN	Tcf	4.41	4.49	4.55	4.68	4.83
		OIL	Tcf	1.31	1.36	1.31	1.38	1.35
		SRV	Tcf	2.53	2.61	2.68	2.78	2.90
		TRK	Tcf	0.48	0.51	0.54	0.59	0.64
		TRN	Tcf	0.22	0.24	0.25	0.27	0.30
		C	Tcf	4.88	4.90	4.89	4.89	4.85
		G	Tcf	0.96	0.99	1.02	1.06	1.10
	Export Revenues [1]		Billion 2010$	$0.57	$3.80	$8.25	$9.83	$10.62
Percentage Change								
Macro	Gross Domestic Product		%	0.02	0.07	0.08	0.06	0.05
	Gross Capital Income		%	(0.01)	(0.07)	(0.10)	(0.09)	(0.08)
	Gross Labor Income		%	(0.01)	(0.05)	(0.07)	(0.07)	(0.07)
	Gross Resource Income		%	2.51	10.16	11.70	9.06	8.09
	Consumption		%	0.04	0.03	0.01	0.00	0.00
	Investment		%	0.06	0.04	(0.02)	(0.01)	(0.01)
Natural Gas	Wellhead Price		%	1.19	6.27	8.28	6.86	6.26
	Production		%	0.26	1.63	3.66	4.32	4.18
	Pipeline Imports		%					
	Total Demand		%	(0.43)	(2.41)	(3.56)	(3.29)	(3.17)
	Sectoral Demand	AGR	%	(0.70)	(3.37)	(4.64)	(4.09)	(3.82)
		COL	%					
		CRU	%					
		EIS	%	(0.70)	(3.34)	(4.61)	(4.08)	(3.81)
		ELE	%	(0.43)	(2.60)	(3.99)	(3.78)	(3.73)
		GAS	%					
		M_V	%	(0.45)	(2.42)	(3.63)	(3.38)	(3.25)
		MAN	%	(0.61)	(3.09)	(4.31)	(3.83)	(3.59)
		OIL	%	(0.60)	(3.14)	(4.36)	(3.84)	(3.58)
		SRV	%	(0.26)	(1.59)	(2.53)	(2.41)	(2.34)
		TRK	%	(0.16)	(0.99)	(1.74)	(1.77)	(1.77)
		TRN	%	(0.19)	(1.03)	(1.79)	(1.82)	(1.82)
		C	%	(0.19)	(1.31)	(2.14)	(2.06)	(2.01)
1	Export revenues are based on LNG exports net of liquefaction loss.							

Figure 164: Detailed Results for HEUR_SD_HR_QR

Scenario: HEUR_SD_HR_QR								
	Description		Units	**2015**	**2020**	**2025**	**2030**	**2035**
Level Values								
Macro	Gross Domestic Product		Billion 2010$	$15,974	$18,013	$20,443	$23,027	$25,927
	Consumption		Billion 2010$	$12,444	$14,003	$16,013	$18,184	$20,567
	Investment		Billion 2010$	$2,486	$2,804	$3,178	$3,532	$3,996
Natural Gas	Wellhead Price		2010$ per Mcf	$3.61	$4.61	$4.93	$5.21	$5.59
	Production		Tcf	25.06	27.96	29.83	31.13	32.17
	Exports		Tcf	1.10	4.38	4.38	4.38	4.38
	Pipeline Imports		Tcf	2.26	1.27	0.25	0.14	0.14
	Total Demand		Tcf	26.22	24.85	25.70	26.89	27.92
	Sectoral Demand	AGR	Tcf	0.15	0.14	0.15	0.15	0.16
		COL	Tcf	-	-	-	-	-
		CRU	Tcf	-	-	-	-	-
		EIS	Tcf	3.33	3.08	3.18	3.19	3.13
		ELE	Tcf	8.04	7.44	7.59	8.21	8.95
		GAS	Tcf	-	-	-	-	-
		M_V	Tcf	0.20	0.18	0.17	0.18	0.18
		MAN	Tcf	4.27	4.03	4.29	4.48	4.64
		OIL	Tcf	1.27	1.21	1.23	1.32	1.30
		SRV	Tcf	2.49	2.46	2.59	2.70	2.82
		TRK	Tcf	0.48	0.49	0.53	0.57	0.63
		TRN	Tcf	0.22	0.23	0.24	0.27	0.29
		C	Tcf	4.82	4.66	4.75	4.78	4.75
		G	Tcf	0.95	0.93	0.98	1.03	1.07
	Export Revenues [1]		Billion 2010$	$3.68	$18.70	$20.00	$21.15	$22.70
Percentage Change								
Macro	Gross Domestic Product		%	0.09	0.28	0.16	0.11	0.10
	Gross Capital Income		%	(0.07)	(0.34)	(0.26)	(0.20)	(0.18)
	Gross Labor Income		%	(0.06)	(0.25)	(0.19)	(0.15)	(0.14)
	Gross Resource Income		%	17.17	52.44	29.47	20.17	17.87
	Consumption		%	0.12	0.03	(0.00)	0.00	0.01
	Investment		%	0.11	(0.22)	0.02	0.01	0.02
Natural Gas	Wellhead Price		%	7.94	31.55	20.45	14.94	13.53
	Production		%	1.49	5.68	7.61	8.45	8.20
	Pipeline Imports		%					
	Total Demand		%	(2.72)	(10.38)	(8.12)	(6.77)	(6.50)
	Sectoral Demand	AGR	%	(4.17)	(14.15)	(10.50)	(8.40)	(7.79)
		COL	%					
		CRU	%					
		EIS	%	(4.09)	(13.96)	(10.43)	(8.37)	(7.77)
		ELE	%	(2.74)	(11.19)	(9.08)	(7.76)	(7.61)
		GAS	%					
		M_V	%	(2.68)	(10.27)	(8.23)	(6.94)	(6.64)
		MAN	%	(3.73)	(13.03)	(9.73)	(7.85)	(7.33)
		OIL	%	(3.77)	(13.33)	(9.87)	(7.86)	(7.32)
		SRV	%	(1.69)	(7.15)	(5.87)	(5.01)	(4.85)
		TRK	%	(0.98)	(4.48)	(4.06)	(3.70)	(3.68)
		TRN	%	(1.04)	(4.59)	(4.19)	(3.81)	(3.78)
		C	%	(1.34)	(6.04)	(5.01)	(4.31)	(4.17)
1	Export revenues are based on LNG exports net of liquefaction loss.							

APPENDIX D - COMPARISON WITH EIA STUDY

NERA's modeling of shifts in natural gas price, production, and demand are built off an attempt to replicate EIA's price path. This was an important step to ensure that the NERA model output was consistent with the EIA's model. Of particular importance was the ability to replicate EIA's natural gas prices as closely as possible since it is a key driver of macroeconomic impacts. In this process, we ran the exact export scenarios reflected in the EIA Study. We ran Low/Slow, Low/High, High/Slow, and High/Rapid export expansion scenarios for the Reference, High Shale, and Low Shale outlooks. In total we ran 16 EIA consistent scenarios to compare model results. NERA Reference shale gas case scenarios are referenced as NERA_REF_LS, NERA_REF_LR, NERA_REF_HS, and NERA_REF_HR. Similarly, the High Shale and Low Shale case outlook for the NERA Study is referenced as NERA_HEUR_LS, NERA_HEUR_LR, NERA_HEUR_HS, NERA_HEUR_HR, NERA_LEUR_LS, NERA_LEUR_LR, NERA_LEUR_HS, NERA_LEUR_HR, respectively. The corresponding EIA scenarios are referenced as EIA_REF_LS, EIA_REF_LR, EIA_REF_HS, EIA_REF_HR, EIA_HEUR_LS, EIA_HEUR_LR, EIA_HEUR_HS, EIA_HEUR_HR, EIA_LEUR_LS, EIA_LEUR_LR, NERA_LEUR_HS, and NERA_LEUR_HR.

The natural gas supply curve in the NERA model was calibrated to EIA's natural gas supply curve in order to produce a response similar to the EIA High/Rapid scenario for the respective baselines. While the results of this price calibration scenario were nearly duplicated, other macroeconomic scenarios exhibited some differences between the NERA and EIA model runs. These variances are due primarily to differences in the model structure and modeling characteristics such as sectoral price elasticity of demand, supply elasticity, and other behavioral model parameters.

For changes in natural gas prices, the most apparent difference between the EIA and NERA model runs is seen in the High/Slow scenario. This is true for the Reference, High EUR and Low EUR baselines as seen in Figure 165, Figure 166, and Figure 167.These differences arise because we first estimate the implied price elasticity of natural gas supply to replicate the High/Rapid case and then adopt that elasticity for the other scenario runs.

Figure 165: Reference Case Natural Gas Price Percentage Changes

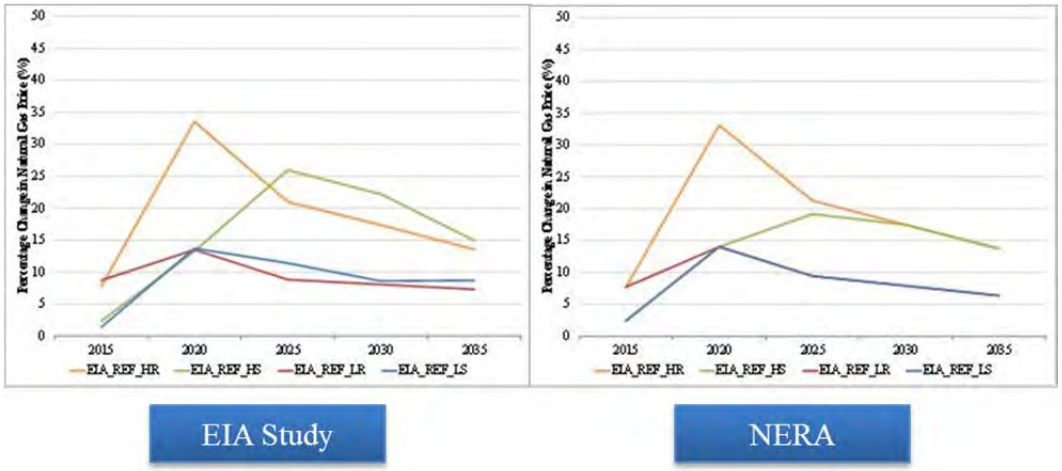


Figure 166: High EUR Natural Gas Price Percentage Changes

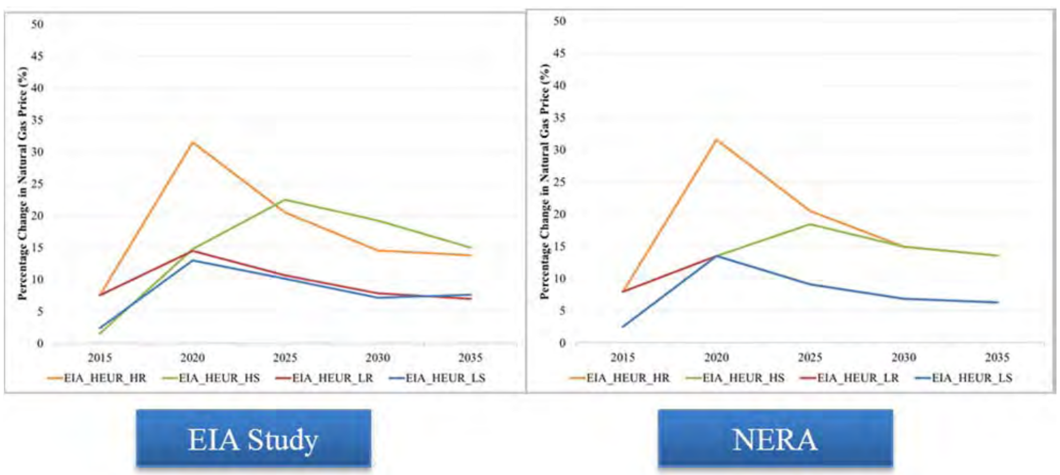
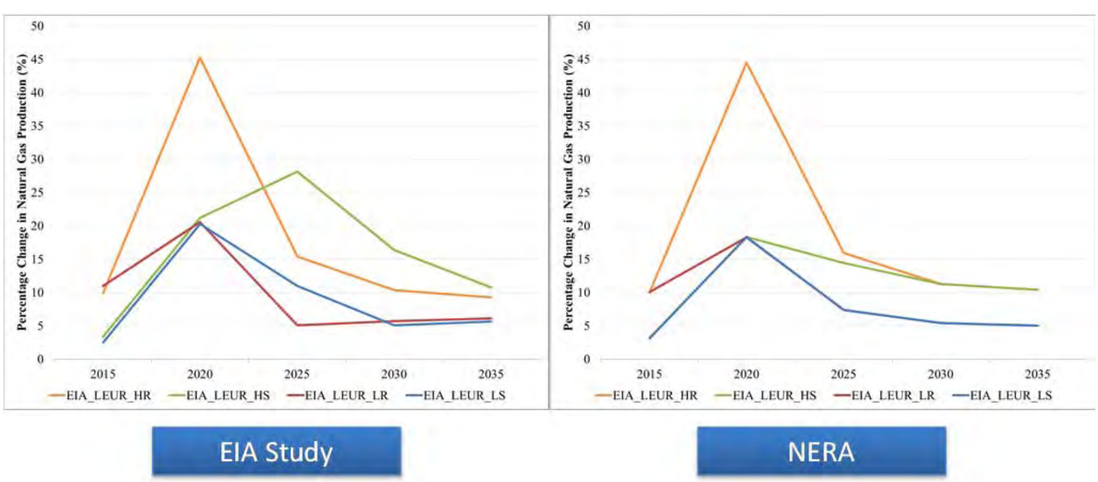


Figure 167: Low EUR Natural Gas Price Percentage Changes



The prices seen in the EIA High/Slow scenario in each baseline case deviate primarily in 2025, but also in 2030, in the range of 5% to 10% higher than the price change seen in the NERA High/Slow scenario. The low/slow scenario also shows small, but noticeable, differentials between the EIA and NERA model runs, particularly with the Reference and Low EUR baselines in 2025. Other than these differences, the general paths of price development in the NERA model runs tend to closely follow those estimated in the EIA study.

Changes in levels of natural gas demand and production show greater differences between the EIA and NERA runs than those seen in price. As briefly mentioned above, and elaborated on to a greater extent below, much of these variances result from the different elasticities used in the models and the overall model structures. The similar paths, but different magnitudes, of demand and production changes compared to the closely matched price changes reveal implied elasticities as a major source of variance. Figure 169 shows the implied supply elasticities for each case in 2015, 2025, and 2035.

The EIA Study assumed four different export scenarios for three different natural gas resources estimates (Reference, High Shale EUR, and Low Shale EUR). The scenarios for each baseline provide sufficient information about natural gas prices and supply quantities to be able to examine the natural gas supply curves. The supply curves are characterized by prices, quantities and the curvature. The current study makes all effort to simulate the EIA's supply curves despite the differences in the model construct. Figure 168 shows the EIA Study and NERA study supply curves for years 2020 and 2035 for the three natural gas resource outlooks.

Examining the curves suggests that the short-run supply curves (2020) are more inelastic than the long-run (2035) supply curves in both studies. The flattening of the supply curves is due to the fact that production and resource constraints are less binding over time. Under the High EUR case, 30 to 34 Tcf of natural gas can be supplied within a price range of $5 to $6/Mcf in the long run. However, under the Low EUR case, less natural gas can be supplied at a much higher price.

The EIA Study supply curves are shown as solid lines and the NERA supply curves are shown as dotted lines. Although the long-run supply curves are fairly close to one another, the short-run NERA supply curves are more inelastic. Given the supply curves, for a given change in quantity supplied, natural gas production in NERA model is relatively more price responsive in 2020 than in the EIA Study. The differences in the underlying assumption of the implied supply elasticities in 2020 drive this shape of the supply curve.

Figure 168: Natural Gas Supply Curves

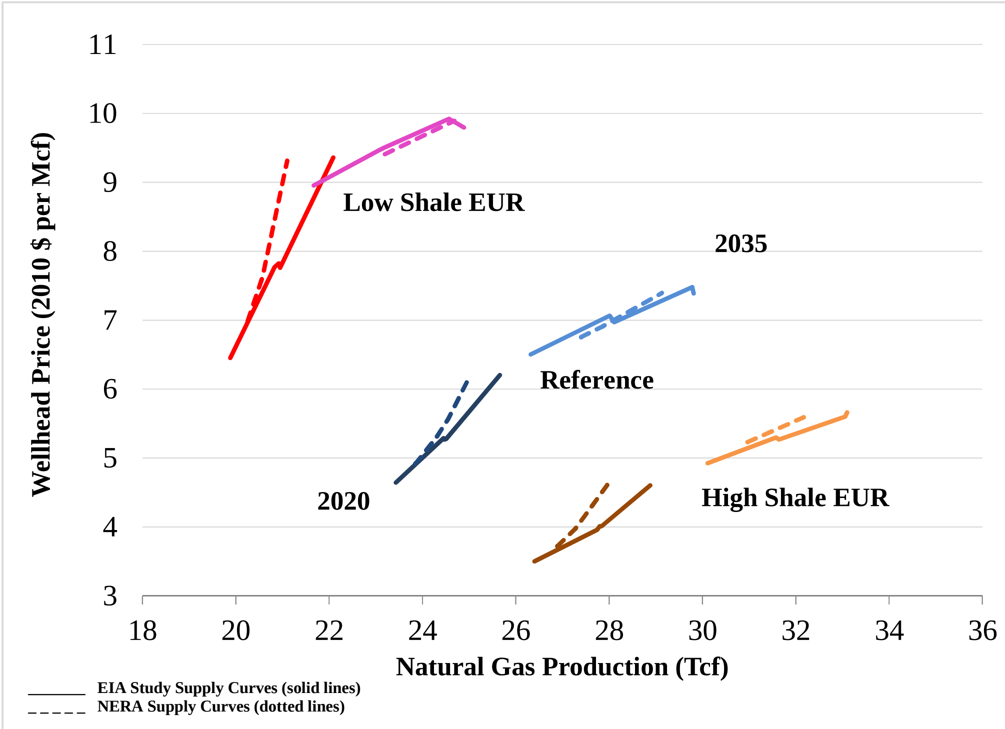
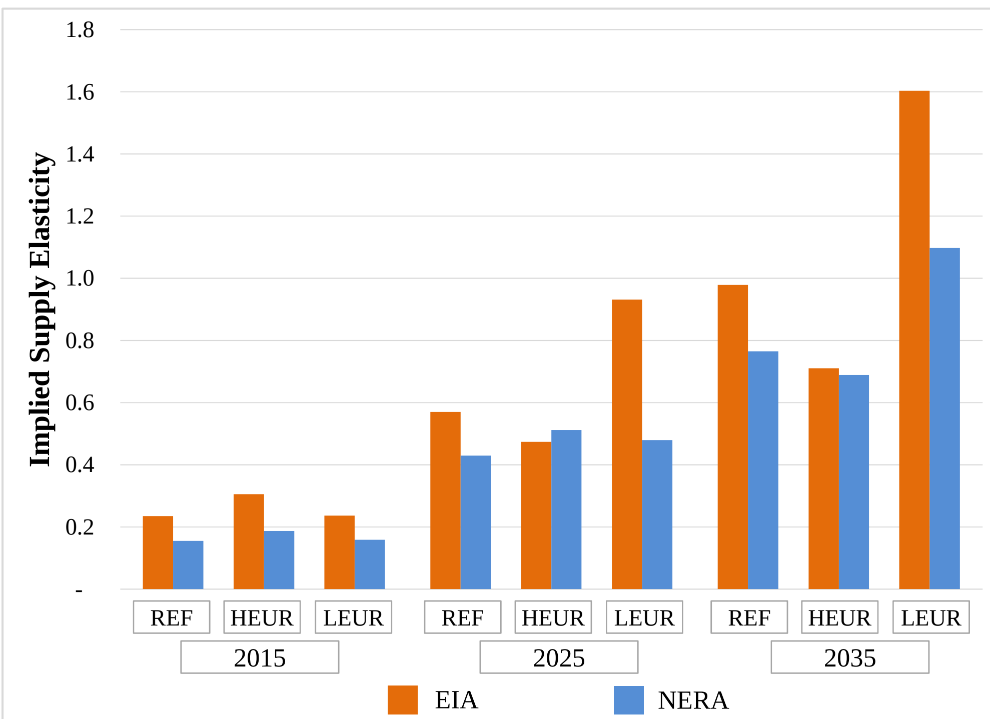


Figure 169: Implied Elasticities of Supply for Cases



Overall, the changes in natural gas demand are dampened in the EIA Study relative to the changes seen in the NERA model results, as seen in Figure 170, Figure 171, and Figure 172. The biggest differences appear to be found in the two rapid scenarios, High/Rapid and Low/Rapid. For each of the baseline cases, the rapid scenarios in the EIA Study show a significantly smaller magnitude of change in demand than they do in the comparable NERA model runs. Similar to the changes in price seen earlier, these differences are most pronounced in 2025 and 2030.

Figure 170: Reference Case Natural Gas Demand Percentage Changes

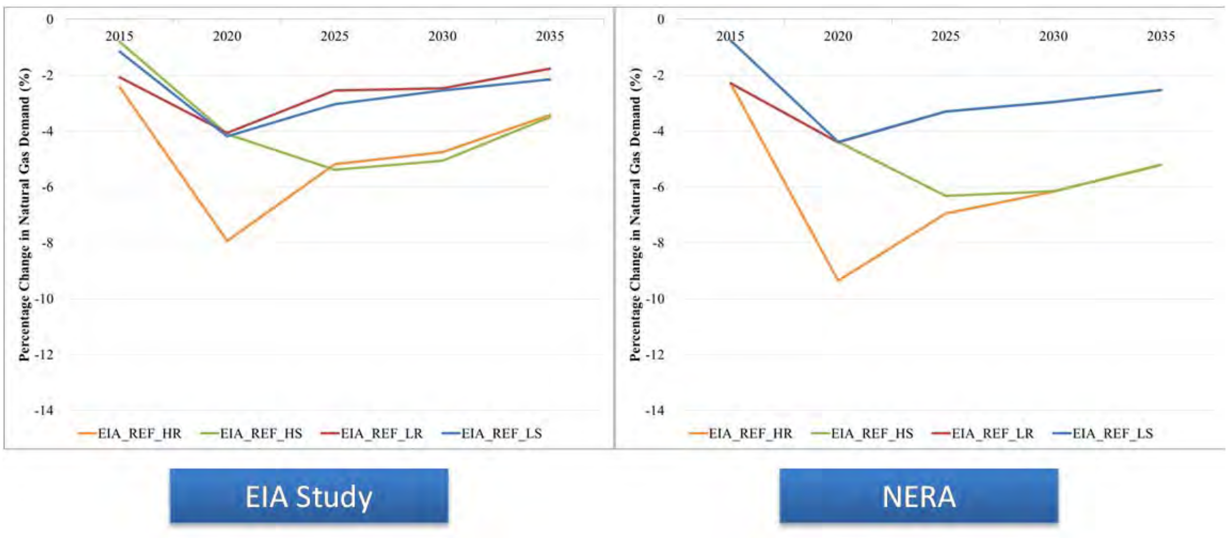


Figure 171: High EUR Natural Gas Demand Percentage Changes

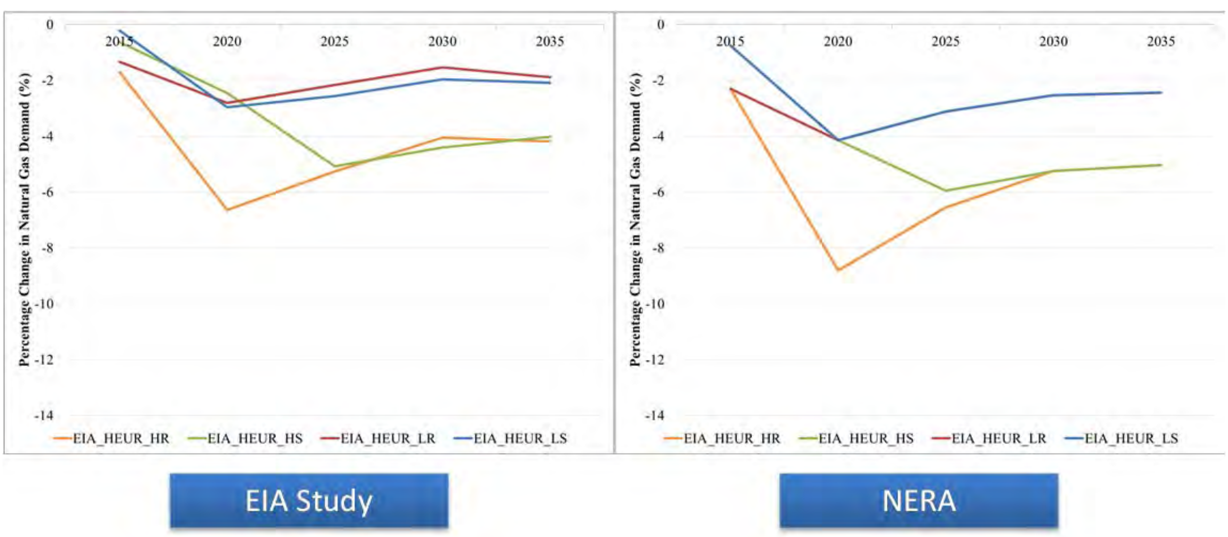
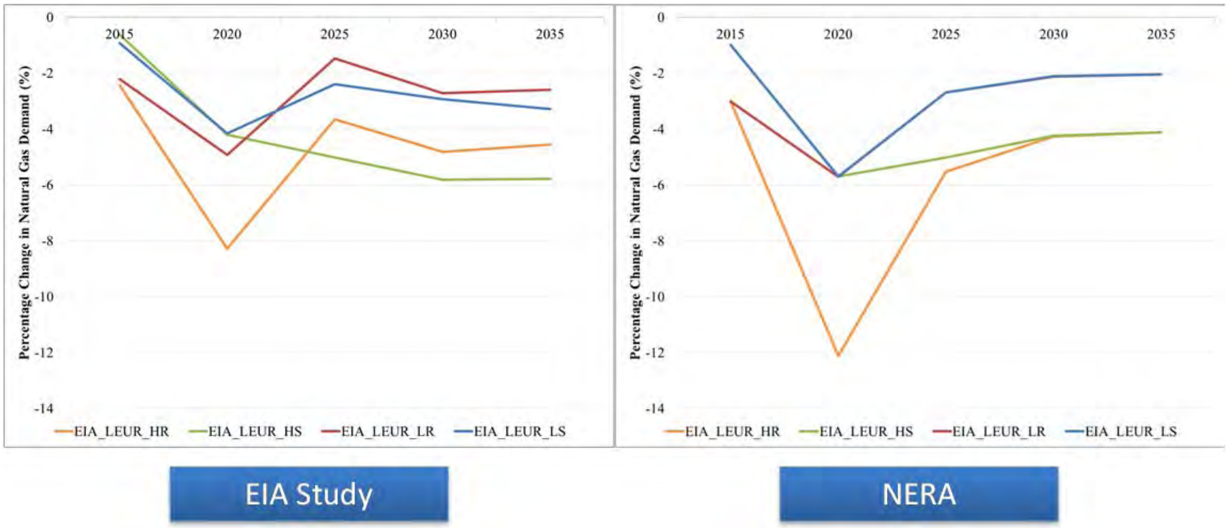


Figure 172: Low EUR Natural Gas Demand Percentage Changes



The results of the Low EUR baseline seen in Figure 172 show the most variance between the EIA and NERA results. In addition to the previously mentioned observation of overall lower magnitude changes in the EIA numbers relative to the NERA numbers and the largest differences being seen in 2025 and 2030, the paths of demand change in the two slow scenarios (High/Slow and Low/Slow) vary in later model years. In the EIA Study the changes in the High/Slow and Low/Slow scenarios get larger from 2025 to 2035 while in the NERA model the changes get smaller towards the end of the model horizon.

Differences between the changes in natural gas production seen in the EIA Study and the NERA modeling results are similar to those seen in demand changes, but in the opposite direction. In this metric, the EIA results show greater magnitudes of change than the NERA results, as can be seen in Figure 173, Figure 174, and Figure 175. This difference can be as large as 3% to 4%, as seen in the 2030 and 2035 years of the Reference Case high scenarios (High/Rapid and High/Slow).

Figure 173: Reference Case Natural Gas Production Percentage Changes

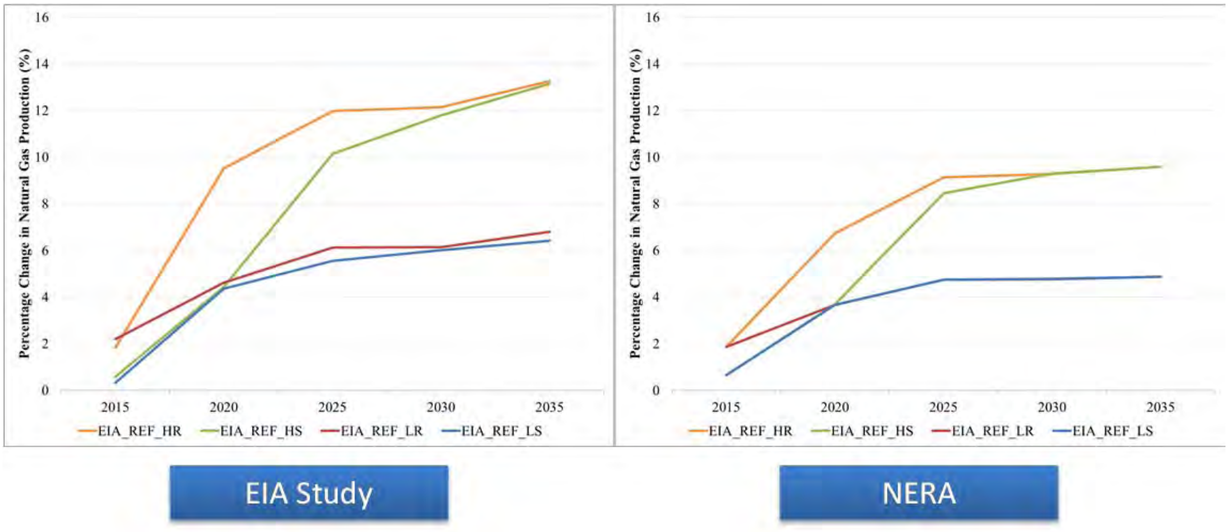


Figure 174: High EUR Natural Gas Production Percentage Changes

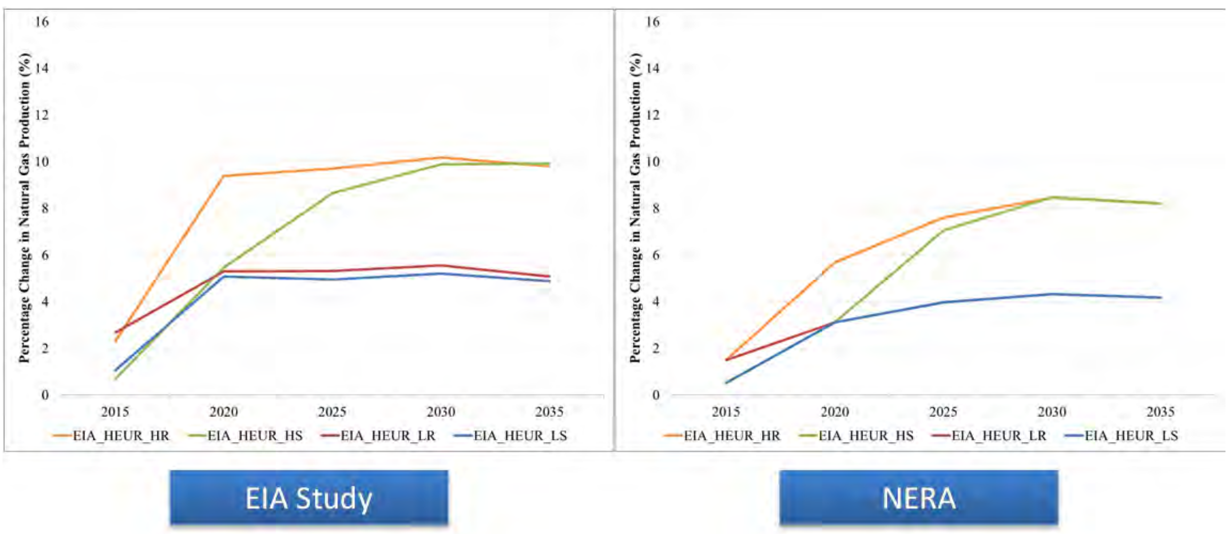
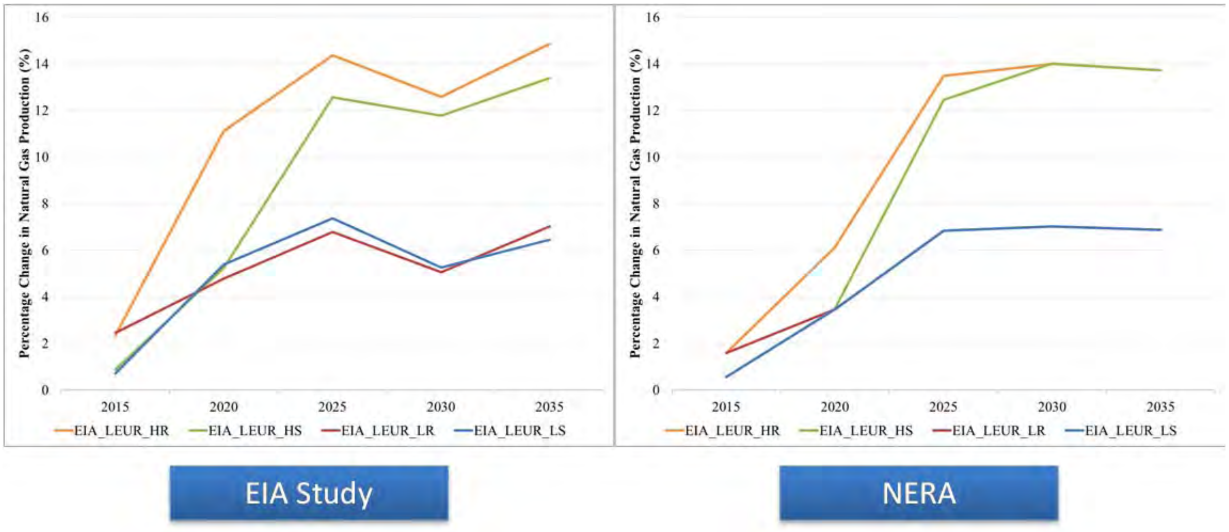


Figure 175: Low EUR Natural Gas Production Percentage Changes



Apart from the overall difference in levels of change seen between the two sets of model results, the general paths and patterns remain fairly similar because they are primarily driven by the level values and the pace of export expansion. The largest differences tend to occur in 2025 and 2030, similar to what is observed in the previous results, but the production changes also show some more variation in 2020.

Comparing changes in natural gas demand at a sectoral level reveal additional similarities and differences between the EIA Study model runs and the NERA model runs. As seen in Figure 176, Figure 177, and Figure 178, while overall levels of natural gas consumption are relatively consistent between the EIA Study and the NERA results, the sectoral components exhibit notable divergences. In particular, the NERA results show much greater demand response in the industrial sector while at the same time much less demand response in the electricity sector. These differences appear to be consistent across all baseline cases. The main reason for the variations in the electricity sector comes from the different way that the sector is modeled. EIA's NEMS model has a detailed bottom-up representation of the electricity sector, while the electricity sector in the NERA model is a nested CES function with limited technologies. This means that NEMS allows for switching from natural gas-based generation to other technology types easily, while the possibility of switching out of natural gas is more limited and controlled in the NERA model.

Figure 176: Reference Case Average Change in Natural Gas Consumed by Sector

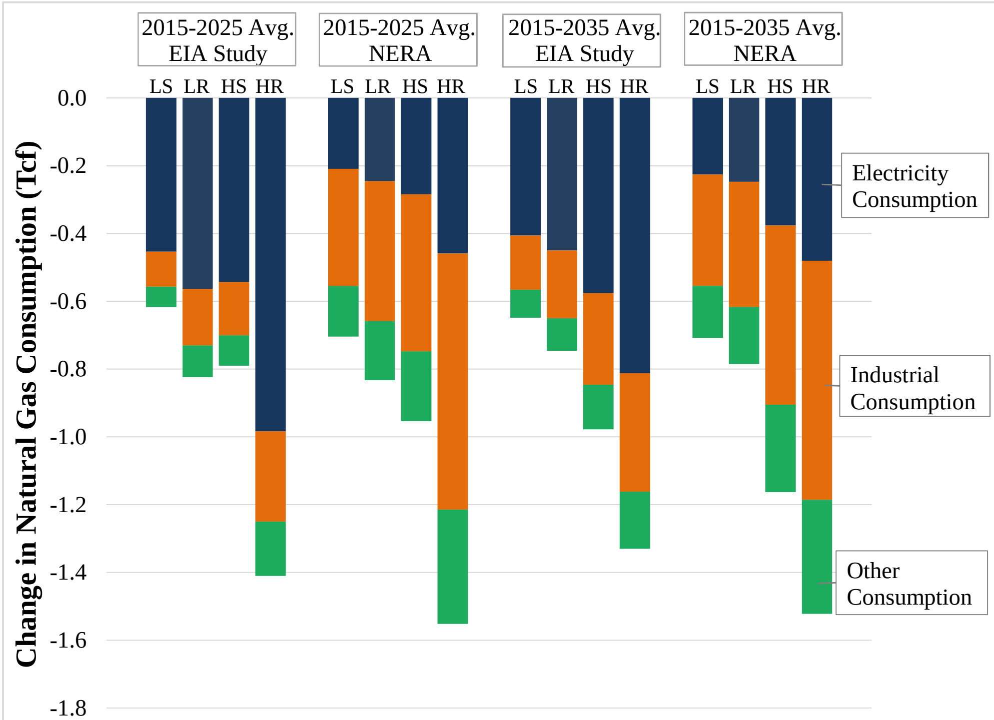


Figure 177: High EUR Average Change in Natural Gas Consumed by Sector

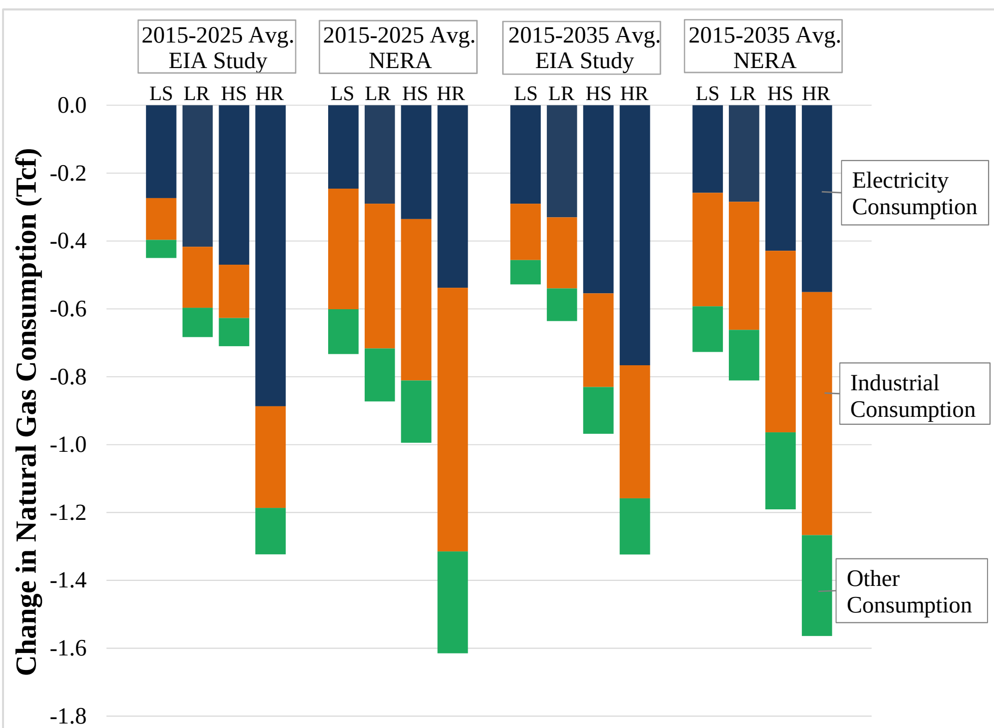
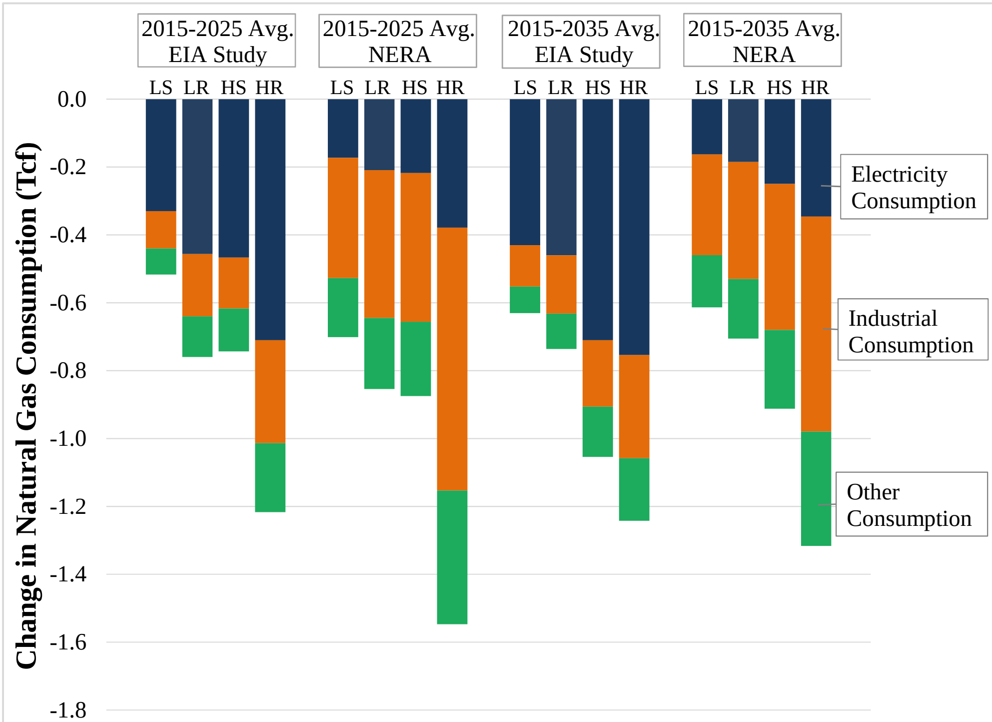


Figure 178: Low EUR Case Average Change in Natural Gas Consumed by Sector



APPENDIX E - FACTORS THAT WE DID NOT INCLUDE IN THE ANALYSIS

There are a number of issues that this study did not address directly. To avoid the misinterpretation of these results or the drawing of unwarranted implications, this section provides brief comments on each.

A. How Will Overbuilding of Export Capacity Affect the Market

This study assumes that the amount of capacity built will match market demand and that the pricing of liquefaction services will be based on long-run marginal costs. Should developers overbuild capacity, there could be pressure on take-or-pay contracts and potentially the margins earned for liquefaction services could be driven below the amount required to cover debt service and expected profits, just as has been the case with petroleum refining margins during periods of slack capacity.

B. Engineering or Infrastructure Limits on How Fast U.S. Liquefaction Capacity Could Be Built

Many of the scenarios investigated in this report assume rates of expansion of liquefaction facilities in the U.S. (and worldwide) that some industry sources believe will strain the capacity of engineering and construction providers. This could drive up the cost of building liquefaction facilities and constrain the rate of expansion to levels lower than those projected in the different scenarios investigated in this report, even if the U.S. resource and global market conditions were as assumed in those scenarios. This possibility requires analysis of the capabilities of the relevant global industries to support rapid construction that could be addressed in later studies.

C. Where Production or Export Terminals Will Be Located

There are proposals for export facilities in the Mid-Atlantic, Pacific Northwest and Canada, all of which could change basis differentials and potentially the location of additional natural gas production, with corresponding implications for regional impacts. To analyze alternative locations of export facilities it would be necessary to repeat both the EIA and the NERA analyses with additional scenarios incorporating demand for natural gas export in different regions.

D. Regional Economic Impacts

Since the EIA assumed that all of the demand for domestic production associated with LNG exports was located in the Gulf region, it was not possible in this study to examine regional impacts on either natural gas prices or economic activity. The Gulf Coast is not necessarily a representative choice given the range of locations now in different applications, so that any attempt to estimate regional impacts would be misleading without more regional specificity in the location of exports.

E. Effects on Different Socioeconomic Groups

Changes in energy prices are often divided into "effects on producers" and "effects on consumers." Although convenient to indicate that there are winners and losers from any market or policy change, this terminology gives limited insight into how the gains and losses are distributed in the economy. The ultimate incidence of all price changes is on individuals and households, for private businesses are all owned ultimately by people. Price changes affect not only the cost of goods and services purchased by households, but also their income from work and investments, transfers from government, and the taxes they pay. More relevant indicators of the distribution of gains and losses include real disposable income by income category, real consumption expenditures by income category, and possibly other measures of distribution by socioeconomic group or geography. This study addresses only the net economic effects of natural gas price changes and improved export revenues, not their distribution.

F. Implications of Foreign Direct Investment in Facilities or Gas Production

In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources. Macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment ("FDI") that was additional to baseline capital flows into the U.S. FDI would largely affect the timing of macroeconomic effects, but quantifying these differences would require consideration of additional scenarios in which the business model was varied.

APPENDIX F – COMPLETE STATEMENT OF WORK

Task Title: Macroeconomic Analysis of LNG Exports

<u>INTRODUCTION:</u>

U.S. shale gas production has increased significantly due to novel hydraulic fracturing and horizontal drilling techniques that have reduced production costs. In the *Annual Energy Outlook 2011* prepared by the Department of Energy's Energy Information Administration, domestic natural gas production grows from 21.0 trillion cubic feet (Tcf) in 2009 to 26.3 Tcf in 2035, while shale gas production grows to 12.2 Tcf in 2035, when it is projected to make up 47 percent of total U.S. production. With this increased volume of domestic natural gas supply available, several companies have applied to the DOE/FE under section 3 of the Natural Gas Act ("NGA")[55] for authorization to export domestic natural gas as LNG to international markets where prices are currently higher. DOE/FE must determine whether applications to export domestically produced LNG to non-free trade agreement ("FTA") countries are consistent with the public interest[56].

To assist with the review of current and potential future applications to DOE/FE to export domestically produced LNG, DOE/FE has requested a natural gas export case study be performed by EIA. The EIA study will provide an independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios using the *AEO 2011* National Energy Modeling System ("NEMS") model. While useful to provide the range of marginal full-cost domestic natural gas production in different scenarios, the EIA NEMS case study will not address the macroeconomic impact of natural gas exports on the U.S. economy. A macroeconomic study that evaluates the impact of LNG exports is needed to more fully examine the impact of LNG exports on the U.S. economy.

<u>PURPOSE:</u>

The purpose of this task is to evaluate the macroeconomic impact of LNG exports using a general equilibrium macroeconomic model of the U.S. economy with an emphasis on the energy sector and natural gas in particular. The general equilibrium model should be developed to incorporate the EIA case study output from NEMS into the natural gas production module in order to calibrate supply cost curves in the macroeconomic model. A macroeconomic case study will be performed to evaluate the impact that LNG exports could have on multiple economic factors, but primarily on U.S. Gross Domestic Product, employment, and real income.

---

[55] The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA (15 U.S.C. §717b) has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04E issued on April 29, 2011.

[56] Under NGA section 3(c), the import and export of natural gas, including LNG, from and to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas and the import of LNG from other international sources are deemed to be consistent with the public interest and must be granted without modification or delay. Exports of LNG to non FTA countries have not been deemed in the public interest and require a DOE/FE review.

The cases to be run will reflect LNG export volumes increasing by one billion cubic feet per day (Bcf/d) annually until reaching six Bcf/d from a reference case aligned with the *AEO 2011* reference case, a high natural gas resource case, and a low natural gas resource case. Additional cases will be run to evaluate the impact of LNG export volumes that increase much slower and much faster than in the reference case.

Some have commented that U.S. domestic natural gas prices could become disconnected with marginal domestic natural gas production cost and be influenced by higher international market prices. An analysis will be performed to assess whether there is an additional price increase, a "tipping point" price increase, above which exports of LNG have negative impacts on the U.S. economy for several of the cases. The "tipping point" price increase in this analysis could be above the marginal full production cost.

A qualitative report will be prepared that discusses how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This analysis will include an assessment of whether there are scenarios in which the domestic market could become unlinked to marginal production cost and instead become linked to higher international petroleum-based prices, and whether this could be a short-term or long-term impact, or both.

Initially, a preliminary assessment of the macroeconomic impact of the cases will be prepared and discussed with DOE. This will provide an opportunity for any adjustments to the ultimate cases that will be prepared. Finally, a report will be prepared that discusses the results of the macroeconomic study including topics identified in the Statement of Work.

STATEMENT OF WORK:

The types of analysis and discussions to be conducted include, but are not limited to:

1. U.S. Scenario Analysis (all 16 EIA cases) – Perform a case study on the impacts of a range of LNG export volumes on domestic full production costs under various export volume scenarios. A macroeconomic model will be aligned with the *AEO 2011 Reference Case* and other cases from the DOE/FE-requested EIA case study in different scenarios. Modify a general equilibrium model to calibrate supply cost curves in the macroeconomic model for consistency with EIA NEMS model. The following cases will be run with 5-year intervals through 2035:
    a. **Reference LNG Export Case –** using the macroeconomic model aligned with the *AEO 2011 Reference Case*, show export-related increases in LNG demand equal to the four export scenarios in the EIA study.
    b. Run sensitivity cases related to alternative shale gas resources and recovery economics. These include:
        i. **Low Shale Resource LNG Export Case** - align the macroeconomic model to the *AEO 2011 Low Shale EUR Case*, reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

ii. **High Shale Resource LNG Export Case** – align the macroeconomic model to the *AEO 2011 High Shale EUR Case*, reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

iii. **High Economic Growth LNG Export Case** - align the macroeconomic model to the *AEO 2011 High Economic Growth Case;* reflect LNG export volumes over time equal to the four export scenarios in the EIA study.

c. Run additional sensitivity cases – **Slow Increase in LNG Exports Case** - using the macroeconomic model aligned with the *AEO 2011 Reference Case*, increase LNG exports increase at a slower pace, growing at 0.5 Bcf/d beginning in 2015, until reaching 6 Bcf/d.

2. Preliminary Analysis – Prepare a preliminary analysis of the above cases and provide an initial summary of whether those cases have a positive or negative impact on GDP. After providing that information, discuss the results and determine whether the cases identified are still valid, if some cases should be eliminated, or others added.
3. Worldwide Scenario Analysis – Develop four global LNG market scenarios that define a range of international supply, demand, and market pricing into which U.S. LNG could be exported, as defined below. Using these scenarios, identify potential international demand for U.S. LNG exports, recognizing delivered LNG prices from the United States versus other global sources.
   a. Base case which is calibrated to EIA *International Energy Outlook 2011* for all natural gas
   b. Increased global LNG demand
   c. A restricted global LNG supply scenario in which only liquefaction facilities, of which there is already substantial construction, are completed
   d. Combination of higher international LNG demand and lower international LNG supply
4. Prepare a sensitivity analysis to examine how the ownership of the exported LNG and/or the liquefaction facility affects the U.S. economy.
5. Macroeconomic Report – Prepare a report that discusses the results of the different cases run with the key focus on the macroeconomic impacts of LNG exports. Combine global analysis and U.S. analysis to create new export scenarios that could be supported by the world market (as opposed to the EIA study in which LNG exports were exogenous to the model). Identify and quantify the benefits and drawbacks of LNG exports. Using a macroeconomic model, evaluate the comprehensive impact of all factors on:
   a. U.S. GDP
   b. Employment
   c. Household real income

   The Report will also include a discussion on:

   a. The observations on key cases run

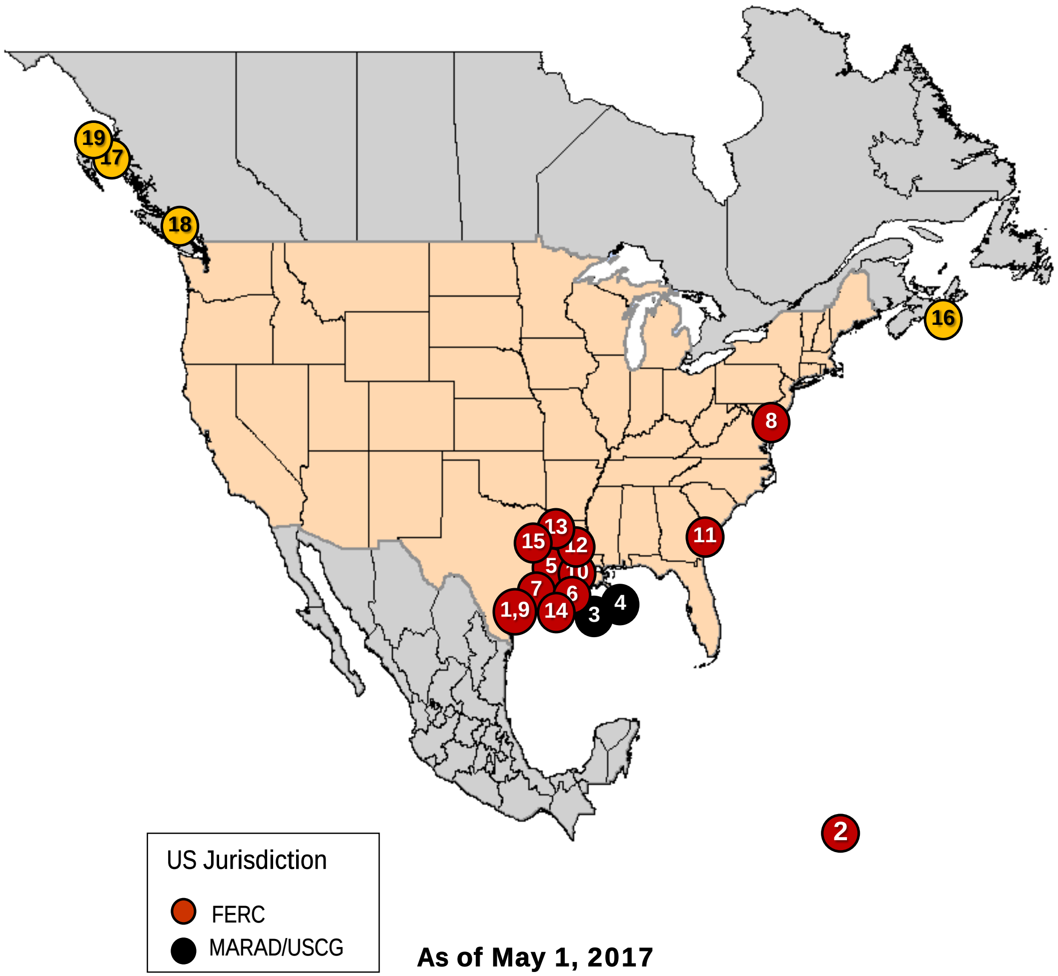
b. Balance of trade impact
c. Expected impact on tax receipts from increased production of natural gas and exports
d. The impact of LNG exports on energy intensive sectors for the scenarios developed
e. Ownership sensitivity analysis
f. Benefits
   - Jobs creation for the nation, not just a region
   - Potential increases in Federal revenues
   - Export earnings and balance of trade
g. Drawbacks
   - Increased natural gas prices
   - Potential for, and impact of, loss of jobs in energy intensive industries
h. GDP Macroeconomic impact
   - Authoritative analysis on GDP of above factors
i. Other relevant analysis and information developed in consultation with DOE/FE

6. The price impacts of natural gas exports will be discussed in a qualitative report that includes how natural gas prices are formed in the United States and the potential impact that higher international prices could have on the U.S. market. This report could be stand-alone or part of the overall macroeconomic study. It will include, at a minimum, a discussion of:
   a. Current market mechanism that establishes U.S. domestic benchmark prices (e.g., Henry Hub)
   b. Potential market mechanism for linkage of domestic markets with higher international markets
   c. The potential linkage of natural gas with petroleum in international markets
7. Assess whether there is some volume of LNG exports, or price increase, above which the United States loses the opportunity for domestic value added industry development from use of low-cost domestic natural gas resources. The discussion will include:
   a. Identification of energy-intensive, trade-exposed industries potentially affected and characterization of their energy costs, employment and value added compared to all manufacturing
   b. Potential impacts on U.S. production of selected natural gas based bulk chemicals
8. After releasing the study results, at the request of DOE, prepare up to three responses to questions raised about the study in an LNG export proceeding or other public release of the study in which these questions or issues are raised

NERA Economic Consulting
1255 23rd Street NW
Washington, DC 20037
Tel: +1 202 466 3510
Fax: +1 202 466 3605
www.nera.com

Exhibit 5

North American LNG Import/Export Terminals
Approved



As of May 1, 2017

Import Terminals

U.S.

APPROVED - UNDER CONSTRUCTION - FERC

1. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)

APPROVED – NOT UNDER CONSTRUCTION - FERC

2. Salinas, PR: 0.6 Bcfd (Aguirre Offshore GasPort, LLC) (CP13-193)

APPROVED - NOT UNDER CONSTRUCTION - MARAD/Coast Guard

3. Gulf of Mexico: 1.0 Bcfd (Main Pass McMoRan Exp.)
4. Gulf of Mexico: 1.4 Bcfd (TORP Technology-Bienville LNG)

Export Terminals

U.S.

APPROVED - UNDER CONSTRUCTION - FERC

5. Sabine, LA: 0.7 Bcfd (Cheniere/Sabine Pass LNG) (CP11-72 & CP14-12)
6. Hackberry, LA: 2.1 Bcfd (Sempra–Cameron LNG) (CP13-25)
7. Freeport, TX: 2.14 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction) (CP12-509) (CP15-518)
8. Cove Point, MD: 0.82 Bcfd (Dominion–Cove Point LNG) (CP13-113)
9. Corpus Christi, TX: 2.14 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)
10. Sabine Pass, LA: 1.40 Bcfd (Sabine Pass Liquefaction) (CP13-552) ★
11. Elba Island, GA: 0.35 Bcfd (Southern LNG Company) (CP14-103)

APPROVED – NOT UNDER CONSTRUCTION - FERC

12. Lake Charles, LA: 2.2 Bcfd (Southern Union – Lake Charles LNG) (CP14-120)
13. Lake Charles, LA: 1.08 Bcfd (Magnolia LNG) (CP14-347)
14. Hackberry, LA: 1.41 Bcfd (Sempra - Cameron LNG) (CP15-560)
15. Sabine Pass, TX: 2.1 Bcfd (ExxonMobil – Golden Pass) (CP14-517)

Canada

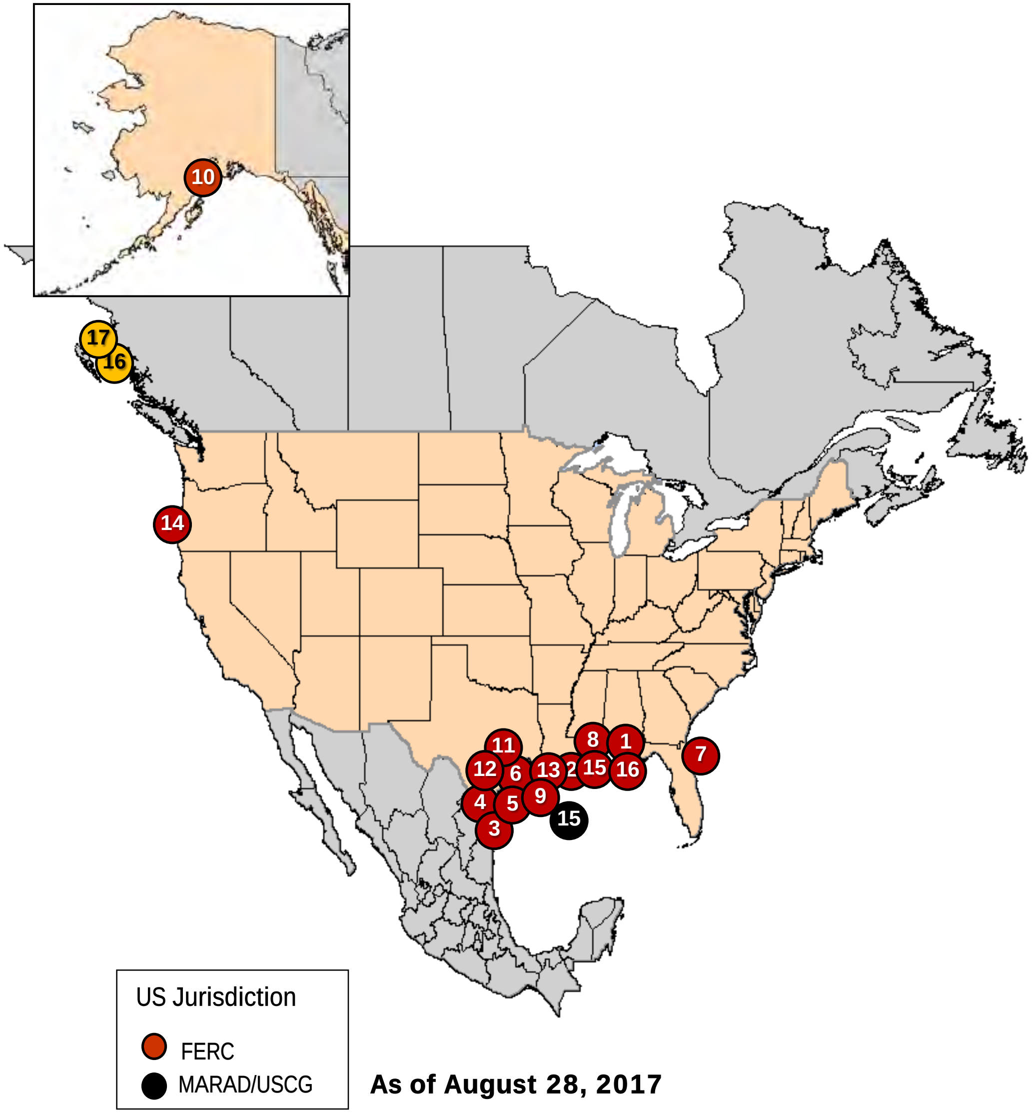
APPROVED – NOT UNDER CONSTRUCTION

16. Port Hawkesbury, NS: 0.5 Bcfd (Bear Head LNG)
17. Kitimat, BC: 3.23 Bcfd (LNG Canada)
18. Squamish, BC: 0.29 Bcfd (Woodfibre LNG Ltd)
19. Prince Rupert Island, BC: 2.74 Bcfd (Pacific Northwest LNG)

★ Trains 5 & 6 with Train 5 under construction

Exhibit 6

North American LNG Export Terminals
Proposed



As of August 28, 2017

PROPOSED TO FERC
Pending Applications:
1. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
2. Cameron Parish, LA: 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
3. Brownsville, TX: 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
4. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
5. Brownsville, TX: 0.9 Bcfd (Annova LNG Brownsville) (CP16-480)
6. Port Arthur, TX: 1.86 Bcfd (Port Arthur LNG) (CP17-20)
7. Jacksonville, FL: 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
8. Plaquemines Parish, LA: 3.40 Bcfd (Venture Global LNG) (CP17-66)
9. Calcasieu Parish, LA: 4.0 Bcfd (Driftwood LNG) (CP17-117)
10. Nikiski, AK: 2.63 Bcfd (Alaska Gasline) (CP17-178)
11. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev) (CP17-470)

Projects in Pre-filing:
12. Corpus Christi, TX: 1.4 Bcfd (Cheniere – Corpus Christi LNG) (PF15-26)
13. Cameron Parish, LA: 1.84 Bcfd (G2 LNG) (PF16-2)
14. Coos Bay, OR: 1.08 Bcfd (Jordan Cove) (PF17-4)
15. Cameron Parish, LA: 1.18 Bcfd (Commonwealth, LNG) (PF17-8)
16. LaFourche Parish, LA: 0.65 Bcfd (Port Fourchon LNG) (PF17-9)

PROPOSED TO U.S.-MARAD/COAST GUARD
15. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)

PROPOSED CANADIAN SITES
16. Kitimat, BC: 1.28 Bcfd (Apache Canada Ltd.)
17. Douglas Island, BC: 0.23 Bcfd (BC LNG Export Cooperative)

Exhibit 7

(202) 219–3032. The registration deadline is Tuesday, September 2, 2014.

Individuals who will need accommodations for a disability in order to attend the hearing (i.e., interpreting services, assistive listening devices, and/or materials in alternative format) should notify the Advisory Committee no later than Tuesday, September 2, 2014 by contacting Ms. Tracy Jones at (202) 219–2099 or via email at *tracy.deanna.jones@ed.gov.* We will attempt to meet requests after this date, but cannot guarantee availability of the requested accommodation. The hearing site is accessible to individuals with disabilities. Individuals who use a telecommunications device for the deaf (TTY) may call the Federal Information Relay Service (FRS) toll free at 1–800–877–8339.

Records are kept for Advisory Committee proceedings, and are available for inspection at the Office of the Advisory Committee on Student Financial Assistance, Capitol Place, 80 F Street NW., Suite 413, Washington, DC from the hours of 9:00 a.m. to 5:30 p.m. Eastern Standard Time, Monday through Friday, except Federal holidays. Information regarding the Advisory Committee is available on the Committee's Web site, *www2.ed.gov/ACSFA.*

Dated: August 11, 2014.

William J. Goggin,

Executive Director, Advisory Committee on Student Financial Assistance.

[FR Doc. 2014–19326 Filed 8–14–14; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Addendum to Environmental Review Documents Concerning Exports of Natural Gas From the United States

Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC.	[DOE/EIS–0487]
Cameron LNG, LLC	[DOE/EIS–0488]
Jordan Cove Energy Project, L.P.	[DOE/EIS–0489]
Lake Charles Exports, LLC and Trunkline LNG Export, LLC.	[DOE/EIS–0491]
LNG Development Company, LLC (d/b/a Oregon LNG).	[DOE/EIS–0492]
Cheniere Marketing, LLC	[DOE/EIS–0493]
Excelerate Liquefaction Solutions I, LLC.	[DOE/EIS–0494]
CE FLNG, LLC	[DOE/EIS–0497]
Magnolia LNG, LLC	[DOE/EIS–0498]
Dominion Cove Point LNG, LP.	[DOE/EA–1942]
Southern LNG Company, L.L.C.	[DOE/EA–1963]
Golden Pass Products LLC	[DOE/EA–1971]
Sabine Pass Liquefaction, LLC.	[DOE/EA–1983]

AGENCY: Office of Fossil Energy, Department of Energy.

ACTION: Notice of Availability of Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States.

SUMMARY: The Office of Fossil Energy (FE) of the Department of Energy (DOE) announces the availability of the *Addendum to Environmental Review Documents Concerning Exports of Natural Gas From the United States* (Addendum).

FOR FURTHER INFORMATION CONTACT: John Anderson, U.S. Department of Energy (FE–34), Office of Natural Gas Regulatory Activities, Office of Fossil Energy, Forrestal Building, Room 3E–042, 1000 Independence Avenue SW., Washington, DC 20585; Edward LeDuc, U.S. Department of Energy (GC–51), Office of the Assistant General Counsel for Environment, Forrestal Building, 1000 Independence Avenue SW., Washington, DC 20585.

ADDRESSES: The Addendum and other relevant documents are available for download at *http://www.energy.gov/fe/services/natural-gas-regulation,* and for inspection and copying in the Division of Natural Gas Regulatory Activities docket room, Room 3E–042, 1000 Independence Avenue SW., Washington, DC 20585. The docket room is open between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION: The purpose of this Addendum is to provide additional information to the public regarding the potential environmental impacts of unconventional natural gas exploration and production activities. DOE has received many comments in related proceedings expressing concerns about the potential impacts from increased development of unconventional natural gas resources in the United States, particularly production that involves hydraulic fracturing. While not required by the National Environmental Policy Act (NEPA), DOE has prepared this Addendum in an effort to be responsive to the public and provide the best information available.

On June 4, 2014, DOE published a **Federal Register** notice (79 FR 32258) announcing the availability of the draft Addendum for public review and comment. The comment period closed on July 21, 2014. DOE received 18 comment submittals, comprised of a total of 40,754 individual comments. DOE considered all the comments and prepared the final Addendum. In an effort to assist readers DOE used bold text and vertical lines in the margin to indicate where the draft Addendum has been revised or supplemented. A summary of the public comments and DOE's responses is included in the final Addendum.

Issued in Washington, DC, on August 11, 2014.

Christopher A. Smith,

Principal Deputy Assistant Secretary, Office of Fossil Energy.

[FR Doc. 2014–19368 Filed 8–14–14; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Procedures for Liquefied Natural Gas Export Decisions

AGENCY: Office of Fossil Energy, Department of Energy.

ACTION: Final revised procedures.

SUMMARY: The U.S. Department of Energy (DOE or the Department) will act on applications to export liquefied natural gas (LNG) from the lower-48 states to countries with which the United States does not have a free trade agreement requiring national treatment for natural gas only after completing the review required by the National Environmental Policy Act (NEPA), suspending its practice of issuing conditional decisions prior to final authorization decisions.

DATES: *Effective Date:* August 15, 2014.

FOR FURTHER INFORMATION CONTACT: John Anderson, U.S. Department of Energy, Office of Oil and Gas Global Security and Supply, Office of Fossil Energy, Forrestal Building, Room 3E–042, 1000 Independence Avenue SW., Washington, DC 20585, (202) 586–5600; Samuel Walsh, U.S. Department of Energy, Office of the General Counsel, Forrestal Building, 1000 Independence Avenue SW., Washington, DC 20585, (202) 586–6732.

SUPPLEMENTARY INFORMATION:

I. Proposed Procedural Change

The Department of Energy is responsible for authorizing exports of natural gas to foreign nations pursuant to section 3 of the Natural Gas Act, 15 U.S.C. 717b. For proposed exports to countries with which the United States lacks a free trade agreement requiring national treatment for trade in natural gas (non-FTA countries), the Department conducts an informal adjudication and grants the application unless the Department finds that the proposed exportation will not be consistent with the public interest. 15 U.S.C. 717b(a). Before reaching a final decision on a non-FTA application, the Department must also comply with the National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.* Typically, the agency responsible for permitting the export facility serves as the lead agency in the NEPA review process and DOE serves as a cooperating agency within the meaning of the Council on Environmental Quality's (CEQ) regulations. 40 CFR 1501.4, 1501.5. For LNG terminals located onshore or in state waters, the agency responsible for permitting the export facilities is the Federal Energy Regulatory Commission (FERC) pursuant to Section 3(e) of the Natural Gas Act. 15 U.S.C. 717b(e). For LNG terminals located offshore beyond state waters, the responsible agency is the Maritime Administration (MARAD) within the Department of Transportation pursuant to Section 3(9) of the Deepwater Ports Act, as amended by Section 312 of the Coast Guard and Maritime Transportation Act of 2012 (Pub. L. 112–213).

For more than 30 years, DOE's regulations governing natural gas imports and exports have allowed for conditional decisions, on a discretionary basis, before DOE completes its review process.[1] DOE's regulations at 10 CFR 590.402, entitled "Conditional orders," state that DOE may issue a conditional order at any time during a proceeding prior to issuance of a final opinion and order. In the past three years, DOE has issued eight conditional authorizations for exports of LNG to non-FTA countries.[2] In each of these proceedings, DOE has made preliminary findings on all factors relating to the public interest other than environmental issues. The conditional authorization orders have explained that, before taking final action, DOE will reconsider its public interest analysis in light of the information gathered in the environmental review.[3]

DOE has acted on non-FTA LNG export applications according to the order of precedence posted on DOE's Web site on December 5, 2012. On June 4, 2014, however, DOE published a notice in the **Federal Register** proposing to suspend its practice of issuing conditional decisions prior to completion of the NEPA review process for LNG export applications from the lower-48 states. *Dep't of Energy, Proposed Procedures for Liquefied Natural Gas Export Decisions; Notice of Proposed Procedures,* 79 FR 32261 (Proposed Procedures Notice). DOE did not propose to amend 10 CFR 590.402 and, therefore, under the proposal would retain discretion to issue conditional decisions in the future.

DOE explained that, under the newly proposed procedures, DOE would cease to act on non-FTA LNG export applications according to the published order of precedence. Instead, DOE would act on applications in the order they become ready for final action. The Proposed Procedures Notice stated that an application is ready for final action when DOE has sufficient information on which to base a public interest determination and when DOE has completed its NEPA review. The Proposed Procedures Notice further explained that, for purposes of setting the order in which DOE will act, an application would be deemed to have completed the pertinent NEPA review process as follows: (1) For those projects requiring an Environmental Impact Statement (EIS), 30 days after publication of a Final EIS; (2) for projects for which an Environmental Assessment (EA) has been prepared, upon publication by DOE of a Finding of No Significant Impact (FONSI); or (3) upon a determination by DOE that an application is eligible for a categorical exclusion pursuant to DOE's regulations implementing NEPA, 10 CFR 1021.410, Appx. A & B. DOE explained that this test would apply in the same fashion regardless of whether FERC, MARAD, or DOE has served as the lead agency for preparation of the environmental review document.

The Proposed Procedures Notice also made clear that the proposed procedures would not affect the continued validity of the conditional authorizations DOE had already issued. For those applications, DOE stated it would proceed as explained in the orders: By reconsidering the conditional authorization in light of the information gathered in the environmental review once that review is complete and taking appropriate final action.

The Department offered four reasons for the proposed procedural change. *See* Proposed Procedures Notice at 79 FR 32263–32264. First, the Department explained that conditional authorizations no longer appear necessary for FERC or the majority of applicants to commit resources to the NEPA review process. Second, the Department explained that by suspending its practice of issuing conditional decisions and ceasing to follow the order of precedence published on December 5, 2012, DOE would better be able to ensure prompt action on applications that are otherwise ready to proceed. Third, the Department explained that the proposed procedures would improve the quality of information on which DOE bases its decisions. Finally, the Department noted that suspending its practice of issuing conditional decisions would better allocate departmental resources by reducing the likelihood that the Department would be forced to act on applications with little prospect of proceeding.

II. Public Comments

The Department received 74 comments in response to the Proposed Procedures Notice.[4] Many of the comments expressed general support for or opposition to LNG exports or otherwise urged substantive changes to DOE's public interest analysis. DOE officials have read and considered these comments carefully, but consider them outside the scope of the Proposed Procedures Notice, which addressed only whether DOE should suspend its current practice of issuing conditional decisions prior to completion of NEPA review.

The remaining relevant comments generally fall into three groups: Comments on the rationale DOE provided for the proposed procedures, comments on the test proposed for when an application is ready for final decision, and comments on the timing of final decisionmaking once an application is ready for final action.

A. Comments on the Rationale for the Proposed Procedures

Public Comments: DOE's first rationale advanced in support of the proposed procedural change was that conditional decisions no longer appear necessary for FERC or the majority of

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[1] *Dep't of Energy, Import and Export of Natural Gas; New Administrative Procedures; Proposed Rule,* 46 FR 44696 (Sept. 4, 1981).

[2] *LNG Develop. Co., LLC (d/b/a Oregon LNG),* DOE/FE Order No. 3465 (July 31, 2014) [hereinafter *Oregon LNG*]; *Jordan Cove Energy Project, L.P.,* DOE/FE Order No. 3413 (March 24, 2014); *Cameron LNG, LLC,* DOE/FE Order No. 3391 (Feb. 11, 2014); *Freeport LNG Expansion, L.P. et al.,* DOE/FE Order No. 3357 (Nov. 15, 2013); *Dominion Cove Point LNG, LP,* DOE/Order No. 3331 (September 11, 2013); *Lake Charles Exports, LLC,* DOE/FE Order No. 3324 (Aug. 7, 2013); *Freeport LNG Expansion, L.P. et al.,* DOE/FE Order No. 3282 (May 17, 2013); *Sabine Pass Liquefaction, LLC,* DOE/FE Order No. 2961 (May 20, 2011).

[3] *See, e.g., Oregon LNG,* DOE/FE Order No. 3465, at 138.

[4] The comments are available at: *http://energy.gov/fe/proposed-procedures-liquefied-natural-gas-export-decisions* (Comments).

applicants to commit resources to the NEPA review process. Many commenters supported this claim. Several other commenters questioned it, however, observing that conditional decisions may have value for applicants even if they have already initiated NEPA review. Likewise, they asserted that conditional decisions may be of value to other stakeholders, such as financial parties, LNG purchasers, or foreign governments.

DOE Response: DOE acknowledges that conditional decisions may hold value for some applicants and may supply useful information to third parties. Nevertheless, the justification for issuing conditional decisions before completing NEPA review is much weaker in an environment where applicants are willing to commit resources to NEPA review even without a conditional decision. In the approximately 18 months since we established the existing order of precedence, we have had an opportunity to observe industry developments, as well as the progress of numerous individual projects in the FERC-led NEPA review processes. We have seen numerous instances where applicants have proven willing to commit resources to NEPA review before having received a conditional authorization. As noted above, to date DOE has issued eight conditional authorizations (including one, *Sabine Pass,* which is now final) cumulatively authorizing non-FTA exports in a combined total of 10.52 billion cubic feet per day of natural gas (Bcf/d). Many of these applicants had made substantial progress in preparing resource reports for the NEPA review process before receiving their conditional authorizations. Likewise, among applicants that have not yet received a conditional decision, at least seven projects constituting 9.51 Bcf/d in requested export capacity have made considerable progress in the NEPA review process.[5] These examples demonstrate that, broadly speaking, conditional decisions are no longer necessary for applicants to commit substantial resources to the NEPA review process.

Public Comments: The second rationale advanced in support of the proposed procedural change was that it would ensure that applications otherwise ready for DOE action will not be held back by their position in the order of precedence. Many commenters voiced support for the proposed procedures for this reason. One commenter, however, asserted that under the proposed procedures, DOE will no longer concurrently evaluate whether applications are in the public interest while these applications are undergoing NEPA review. This commenter, therefore, concluded that the proposed procedures would lengthen DOE's review time. This commenter also asserted that it is arbitrary for DOE to require the completion of NEPA review before DOE completes its public interest review.

DOE Response: DOE wishes to clarify that applicants can and should apply concurrently to DOE and to FERC or MARAD. DOE will begin the process of evaluating whether an application is in the public interest prior to completion of NEPA review, but will not issue a final decision before the NEPA review is complete. The requirement that NEPA review be completed prior to a final public interest determination is not arbitrary, but rather flows from the most fundamental requirement in NEPA: that agencies consider environmental impacts prior to deciding to undertake a major federal action. *See* 10 CFR 1021.210(b) ("DOE shall complete its NEPA review for each DOE proposal before making a decision on the proposal."); *see also Silentman* v. *Federal Power Commission,* 566 F.2d 237 (D.C. Cir. 1977) (a cooperating agency must await the lead agency's completion of its impact statement before taking final action).

Public Comments: The third rationale advanced in support of the proposed procedural change was that it would improve the quality of information on which DOE bases its decisions. One reason provided for why the proposed procedures would improve the quality of information is that, by restricting its decisions to applicants that have undertaken the considerable expense of providing the engineering and design information necessary to complete NEPA review, DOE would make its decisions on a cohort of projects that are, on average, more likely to be financed and built than those that have not completed NEPA review. By focusing on projects that are more likely to proceed, DOE reasoned that it would be better positioned to evaluate the cumulative impacts of its decisions on natural gas markets. One commenter rejected this reasoning, stating that applicants with the wherewithal to build LNG export facilities also have the wherewithal to complete the permitting process.

DOE Response: The commenter's observation that applicants with the wherewithal to build LNG export facilities also have the wherewithal to complete the permitting process supports rather than undermines DOE's reasoning. DOE's view is that LNG projects for which NEPA review is complete have already shown themselves more likely to advance to commercial operation than projects that have not yet commenced the NEPA process (or have stalled at that stage) for whatever reason. By eliminating the possibility that DOE will issue conditional decisions on applications that never complete the NEPA review process, the proposed procedures will help to focus DOE's decisionmaking on projects that are more likely to proceed and, therefore, will benefit DOE's ability to assess cumulative market impacts.

Public Comments: DOE noted that it generally would be preferable to integrate the consideration of all public interest factors in a single, final order. Under existing procedures, DOE has focused on economic and international factors at the conditional decision stage and considered environmental factors at the final stage, once NEPA review is complete. Under the proposed procedures, DOE would evaluate all such public interest factors in one order. One commenter asserted that DOE failed to explain why it is generally preferable to integrate analysis of all public interest factors in a single order.

DOE Response: DOE's public interest determinations involve consideration of a wide range of factors. These public interest factors include economic, international, and environmental considerations that, under current practice, have been bifurcated between DOE's conditional and final authorizations. In some instances, the bifurcation is not problematic because the issues are largely distinct. In other instances, however, there may be overlap between environmental and non-environmental issues that would be more efficiently and thoroughly resolved in a single order. For these reasons, DOE believes that it is generally preferable to consider these factors concurrently and to present them in a single analysis. Further, doing so demonstrates that each factor is given full consideration and allows DOE to communicate its decision to the public in a simpler, more comprehensible way.

[5] *See Corpus Christi Liquefaction, LLC,* FERC Docket No. CP12–507; *Excelerate Liquefaction Solutions (Port Lavaca I), LLC et al.,* FERC Docket Nos. CP14–71, 72 & 73; *Southern LNG Co. LLC,* FERC Docket No. CP14–103; *CE FLNG,* FERC Docket No. PF13–11, *Golden Pass Products LLC,* FERC Docket No. PF13–14; *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.,* FERC Docket No. CP14–12; *Magnolia LNG, LLC,* FERC Docket No. PF13–9. In addition to these projects that have made substantial progress, two others have recently been accepted for pre-filing at FERC. *See Gulf LNG Liquefaction Company, L.L.C.,* FERC Docket No. PF 13–4, *Louisiana Energy, LLC,* FERC Docket No. PF14–17.

B. Comments on the Test for When an Application is Ready for Final Decision

Public Comments: As explained above, DOE proposed that it would act on applications in the order they become ready for final decision. DOE specified that an application is ready for final decision when DOE has completed the NEPA review and when DOE has sufficient information on which to base a public interest determination. One commenter recommended that the requirement that DOE has sufficient information on which to base a public interest determination be removed. This commenter asserted that, because the Natural Gas Act creates a rebuttable presumption in favor of authorizing imports and exports, DOE lacks the power to ensure that the record in a proceeding is complete before taking final action.

DOE Response: In the revised procedures, DOE will retain the requirement that it have sufficient information on which to base a public interest determination as a predicate to final action. The commenter is correct that the Natural Gas Act creates a rebuttable presumption in favor of authorizing imports and exports. But that presumption does not remove DOE's power to impose informational requirements on applicants or to decide when it has a complete record on which to base its decision. *See, e.g.,* 10 CFR 590.202, 590.203.

Public Comments: DOE proposed that it would act on applications in the order they become ready for final decision and that an application is ready for final decision when DOE has completed the pertinent NEPA review. DOE further specified that the application will be deemed to have completed the pertinent NEPA review (1) for those projects requiring an EIS, 30 days after publication of a Final EIS, (2) for projects for which an EA has been prepared, upon publication by DOE of a Finding of No Significant Impact (FONSI), or (3) upon a determination by DOE that an application is eligible for a categorical exclusion pursuant to DOE's regulations implementing NEPA, 10 CFR 1021.410, Appx. A & B.

Commenters urged DOE to clarify that the pertinent NEPA review may be one in which DOE serves as a cooperating agency and either FERC or MARAD serves as lead agency. Relatedly, one commenter sought clarification as to whether DOE intends to issue a FONSI in cases where it adopts an EA prepared by another agency, and whether DOE may accept a categorical exclusion determination made by another agency.

DOE Response: The pertinent NEPA review referred to in the Proposed Procedures Notice may be one for which another agency is the lead agency and DOE is a cooperating agency, provided that DOE ultimately elects to adopt the EA or EIS produced by the lead agency. As a cooperating agency, DOE may adopt an EIS or EA prepared by another agency and need not re-publish those documents for additional comment. 40 CFR 1506.3(c). Nevertheless, even when it is participating as a cooperating agency, DOE is ultimately responsible for its own NEPA compliance. Therefore, where another agency has prepared an EA or EIS that DOE has chosen to adopt, DOE must conduct its own independent analysis and issue its own FONSI or Record of Decision, respectively. Similarly, DOE must issue its own categorical exclusion determination. A categorical exclusion determination issued by another agency may inform DOE's decisionmaking, but DOE may only determine that a proposed action is categorically excluded from NEPA review in accordance with its own regulations. 10 CFR 1021.410, Appx. A & B. We note that DOE's list of categorical exclusions applicable to specific agency actions includes: "approvals or disapprovals of new authorizations or amendments of existing authorizations to import or export natural gas under section 3 of the Natural Gas Act that involve minor operational changes (such as changes in natural gas throughput, transportation, and storage operations) but not new construction." *Id.* Appx. B at B5.7.

Public Comments: One commenter questioned why, for projects requiring an EIS, completion of the NEPA review process occurs 30 days after publication of the EIS rather than upon publication of the EIS.

DOE Response: The CEQ regulations implementing NEPA generally prohibit agencies from making a final decision in reliance on an EIS until 30 days after publication by the Environmental Protection Agency of the notice of availability for the final EIS. 40 CFR 1506.10(b)(2). In cases where DOE is a cooperating agency in the preparation of an EIS, DOE must also adopt the final EIS before it can issue a Record of Decision.

C. Comments Related to the Timing of Final Decisions

Public Comments: Numerous commenters urged DOE to establish a uniform deadline by which DOE will issue final decisions after an application's NEPA review is complete. These commenters contend that a deadline would provide greater regulatory certainty enabling better planning and investment decisions.

DOE Response: DOE is sympathetic to this concern. Indeed, one of the overriding purposes of the procedural changes announced in this notice is to enable prompt action on applications that are ready for final decision. However, DOE has several concerns with creating a uniform deadline. First, each application contains novel issues such that a deadline that is reasonable for the majority of cases may be unreasonable in an individual case. Second, DOE lacks control over when the NEPA review for applications is complete. Were the final EIS for several applications to be completed at or around the same time, compliance with a fixed deadline may be unworkable. For these reasons, DOE declines to create a deadline for final decisions in this notice.

III. Revised Procedures

For the reasons provided in the Proposed Procedures Notice and in this notice, DOE will implement the procedural changes substantially as proposed. Specifically, DOE will suspend its practice of issuing conditional decisions on applications to export LNG to non-FTA countries from the lower-48 states.[6]

DOE will no longer act in the published order of precedence, but will act on applications in the order they become ready for final action. An application is ready for final action when DOE has completed the pertinent NEPA review process and when DOE has sufficient information on which to base a public interest determination. For purposes of determining the order in which DOE will act on applications before it, DOE will use the following criteria: (1) For those projects requiring an EIS, 30 days after publication of a Final EIS, (2) for projects for which an EA has been prepared, upon publication by DOE of a Finding of No Significant Impact, or (3) upon a determination by DOE that an application is eligible for a categorical exclusion pursuant to DOE's

[6] The revised procedures will apply only to exports from the lower-48 states. In the Proposed Procedures Notice, DOE stated that no long-term applications to export LNG from Alaska were currently pending and, therefore, DOE could not say whether there may be unique features of Alaskan projects that would warrant exercise of the DOE's discretionary authority to issue conditional decisions. After publishing the Proposed Procedures Notice, DOE received one application to export LNG from Alaska. *See* Alaska LNG Project LLC, Application for Long-Term Authorization to Export Liquefied Natural Gas, Docket No. 14–96–LNG (July 18, 2014). DOE will consider whether to issue a conditional decision on that application, or any future application to export from Alaska, in the context of those proceedings.

regulations implementing NEPA, 10 CFR 1021.410, Appx. A & B.

These revised procedures will not affect the continued validity of the conditional orders the Department has already issued. For those applications, the Department will proceed as explained in the conditional orders: When the NEPA review process for those projects is complete, the Department will reconsider the conditional authorization in light of the information gathered in the environmental review and take appropriate final action.

Issued in Washington, DC, on August 11, 2014.

Christopher A. Smith,

Principal Deputy Assistant Secretary, Office of Fossil Energy.

[FR Doc. 2014–19364 Filed 8–14–14; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. DI14–3–000]

Chenega Bay Utilities; Notice of Declaration of Intention and Soliciting Comments, Protests, and/or Motions To Intervene

Take notice that the following application has been filed with the Commission and is available for public inspection:

a. *Application Type:* Declaration of Intention

b. *Docket No:* DI14–3–000

c. *Date Filed:* June 6, 2014

d. *Applicant:* Chenega Bay Utilities

e. *Name of Project:* Chenega Hydroelectric Project

f. *Location:* The proposed Chenega Hydroelectric Project will be located on Anderson Creek immediately downstream from the city water supply dam, near the village of Chenega Bay, Alaska, affecting T. 001S, R. 008E, S. 23 and 26, Seward Meridian.

g. *Filed Pursuant to:* Section 23(b)(1) of the Federal Power Act, 16 USC 817(b) (2012).

h. *Applicant Contact:* Charles Totemoff, Chenega Bay Utilities, 3000 C Street, Suite 301, Anchorage, AK 99503; telephone: (907) 277–5706, *cwt@chenegacorp.com mail to: mpdpe@aol.com.*

i. *FERC Contact:* Any questions on this notice should be addressed to Jennifer Polardino, (202) 502–6437, or Email address: *Jennifer.Polardino@ferc.gov*

j. Deadline for filing comments, protests, and/or motions is: 30 days from the issuance of this notice by the Commission.

Comments, Motions to Intervene, and Protests may be filed electronically via the Internet. See 18 CFR 385.2001(a)(l)(iii) (2014) and the instructions on the Commission's Web site under the "eFiling" link. If unable to be filed electronically, documents may be paper-filed. To paper-file, an original and eight copies should be mailed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426. For more information on how to submit these types of filings, please go to the Commission's Web site located at *http://www.ferc.gov/filing-comments.asp.*

Please include the docket number (DI14–03–000) on any comments, protests, and/or motions filed.

k. *Description of Project:* The proposed 60-kW run-of-river Chenega Hydroelectric Project will consist of: (1) An intake chamber, making use of Anderson Creek (2) a 14-inch-diameter, 1600-foot-long pipe, which will be buried a minimum of three feet under the existing roadway and will convey the water from the intake to the powerhouse; (3) a 16 feet by 20 feet powerhouse at an elevation of 64 feet above mean sea level; (4) a twin-jet Pelton turbine rated at 170 feet of net head coupled to a generator with an average inflow of 5.4 cfs; (5) a 24-inch diameter, 40-foot long culvert pipe (6) a 4.5-foot-wide by one-foot-deep stream channel excavated from the existing ground (7) a screening box and new constructed spillway; (8) and appurtenant facilities.

When a Declaration of Intention is filed with the Federal Energy Regulatory Commission, the Federal Power Act requires the Commission to investigate and determine if the project would affect the interests of interstate or foreign commerce. The Commission also determines whether or not the project: (1) Would be located on a navigable waterway; (2) would occupy public lands or reservations of the United States; (3) would utilize surplus water or water power from a government dam; or (4) would be located on a non-navigable stream over which Congress has Commerce Clause jurisdiction and would be constructed or enlarged after 1935.

l. *Locations of the Application:* Copies of this filing are on file with the Commission and are available for public inspection. This filing may be viewed on the web at *http://www.ferc.gov* using the "eLibrary" link. Enter the Docket number excluding the last three digits in the docket number field to access the document. You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filings and issuances related to this or other pending projects. For assistance, call 1–866–208–3676 or email *FERCOnlineSupport@ferc.gov* for TTY, call (202) 502–8659. A copy is also available for inspection and reproduction at the address in item (h) above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. Comments, Protests, or Motions to Intervene—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

o. Filing and Service of Responsive Documents—All filings must bear in all capital letters the title "COMMENTS", "PROTESTS", AND/OR "MOTIONS TO INTERVENE", as applicable, and the Docket Number of the particular application to which the filing refers. A copy of any Motion to Intervene must also be served upon each representative of the Applicant specified in the particular application.

p. Agency Comments—Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

Dated: August 7, 2014.

Kimberly D. Bose,

Secretary.

[FR Doc. 2014–19302 Filed 8–14–14; 8:45 am]

BILLING CODE 6717–01–P

Exhibit 8

https://www.reuters.com/article/us-commodities-summit-jera/japans-jera-in-talks-for-lng-contract-with-no-destination-limits-idUSKBN1CG0SR

Japan's JERA in talks for LNG contract with no destination limits

Osamu Tsukimori
October 11, 2017

TOKYO (Reuters) - Japan’s JERA Co, the world’s biggest importer of liquefied natural gas (LNG), is set to sign a new LNG contract soon that would be free of destination restrictions as it looks to secure volumes to replace some expiring long-term deals, its top official said on Wednesday.

JERA has been pushing to drop the so-called destination clause in long-term contracts that limits where a cargo can be delivered, after Japan’s Fair Trade Commision (FTC) ruled that such restrictions are anti-competitive.

Faced with that ruling, sellers of long-term LNG have been willing to remove the destination clauses, President Yuji Kakimi said in an interview at the Reuters Global Commodities Summit.

He added that JERA has made progress in talks with existing long-term LNG sellers to revise clauses that would require splitting the profits from reselling LNG cargoes between JERA and the original seller.

Talks on the new term contract come as JERA faces the expiry of long-term contracts with Malaysia, Abu Dhabi and Qatar in 2018, 2019 and 2021 respectively, each with annual volumes of around 4 million tonnes.

JERA, a joint venture between Tokyo Electric Power and Chubu Electric Power, takes in around 35 million tonnes a year of LNG.

Those contracts, which industry sources have said include destination restrictions, are not to be renewed automatically, Kakimi said at the Summit, held at the Reuters office in Tokyo.

He said for the moment JERA’s supply contracts closely match its demand.

“But some time ahead, there is some room (for new LNG) and we are in talks with some select sellers and expect to have a deal soon that is free of destination clauses,” he said.

He did not reveal the seller, volume or term of the contract under discussion, which would be JERA’s first since the Fair Trade Commission’s ruling.

JERA plans to cut the volume of gas it buys under long-term contracts by 42 percent by 2030 from current levels, Kakimi told Reuters last year.

He said sellers of LNG from older projects who want to sign new contracts can afford to be more flexible in their offers than proposed new LNG projects that need to lock in long-term deals to secure financing for their multi-billion dollar plans.

“Existing sellers (of long-term LNG), who have recouped their investments, can make various proposals to buyers not limited to long-term but also mid-term and short-term. We would like to see a wide range of proposals from them,” Kakimi said.

“There are sellers that truly need long-term contracts, and it is a natural course to take to dedicate the long-term portion of our LNG purchases to those sellers.”

COAL NEGOTIATIONS

Kakimi expects that JERA’s annual coal price negotiations will also become tougher as upstream assets have become concentrated in fewer hands. He pointed to Glencore's recent purchase of Yancoal's Hunter Valley, Australia, assets as an example of a company with a dominant presence in coal mining, particularly high-quality coal.

"As is true with LNG, upstream assets in coal are seeing oligopolization," he said. "It is true that the negotiations would become more difficult for buyers."

To reduce the concerns about high prices for coal purchases, JERA's parent companies are turning toward using a more diverse range of coal, including lower quality coal with less heat content, he said.

"Our parent firms used to rely on high-quality mines for 70 to 80 percent of total in the past, but now the ratio has declined to around 30 to 40 percent," he said.

JERA's parent companies consume about 20 million tonnes of coal annually.

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Additional reporting by Yuka Obayashi, Kentaro Hamada and Aaron Sheldrick; Editing by Christian Schmollinger

Exhibit 9

https://timesofindia.indiatimes.com/business/india-business/india-to-renegotiate-lng-rate-with-us-russia/articleshow/60939421.cms

India to renegotiate LNG rate with US, Russia

PTI | Oct 4, 2017, 16:41 IST

Representative image

NEW DELHI: After getting Qatar and Australia to lower gas price, India is seeking to renegotiate rate of LNG (liquefied natural gas) it has contracted from the US and Russia to reflect current market realities, GAIL Chairman and MD B C Tripathi said on Wednesday.

"We have successfully renegotiated, along with Petronet LNG Ltd, two long-term (LNG import) contracts. We are now working on third and fourth contract," he said at a Ficci (Federation of Indian Chambers of Commerce and Industry) conference here.

While Tripathi did not name the contracts, he was referring to last month's in-principle agreement with Exxon Mobil Corp for a cut in price of 1.44 million tonnes a year LNG to be imported from Australia's Gorgon project.

In 2015, India renegotiated price of the long-term deal to import 7.5 million tonnes per year of LNG from Qatar, helping save Rs 8,000 crore.

"This is how market structure has changed," Tripathi said. "The point which I am trying to drive is that we are moving from a supply constraint market to a supply surplus market."

Tripathi said market structure has changed from a time when Indian firms struggled to get an appointment with LNG exporters to gas suppliers now running after the world's fastest growing energy market.

This has primarily happened because availability has increased and prices have slumped in global energy markets.

Though he did not name the two other contracts for which GAIL, India's biggest gas distributor, is seeking price renegotiation, officials said he was referring to LNG contracted from the US and Russia.

GAIL wants to renegotiate the 2011 sales and purchase agreement (SPA) with Cheniere Energy for import of 3.5 million tonnes of LNG annually, with yearly fixed fees of $548 million and a term of 20 years.

The state-owned firm had agreed to pay Cheniere a price of $3 per million British thermal unit (mmBtu) plus 115 per cent prevailing Henry Hub natural gas price.

Officials said GAIL wants the fixed portion to be lowered to bring down landed cost of LNG to around $7-8 per mmBtu as against the present $9.7.

LNG in the spot or current market is available for less than $6 per mmBtu.

The US supplies are scheduled to begin from the next year.
Besides the 3.5 million tonnes per annum of LNG from Houston-based Cheniere, GAIL has booked 2.3 million tonnes a year capacity at Dominion's Cove Point liquefaction facility.

Also, GAIL wants Russia's Gazprom to delay and lower the price of gas it has purchased under a 20-year deal.

Shipments under the deal, initially expected to start in 2018-19, are linked to crude oil prices.

GAIL had in 2012 signed a deal with Gazprom to buy 2.5 million tonnes a year of LNG for 20 years from the Shtokman LNG export plant in the Barents Sea.

Exhibit 10

https://www.reuters.com/article/us-india-japan-lng/india-japan-to-team-up-to-get-more-flexible-lng-deals-idUSKBN1CG2DD

India, Japan to team up to get more flexible LNG deals

Tommy Wilkes, Nidhi Verma
OCTOBER 11, 2017

NEW DELHI (Reuters) - India will work with Japan to make long-term liquefied natural gas (LNG) import deals more affordable for its price-sensitive consumers, it said on Wednesday, as these two big importers try to secure better prices and concessions from suppliers.

The arrangement will help state-run GAIL India Ltd swap a part of its 5.8 million tonnes of LNG booked with firms from the United States with that of Japan's contracted volumes in Asia and elsewhere, Sunjay Sudhir, joint secretary for international cooperation in India's federal oil ministry, told Reuters.

The world's biggest LNG buyers, all in Asia, are increasingly clubbing together to secure more flexible supply contracts in a move that shifts power to importers from producers in an oversupplied market.

An alliance of big buyers puts pressure on exporters such as Qatar, Australia and Malaysia. They prefer to have clients locked into fixed supply contracts that run for decades and make buyers take fixed amounts of monthly volumes irrespective of demand, with no right to re-sell surplus supplies to other end-users.

"Without joining any club, we would like to work with other major consumers to promote a flexible and open LNG market," Sudhir said.

India's cabinet on Wednesday approved the proposal to sign a Memorandum of Cooperation with Japan that it said would help to diversify gas supplies, strengthen energy security and lead to more competitive prices.

Japan is the world’s largest LNG importer, and India the fourth biggest.

Under the arrangement, the two countries will try to get more flexibility in LNG contracts and abolish the Destination Restriction Clause, which prevents them from re-selling imports to third parties.

“The agreement will have a swap clause as well, like we can swap our Australian LNG from Gorgon project with LNG booked by Japan with Qatar,” India’s oil minister Dharmendra Pradhan, who is traveling to Japan next week, told reporters.

India last month agreed to buy more LNG from the Gorgon project after Exxon Mobil agreed to cut prices under a long-term deal.

India and Japan will also look at establishing LNG spot price indices that reflect true supply and demand.

Pradhan earlier this week said that India wanted to set up a gas trading exchange for transparent market-driven prices that would encourage investment into the sector.

India wants to increase its share of gas in its energy mix from about 6.5 percent now to about 15 percent in the next few years. Locally produced gas is sold at a government-set price formula.

The president of Japan’s JERA Co, the world’s biggest LNG importer, told Reuters on Wednesday that his firm was set to sign a new LNG contract that would be free of destination restrictions.

LNG markets have been marked by oversupply since 2014 as production has jumped.

Editing by Jane Merriman

Exhibit 11

BEFORE THE UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Connector Gas Pipeline, LLC **Jordan Cove Energy Project, L.P.**	)))))	Docket No. CP13-492-000 Docket No. CP13-483-000

[CORRECTED] MOTION FOR LEAVE TO ANSWER AND ANSWER
of Evans Schaaf Family LLC, Deborah Evans and Ron Schaaf, Robert Barker, John Clarke, Oregon Women's Land Trust, Stacey McLaughlin and Craig McLaughlin

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission")[1], Intervenors Robert Barker, John Clarke, Oregon Women's Land Trust, Evans Schaaf Family LLC, Deborah Evans, Ron Schaaf, Stacey McLaughlin and Craig McLaughlin ("Intervenor landowners") hereby request leave to answer and also answer the Request for Rehearing of Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP ("Rehearing Request") filed on April 8, 2016 in the above-captioned docket. Intervenor landowners each own property along the proposed Pacific Connector Pipeline route and those properties and the landowners themselves would be substantially harmed by the proposed pipeline and any decision to authorize the Applicants to exercise the power of eminent domain.[2]

The Rehearing Request was filed in response to FERC's March 11, 2016 Order denying applications by the Jordan Cove Energy Project, L.P. ("JCEP") and Pacific Connector Gas Pipeline, LP ("PCGP," collectively "Applicants") for the Pacific Connector pipeline and Jordan Cove LNG export terminal projects.

[1] 18 C.F.R. §§ 385.212, .213 (2015).
[2] Impacts to Intervenor landowners are described in our December§ 9, 2015 comments to FERC. http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20151210-5000.

The Applicants' Rehearing Request asks FERC to reverse its denial of the Applicants' projects and to accept a host of post-decision evidence the Applicants claim support reversal of FERC's recent denials. Intervenor landowners request that FERC deny the Applicants' request to re-open the record and deny Applicant's Rehearing Request.

From a procedural standpoint, the Applicants have had years to develop the factual record to demonstrate that their projects were in the public interest and have failed to do so. They now seek a belated reprieve from their failure by attempting to shoehorn claimed "new" evidence under 18 CFR § 385.713(c)(3) contending FERC's denial was "based on matters not available for consideration by the Commission." Applicants had more than ample time and opportunity to develop that evidence and Applicants have shown no compelling reason to reopen the record at this late date.

FERC's general rule of course is that "the record once closed will not be reopened."[3] The Commission can of course re-open the record when there are "extraordinary circumstances"[4], but only when "the movant has demonstrated the existence of extraordinary circumstances that outweigh the need for finality in the administrative process.[5]" There is nothing "extraordinary" about the non-binding agreements Applicants now offer and the benefits of finality exceed any claimed benefit of re-opening the record. As the Commission has stated. "[W]e recognize of course that changes have occurred since

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[3] Transwestern Pipeline Co., Opinion No.§ 238, 32 FERC ¶ 61,009 (1985), reh'g denied, Opinion No. 238-A, 36 FERC ¶ 61,175 at 61,453 (1986).
[4] CMS Midland, Inc., 56 FERC ¶ 61,177 at 61,624, reh'g denied, 56 FERC ¶ 61,361 (1991).
[5] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 *citing East Texas Electric Cooperative, Inc. v. Central and South West Services, Inc.*, 94 FERC ¶ 61,218 at 61,801 (2001).

the close of the record. But such changes always occur. Yet litigation must come to an end at some point. Hence the general rule is that the record once closed will not be reopened.[6]

Even after FERC staff sent repeated information requests to the Applicants for evidence of market demand and evidence that the Applicants were making diligent efforts to obtain pipeline right-of-way easements, the Applicants' failed to provide any meaningful evidentiary response. Instead, the Applicants conflated their affirmative public interest obligations under § 7 of the NGA with the separate and distinct standard for LNG terminals under § 3 asserting that the two standards were essentially interchangeable. When FERC properly denied the Applicants' applications, it did so only after the Applicants had missed every reasonable opportunity to demonstrate both the commercial viability of their project and of credible efforts to obtain pipeline easements.

After close to ten years of having their properties hang in the high-impact limbo of the Pacific Connector Pipeline permitting process, FERC's denial decision gave landowners along the proposed pipeline a well-deserved piece of certainty. The Applicants are now essentially asking FERC for a post-denial "do-over" with a host of new facts that appear to be developed in large part directly in response to FERC's denial. We ask FERC to carefully review all of the confidential information submitted by the Applicants to determine whether it provides any genuine evidence addressing any of the criteria identified by FERC in its October 14, 2015 information request to the Applicants. We suspect it does not.

Additionally, FERC's repeated earlier data requests and Applicants' responses outlined in § 3. Market and Services of FERC's denial Order demonstrate that the Applicant

[6] *Transwestern Pipeline Co.,* Opinion No. 238, 32 FERC ¶ 61,009 (1985), *reh'g denied,* Opinion No. 238-A, 36 FERC ¶ 61,175 at 61,453 (1986).

was given every opportunity to comply with FERC's policy standards and expectations of process but failed to do so.[7]

The Applicants now ask FERC to consider this quickly developed "new evidence," long-after the procedural timelines for providing such evidence have passed. Were FERC to allow this level of post-decision evidence it would establish a terrible precedent allowing applicants to essentially neglect their burden of providing genuine evidence of market demand and making reasonable efforts to obtain pipeline easements until after FERC issued a denial decision. Such a precedent would turn FERC's well-defined, well-understood project review process, on its head.

Contorting this process, as Applicants ask FERC to do, is particularly damaging to landowners who face serious impacts on their ability to use, sell, lease and plan for the future of their properties while the specter and uncertainty of a pipeline siting decision

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[7] October 14, 2015 Letter from FERC to Pacific Connector: "Commission staff is not aware of a previous instance of having to make a finding of public convenience and necessity under § 7 of the NGA for major new pipeline on the basis that a related import/export facility is deemed to be not inconsistent with the public interest under § 3 of the NGA when the pipeline may need to rely significantly on eminent domain and has not provided evidence that a significant proportion of the pipeline's capacity has been subscribed under precedent agreements.

1. Provide the following information related to the capacity of the Pacific Connector pipeline:
    a. Discuss the status of negotiations between Jordan Cove, Pacific Connector, and the potential liquefaction and transportation customers.
    b. Has Pacific Connector entered into any commitments for firm service on its proposed pipeline? If so, please identify the shipper(s), quantities, terms, and rates.
    c. If Pacific Connector has entered into precedent agreements, when did, or when will Pacific Connector conduct an open season. Provide copies of any open season notices that have, or will be posted. Provide the results of the open season immediately, if the results are known, or within 5 days after the end of a pending open season.
2. Provide the following:
    a. The number of land parcels and acres making up the permanent and temporary right-of-way necessary for the construction and operation of the pipeline.
    b. The number and percentage of the land parcels and acres in Question 2(a) that are within or collocated with existing rights-of-way.
    c. The number and percentage of the land parcels and acres in Question 2(a) for which Pacific Connector has easements.

hangs over their property. From the perspective of fair and reasonable energy siting policy, FERC should deny the Applicants' request for a rehearing and the reversal of its denial.

As discussed below, even if FERC elects to consider what Applicants claim is late-breaking evidence of new-found market demand, the agreements and arguments they provide do not support FERC's reversal of its project denial or issuance of a certificate. The incentive for the Applicants to quickly cobble together inflated evidence of market demand is obvious. But the preliminary non-binding agreements for LNG with JERA and Itochu offered by the Applicants do not support a level of demand that would warrant FERC's reversal of its denial order. Similarly, the precedent agreements the Applicants make between themselves and with Macquarie Energy LLC ("Macquarie"), the Applicants' financial advisor and a substantial Veresen stockholder, appear to be nothing more than a thinly disguised effort to keep their project afloat, but they should not be confused with genuine market demand.

This reality appears especially true in light of the fundamental dynamics of the Applicants' target LNG market in Asia. The Applicants cannot and do not provide rational evidence as to how their greenfield project is able to compete in a low-priced LNG market that has a glut of new supply and a global and national field of competitors that can deliver LNG at a significantly lower cost.

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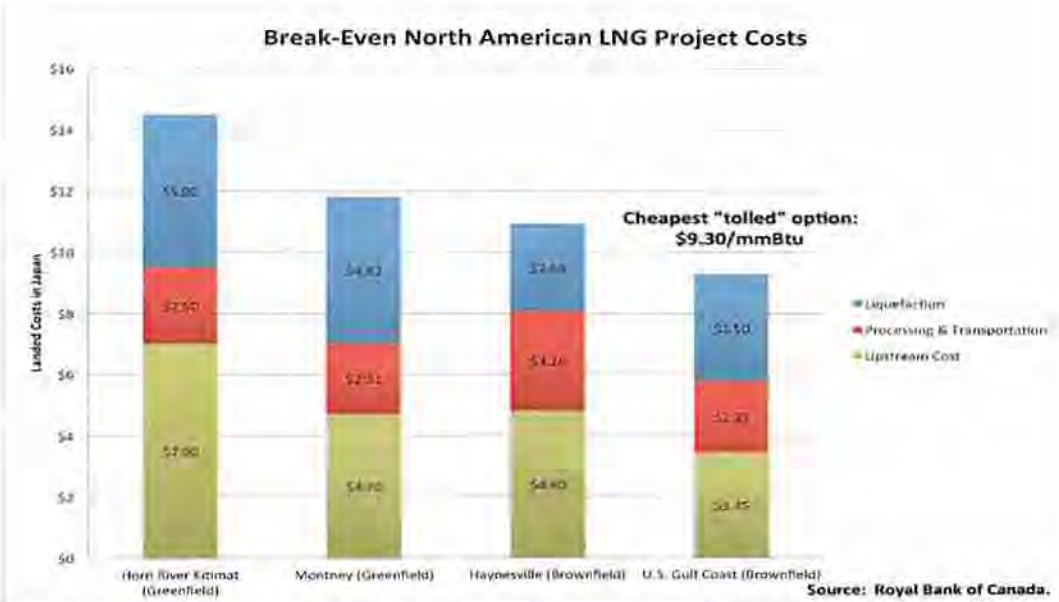

Figure 7. Break-even North American LNG project costs landed in Japan. Source: Royal Bank of Canada and Labyrinth Consulting Services, Inc.[8] Jordan Cove's break even costs certainly exceed that of brownfield projects and Jordan Cove's backers have identified $11/mmBtu as its expected price point for shipping LNG to Japan. *See* Intervenor landowner's December 9, 2015 letter to FERC.

Furthermore, the Applicants offer no evidence that they have made any reasonable effort towards securing additional pipeline rights-of-way. To the contrary, they admit they have not even begun such efforts "in earnest." Request 22. They instead ask FERC to give them the powerful tool of eminent domain absent any showing they have credibly worked to minimize the impact of eminent domain on landowners through negotiation. While the Applicants point to the Commission's approval of Cheniere Creole Trail Pipeline L.P as supporting its rehearing request, they ignore the fact the Cheniere project already had LNG trains 1-4 fully contracted and train 5 almost fully contracted prior to FERC's approval. They also ignore FERC's recognition in its approval that most of the Cheniere pipeline route was along existing rights-of-way.

In light of its weak evidence of demand and continuing failure to obtain landowner easements, the Applicant's effectively ask FERC to reverse its denial and approve their

[8] *A Reality Check For U.S. Natural Gas Ambitions* - July 31, 2015 - http://oilprice.com/Energy/Natural-Gas/A-Reality-Check-For-US-Natural-Gas-Ambitions.html.

projects by conditioning its use of eminent domain on the execution of precedent agreements. Request 2. Approval conditions have value for project approvals where there is substantial evidence that *there is* market demand for a project and that the project *would be* in the public interest. Such conditions, however, should not and cannot serve as a substitute for the affirmative evidence required for FERC to make a public interest determination as required under § 7 of the Natural Gas Act (NGA). 15 USC § 717(f).

For the reasons addressed below, FERC should reject the Applicants' rehearing request.

1. The Applicants' Failure to Make Any Reasonable or Credible Effort to Obtain Easements Undermines Any Finding the Project is in the Public Interest.

While the Applicants base their request for reconsideration on exaggerated evidence of market demand, they do not and cannot argue that they have made any reasonable effort to work with landowners to obtain property easements for the pipeline. As FERC is aware, PCGP has obtained only 4.7% of the right-of-way easement acreage and 2.8% of the needed construction easement acreage. Applicants have not provided any evidence showing those percentages have increased in any meaningful way. Applicants have yet to begin negotiations with landowners in earnest as made evident by the incredibly low percentage of construction and ROW easements they have obtained to date.

Instead of making efforts to obtain the necessary easements through arm's length negotiation, the Applicants attempt to diminish the profound impacts that eminent domain would have on the purported 287 landowners along the pipeline route. Request 25. Like many of their claims, the Applicants do not cite to any evidence in the FERC record to demonstrate the source for the number "287". The Applicants also do not make clear whether 287 refers to the number of landowners who they believe may be subject to eminent domain for the permanent ROW, but that is what appears to be likely. Reducing individual landowners to mere statistics ignores the incredible impacts that pipeline construction, and the use of eminent domain to obtain construction easements, has on the large number of landowners along the pipeline route who have farms, homes, and a myriad of commercial and other uses on their properties.

Intervenor landowners believe the actual number of affected landowners is not 287, but 630. This estimate of 630 landowners was calculated by taking the total number of landowners listed in Appendix A of the FEIS ("Affected Landowners on or Adjacent to Proposed Facilities and Routes") and reducing it by subtracting the number of "public" landowners from the list. Any ambiguity regarding the total number of landowners who would in fact be impacted by the pipeline is directly attributable to the Applicants because of the lack of clear data in the FEIS they prepared. Even the FEIS noted, however, that, "[D]uring the scoping process, **many** landowners commented on the Pacific Connector pipeline."[9]

While Intervenor landowners believe the number of landowners impacted by the pipeline is significantly higher than 287, the specific number is less important point than the fact that for many landowners along the pipeline route, Applicants have not made even a token effort to obtain easements. This is completely inconsistent with FERC policy documents and the NGA. FERC Policy Statements 90 FERC ¶ 61,128; 88 FERC ¶ 61,227; 92 FERC ¶ 61,094.

The Applicants downplay their failure to obtain easements on the grounds that only a small percentage of the pipeline route would run through residentially zoned lands.

[9] FEIS 4-20.

Request 22. This is a specious argument at best because many homes that are in close proximity to the pipeline are located on rural properties not zoned as "residential." Moreover, irrespective of whether a landowners' use is for residential, farming, oyster farming, commercial or other purposes, the impact of taking a person's land against their will through the power of eminent domain should not be taken lightly or minimized.

The Applicants assert that FERC should issue a certificate by conditioning its power to utilize eminent domain on the Applicants' first obtaining service agreements. Request 26. If the Applicants cannot obtain service agreements there would not be any harm to the landowners they argue. This ignores the fact that the Applicants have the burden to demonstrate demand *before* a certificate is issued. 15 U.S.C. § 717(f). It is not surprising that the Applicants would like to secure a certificate and then sit back and wait to see if real market demand develops at some unspecified future date but that is wholly contrary to long-established FERC policy and the NGA. This concept also ignores the continuing impacts on Intervenors and many other landowners as they would be forced to live with the uncertainty of pipeline construction and eminent domain hanging over their properties for what amounts to an indefinite period. This constitutes a very real and significant threat to landowners' ability to make long-term decisions regarding the use of their properties including the sale and lease of such properties. We know already from hard experience that few buyers are willing to enter into a property purchase agreement if the threat of a 3' diameter pipeline and eminent domain proceeding are included in the property purchase.

It is also telling that the Applicants' Request states that, "[o]nce acquisition of PCGP's right of way <u>begins in earnest</u>, it is unlikely to require extensive use of the power of eminent domain…" Request 22 (emp. added.) Applicants similarly explained, "[t]here is no need at this point for PCGP to have begun a broader effort to acquire, or to obtain options on the remainder of the right of way." *Id.* The continuing inability of the Applicants to demonstrate the presence of current market demand is underscored as well by the Applicants' request for up to eight years to complete its 420 MW South Dunes Power Plant.[10]

That years into project planning PCGP admits that it has not begun easement acquisition "in earnest" should disqualify it from obtaining a certificate at this point. Every pipeline applicant would surely enjoy having the actual power of eminent domain pursuant to a certificate before it started negotiation with any landowners. Giving project applicants this level of power over landowners would exacerbate an already imbalanced bargaining position and is contrary to the goals underlying FERC's certificate policies. FERC Policy Statements, 90 FERC ¶ 61,128; 88 FERC ¶ 61,227; 92 FERC ¶ 61,094. If the Applicants are issued a certificate despite their admitted lack of effort to work with landowners along the pipeline route it would set a precedent that would quickly become the norm for other pipeline developers.

2. The Applicants' Preliminary Agreements Do Not Provide Evidence of Project Demand Sufficient to Support a Public Interest Determination.

In light of the continuing drop in the price of Asian LNG, the global oversupply of LNG, and the shrinking Asian demand for LNG, the Applicants' preliminary and non-binding agreements for capacity only, and excluding liquefaction and tolling costs, fall far short of

[10] Energy Facility Siting Council SDPP Final Proposed Order and Appendices 2015-10-12, page 15. https://www.oregon.gov/energy/Siting/docs/SDP/Proposed%20Order/SDP%20Final%20Proposed%20Order%20and%20Appendices%202015-10-12.pdf.

the evidence that should be required to provide a credible basis for reversing FERC's denial -- evidence that has been repeatedly sought by FERC staff.

The Applicants' attempt to inflate its preliminary agreements with JERA and other parties into a sign of strong demand for the Jordan Cove project is flawed for a number of reasons. The preliminary agreement is just that, preliminary and non-binding. Despite FERC's repeated requests for evidence of "commitments for firm service" and its plans to hold an open season, the Applicants' Request still does not provide any concrete timing for when it expects to have either service agreements or an open season.

Applicants offer no credible evidence that JERA actually intends to truly commit to a 20-year binding contract any time soon with this greenfield LNG terminal. Moreover, as a "greenfield," terminal, it will necessarily have significantly higher prices than a number of current and planned brownfield projects with available LNG supply. Indeed, there are real reasons to question the likelihood that JERA will ever reach a final agreement with Jordan Cove at a price the terminal could realistically meet. It is also worth noting that JERA, as an LNG buyer, only benefits from the oversupply of LNG and the prospect of a potential Jordan Cove terminal only furthers its clear self-interest in maintaining depressed LNG prices.

JERA's commitment is particularly questionable in light of its recent announcement it was significantly reducing its reliance on long-term LNG contracts as Japan's LNG demand predictions continue to shrink. "We want to change drastically," Jera's president Yuji Kakimi told a news conference. As reported by Platts:

> Maturing long-term contracts to buy LNG will be replaced with short-term contracts, spot buying, and long-term offtake volume from projects Jera has stakes in, Kakimi said. As of this July, Jera's long-term offtake volume will be 35 million mt/year, which it planned to cut to 15 million mt/year by its 2030-31 year.

See Exhibit 1, "Japan's Jera to change LNG buying strategy under 15-year plan", Feb. 10, 2016.

As similarly reported:

> JERA, which buys around 80 percent of its gas on long-term contracts, will only contract volumes to cover the absolute minimum of fuel needed, using the most optimistic scenarios for rebooting its nuclear power plants and the take-up for renewable energy being promoted by the government. Additional requirements for gas will be met with mid-term and short-term contracts or spot purchases, Kakimi [Jera's President] said.

See Exhibit 2, "Japan's Jera says will significantly cut long-term LNG contracts", Reuters Oct. 21, 2015.

In light of the current depressed state of LNG market fundamentals, JERA is even considering selling LNG supply it already has under contract with Freeport LNG to Europe. *See* Exhibit 3, "Jera eyes selling US Freeport LNG volume to Europe as alternative to Japan", Platts May 28, 2015. The notion that JERA is likely to complete a binding 20-year agreement with Jordan Cove anytime soon is inconsistent with both its new business strategy and the fundamentals of the LNG market.

The Applicants' preliminary agreements with gas trader ITOCHU is similarly speculative. While the Applicants assert their preliminary agreement with JERA was underway prior to FERC's March 11, 2016 denial order, it is telling that they make no similar claim as to ITOCHU PA or its precedent agreement with Macquarie'. While the Applicants have a clear incentive to attempt to quickly create the illusion of market demand, there is little evidence to support the contention that these preliminary agreements with JERA or ITOCHU reflect genuine evidence of actual market demand.

The Applicants' incentive for the precedent agreement between themselves for 592,354 Dth/d on the pipeline is a transparent contrived ploy to create the illusion of demand and hardly substitutes for the type of hard evidence of market demand that would give FERC or the public any rational basis for finding there is now true demand for the project. PCGP's precedent agreement with Macquarie, PCGP's financial advisor for the project and also a substantial Veresen stockholder, is similarly disingenuous. *See* Exhibits 4 and 5[11].

The Applicants are desperate to find new evidence of market demand and are understandably concerned that FERC's denial, if allowed to stand, will mean the primary project players could see years of investment, however misguided, lost. In light of this motivation, the timing of these new "agreements" and the speed at which they were completed must be seriously questioned. Intervenor landowners submit that there is little basis for interpreting these agreements as reflecting genuine market demand as opposed to a quick scramble to create some contrived basis for a rehearing request.

The preliminary agreement with Avista for a token amount of gas is similarly insufficient evidence of demand for pipeline capacity. While Avista may be supportive of the project from a political perspective, the small gas volumes in its precedent agreement can fairly be seen as part of the effort to create a fig leaf of demand. In addition to the minimal quantity of gas at issue, the suggestion that, "PCGP is committed to serving local communities located along the pipeline and has agreed to install taps for natural gas deliveries to these smaller communities" is entirely speculative. The Applicants assert that, "this substantial new quantity of capacity will enable significant economic development in

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11 https://www.macquarieresearch.com/rp/web/guest/searchdisclosures?p_p_id=Disclosure_WAR_portletsresearch&p_p_lifecycle=0&p_p_state=exclusive&p_p_mode=view&_Disclosure_WAR_portletsresearch_sort=company&_Disclosure_WAR_portletsresearch_dir=asc&_Disclosure_WAR_portletsresearch_page=243&_Disclosure_WAR_portletsresearch_implicitModel=true&_Disclosure_WAR_portletsresearch_action=filterDisclosureResult.

the region by attracting new industries and providing additional natural gas to existing industrial, commercial and residential users throughout southern Oregon." Request 6. They cite, however, no actual evidence that added gas supply would attract the "new industry" and no evidence that expanded gas supply would trigger industrial expansion or is even needed. While this local supply was of course never a core purpose of the pipeline project, it is also relevant to note that neither a local demand nor the related industrial expansion was considered in the project FEIS.

3. The Applicants' Claims of Market Demand Have to be Considered in Light of Weak LNG Markets.

The Applicants' Rehearing Request glosses over the basic market realities of the current LNG market and specifically the Asian LNG market their project was intended to target. The Applicants assert in their Request that, "[t]he fact that the Applicants had not provided more evidence of customer commitment to the Project as of the date of the March 11 Order reflects circumstances in the global LNG market, and should not be taken as an indication that the Project does not have market support." Request 11. But the most powerful "circumstances in the global LNG market" right now are the continuing low price and over supply of LNG. The Applicants' suggestion that there is a more complicated reason for their failure to secure customer commitments is without merit and does not warrant FERC's rehearing.

In that regard, it is worth comparing the extensive evidence of market demand that was presented to FERC prior to its approval of the Sabine Pass, Corpus Christi, Magnolia and Freeport LNG terminals with the very limited evidence of demand the Applicants have provided. The chart below illustrates key milestones obtained by each of six LNG terminals leading up to FERC approval. Information in this chart came from a combination of FERC order documents and news releases issued by the individual LNG companies. The Applicants, by comparison, were never able to secure long term binding contracts, easements or financing for locked-in engineering, procurement and construction contracts (EPC) for this significant greenfield project over similar time durations, further indication of the array of challenges this project has faced from the beginning.

Comparison of U.S. LNG Export Terminals Key Milestones

TIME LINE OF LNG PROJECTS

	Cheniere Sabine Pass (Trains 1-4)	Freeport LNG (Trains 1-3)	Cheniere Corpus Christi (Trains 1-3)	Cheniere Sabine Pass (Trains 5-6)	Magnolia LNG (Trains 1-4)	Jordan Cove (Trains 1-4)
Total Capacity	16 mtpa	13.2 mpta	13.5 mtpa	9 mtpa	8 mpta	6.8 mpta
New Pipeline			23 mi, 48"	94.8 mi, 42"		232 mi, 36"
FERC Pre-filing Approval	8/4/2010	12/1/2010	12/16/2011	3/8/2013	1/1/2013	6/1/2012
MOU/HOA/Term Sheets*	5	0	0	0	4	0
Binding 20 Yr Contracts^	0	0	0	2 - (3.75)	0	0
Filed Application	1/31/2011	12/9/2011	8/31/2012	9/30/2013	4/30/2014	5/21/2013
MOU/HOA/Term Sheets	2	0	0	0	0	3 (2013)
Binding 20 Yr Contracts	1 (3.5)	5 (13.2)	1 (.8)	0	1 (2.0)	0
Signed EPC	11/13/2011	12/1/2013	12/9/2013	6/15/2013	11/13/2015	0
Binding 20 Yr Contracts	4 (10.5)	0	8 (6.48)	0	0	0
Final EIS	12/28/2011	6/16/2014	10/8/2014	12/12/2014	11/13/2015	9/30/2015
Binding 20 Yr Contracts	0	0	1 (.77)	0	0	0
FERC Approval	4/16/2012	7/30/2014	12/30/2014	4/6/2015	4/15/2016	DENIED (3-11-2016)
Notice to Proceed	8/9/2012	11/1/2014	5/13/2015	6/30/2015		
Binding 20 Yr Contracts	(2.0)	0	1 (.6)	0		
Total Binding Contracts	**16 mtpa**	**13.2 mpta**	**8.65**	**3.75 mtpa**	**2.0 mpta**	**0 mpta**
Volume Uncontracted~	0 mpta	0 mpta	4.85 mpta	.75 (Train 5)	6.0 mpta	

*Non-binding Memorandums of Understanding, Heads of Agreements and Term Sheet Agreements reported by companies
^ Legally binding 20 year Liquefaction Tolling Agreements, Use or Pay and Sales and Purchase Agreements.
~ Based on contracts announced in press releases, these could vary if data wasn't announced.

KEY:	Preliminary Agreements	Binding Contracts (vol.)	Key Milestone Dates	FERC Approval	Total Binding 20 Yr Contracts	Volume NOT contracted

As evidenced by Sabine Pass LNG's experience, where only three of the seven original MOU signers ultimately signed binding 20 year contracts, **preliminary agreements even under favorable market conditions can be weak evidence of demand and often do not translate into binding long-term agreements**.

The Applicants point to speculative evidence of future demand that is at odds with the fundamental market shifts that have sent LNG prices to 18-year record lows this month.[12] While the Applicants point to speculative global demand increases in LNG as an "opportunity looming," they ignore the realities that LNG imports into their target Asian markets are only projected to decrease further in 2020 and even global projections of when demand may balance supply extend from 2025 to 2030.[13] As discussed in Intervenor landowners' previous comments, the combination of Japan's restart of its nuclear generators, an increased reliance on renewables, and the abundance of lower priced alternative sources of LNG are projected to only further depress Asian LNG demand for Jordan Cove LNG in 2020. *See* Exhibit 6, "Japan LNG demand expected to fall by 2020 on nuclear restarts, renewables", Platts Dec 15, 2015; Exhibit 7, "S. Korea secures 23.5 mil mt in 2027 LNG term deals, 62% of expected demand", Platts, Oct. 7, 2015.

A recent LNG export market analysis prepared for U.S. DOE underscores the fact that global LNG market demand is unlikely to grow to the point of creating demand for the Jordan Cove project until 2030.[14] Such realities undermine the Applicants' claims that speculative demand increases in 2020 constitute sufficient evidence of a current demand for LNG.

As one market assessment[15] recently explained:

> The traditional prime Asian LNG buyers have all cut back their demand forecasts. With the optimistically predicted restart of numerous nuclear reactors in Japan and continuation of lower consumption levels, Japan

[12]http://www.desmogblog.com/2016/04/14/will-lng-exports-save-shale-gas-drilling-industry-s-rofitability-not-so-fast
[13]http://oilprice.com/Energy/Energy-General/*The-Great-Glut-Why-LNG-Markets-Might-Not-Balance-Before-2025*.html.
[14] *The Macroeconomic Impact of Increasing U.S. LNG Exports*, October 29, 2015, online at energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf
[15] http://www.energylawexchange.com/the-top-10-questions-facing-the-lng-industry-in-2016.

> predicts its LNG demand is declin[ing] – in one estimate, to 77 MTPA in 2020 as compared to 86 MTPA in 2014.[35] Kogas, the second largest LNG buyer in the world after Jera, has also revised its demand forecast downwards.[36] Likewise, demand growth for China has dampened with recently lowered forecasts – in one forecast, by 15% for the upcoming few years.[37]

Furthermore, the Applicants' submittals do nothing to change the major competitive disadvantage that greenfield projects like the Jordan Cove terminal have when compared to a brownfield project such as Freeport LNG or the streamlined, turn-key construction of Magnolia LNG—each benefiting from existing and nearby infrastructure and able to offer LNG at prices well below Jordan Cove. *See* Exhibit 8, "Magnolia LNG Executes EPC Contract with KBR-SK JV", Magnolia LNG Nov. 16, 2015. While the Applicants of course rely on the geographic proximity of the Jordan Cove project to the Asian market, they offer no tangible evidence that that proximity translates to LNG prices for Asian customers that are lower than the diversity and portfolio sourcing of Jordan Cove's global competitors which have either completed or near completed projects.

CONCLUSION

For these reasons, Intervenor landowners ask FERC to deny the Applicants' request for a rehearing.

Respectfully submitted,
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CERTIFICATE OF FILING

I certify that on April 26, 2016, I filed the foregoing [Corrected] Motion to File Answer and Answer by efiling with:

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
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Washington, DC 20426

s/ *Jeri G. Zwick*
Jeri G. Zwick
Legal Assistant to Thane W. Tienson

EXHIBIT 1

http://www.platts.com/latest-news/natural-gas/asia/japans-jera-to-change-lng-buying-strategy-under-26364369

Platts

Japan's Jera to change LNG buying strategy under 15-year plan

Tokyo (Platts)--10 Feb 2016 658 am EST/1158 GMT

Japan's Jera Co -- a joint venture between Chubu Electric and Tokyo Electric Power Co -- outlined a 15-year business plan Wednesday that will see its LNG buying become more flexible, resulting in fewer long-term contracts.

"We want to change drastically," Jera president Yuji Kakimi told a news conference.

Maturing long-term contracts to buy LNG will be replaced with short-term contracts, spot buying, and long-term offtake volume from projects Jera has stakes in, Kakimi said.

As of this July, Jera's long-term offtake volume will be 35 million mt/year, which it planned to cut to 15 million mt/year by its 2030-31 year.

The business plan includes boosting domestic as well as overseas power generation businesses and to enhance LNG trading capability.

"We want to trade LNG, handling several million mt of volume," Kakimi said.

Jera also aims to increase the number of LNG ships in its fleet to about 30 by 2030-31, from 16.

By 2030-31, Jera expects to have 30-40 million mt/year of contracted LNG volume, compared with 40 million mt/year now, while its contracted coal volume will grow to 20-30 million mt/year from 20 million mt/year.

Its long-term business plan was unveiled at a time when Japanese LNG demand was expected to fall with the restart of nuclear reactors and growing solar power.

Given Japan is liberalizing its domestic retail electricity and gas markets, cheap fuel sources, such as coal, were also expected to gain currency.

GOING GLOBAL

Jera reshuffled top management,including a new chairman in Hendrik Gordenker, who has been a senior adviser and external expert for Jera since last May and is also a former partner at law firm White & Case LLP in Tokyo.

Gordenker said he will be involved in various functions including global strategy as well as communicating with stakeholders worldwide.

"We have to establish Jera in order to go to the international stage with global approach," he said.

Ahead of the start of US Freeport project in 2018, Jera has been preparing to hire local LNG traders in its Houston office, Kakimi said.

Kakimi also reiterated that offtake volume from the US Freeport project will be brought to Japan or sold in Europe.

Jera has a natural gas liquefaction tolling agreement with Freeport LNG in Texas.

Under the supply deal, Chubu will be able to offtake 2.2 million mt/year of LNG with no destination restrictions.

As for its power generation business, Jera said it aims to increase overseas power generation capacity to 20 GW by 2030-31 from a current 6 GW, and domestic capacity to 12 GW from 650 MW.

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http://www.reuters.com/article/us-commodities-summit-jera-idUSKCN0SF0Y320151022

Reuters

Japan's Jera says will significantly cut long-term LNG contracts

TOKYO | By Osamu Tsukimori and Yuka Obayashi

Jera Co President Yuji Kakimi poses for a picture before the Reuters Commodities Summit in Tokyo, Japan October 21, 2015.
Reuters/Toru Hanai

Japan's JERA Co, set to become the world's biggest buyer of liquefied natural gas (LNG) next year, plans to significantly cut the amount of gas it purchases on long-term contracts, the company's president told the Reuters Global Commodities Summit.

JERA, a joint venture set up by Tokyo Electric Power (Tepco) (9501.T) and Chubu Electric Power (9502.T) to initially handle fuel procurement with a possibility of eventually taking over thermal power stations, has more than 10 million tonnes of gas on long-term contracts that expire by around 2020.

But the company will not automatically renew them, President Yuji Kakimi said.

The move puts more question marks over planned big LNG projects, which rely on long-term contracts to get financing approved, amid a downturn in commodities markets that has cut investment in many areas.

JERA, which buys around 80 percent of its gas on long-term contracts, will only contract volumes to cover the absolute minimum of fuel needed, using the most optimistic scenarios for rebooting its nuclear power plants and the take-up for renewable energy being promoted by the government.

Additional requirements for gas will be met with mid-term and short-term contracts or spot purchases, Kakimi said.

"Our original mission of procuring at a similar level to Europe and the U.S. is close to being achieved with oil price falling, but even if oil prices rose, we have to make sure that (procurement) costs are capped," he said.

JERA will surpass Korea Gas Corp (036460.KS) as the world's single biggest buyer of LNG with annual purchases of around 40 million tonnes once it fully integrates the partners' existing contracts next summer.

Kakimi said Jera's annual purchases of gas are expected to decline in line with government forecasts, implying the company will be burning around 28 million tonnes a year by 2030.

He also said the company is expanding Chubu Electric's unit in Houston to start LNG trading opportunities when the Freeport LNG project, in which Chubu invests in, starts export in 2018.

CUTTING COAL PROCUREMENT COST

JERA also aims to broaden its sources of coal to lower its reliance on high-quality Australian coals in order to cut costs.

Australia is by far the biggest supplier to Japan, accounting for nearly 80 percent of Japan's thermal coal imports in the first eight months of this year.

"Since it looks difficult to see more flows from Indonesia under current market circumstances, it is important to develop new sources such as Russia, the U.S., Colombia and Africa," Kakimi said.

JERA, which buys about 20 million tonnes of thermal coal a year, is also interested in buying into in coal mines to hedge against rises in coal prices, he said.

He declined to say how much a stake it aims to buy, but said stakes equivalent to 30-40 percent of its procurement would be "too much" under the current market.

Thermal coal benchmarks hit record lows earlier this month due to a sharp slowdown in demand, especially in Asia, and with overall mining output remaining stubbornly high.

Kakimi thinks prices have hit bottom.

"I actually said last year the prices had hit the bottom, but they kept on falling," he said. "But I really think the market is at the bottom as mines have been closing and coal mining companies have been putting themselves up on sale."

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(Additional reporting by Billy Mallard, Kentaro Hamada, Kazuhiko Tamaki and Hitoshi Ishida; Editing by Aaron Sheldrick and Michael Perry) http://www.platts.com/latest-news/natural-gas/tokyo/interview-jera-eyes-selling-us-freeport-lng-volume-26103915

EXHIBIT 3

Interview: Jera eyes selling US Freeport LNG volume to Europe as alternative to Japan

Tokyo (Platts)--28 May 2015 552 am EDT/952 GMT

Japan's Jera, the joint venture between Tokyo Electric Power Company and Chubu Electric, eyes selling volumes from the US Freeport LNG project to Europe or other markets as an alternative, if it is not economically viable to bring the LNG to Japan, the company's president said this week.

"At current prices, US LNG could be more expensive [for the Japanese market]. In such a case, we could consider options where we buy spot cargoes in Asia [for the domestic market] and sell US LNG to other markets," Jera President Yuji Kakimi told Platts in an interview, adding that selling into Europe or South America are options.

"The Freeport project offers us flexibility and will allow us to trade by hedging risks. We could take advantage of differences in prices between markets and move LNG accordingly," he added.

The Platts JKM for July delivery cargoes was assessed at $7.75/MMBtu Wednesday.

Article continues below...

In comparison, US LNG could land in Asia at around $9/MMBtu, based on Wednesday's $2.815/MMBtu settlement for the NYMEX June Henry Hub gas futures contract and using Cheniere's Sabine Pass pricing as a reference.

Financial terms and details of the tolling agreement Chubu Electric signed with Freeport LNG are not clear.

Chubu Electric has a natural gas liquefaction tolling agreement with Freeport LNG in Texas. Under the supply deal, Chubu will be able to offtake 2.2 million mt/year of LNG with no destination restrictions.

Tepco has contracts for the supply of 800,000 mt/year -- two 400,000 mt/year contracts -- of lean LNG from the US Cameron LNG project, in Louisiana, for over 20 years from 2017, under deals with Japanese trading houses Mitsui & Co. and Mitsubishi Corp.

Tepco is, meanwhile, revamping its LNG receiving facilities so that they are able to accept up to 10 million mt/year of lean LNG -- which has a lower calorific value per unit than conventional LNG.

Kakimi said Jera should have geographically balanced LNG supply sources and also balanced indexations, but declined to say exactly how much volume Jera would aim to have under contracts with oil-linked or natural gas hub-linked pricing in its portfolio.

He, however, noted that Chubu Electric has said it aims to cut oil-linked contracts to 50% of the total.

"We can use this as an example," Kakimi said. "Chubu Electric has not said what the other half should consist of, but Henry Hub-linked, NBP-linked and JKM-linked, and other various benchmarks can be used," he added.

UNCERTAINTIES AHEAD

The establishment of Jera comes ahead of Japan's plan to fully deregulate the country's retail power and gas markets in 2016 and 2017, respectively.

Jera started up on April 30 with about 50 staff, and the integration between Tepco's and Chubu Electric's fuel transport and fuel trading business is expected to be completed by October.

The number of staff will be increased to around 400 people by summer next year, when a wide range of businesses -- such as existing upstream assets, fuel sale and purchase agreements and overseas power generation -- are brought together.

Between Tepco and Chubu Electric, their total LNG procurement is around 40 million mt/year and coal procurement is 19 million mt/year.

Jera hopes to reduce fuel costs by leveraging its large procurement volumes, although Kakimi said there are uncertainties over future LNG demand because of the restart of nuclear reactors, growing solar power, various plans to build coal-fired plants and liberalization of domestic energy markets.

"I think we can cover real demand with long-term contracts, but potential demand that could change because of these factors should be covered by something else such as contracts with mid-term or short-terms," he added.

Kakimi also said a tender is an effective way to procure LNG when there is ample supply in the market.

In December, the two utilities held a tender for the joint procurement of six LNG cargoes for delivery during fiscal 2015-16 (April-March).

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VERESEN

Q2

For the Six Months Ended June 30, 2014

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Veresen Announces 2014 Second Quarter Results and Updates Guidance

CALGARY, ALBERTA (August 6, 2014) – Veresen Inc. ("Veresen" or the "Company") (TSX: VSN) announced today financial and operating results for the three months ended June 30, 2014.

Highlights

- Veresen generated distributable cash[1] of $63.7 million ($0.29 per Common Share) in the second quarter of 2014 compared to $49.2 million ($0.25 per Common Share) in the second quarter of 2013.
- Veresen recorded a net loss attributable to Common Shares of $2.4 million ($0.01 net loss per Common Share) in the second quarter of 2014 compared to net income attributable to Common Shares of $11.5 million ($0.06 net income per Common Share) in the second quarter of 2013.
- Cash from operating activities was $47.9 million in the second quarter of 2014 compared to $55.0 million in the second quarter of 2013.
- In July, Jordan Cove LNG achieved a key regulatory milestone with the receipt of the Notice of Schedule for the environmental review of the LNG terminal and related pipeline from the Federal Energy Regulatory Commission ("FERC").
- Alliance Pipeline filed an application with the National Energy Board ("NEB") for regulatory approval of the tolls and tariff provisions required for Alliance to implement its proposed new services.

"We continue to make good progress in advancing our key strategic initiatives, including the re-contracting of the Alliance Pipeline and development of Jordan Cove LNG. During the first half of 2014, we also completed key financing activities to bolster our financial strength and flexibility," said Don Althoff, President and CEO.

"The filing of Alliance Pipeline's revised toll and tariff application with the NEB, is an important milestone in the re-contracting process. Signing of Precedent Agreements with producers and shippers is ongoing as we move through the regulatory process with the NEB."

Don Althoff added, "With the receipt of our Notice of Schedule from the FERC for our Jordan Cove LNG project, we now have a line of sight to obtaining our Final Environmental Impact Statement, and I'm confident we will obtain this critical permit."

[1] This is not a standard measure under GAAP and may not be comparable to similar measures used by other entities. See the reconciliation of distributable cash to cash from operating activities in the tables attached to this news release.

Financial Highlights	Three months ended June 30		Six months ended June 30	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Net income (loss) before tax				
Pipeline	**30.0**	27.5	**61.5**	52.3
Midstream	**8.7**	15.6	**42.6**	27.0
Power	**1.7**	9.5	**(2.0)**	10.5
Veresen – Corporate	**(40.6)**	(26.6)	**(69.3)**	(53.5)
	(0.2)	26.0	**32.8**	36.3
Gain on sale of assets	**-**	-	**14.3**	-
Tax recovery (expense)	**1.9**	(12.3)	**(10.0)**	(19.2)
Net income	**1.7**	13.7	**37.1**	17.1
Preferred Share dividends	**(4.1)**	(2.2)	**(8.2)**	(4.4)
Net income (loss) attributable to Common Shares	**(2.4)**	11.5	**28.9**	12.7
Per Common Share ($)	**(0.01)**	0.06	**0.14**	0.06

Financial Performance

For the three months ended June 30, 2014, Veresen recorded a net loss attributable to Common Shares of $2.4 million or $0.01 net loss per Common Share compared to net income of $11.5 million or $0.06 per Common Share for the same period last year. The decrease in earnings was primarily driven by higher project development spending related to Jordan Cove LNG, lower midstream earnings, and the revaluation of the York Energy Centre interest rate hedge.

Higher project development spending in the second quarter of 2014 reflects Veresen's efforts to further advance Jordan Cove LNG following its receipt of a conditional order from the U.S. Department of Energy to export liquefied natural gas to those countries that do not have Free Trade Agreement status with the U.S. As Veresen has continued to de-risk this project, the Company has dedicated additional resources towards its commercial, engineering and financing activities and, as anticipated, development spending has increased accordingly.

The Midstream business generated net income of $8.7 million before tax for the three months ended June 30, 2014 compared to $15.6 million for the same period in 2013. Hythe/Steeprock generated consistent earnings relative to the comparative period, while Aux Sable's results were negatively impacted by lower NGL margins resulting from higher gas prices.

A revaluation of the York Energy Centre interest rate hedge resulted in an $11.7 million reduction in second quarter Power earnings compared to the same period last year. Partially offsetting this reduction was the receipt of a $3.9 million retroactive adjustment related to York Energy Centre's power purchase agreement with the Ontario Power Authority.

Second quarter 2014 results also reflect an increase in Pipeline earnings from Alliance, primarily due to higher negotiated depreciation rates and contributions from the Tioga Lateral pipeline.

Distributable Cash

	Three months ended June 30		Six months ended June 30	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Pipeline	**40.6**	37.9	**81.6**	76.4
Midstream	**27.0**	23.7	**69.7**	50.9
Power	**17.8**	7.1	**24.9**	16.9
Veresen – Corporate	**(15.0)**	(15.8)	**(32.0)**	(34.3)
Current tax	**(2.6)**	(1.5)	**(6.7)**	(1.7)
Preferred Share dividends	**(4.1)**	(2.2)	**(8.2)**	(4.4)
Distributable Cash [1]	**63.7**	49.2	**129.3**	103.8
Per Common Share ($)	**0.29**	0.25	**0.62**	0.52

[1] See the reconciliation of distributable cash to cash from operating activities in the tables attached to this news release.

For the three months ended June 30, 2014, Veresen generated distributable cash of $63.7 million or $0.29 per Common Share compared to $49.2 million or $0.25 Common Share for the same period in 2013. Higher distributable cash reflects increased contributions from each of Veresen's Pipeline, Midstream and Power businesses, partially offset by higher taxes and Preferred Share dividends.

Overview of Business Segments

Pipelines

In the second quarter of 2014, Alliance Pipeline filed an application with the NEB for regulatory approval of the tolls and tariff provisions required to implement Alliance's proposed new services commencing December 1, 2015. The NEB application is a key milestone for Alliance as it reflects a move to a new business model under new natural gas transportation agreements. Regulatory approval will allow Alliance to offer its customers a menu of new services and competitive tolls replacing the 15-year service contracts that expire November 30, 2015.

Alliance's new services offering reflects extensive market consultation and includes full-path and segmented receipt and delivery services, a new Canadian trading pool, and a revised hydrocarbon dewpoint specification. Alliance plans to file a regulatory application with the FERC in 2015 to revise its U.S. tariff.

Alliance continues to be in active negotiations with prospective and existing shippers with respect to re-contracting its pipeline capacity post-2015. The signing of binding Precedent Agreements will be timed with the RGP agreements that Aux Sable is negotiating with the producer community.

Midstream

Veresen's maintenance turnaround at the Steeprock natural gas processing plant in British Columbia was completed on budget and on schedule in June 2014. Turnaround activities were performed in a manner consistent with Veresen's ongoing commitment to the health and safety of its employees and contractors, and safeguarding of the environment. The majority of the costs associated with the turnaround will be recovered under Veresen's Midstream Services Agreement with Encana Corporation.

Aux Sable continues to work with producers within an economic radius of the Alliance pipeline to provide options and value for natural gas and natural gas liquids ("NGLs") to reach large and liquid U.S. markets. Aux Sable holds several RGP agreements with producers that will enhance the value of the producers' NGLs.

In June 2014, Aux Sable executed an additional long-term RGP agreement with 7G. The agreement significantly increases the volumes originally agreed to by the companies in February 2013. Under this new long-term agreement, volumes of liquids-rich natural gas are expected to ramp up to 500 mmcf/d. These supplies will be processed at Aux Sable's extraction and fractionation facilities located in Channahon, Illinois.

Power

Construction of the Dasque-Middle run-of-river project in northwest British Columbia is proceeding as planned and it is expected to be in-service in the fourth quarter of 2014. Construction of the 33 MW St. Columban wind project is progressing, with commercial in-service expected in the first half of 2015. The 40 MW Grand Valley III wind project continues to advance through the regulatory process. Testing and commissioning of the 13 MW Whitecourt waste heat facility is ongoing and the facility is expected to be in service by the fourth quarter of 2014.

Jordan Cove LNG

In July 2014, Jordan Cove LNG and the associated Pacific Connector Gas Pipeline received their collective Notice of Schedule for environmental review from the FERC. Receipt of this schedule is an important milestone in the regulatory process. FERC's schedule calls for a final EIS to be issued on February 27, 2015. Based on this schedule, Veresen has reviewed and updated its project timeline and expects to make a final investment decision in mid-2015. With a four-year construction period, commercial LNG production is targeted for mid- to late-2019. Once the FERC issues Jordan Cove LNG its Draft Environment Impact Statement, a public hearing process is initiated.

Veresen continues to be in active negotiations to secure long-term arrangements to produce LNG for international customers. Veresen's objective is to execute binding agreements this year for all of Jordan Cove LNG's initial capacity of 6 million tonnes per annum.

Veresen also continues to negotiate the engineering, procurement and construction contract with a joint venture formed by Kiewit and Black & Veatch for the design and construction the LNG terminal. Veresen expects the EPC contract to be completed in late 2014, following which a Class 1 cost estimate and schedule will be generated by the contractor.

In the second quarter of 2014, Veresen engaged Macquarie Capital as its financial advisor for the Jordan Cove LNG project.

2014 Guidance Update

Veresen has narrowed its guidance for 2014 distributable cash to be in the range of $1.02 per Common Share to $1.20 per Common Share, with a midpoint of $1.11 per Common Share. Further details concerning 2014 guidance can be found in the "Invest" section of Veresen's web site at www.vereseninc.com.

EXHIBIT 5

Company	Bloomberg Ticker	Country / Region	Disclosure Type	Disclosure
Veresen	VSN CN	Canada	General	Macquarie and its affiliates collectively and beneficially own or control 1% or more of any class of Veresen Inc's equity securities.
Verifone Systems Inc.		United States	General	Macquarie Group Limited together with its affiliates, beneficially owns 1% or more of a class of common equity securities of Verifone Systems Inc.
Verisign Inc.		United States	General	Macquarie Group Limited together with its affiliates, beneficially owns 1% or more of a class of common equity securities of Verisign Inc.
VGI Global Media PCL	VGI BKK	Thailand	General	Macquarie Securities (Thailand) Limited may be an issuer of derivative warrants on the securities mentioned in this report.
VGI Global Media PCL	VGI BKK	Thailand	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of VGI Global Media PCL.
Vicinity Centres	VCX AU	Australia	General	MACQUARIE CAPITAL (AUSTRALIA) LIMITED or one of its affiliates has provided Federation Centres Ltd with investment advisory services in the past 12 months, for which it received compensation.
Vicwest	VIC CN	Canada	General	Macquarie Capital Markets North America Ltd., which is a registered broker-dealer and member of FINRA, accepts responsibility for the contents of reports issued by Macquarie Capital Markets Canada Ltd in the United States and sent to US persons. Any US person wishing to effect transactions in the securities described in the reports issued by Macquarie Capital Markets Canada Ltd should do so with Macquarie Capital Markets North America Ltd. The Research Distribution Policy of Macquarie Capital Markets Canada Ltd is to allow all clients that are entitled to have equal access to our research.
Vietnam Sun Corp		Vietnam	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of Vietnam Sun Corp.
Vijaya Bank	VJYBK IN	India	General	Macquarie Group Limited together with its affiliates may have a beneficial interest in the debt securities of the companies mentioned in this report.
Village Roadshow	VRL AU	Australia	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of Village Roadshow Ltd.

2,562 disclosures found in 257 pages, displaying 2,421 to 2,430.

EXHIBIT 6

http://www.platts.com/latest-news/natural-gas/tokyo/japan-lng-demand-expected-to-fall-by-2020-on-27051779

Platts

Japan LNG demand expected to fall by 2020 on nuclear restarts, renewables

Tokyo (Platts)--15 Dec 2015 1234 am EST/534 GMT

Restart of nuclear reactors in Japan, growing renewable sources of energy and a slow economy are expected to push down the country's LNG consumption by 2020 by as much as 10.5% from 2014 levels, Eclipse Energy said this week.

Japan's LNG demand is expected to drop to 77 million mt by 2020 from a record 86 million mt reached in 2014, according to Eclipse, an analytics unit of Platts.

In 2015 itself, Japan bought 3 million mt less LNG in the first 10 months compared with a year earlier.

Kyushu Electric restarted its two 890 MW nuclear reactors at Sendai in August and October, ending Japan's 23 months of nuclear-free period since September 2013.

Kyushu Electric's LNG consumption in September dropped to the lowest level since May 2011, data from the Ministry of Economy, Trade and Industry showed.

From September to November, Kyushu Electric received seven cargoes at its Tobata terminal, down from 13 in the same period last year, according to Platts ship trade-flow software cFlow. Near this terminal is the 1.8 GW Shin Kokura gas-fired station.

Kyushu Electric's Oita LNG terminal, adjacent to its newer 2.295 GW Shin Oita gas-fired power station, received nine cargoes over September-November, the same number of vessels as last year, cFlow showed.

Eclipse estimates that if Kyushu Electric's two 1.18 GW Genkai nuclear reactors start up, it would replace up to around 3-4 LNG cargoes a month. US LNG EXPECTED IN WINTER

By 2019, five more nuclear reactors are expected to restart, including Shikoku Electric's 890 MW No. 3 Ikata reactor, Tohoku Electric's 1.1 GW No. 1 Higashidori reactor, Hokkaido Electric's 912 MW No. 3 Tomari reactor, Hokuriku Electric's 1.206 GW No. 2 Shika reactor and Chugoku Electric's new 1.373 GW No. 3 Shimane reactor.

Summer LNG imports are expected to fall post 2017 because of a growth in renewables capacity in Japan.

Meanwhile demand is expected to drop over the next four years amid a slower economy, and Japan is expected to see an increase in LNG imported through long-term contracts rather than spot, Eclipse said.

Its contracted volume is expected to grow from 82.3 million mt in 2017 to 88.2 million mt in 2019 and 84.8 million mt in 2020, while Japan's LNG demand is projected to drop from 78.2 million mt in 2017 to 77.2 million mt in 2020, according to Eclipse.

"Our forecasts suggest that US-sourced LNG is only called on during the winter peak season at least until 2020," it said.

Japan has so far contracted to buy around 17 million mt/year of LNG from US Freeport, Cameron and Cove Point projects. Eclipse projects just 20-25% utilization of the Japanese tolling contracts in 2018-2019 but a steady increase early

in the next decade rising to about 50% utilization.

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EXHIBIT 7

From http://www.platts.com/latest-news/natural-gas/seoul/s-korea-secures-235-mil-mt-in-2027-lng-term-deals-27868046

Platts

S Korea secures 23.5 mil mt in 2027 LNG term deals, 62% of expected demand

Seoul (Platts)--7 Oct 2015 519 am EDT/919 GM

South Korea has secured 2027 term contracts for 23.5 million mt or 62.3% of the 37.7 million mt it expects to need that year, state-run Korea Gas Corp. said Thursday.

The country has secured 34 million mt for 2015, above the 33.9 million it needs for the year, according to a Kogas report submitted to the National Assembly.

Kogas, which has a monopoly on domestic natural gas sales, expects South Korea's 2015 LNG consumption to be 34 million mt, down from an earlier outlook of 39.8 million due to weak power demand on relatively higher prices of LNG and rising nuclear power output.

Kogas said its revised forecast was made on the basis on sluggish January-July domestic sales, which fell 8.8% year on year.

Kogas planned to import 33.84 million mt in 2015, down 7.4% from 36.33 million mt imported in 2014, given weaker demand.

"Short-term LNG shortage will be made up by short-term contracts to cover winter demand and spot purchasing if necessary, while long-term shortage would be partly filled by volumes from overseas projects in which Kogas is involved," the report said.

Kogas imported 18.35 million mt of LNG over January-July, including 13.08 million mt or 71.3% from the Middle East and South Asia.

It bought 7.32 million mt or 39.9% of its January-July imports from Qatar and 2.45 million mt or 13.4% from Oman, the report said.

It imported 1.87 million mt from Malaysia, 1.44 million mt from Indonesia, 1.15 million mt from Russia and 790,000 mt from Australia in January-July. The other 3.33 million mt came from 10 minor suppliers, including Nigeria, Equatorial Guinea and Brunei.

Of Kogas' total January-July imports, 15.11 million mt or 82.3% came under long- and mid-term contracts, 2.16 million mt or 11.8% was imported under short-term contracts, and 1.08 million mt or 5.9% came from spot buying.

"Under its plans for long- and mid-term contracts, Kogas is seeking more volumes from Australia and North America so as to ease the dependence on Middle East and South Asian nations," the report said.

"In particular, Kogas is pushing to bring in more volumes from projects in which Kogas holds stakes, such as LNG Canada."

Kogas and its partners launched LNG Canada, a project to produce 12 million mt/year of LNG from two trains at Kitimat in the western province of British Columbia in May 2013.

Kogas currently holds a 15% interest in Shell-led LNG Canada after selling a 5% stake to Shell in May last year as part of efforts to reduce its debt.

"Kogas is still pushing to sell additional 5%, which will reduce its stake to 10%," a company official said.

Kogas pushed for sell the 5% stake by the end of 2014 but failed amid the slump in energy prices in the second half of last year.

Kogas, which imported 0.93 million mt from projects in which it holds stakes in 2014, aims to increase the volume to 2.42 million mt in 2017.

The company currently has 15 contracts covering 24.12 million-31.44 million mt/year in imports for 2015-2019.

The deals include 4.92 million mt/year from Qatari RasGas, 2.1 million mt/year from RasGas II and 1.5 million-2 million mt/year from RasGas III, 4.06 million mt/year from Oman's OLNG, and 2 million mt/year from Yemen's YLNG, among others.

Kogas plans to import 2.8 million mt/year from the Sabine Pass terminal in Louisiana from 2017.

It originally planned to buy 3.5 million mt/year from Sabine Pass, but Kogas signed a deal with Total in January 2014 to resell 700,000 mt/year in a bid to reduce import volumes to South Korea.

Under the deal, Kogas will take 2.8 million mt/year while Total will get the remaining 700,000 mt/year.

Kogas also has three mid-term contracts in which Kogas imports 2.73 million-3.88 million mt/year for 2015-2016, the report said.

Besides Kogas, two more South Korean firms are importing LNG directly from overseas sources.

Posco, the country's top steelmaker, has been importing 550,000 mt/year from the BP-led Tangguh LNG consortium in Indonesia since July 2005 under a 20-year contract.

SK E&S, the country's top city gas provider and an affiliate of the country's top oil refiner SK Innovation, also has been importing 600,000 mt/year of LNG directly from Tangguh since 2005 under a 20-year contract.

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EXHIBIT 8

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FOR IMMEDIATE RELEASE
November 16, 2015

Magnolia LNG Executes EPC Contract With KBR-SK JV

Lake Charles, La.—Magnolia LNG, LLC, is pleased to advise that it has agreed to a legally binding lump sum turnkey (LSTK) engineering, procurement and construction contract (EPC Contract) with the KBR-SKE&C joint venture (KSJV) in relation to the Magnolia LNG Lake Charles project.

Contract Highlights:

- EPC Contract LSTK cost of $4.354 billion for four LNG trains and associated facilities;
- EPC guaranteed production of 7.6 mtpa (million tons per annum), or 0.8 mtpa greater than previous guidance;
- The EPC Contract LSTK plant design utilizes the patented OSMR® technology;
- Installed capacity cost/tonne range of $495 to $544 based on final design at FID;
- LNG plant fuel gas consumption of 8%, or 92% feed gas production efficiency guaranteed;
- EPC Contract LSTK price is valid to April 30, 2016.

The EPC Contract covers the engineering, procurement and construction of four LNG production trains with design capacity of 2 mtpa or greater each, two 160,000m3 full containment storage tanks, LNG marine and ship loading facilities, supporting infrastructure and all required post-FID approvals and licenses.

On August 24, 2015, Magnolia LNG announced selection of the Siemens Energy Inc. (Siemens) process compression and driver equipment. The increased power available from the Siemens equipment potentially enables higher final plant design capacity which, following completion of remaining engineering and analysis, will be confirmed prior to Final Investment Decision (FID). As a result, Magnolia LNG's per ton EPC cost may reduce within the range of $495/ton to $544/ton based on the final installed capacity design.

The EPC guaranteed production totalling 7.6 mtpa for the four-train Magnolia LNG project will not change.

The KSJV also provided pricing on a reduced (three train) project scope. The take out cost for one train, estimated by KSJV at $630 million, is subject to final confirmation by December 31, 2015.

Other Costs:
Post-FID costs to commercial operations date in early 2019, which include owner's engineer, O&M mobilisation, insurance, commissioning gas, regulatory, other minor contracts, and capitalized overhead costs, are expected to range between 13.5% ($585 million) and 15.5% ($675 million) of the EPC Contract price. These estimates exclude capitalised interest during construction.

Equity and debt transaction costs, letter of credit fees, and financing costs will be determined at the time of FID, based on final terms agreed with BNP Paribas, lenders and equity providers.

Managing Director's Comments
Magnolia LNG's President and Chief Executive Officer, Maurice Brand said, "We are pleased to announce the final lump sum turn-key EPC contract pricing details after significant efforts by the KSJV and the Magnolia project team, managed by Magnolia LNG's Chief Operating Officer, John Baguley. I want to thank the KBR and SKE&C leadership for their diligence and hard work on delivering the LSTK pricing. The total EPC capital cost in the range of $495 to $544 per ton of LNG plant capacity (for the 8 mtpa or greater plant) establishes a new low for U.S. Gulf Coast projects and is substantially lower compared with recent LNG projects around the world."

"With execution of the EPC contract in hand, we shall continue with final engineering activities but will not commit to out-sized, non-cancellable commitments in advance of execution of offtake agreements for at least 4 mtpa of additional sales," continued Brand.

"The EPC Contract costs agreed with KSJV reinforce the view of Liquefied Natural Gas Limited (LNGL)—Magnolia LNG's parent company—that our business model of mid-scale, modular based LNG trains of nominally 2 mtpa design capacity, incorporating the LNGL's OSMR® LNG liquefaction process is valid, providing a sustainable long-term business platform that can be replicated in future projects."

Revenue Sharing Agreement
For a period of up to 15 years following the declaration of commercial start date for each train, the KSJV may be eligible for annual revenue sharing payments ranging from $0 to $30 million across the four-train plant (maximum of about $0.07/mmBtu per annum). Annual amounts to

be paid to the KSJV reflect a near linear inclining slope starting at $0 for production below 1.7 mtpa up to $30 million for production over 2.0 mtpa, with all annual payments based on actual LNG production achieved in a year reflected on a per train average across the 8 mtpa or greater liquefaction plant.

The revenue sharing arrangement, associated with KSJV's support of the initial scaled commercialisation of LNGL's OSMR® technology and construction approach, when combined with operating and other costs across the 8 mtpa or greater plant is expected to approximate $0.50/mmBtu. The target cost amount of $0.50/mmBtu represents the estimated operating cost implicit in the unchanged EBITDA guidance of approximately $2.50/mmBtu across the four train project.

KSJV Comments

"We are delighted to work with Magnolia LNG on this ground-breaking project for more innovative, cost effective, efficient and greener LNG," said Stuart Bradie, KBR President and CEO. "KBR's long history of success in global LNG, ammonia and plant modularization make us a natural fit for this exciting project and we are pleased to have the opportunity to bring our unique skills, together with our self-perform construction capability and outstanding safety record, to create exceptional value for Magnolia LNG," continued Bradie.

For more information on the Magnolia LNG project, please visit www.MagnoliaLNG.com.

About the Magnolia LNG Project

The Magnolia LNG project is 100% owned by Magnolia LNG, LLC, which is a wholly owned subsidiary company of Liquefied Natural Gas Limited. The project comprises the proposed development of an 8-mtpa LNG project on a 115-acre site, located on an established LNG shipping channel in the Lake Charles District, State of Louisiana, United States of America. The project is based on the development of four LNG production trains of 2 mtpa each using the LNGL's wholly owned OSMR® LNG process technology. Magnolia LNG's business model provides liquefaction services to LNG buyers who pay a monthly fixed capacity fee, plus all LNG plant operating and maintenance costs. LNG buyers contract for liquefaction services under two contract models – a Liquefaction Tolling Agreement, whereby the LNG export terminal is only responsible for processing natural gas into LNG, and an LNG Sales and Purchase Agreement under which the customer buys LNG on a free on board basis (FOB).

About Liquefied Natural Gas Limited

Liquefied Natural Gas Limited is an Australian listed company (Code: LNG and OTC ADR: LNGLY) focused on development of mid-scale LNG plants. LNGL's business strategy aims to deliver

Exhibit 12

https://www.forbes.com/sites/judeclemente/2016/05/15/six-threats-for-the-u-s-liquefied-natural-gas-business/#6c927b3a1b5b
MAY 15, 2016 @ 07:06 PM 5,142

Six Threats For The U.S. Liquefied Natural Gas Business

Jude Clemente , CONTRIBUTOR
I cover oil, gas, power, LNG markets, linking to human development

Combined with lower than expected growth, both oil-linked contract prices and spot prices have plummeted and narrowed the price differentials between the three major markets: the Americas, Europe, and Asia. Per WoodMac, **"Up to half of US LNG at risk of shut-in over next 5 years."** All businesses must keep on their toes by deploying constant SWOT analyses, so here goes six of the Threats for the current U.S. LNG industry.

1. Australia should surpass Qatar and become the largest LNG supplier by 2018. Over $250 billion has been invested since 2009, and Australia will soon have the world's largest, most modern, and technologically advanced LNG export industry in the world. Australia is physically much closer to Asia than we are, taking just 7-10 days to get there, so shipping costs are lower.

Asia already accounts for 70% of all LNG imports and is still see as the main growth market globally, based on rising needs in China and India. Moreover, most of Australia's new LNG export capacity will be available before most U.S. capacity arrives, giving Australia first chance to secure contracts. In many ways, Australian LNG is less affected by the global slump in oil and gas prices, projects pre-sold under long-term contracts, with only 8% of over 9 Bcf/day of new project capacity being un-contracted (**here**).

Australia's LNG export capacity now stands at 6.3 Bcf/day, and this could double to 12-13 Bcf/day by 2019. Australia is also installing floating liquefaction (FLNG) to monetize as much as **100-110 Tcf** in offshore stranded gas. And Australia's per capita income is significantly higher than those in both the U.S. and Canada (**here**), so even though LNG project costs are higher in Australia, the economic (and talent) capacity is major competition.

2. Of the nearly 70% of the European Union's natural gas demand that comes from imports, about 85% arrive via pipeline. Russian piped gas will remain the largest source of foreign gas in Europe, now constituting over 30-33% of supplies. Russian gas is cheaper and operating costs are low: the export infrastructure has already been built. Most of the existing long-term gas

contracts between Gazprom and its European customers will still be in place in 2025, strengthened by today's low oil prices.

Russia's spare capacity to produce natural gas is without equal. Gazprom produces about 43-45 Bcf/day but has the capacity to produce nearly 60 Bcf/day. This giant surplus will allow Russia to ramp up output if Europe's demand for gas increases, a low cost source of supply that could push out U.S. LNG.

Russia has the upper-hand in a price war with us to supply gas to Europe, and our ability to penetrate the European market could simply come down to the willingness of countries to accept higher prices just to reduce reliance on Russia.

If Russia tries to support higher prices and let go market share in Europe, U.S. LNG export capacity could operate at 75%. But, if Russia lets prices fall to hold market share, like Saudi Arabia did to U.S. shale oil, our utilization rates could be just 40%.

Note that China and Europe will NOT be competing for the same Russian gas sources. Europe is the designated market for Russia's current and future gas production in the traditional West Siberian gas basins, so there's great incentive to remain price competitive in Europe. At over 1,150 Tcf, Russia has three times the proven gas that we do. Normally rigid Gazprom has proven to be more flexible under the current oversupply, discounting Lithuania's prices by 25%.

Russia needs Europe more than some realize: **domestic demand is declining** and LNG and projects to Asia are not progressing as quickly as hoped. The European Union is around 80% Gazprom's gas sales. From 2013-2015, Gazprom reports the average gas production cost fell from $1.20 mmBtu in 2013 to $0.84 (**here**), and Gazprom might choose to flood Europe with cheap gas to damage U.S. LNG prospects (**here**).

3. China might be the world's largest incremental gas user and importer, but likely based on piped gas, not LNG. China has signed a $400 billion gas deal with Russia, comprising a framework whereby Gazprom would supply gas for 30 years commencing in 2018. **"A $27 billion natural-gas project in the Russian Arctic has secured the billions in financing it needed from Chinese banks."**

Already sharing a nearly 2,700-mile border, a gas alliance between Russia, the 2nd largest gas producer, and China, the largest energy consumer, is a natural match, and eventually the disagreements on price and route preference will be straightened out.

One estimate has China more than doubling its gas demand to **over 40 Bcf/day by 2020**, with about 40% of that coming from imports (63% pipelines, 37% LNG). Turkmenistan is committed to maintaining its 50% market share of China's imports, and two huge pipeline projects with Russia could block U.S. LNG. Other resource-rich former Soviet Republics **like Kazakhstan** have their sights set on China, and China also wants new prices in its 25-year gas deal with now more flexible Qatar.

Other factors could limit China’s LNG imports, such as domestic production and shale gas. China’s gas production has quietly been booming, up nearly 35% since 2010 to about 12 Bcf/day. China has a solid 125 Tcf of proven natural gas, and holds the largest technically recoverable shale gas reserves at 1,115 Tcf. In fact, the most important question for the future global LNG market could be how shale gas develops in China.

The Great Wall is a perfect example of China’s ingrained dedication to self-reliance, so rising gas (and oil) imports are a known problem that won't go unmitigated. China will remain a coal-based economy, and the Large Substituting for Small program has been installing some of the most efficient coal plants in the world, with super- and ultra-supercritical units reaching 45-50% efficiencies, versus the global average of under 33%.

Even after COP21, LNG import leaders Japan and South Korea are also using more coal, with a combined 61 coal plants set to be built in the next 10 years (**here**). Coal for electricity in Asia is much cheaper than LNG: **Accenture** has coal costing 5 cents/kWh, compared to 11 cents for LNG. COP21 commitments will lower coal prices, enticing coal use. With nuclear just 4 cents, South Korea and developing Asia drive "strong growth" in nuclear power (**here**).

4. Over 90% of India's LNG imports come from mighty Qatar. Petronet LNG, the country's biggest importer, recently revised its contract with RasGas of Qatar. Penalties will be waived and Petronet’s gas price will be halved to $6-7 per mmBtu, demonstrating how key gas and LNG suppliers are willing to alter contracts to maintain market share.

Qatar, "the world's richest country," already exports 12 Bcf/day and is well positioned to ride out low prices because it focuses on efficiency and lower costs, owning **"the value chain from start to finish."** About 33% of Qatar's export LNG volumes are unsold and could push higher cost suppliers out.

India is easily the most energy derived nation on Earth and seeks all gas (all energy really) from all available. India has inked a $20 billion deal to invest in Iran's oil and gas industry. Iran has the world’s 2nd largest gas reserves at over 1,200 Tcf, and opening this endowment to international investment will cause major problems for all gas exporters. And **"Russia, India Inch Closer To $40 Billion Gas Pipeline."**

Shockingly to most I'd bet, India’s natural gas demand has actually been falling, down about 25% since 2010 to under 5 Bcf/day. And just like China, coal-based India is also installing some of the most efficient coal plants with its Ultra Mega Power Projects program. Coal India wants to double output to over 1 billion tonnes by 2020.

5. The estimate is that over half of U.S. total LNG production is destined for Europe by 2020. **Cheniere said in January that it can profitably sell LNG despite lower prices, though margins may be as little as $1 per million Btu to Europe.**

But, all of Europe's key gas suppliers, Russia, Norway, the Netherlands, and Algeria, will be doing all they can to maintain market share in their most important export market. In the first quarter of 2016, Norwegian and Russian gas to Europe reached record levels. Russian gas will be helped even more when sanctions are lifted (**here**).

Europe's gas market has been contracting; efficiency improvements, more renewables, little economic growth, and low carbon prices that discourage coal-to-gas switching. Overall gas demand in the European Union is down 15% since 2010.

Europe's LNG needs could depend on higher coal prices (**here**), which is unlikely anytime soon because of huge oversupply and COP21 commitments that will constrain coal use around the world thereby making coal more available and cheaper. And now, low gas prices and lower usage continue to reduce investment in critical infrastructure. Gas demand projections for Europe have continually been overstated, and most of the ones now indicate a slight incremental gain or even a drop.

Eastern Europe is where U.S. LNG is needed most to lower reliance on Russia. The problem is that there's not enough infrastructure in the area to take in much LNG, or to even import gas from other parts of Europe. Less environmental regulations and a long over-influence of the former Soviet Republics have hurt gas market liquidity in Eastern Europe, where **"gas markets remain fragmented and divided."**

Spain holds over 30% of Europe's LNG re-gasficiation capacity, and the lack of infrastructure to move supplies eastward is a major bottleneck: **"they say the French have refused to allow these interconnections."** The overall gas transport system in Europe **runs east to west.**

And policymakers have been clear: Europe's energy policies are based on making sure that renewables and efficiency, not natural gas, come to dominate, regardless of the cost. **"France studying possible ban on import of U.S. Shale gas."**

6. The global LNG market is still 70% dominated by the long-term, oil-indexed gas contracts that U.S. LNG is expected to help scale down. But, **"less than 15% of contracted volumes expiring in next 5 years."** Even these long-term contracts are becoming increasingly flexible, shown by Gazprom's move toward new market-driven tools.

The competition for the U.S. LNG business will be increasingly fierce. In past years, high oil prices and rising reserves bettered the economics of exporting LNG, driving investment in a new wave of liquefaction projects that will be coming online just as U.S. projects get ramped up.

Exhibit 13a

Jordan Cove Energy Project, L.P.

RECEIVED APR 2 2012

April 2, 2012

By Facsimile
(202) 586-6050

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraph I. of the above-referenced Order, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility to be constructed in Coos County, Oregon for the period from the issuance of the Order on December 7, 2011 through March 2012.

Jordan Cove is steadily conducting development activities. Jordan Cove has identified from among at least ten potential interested counterparties to Liquefaction Tolling Agreements (LTAs) the most promising prospective customers. Initial discussions and due diligence activities are well underway. Serious negotiations for definitive binding LTAs that will cover all of the ratable liquefaction capacity at the terminal will commence in the near future and are expected to be completed by the end of the year.

On February 29, 2012, Jordan Cove filed a request for the Office of Energy Projects of the Federal Energy Regulatory Commission (FERC) to commence the mandatory National Environmental Policy Act pre-filing review process for an application to amend Jordan Cove's FERC authorization to add export facilities, which was docketed in FERC Docket No. PF12-7-000 and approved by letter dated March 6, 2012. FERC Staff conducted onsite environmental review and Jordan Cove held an open meeting on March 27, 2012. Jordan Cove anticipates completing the pre-filing review process and filing its application to amend in October 2012. Jordan Cove currently anticipates that the facility will be operational in the fourth quarter of 2017.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

Robert L. Braddock

Robert L. Braddock
Vice President

125 Central Avenue, Suite 380 • Coos Bay, OR 97420 • Phone: 541 266-7510 • Web: jordancoveenergy.com

Exhibit 13b

Rec'd DOE/FE 10/04/12

Jordan Cove Energy Project, L.P.

October 1, 2012

By Facsimile
(202) 586-6050

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraph I. of the above-referenced Order, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility (Liquefaction Project) for the period from April 1, 2012 through September 2012.

As noted in Jordan Cove's April 2, 2012, semi-annual report, the Office of Energy Projects (OEP) of the Federal Energy Regulatory Commission (FERC or the Commission) commenced the mandatory National Environmental Policy Act pre-filing review process for Jordan Cove's Liquefaction Project on March 6, 2012 in FERC Docket No. PF12-7-000. At that time the pre-filing process was prelude to Jordan Cove's anticipated filing of an application to amend its previously granted Natural Gas Act (NGA) Section 3 authorization for an importation and regasification facility (Import Terminal) in Coos Bay, Oregon; the requested amendment would have sought authority to site the Liquefaction Project at the same location. On April 16, 2012, however, the Commission vacated Jordan Cove's NGA Section 3 authorization for the Import Terminal. In light of that development, on April 30, 2012, Jordan Cove requested an amendment of Jordan Cove's Pre-Filing Request to encompass the Import Terminal facilities that are proposed to be utilized in the Liquefaction Project.

Thereafter, on July 10, 2012, Jordan Cove filed draft Resource Reports 1 and 10. The remainder of the Resource Reports are anticipated to be filed in the fourth quarter of 2012. On August 2, 2012, FERC issued a Notice of Intent to prepare an EIS for the terminal and pipeline. Thereafter, Jordan Cove attended FERC scoping meetings held August 27-30, 2012 in Oregon; additional scoping meetings are scheduled for October 9-11, 2012. Jordan Cove currently anticipates filing its FERC application for the Liquefaction Project in the first quarter of 2013 and commencing operations in the fourth quarter of 2017.

Jordan Cove is progressing in its commercial development activities. From among approximately ten potential counterparties to Liquefaction Tolling Agreements (LTAs), Jordan Cove has narrowed

Office of Natural Gas Regulatory Activities
October 1, 2012
Page Two

the list to the most promising prospective customers and has been engaged intensively in negotiations with them for definitive binding LTAs that will cover all of the ratable liquefaction capacity at the terminal.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

Robert L Braddock

Robert L. Braddock
Vice President

Exhibit 13c

DICKSTEINSHAPIROLLP

1825 Eye Street NW | Washington, DC 20006-5403
TEL (202) 420-2200 | FAX (202) 420-2201 | dicksteinshapiro.com

FAX TRANSMISSION

DATE April 3, 2013	CLIENT NO J5697.0000	
RECIPIENT Attn: Larine Moore, Docket Room Manager	COMPANY U.S. Department of Energy	
FAX 202-586-6050	PHONE	
SENDER Joan M. Darby	PHONE (202) 420-2745	FAX (202) 379-9232
PAGES (INCLUDING COVER SHEET) 3	TIMEKEEPER NO	HARD COPY TO FOLLOW ☒ YES ☐ NO
	SENT BY	DATE/TIME

MESSAGE

Jordan Cove
Energy Project, L.P.

April 3, 2013

By Facsimile
(202) 586-6050

RECEIVED
By moorel at 11:48 am, Apr 03, 2013

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraph I. of the above-referenced Order, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility (Liquefaction Project) for the period from October 1, 2012 through March 2013.

The mandatory National Environmental Policy Act pre-filing review process for Jordan Cove's Liquefaction Project before the Office of Energy Projects (OEP) of the Federal Energy Regulatory Commission (FERC or the Commission) in FERC Docket No. PF12-7-000 has progressed substantially. In November 2013, Jordan Cove filed revised draft Resource Report 13 as well as its responses to the comments on the Liquefaction Project that were filed during the scoping period. In January and February 2013, Jordan Cove filed revised draft Resource Reports 1 and 10, responsive to OEP's comments on the drafts that had been filed in July 2012, and draft Resource Reports 2-9 and 11. As of this date, FERC has issued its comments on all draft Resource Reports, in all cases requesting that the clarifications or additional information be included in Jordan Cove's FERC application. Jordan Cove currently anticipates filing its FERC application for the Liquefaction Project in May 2013 and commencing operations in the first quarter of 2018.

On the commercial front, Jordan Cove continues to engage in intensive negotiations with several potential customers who have expressed very serious interest in the project because of its advantageous geographic position and attractive economics. Jordan Cove expects to enter into memoranda of agreement and/or precedent agreements to long term liquefaction tolling agreements with one or more of these potential customers in the fourth quarter of this year or the first quarter of 2014, which are expected to cover, in aggregate, all of the terminal's ratable liquefaction capacity.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

/s/
Robert L. Braddock
Vice President

Exhibit 13d

Jordan Cove Energy Project, L.P.

October 1, 2013

By Facsimile
(202) 586-6050

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraph I. of the above-referenced Order, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility (Liquefaction Project) for the period from April 1, 2013 through September 2013.

On May 21, 2013, after completion of the mandatory National Environmental Policy Act pre-filing review process for the Liquefaction Project before the Office of Energy Projects (OEP) of the Federal Energy Regulatory Commission (FERC or the Commission) in FERC Docket No. PF12-7-000, Jordan Cove filed its Application for Authority to Site, Construct and Operate a Liquefied Natural Gas Export Terminal in FERC Docket No. CP13-483-000. Jordan Cove has worked to advance its Application by filing supplemental related information, answers to interventions and comments filed by others, and responses to FERC's environmental data requests. Responses to FERC's engineering data requests will be filed this week. Jordan Cove anticipates that FERC Staff will issue a Draft Environmental Impact Statement by year's end.

On the commercial front, Jordan Cove has made substantial progress in its in intensive negotiations with several potential customers. Jordan Cove continues to expect to enter into memoranda of agreement and/or precedent agreements to long term liquefaction tolling agreements with one or more of these potential customers in the fourth quarter of this year or the first quarter of 2014, which are expected to cover, in aggregate, all of the terminal's ratable liquefaction capacity.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

Robert L Braddock

Robert L. Braddock
Vice President

Exhibit 13e

RECEIVED
By Docket Room at via fax 4/12/04

Jordan Cove Energy Project, L.P.

April 11, 2014

By Facsimile
(202) 586-6050

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from October 1, 2013 through March 2014.

In connection with Jordan Cove's Application for Authority to Site, Construct and Operate a Liquefied Natural Gas Export Terminal filed with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. CP13-483-000, Jordan Cove during the October through March period has worked to advance its Application by filing supplemental related information and responses to FERC's various environmental and engineering data requests. Jordan Cove is working diligently to submit to FERC the few items that remain outstanding. Jordan Cove anticipates that FERC Staff will issue a Draft Environmental Impact Statement in early May 2014.

With respect to commercial arrangements, Jordan Cove has entered into non-binding Heads of Agreement (HOAs) with a number of large-scale, prospective customers in the Asia Pacific region. These HOAs are for a total capacity exceeding the Jordan Cove terminal capacity. Jordan Cove is engaged in negotiations with these prospective customers and expects to enter into binding long-term liquefaction tolling agreements with a subset of them for all of the terminal's ratable liquefaction capacity by the end of 2014.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

Robert L. Braddock

Robert L. Braddock
Vice President

Exhibit 13f

Jordan Cove
Energy Project, L.P.

October 2, 2014

By Facsimile
(202) 586-6050

RECEIVED
OCT - 2 2014

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project, L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project, L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from April 1, 2014 through September 2014.

In connection with Jordan Cove's Application for Authority to Site, Construct and Operate a Liquefied Natural Gas Export Terminal filed with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. CP13-483-000, Jordan Cove during the April through September period has worked to advance its Application by: (1) obtaining a "letter of no objection" submitted to FERC by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration; (2) filing with FERC Jordan Cove's responses to FERC's additional engineering data requests; and (3) filing with FERC various supplemental information related to the environmental resource reports. At this time Jordan Cove has responded fully to all requests from FERC. Jordan Cove anticipates that FERC Staff will issue a Draft Environmental Impact Statement in October 2014.

Jordan Cove has entered into non-binding Heads of Agreement (HOAs) with a number of large-scale, prospective customers in the Asia Pacific region. These HOAs are for a total capacity exceeding the Jordan Cove terminal capacity. Although several of the HOAs have expired, Jordan Cove is continuing negotiations with some of these prospective customers, as well as with other prospective customers that did not enter into HOAs, and expects to enter into binding long-term liquefaction tolling service agreements (LTSAs) with a subset of them for all of the terminal's ratable liquefaction capacity by the end of the first quarter of 2015.

Should you have any questions, please do not hesitate to contact me at (541) 266-7510.

Sincerely,

/s/Robert L. Braddock

Robert L. Braddock
Vice President

Exhibit 13g

Jordan Cove LNG LLC
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Houston, Texas
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www.jordancovelng.com
A Veresen Inc. company

RECEIVED U.S. DEPARTMENT OF ENERGY
By Docket Room via email 04/01/15

April 1, 2015

By Email
fergas@hq.doe.gov

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project L.P. (Jordan Cove), Jordan Cove submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from October 1, 2014 through March 2015. As of the end of 2014, Jordan Cove is now wholly-owned indirectly by Jordan Cove LNG L.P.

The most significant milestone during the October through March period in connection with Jordan Cove's Application for Authority to Site, Construct and Operate a Liquefied Natural Gas Export Terminal filed with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. CP13-483-000, was the issuance on November 7, 2014 of the Draft Environmental Impact Statement (DEIS). The comment period on the DEIS concluded on February 13, 2015. On February 6, 2015, FERC issued a Notice of Revised Schedule of Environmental Review, which set June 12, 2015 for issuance of the Final Environmental Impact Statement.

During the same period Jordan Cove has been engaged with its contractors Black & Veatch and Kiewit in construction planning and developing definitive cost estimates. At the same time, intensive negotiations with certain large-scale, prospective customers in the Asia Pacific region have progressed. Jordan Cove expects to enter into binding long-term liquefaction tolling service agreements (LTSAs) for all of the terminal's ratable liquefaction capacity by the end of 2015.

Should you have any questions, please do not hesitate to contact me at (713) 400-2809.

Sincerely,

/s/ William M. Fowler

William M. Fowler
Director, Regulatory Affairs

Exhibit 13h

Jordan Cove LNG LLC
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Houston, Texas
77005
T: (713) 400-2800

www.jordancovelng.com
A Veresen Inc. company

RECEIVED
By DOE at 12:59 pm, Oct 02, 2015

October 2, 2015

By Email
fergas@hq.doe.gov

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from April 1, 2015 through September 2015.

The most significant milestone during the April through September period in connection with Jordan Cove's Application for Authority to Site, Construct and Operate a Liquefied Natural Gas Export Terminal filed with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. CP13-483-000, was the issuance on the last day of the period, September 30, 2015, of the Final Environmental Impact Statement (FEIS). Jordan Cove now anticipates the issuance of a FERC order on its proposed facilities in the near future.

During the same period Jordan Cove continued to engage with its contractors in construction planning. Jordan Cove also progressed in its intensive negotiations with certain large-scale, prospective customers in the Asia Pacific region. Jordan Cove expects that it will make a final investment decision in 2016.

Should you have any questions, please do not hesitate to contact me at (713) 400-2809.

Sincerely,

/s/ William M. Fowler

William M. Fowler
Director, Regulatory Affairs

Exhibit 13i

Jordan Cove LNG LLC
5615 Kirby, Suite 500
Houston, Texas
77005
T: (713) 400-2800

www.jordancovelng.com
A Veresen Inc. company

RECEIVED
By DOE at 4:37 pm, Apr 01, 2016

April 1, 2016

By Email
fergas@hq.doe.gov

Office of Natural Gas Regulatory Activities
Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from October 1, 2015 through March 31, 2016.

During the October through March period, Jordan Cove continued intensive negotiations with certain large-scale, prospective customers in the Asia Pacific region. On March 22, 2016, Veresen Inc., the owner of Jordan Cove, announced that it had finalized with JERA Co., Inc. (JERA), a joint venture of Tokyo Electric Power Company, Incorporated and Chubu Electric Power Co., Inc., key commercial terms for the long-term provision of natural gas liquefaction capacity at the Jordan Cove facility. The agreement covers at least 1.5 MMTPA for an initial term of 20 years. With JERA as the anchor customer, Jordan Cove expects that its continuing negotiations with other prospective customers will result in additional agreements in the near future.

On March 11, 2016, the Federal Energy Regulatory Commission (FERC) issued an order denying the Applications of Jordan Cove and Pacific Connector Gas Pipeline (PCGP) for authorization for the LNG terminal and liquefaction facility and the connecting pipeline, respectively, in FERC Docket Nos. CP13-483-000 and CP13-492-000. Jordan Cove and PCGP will seek rehearing of that order.

Should you have any questions, please do not hesitate to contact me at (713) 400-2809.

Sincerely,

/s/ William M. Fowler

William M. Fowler
Director, Regulatory Affairs

Exhibit 13j

Jordan Cove LNG℠

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RECEIVED
By DOE/FE at 4:17 pm, Oct 26, 2016

October 26, 2016

By Email
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Office of Natural Gas Regulatory Activities Office of Fossil Energy
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Jordan Cove Energy Project L.P.
Semi-Annual Report
DOE/FE Order No. 3413, FE Docket No. 12-32-LNG
DOE/FE Order No. 3041, FE Docket No. 11-127-LNG

Dear Sirs and Madams:

In compliance with Ordering Paragraphs M. and I. of the above-referenced Orders 3413 and 3041, respectively, Jordan Cove Energy Project L.P. (Jordan Cove) submits this semi-annual report on the progress of Jordan Cove's planned LNG terminal and liquefaction facility for the period from April 1, 2016 through September 30, 2016.

During the April through September period, Jordan Cove continued intensive negotiations with certain large-scale, prospective customers in the Asia Pacific region. On April 8, 2016, Jordan Cove announced that it had reached preliminary agreement with ITOCHU Corporation (ITOCHU) with respect to certain key commercial terms for the purchase by ITOCHU of 1.5 million tons per annum of natural gas liquefaction capacity for an initial term of 20 years. Negotiations with a third major Asian customer are in advanced stages and are anticipated to be concluded in the near future.

On April 8, 2016, Jordan Cove submitted a Request for Rehearing to the Federal Energy Regulatory Commission (FERC) in FERC Dockets No. CP13-483-000 and CP13-492-000. On May 9, 2016, FERC issued and Order Granting Rehearings for Further Consideration (Tolling Order). We continue to await FERC's decision.

Should you have any questions, please do not hesitate to contact me at (713) 400-2809.

Sincerely,

/s/ William M. Fowler

William M. Fowler
Director, Regulatory Affairs

Exhibit 13k

RECEIVED
By DOE at 3:21 pm, Apr 03, 2017

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April 3, 2017

Larine Moore
Office of Natural Gas Regulatory Activities
U.S. Department of Energy
FE-34
P.O. Box 44375
Washington, DC 20026

Re: *Jordan Cove Energy Project, L.P.*, DOE/FE Docket Nos. 12-32-LNG, 11-127-LNG
Semi-Annual Report

Dear Ms. Moore:

Pursuant to Ordering Paragraph M of DOE/FE Order No. 3413 and Ordering Paragraph I of DOE/FE Order No. 3041, Jordan Cove Energy Project L.P. ("JCEP") hereby submits its semi-annual report describing the describing the progress of the proposed liquefaction facility.[1] On December 9, 2016, the Federal Energy Regulatory Commission ("FERC") issued its Order Denying Rehearing regarding JCEP's proposed facility and the associated natural gas pipeline.[2] FERC's order was without prejudice to JCEP submitting a new application. On January 23, 2017, JCEP commenced FERC's pre-filing review process, which is the first step to submitting a new application to FERC to construct the proposed facility. JCEP continues to pursue other required federal, state, and local permits and authorizations for its facility. JCEP has also continued its negotiations with prospective customers for liquefaction services.

Please contact me if you have any questions.

Respectfully submitted,

/s/ John S. Decker
John S. Decker
Attorney for Jordan Cove LNG, L.P.

---

1 *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 (Mar. 24, 2014); *Jordan Cove Energy Project, L.P.*, DOE/FE Order No 3041 (Dec. 7, 2011).
2 *Jordan Cove Energy Project, L.P.*, 157 FERC ¶ 61,194 (2016).

Exhibit 13I

Vinson&Elkins

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By DOE at 4:29 pm, Oct 02, 2017

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October 2, 2017

Larine Moore
Office of Natural Gas Regulatory Activities
U.S. Department of Energy
FE-34
P.O. Box 44375
Washington, DC 20026

Re: *Jordan Cove Energy Project, L.P.*, DOE/FE Docket Nos. 12-32-LNG, 11-127-LNG
Semi-Annual Report

Dear Ms. Moore:

Pursuant to Ordering Paragraph M of DOE/FE Order No. 3413 and Ordering Paragraph I of DOE/FE Order No. 3041, Jordan Cove Energy Project L.P. ("JCEP") hereby submits its semi-annual report describing the progress of the proposed liquefaction facility.[1] On September 21, 2017, JCEP filed an application with the Federal Energy Regulatory Commission pursuant to Section 3 of the Natural Gas Act for authorization to site, construct, and operate the proposed facility. JCEP continues to pursue other required federal, state, and local permits and authorizations for its facility. JCEP has also continued its negotiations with prospective customers for liquefaction services.

Please contact me if you have any questions.

Respectfully submitted,

/s/ John S. Decker
John S. Decker
Attorney for Jordan Cove Energy Project L.P.

---

[1] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 (Mar. 24, 2014); *Jordan Cove Energy Project, L.P.*, DOE/FE Order No 3041 (Dec. 7, 2011).

Exhibit 14a

RECEIVED DOE/FE via Email
By DOE at 3:14 pm, Apr 03, 2017

Vinson&Elkins

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April 3, 2017

Larine Moore
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P.O. Box 44375
Washington, DC 20026

Re: *Jordan Cove LNG, L.P.*, DOE/FE Docket Nos. 13-141-LNG
Semi-Annual Report

Dear Ms. Moore:

Pursuant to Ordering Paragraph H of DOE/FE Order No. 3412, Jordan Cove LNG L.P. ("JCLNG") hereby submits its semi-annual report describing the status of its long term contracts for the import or supply of natural gas.[1] JCLNG remains in negotiations with potential counterparties regarding long-term imports and supply of natural gas.

Please contact me if you have any questions.

Respectfully submitted,

/s/ John S. Decker
John S. Decker
Attorney for Jordan Cove LNG, L.P.

[1] *Jordan Cove LNG, L.P.*, DOE/FE Order No. 3412 (Mar. 18, 2014).

Exhibit 14b

Vinson&Elkins

RECEIVED
By DOE at 4:34 pm, Oct 02, 2017

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October 2, 2017

Larine Moore
Office of Natural Gas Regulatory Activities
U.S. Department of Energy
FE-34
P.O. Box 44375
Washington, DC 20026

Re: *Jordan Cove LNG, L.P.*, DOE/FE Docket No. 13-141-LNG
Semi-Annual Report

Dear Ms. Moore:

Pursuant to Ordering Paragraph H of DOE/FE Order No. 3412, Jordan Cove LNG L.P. ("JCLNG") hereby submits its semi-annual report describing the status of its long term contracts for the import or supply of natural gas.[1] JCLNG remains in negotiations with potential counterparties regarding long-term imports and supply of natural gas.

Please contact me if you have any questions.

Respectfully submitted,

/s/ John S. Decker
John S. Decker
Attorney for Jordan Cove LNG L.P.

---

1 *Jordan Cove LNG, L.P.*, DOE/FE Order No. 3412 (Mar. 18, 2014).

Exhibit 15

THE MACROECONOMIC IMPACT OF INCREASING U.S. LNG EXPORTS

October 29, 2015

OXFORD ECONOMICS

LTI

center for ENERGY STUDIES

Rice University's Baker Institute for Public Policy

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DOE Contact:
Robert Smith, Office of Fossil Energy, U.S. Department of Energy

This work was performed under DOE NETL Contract Number DE-FE0004002; SCNGO Task 200.01.01.000.

Prepared by:
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Table of Contents

Executive Summary

Key Findings:

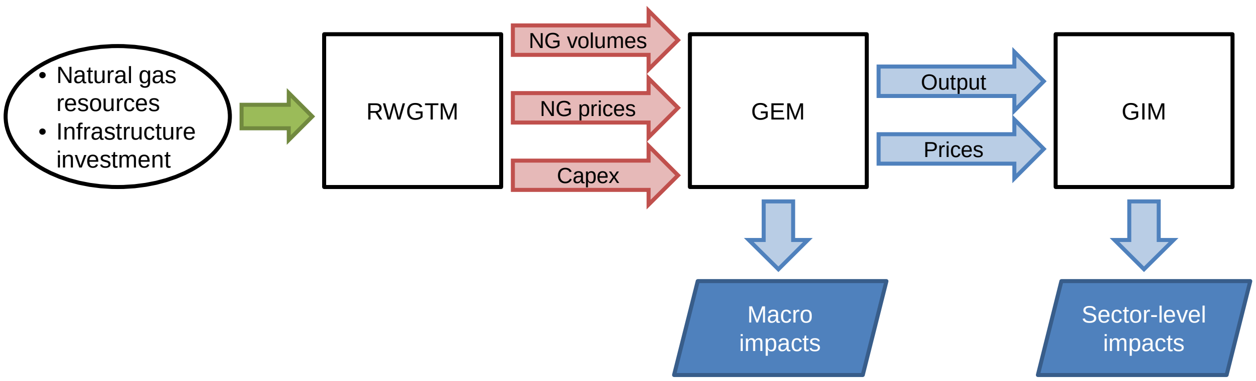
- **Rising liquefied natural gas (LNG) exports are associated with a net increase in domestic natural gas production.** The study finds that the majority of the increase in LNG exports is accommodated by expanded domestic production rather than reductions in domestic demand.
- **As exports increase, the spread between U.S. domestic prices and international benchmarks narrows.** In every case, greater LNG exports raise domestic prices and lower prices internationally. The majority of the price movement (in absolute terms) occurs in Asia.
- **The overall macroeconomic impacts of higher LNG exports are marginally positive, a result that is robust to alternative assumptions for the U.S. natural gas market.** With external demand for U.S. LNG exports at 20 billion cubic feet per day (Bcf/d), the impact of increasing exports from 12 Bcf/d is between 0.03 and 0.07 percent of gross domestic product (GDP) over the period of 2026–2040, or $7–$20 billion USD annually in today's prices
- **An increase in LNG exports from the United States will generate small declines in output at the margin for some energy-intensive, trade-exposed industries**. The sectors that appear most exposed are cement, concrete, and glass but the estimated impact on sector output is very small compared to expected sector growth to 2040.
- **Negative impacts in energy-intensive sectors are offset by positive impacts elsewhere.** Other industries benefit from increasing U.S. LNG exports, especially those that supply the natural gas sector or benefit from the capex needed to increase production. This includes some energy-intensive sectors and helps offset some of the impact of higher energy prices.

The Center for Energy Studies (CES) at Rice University's Baker Institute and Oxford Economics were commissioned by Leonardo Technologies, Inc. (LTI) on behalf of the Department of Energy (DOE) to undertake a scenario-based assessment of the macroeconomic impact of alternative levels of U.S. LNG exports under a range of assumptions concerning U.S. resource endowment, U.S. gas demand, and the international market environment. This report presents the findings of this analysis, highlighting key assumptions and impact channels. Background material describing the rationale behind this report can be found in Annex A.

The growth in shale gas production in the United States has presented a number of opportunities and challenges for the U.S. economy. On the one hand, U.S. shale gas production has lowered the domestic price of natural gas so that the United States now has among the lowest prices in the world. This has been a boon for consumers and led to gains in competitiveness for U.S. manufacturers. On the other hand, low gas prices in the United States negatively impact the profitability of U.S. domestic natural gas upstream and midstream operators, but have spurred interest in exporting LNG from the United States to higher priced markets. While selling natural gas at higher prices on the world market would increase profits for U.S. gas producers, the narrowing of the price gap between the United States and the rest of the world would erode some of the benefits that have accrued to U.S. consumers and manufacturers. Considering these potential tradeoffs, this paper examines whether it is ultimately economically advantageous for the United States to export LNG between 12 and 20 Bcf/d.

The analysis presented in this paper uses a highly specialized, multi-stage modeling approach highlighted in Figure ES1. First, the Center for Energy Studies at Rice University's Baker Institute used its Rice World Gas Trade Model (RWGTM) to simulate various alternative futures for the global natural gas market. These output data are then input into the Oxford Economics Global Economic Model (GEM) and Global Industry Model (GIM) to simulate broad macroeconomic and sectoral impacts of the various alternative paths for the global gas market.

Figure ES1. Modeling Approach



A comprehensive set of scenarios were prepared to understand the impact of higher U.S. LNG exports under a range of circumstances for domestic and international gas markets. This was done to establish conclusions that are not dependent on any particular set of starting conditions for the U.S. or international gas markets, and to highlight the impact of increasing U.S. LNG exports under alternative domestic and international conditions. The Reference domestic case (Ref) assumes existing energy policy in the United States continues and assumptions regarding the resource endowment are consistent with those of the Energy Information Administration (EIA). The alternative domestic cases assume a higher gas resource recovery (HRR) in the United States, a lower gas resource recovery (LRR) in the United States, and a higher U.S. demand for natural gas (Hi-D).

The Reference international case assumes that current energy policies around the world—including those setting domestic prices, dictating exports/imports, and/or addressing the environment—continue unchanged, while the macroeconomic outlook outside of the United States is drawn from the Oxford GEM. We then consider sets of circumstances that result in different international demand pull for U.S.-sourced LNG—the variants considered are international conditions sufficient to support 12 Bcf/d and 20 Bcf/d of U.S. LNG exports. Table ES1 outlines the full matrix of scenarios that were considered.

Table ES1. Study Scenarios

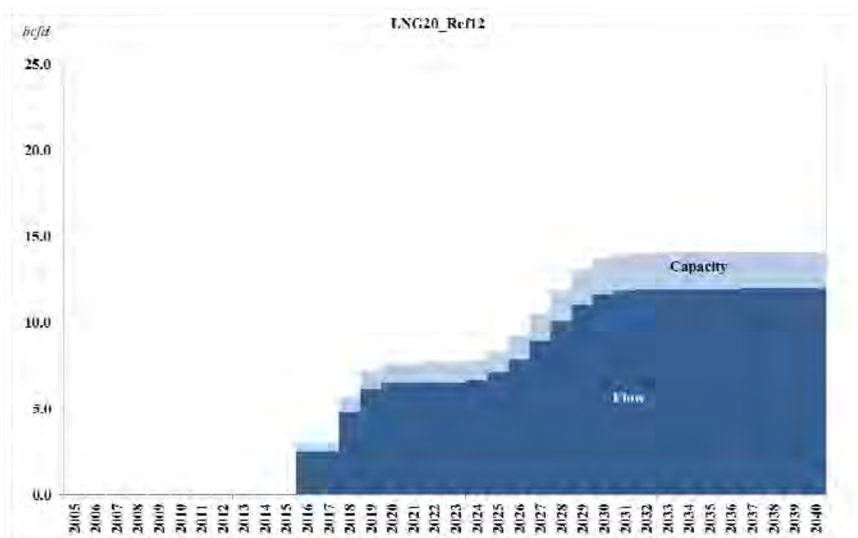
		Domestic Scenarios			
International Demand Scenarios		Reference	High Resource Recovery	Low Resource Recovery	High Natural Gas Demand
Reference		Ref_Ref	Ref_HRR	Ref_LRR	Ref_Hi-D
Global Demand for U.S. LNG Supports 12 Bcf/d		LNG12_Ref	LNG12_HRR	LNG12_LRR	LNG12_Hi-D
Global Demand for U.S. LNG Supports 20 Bcf/d	U.S. LNG Exports 12 Bcf/d	LNG20_Ref12	LNG20_HRR12	LNG20_LRR12	LNG20_Hi-D12
	U.S. LNG Exports 20 Bcf/d	LNG20_Ref20	LNG20_HRR20	LNG20_LRR20	LNG20_Hi-D20
	U.S. LNG Exports Endogenous	LNG20_Ref	LNG20_HRR	LNG20_LRR	LNG20_Hi-D

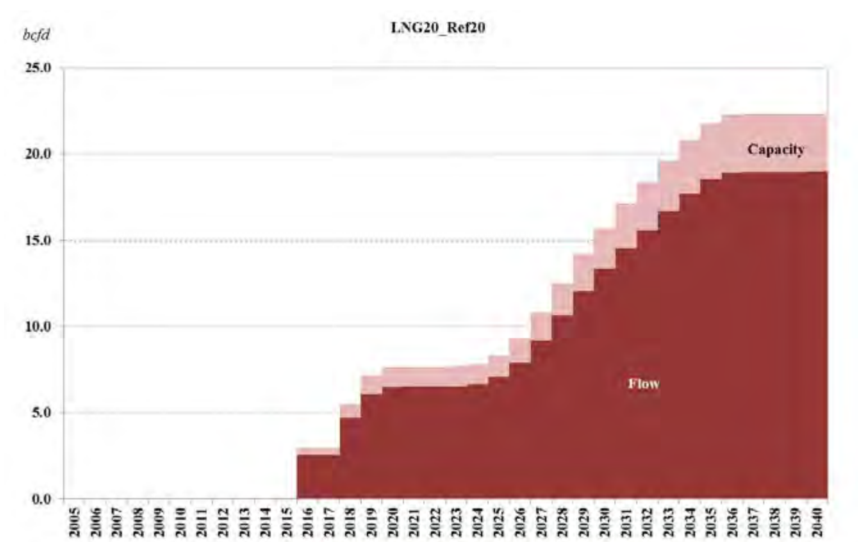
The primary focus of the study is to assess the impact of U.S. LNG exports rising above 12 Bcf/d in circumstances where international demand is high enough to support 20 Bcf/d of U.S. LNG exports (the bottom three rows of Table ES1 highlighted above). Greater volumes of LNG exports support continued long-term expansion of U.S. production. The scenario analysis reveals that domestic production continues to increase throughout the time horizon when LNG export volumes can expand to 20 Bcf/d. This contrasts to the case when exports do not exceed 12 Bcf/d and production plateaus and declines slightly in the 2030s. The majority of the increase in LNG exports is accommodated by expanded domestic production rather than reductions in domestic demand, a result that reflects the very elastic long-run supply curve in North America. Greater LNG exports effectively serve as additional demand for U.S. natural gas, which facilitates expansion in the domestic upstream sector.

The analysis also shows that the spread between Henry Hub prices and other international benchmark prices narrows as U.S. LNG exports increase. Increased exports from the United States help to alleviate the highly constrained supply situation internationally, although supplies from other regions also play a role. Altogether, the spread between Henry Hub price and international benchmark prices abroad narrows with greater volumes of U.S. LNG exports, it remains large enough to support the flow of trade. In fact, when U.S. LNG exports are determined endogenously, meaning they generally exceed 20 Bcf/d, the price spreads are narrowest thereby reflecting full capture of the U.S. LNG arbitrage opportunity. Finally, the majority of the price movement occurs abroad, not domestically, with the most significant impact occurring in Asia.

In the scenarios where international demand pull is sufficient to support 20 Bcf/d of U.S. LNG exports, the export volume growth occurs primarily after the mid-2020s. Figure ES2 highlights U.S. LNG export capacity and export volumes across the 12 Bcf/d and 20 Bcf/d cases under the Reference domestic case assumptions, respectively. Of note is the fact that the two scenarios do not differ much from each other until after 2030. This occurs because international demand for U.S. LNG must grow beyond what is already slated to begin supplying the market over the next few years, which includes Australia and already approved U.S. LNG export capacity. So, while international demand continues to increase, it must first work through a large amount of available LNG supply before turning to U.S.-sourced LNG to balance the global market.

Figure ES2. LNG Export Capacities and Volumes in the LNG20_Ref12 and LNG20_Ref20 Cases

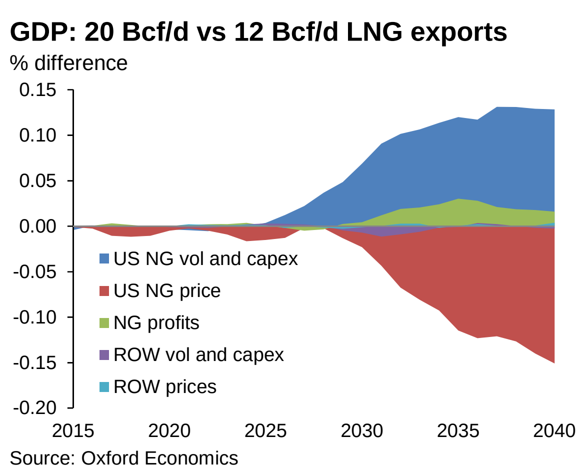




The macroeconomic impacts of increasing U.S. LNG exports to 20 Bcf/d from 12 Bcf/d can be decomposed into five main channels. These are (1) higher U.S. natural gas production and investment; (2) higher U.S. natural gas prices; (3) recycling of extra profits from the U.S. natural gas sector; (4) changes to natural gas production and investment in the rest of the world; and (5) lower international gas prices. The first two channels are the most significant for the United States and broadly offset each other.

The overall macroeconomic impacts of increasing U.S. LNG exports to 20 Bcf/d from 12 Bcf/d are small, reflecting the small size of the shocks relative to the economy overall (see Figure ES3). In the Reference domestic scenario, the increase in net gas exports is equivalent to 0.02 percent of GDP on average over 2026–2040, and the incremental investment in the gas sector associated with the increase in exports in that span is just 0.06 percent of GDP. In aggregate, the size of the economy is little changed in the long run, with GDP 0.03 percent ($7.7 billion USD annually in today's prices) higher on average over 2026–2040 than in the 12 Bcf/d export case.

Figure ES3. GDP Impact by Channel, 20 Bcf/d vs. 12 Bcf/d LNG Exports in the Reference Domestic Scenario

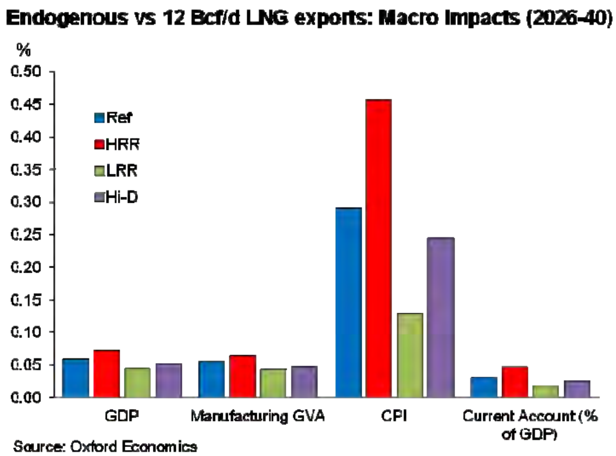


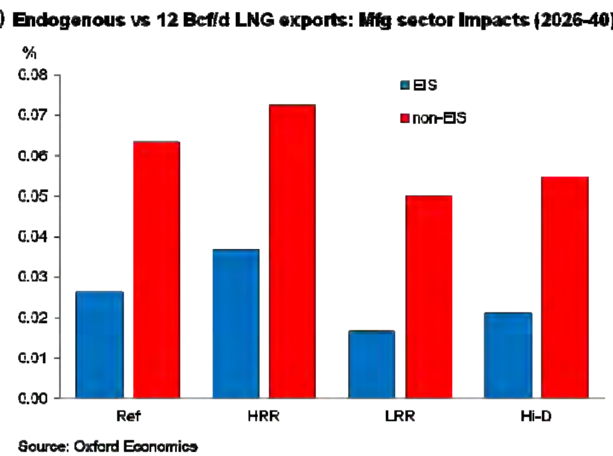
Impacts vary at the sector level. Firms that supply the natural gas sector and are involved in developing the infrastructure and supply chains needed to increase production and LNG exports benefit. This includes firms in the construction and metals sectors. However, higher natural gas prices in the United States associated with greater U.S. LNG exports are negative for the energy-intensive manufacturing sectors. It is important to note, however, that even in the energy-intensive sectors—such as such as glass, cement, and chemicals—the impacts are small compared with the expected growth in output through 2040.

When U.S. LNG exports rise to their market determined level (rather being held to 20 Bcf/d), the macroeconomic dynamics are the same as highlighted above but with a slightly larger overall impact, reflecting the higher level of U.S. gas exports, production, and associated investment. The impact on Henry Hub prices is also larger, but this is not sufficient to offset the extra stimulus to the U.S. economy from greater LNG exports. In the Reference domestic case, the impact on GDP is on average 0.06 percent over the period 2026–2040.

The conclusions are robust to alternative assumptions regarding U.S. gas resources and demand. The overall gain for the U.S. economy is greatest in the High Resource Recovery (HRR) scenario as this is associated with largest increase in domestic gas production and exports, but the impacts are also positive in the Low Resource Recovery (LRR) and High Domestic Demand (Hi-D) cases (Figure ES4 and Table ES2).

Figure ES4. Economic Impacts of Increasing LNG Exports, 2026–2040





The results detailed in this report suggest that the overall macroeconomic impacts of LNG exports are marginally positive. Across the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports.

Table ES2. Impact of Increasing LNG Exports, Annual Avg. Change from 12 Bcf/d, 2026–2040

	12 Bcf/d to 20 Bcf/d LNG Exports		12 Bcf/d to Market-Determined (endogenous) LNG Export Level			
	Reference	High Resource Recovery	Reference	High Resource Recovery	Low Resource Recovery	High Natural Gas Demand
U.S. Natural Gas Market (Bcf/d)						
NG Production	3.7	5.1	4.8	8.4	2.5	4.0
	4.0%	*5.1%*	*5.2%*	*8.5%*	*2.8%*	*4.1%*
NG Consumption	0.1	0.3	0.1	0.5	0.0	0.2
	0.1%	*0.3%*	*0.1%*	*0.5%*	*0.0%*	*0.2%*
NG Exports	4.3	5.1	5.4	8.5	2.7	4.3
	26%	*28%*	*33%*	*47%*	*17%*	*26%*
NG Imports	0.7	0.4	0.7	0.7	0.2	0.4
	4.2%	*2.4%*	*4.3%*	*4.6%*	*1.2%*	*2.6%*
Prices (2010$)						
Henry Hub Price	$0.27	$0.25	$0.32	$0.41	$0.19	$0.29
	4.3%	*4.7%*	*5.2%*	*7.5%*	*2.6%*	*4.3%*
NBP (UK)	$0.00	-$0.02	$0.02	-$0.04	-$0.02	-$0.03
	0.0%	*-0.1%*	*0.1%*	*-0.4%*	*-0.2%*	*-0.3%*
German Border (NW Europe)	$0.01	$0.00	$0.02	-$0.01	-$0.01	-$0.01
	0.1%	*0.0%*	*0.1%*	*-0.1%*	*-0.1%*	*0.0%*
JKM (Asia-Pacific)	-$1.23	-$1.52	-$1.51	-$2.24	-$0.84	-$1.21
	-6.8%	*-8.4%*	*-8.4%*	*-12.4%*	*-4.6%*	*-6.7%*
Macroeconomic Impacts						
GDP (annual avg., 2014$B)	$7.7	$7.3	$16.7	$20.5	$12.5	$14.4
	0.03%	*0.03%*	*0.06%*	*0.07%*	*0.04%*	*0.05%*
Employment (000s)	9.6	11.3	24.1	35.2	18.4	19.2
	0.01%	*0.01%*	*0.01%*	*0.02%*	*0.01%*	*0.01%*
CPI (level)	0.24%	0.30%	0.29%	0.46%	0.13%	0.24%
Current Account (% of GDP)	0.02	0.03	0.03	0.05	0.02	0.03
Sector Value-Added:						
Manufacturing	0.02%	0.02%	0.06%	0.06%	0.04%	0.05%
EIS	0.01%	0.02%	0.03%	0.04%	0.02%	0.02%
Non-EIS	0.03%	0.02%	0.06%	0.07%	0.05%	0.05%
Agriculture	0.01%	0.02%	0.02%	0.04%	0.01%	0.01%
Extraction	1.81%	2.39%	2.34%	3.94%	1.23%	1.90%
Construction	0.16%	0.15%	0.27%	0.34%	0.18%	0.23%
Services	-0.01%	-0.02%	0.00%	-0.02%	0.01%	0.00%

1 Introduction

The application of horizontal drilling with hydraulic fracturing has triggered perhaps the most transformative development in energy markets in recent history. The so-called "shale gas revolution" has seen production of natural gas extracted from ultralow permeability, ultralow porosity shale formations in the United States ramp up considerably. As noted in previous literature, the scale of the shale gas resource and the pace at which its production is expanding carries both economic and geopolitical implications (see, for example, Medlock, Jaffe, and Hartley [2011]).

Shale gas in the United States has grown in less than a decade to comprise about one-half of U.S. domestic production. The rapid expansion of domestic production has made the prospect of U.S. liquefied natural gas (LNG) *exports*—unthinkable just a decade ago—an emerging reality. This will impact U.S. domestic natural gas upstream and midstream operators as well as domestic economic interests farther downstream, particularly in gas-intensive industries, and raises questions about the net macroeconomic impact of the interactions and tradeoffs among LNG exporters, upstream producers, midstream operators, and domestic consumers.

U.S. shale gas production has already tangibly lowered the price of natural gas for domestic consumers. From 2003–2006, U.S. natural gas prices were among the highest in the world. However, the United States now enjoys among the lowest prices in the world. Moreover, the dramatic drop in domestic price owing to rapidly expanding domestic production has impacted fuel use in power generation—namely the substitution of natural gas for coal—and has instigated deeper discussion centering on natural gas as a bridge to a low-carbon future. In general, low-cost and abundant natural gas reduces the impact on electricity rates of addressing a variety of environmental concerns in the power-generation sector.

Furthermore, low-price natural gas is contributing to a revitalization of the industrial base in the United States. The economic benefit at the upstream level is apparent, as employment numbers in the upstream oil and gas sector have increased to support the very active shale drilling programs, which require relatively high levels of labor input.[1] Farther downstream, there are also ongoing and planned expansions in the petrochemical and manufacturing sectors, a development fueled by low-cost natural gas. Indeed, the recent era of low natural gas prices has been widely touted as a boon to domestic manufacturers, particularly in energy-intensive manufacturing industries such as chemicals, glass, and metals.

At the same time, natural gas producers are understandably eager to take advantage of higher prices on the global market. To date, the U.S. Department of Energy (DOE) has received requests for LNG export licenses for export capacity totaling nearly 47 billion cubic feet per day (Bcf/d).[2] However, some question whether it is ultimately economically advantageous for the United States to export LNG, arguing that the price advantage enjoyed by U.S. manufacturers is a key competitive advantage. Indeed, the U.S. DOE is required to assess whether or not exports to non-FTA countries is in the public interest, a so-called public interest determination.

Further, for all of the discussion of LNG exports as new source of demand for domestically produced natural gas, high volumes of LNG exports are not a forgone conclusion (see Medlock [2012, 2014]).

[1] See Hartley, Medlock, Temzelides, and Zhang (2014) and Agerton, Hartley, and Medlock (2015).

[2] At the time of this writing, FTA license applications totaled just over 46 Bcf/d and non-FTA license applications totaled just over 41 Bcf/d.

International supply and demand conditions are important for understanding how North American natural gas fits into the global supply picture. U.S. natural gas will be an attractive source of supply to foreign consumers as long the cost to deliver is competitive with other sources of supply. Moreover, the commensurate investments in production, liquefaction, and shipping must remain attractive to investors. As such, when assessing the potential impacts of greater U.S. LNG exports it is important to consider how the North American natural gas market might evolve under different scenarios defined by variations in both domestic and international market drivers.

The primary purpose of this study is to assess the net macroeconomic impacts on the U.S. economy of greater LNG exports under a range of domestic and international market conditions. As will be expounded below, this includes alternative assumptions for domestic resource availability, domestic gas demand, and a range of international supply and demand conditions that generate different potential market pull for U.S. LNG exports. This paper assesses the impact of increasing U.S. LNG exports under these different domestic and international scenarios.

The remainder of this report is structured as follows. Section 2 outlines the modeling approach used in the study and presents the range of scenarios modeled. Section 3 describes the assumptions driving the natural gas market in each scenario. Section 4 presents the results of the analysis and highlights key drivers. Section 5 offers some concluding remarks. Finally, detailed model descriptions and detailed results for all scenarios are included in the Annexes.

2 Methodology

2.1 Modeling Approach

The analysis presented in this paper uses a highly specialized, multi-stage modeling approach. First, the Center for Energy Studies (CES) at Rice University's Baker Institute used its Rice World Gas Trade Model (RWGTM) to simulate various alternative futures for the global natural gas market.[3] Specifically, the RWGTM is used to investigate how various assumptions about international and domestic demand and resource availability could impact the U.S. natural gas market over the coming decades. Since economic, geopolitical, and technological forces can shape market outcomes in many different ways, the non-stochastic nature of the RWGTM facilitates analysis of multiple scenarios that characterize how these various factors impact current and future investment decisions.[4]

In general, the RWGTM is used to consider possible paths for natural gas investments, production, consumption, and prices—both regional and global—incorporating various economic, geopolitical, and other investment and trade barriers and incentives, thus allowing an assessment of the effects of

[3] The RWGTM was developed by Kenneth B. Medlock III and Peter R. Hartley at Rice University using the MarketBuilder software platform provided through a research license with Deloitte MarketPoint, LLC. The architecture of the RWGTM, the data inputs, and modeled political dimensions are distinct to Rice and its researchers. The RWGTM is used to evaluate how different geopolitical pressures, domestic policy frameworks, and market developments can influence the long-run evolution of regional and global gas markets and how those developments in turn influence geopolitics. A brief description of the RWGTM is contained in Annex B of this report, and more detail is available upon request.

[4] A significant core data constituent of this analysis is rooted in recently published Baker Institute Center for Energy Studies research (see *The Market Impacts of New Natural Gas-Directed Policies*). This study, funded by the Alfred P. Sloan Foundation, is available at http://bakerinstitute.org/center-for-energy-studies/. As detailed therein, that study utilizes data derived from other ongoing studies, namely those at The University of Texas Bureau of Economic Geology (*Shale Resources and Reserve Study*), Resource for the Future (*Managing the Risks of Shale Gas Development*), and the University of Colorado-Denver (*Understanding the Politics of Shale Gas Development: A Focus on Colorado, New York, and Texas)*. The study at the UT Bureau of Economic Geology provides critical benchmarking for shale gas well decline profiles and production costs. Studies at RFF and CU-Denver provide indications of likely policy directions of local, State, and Federal Governments. All international components are derived from Baker Institute CES research.

these factors on natural gas market development.[5] The RWGTM can also be used to understand the effects of changes in core economic variables affecting energy production—such as fiscal terms, limits on access to resources, fixed and operating costs, constraints on rigs, equipment and personnel, and technology. For each scenario considered in this study, the model produces detailed outputs—both domestically and internationally—covering natural gas production, trade, and prices, as well as associated capital investment in the natural gas value chain.

These output data are then input into the Oxford Economics Global Economic Model (GEM) to simulate the broad macroeconomic impacts of the various alternative paths for the global natural gas market. The GEM covers 46 economies in detail and provides headline statistics for another 35 economies. The model provides a rigorous and consistent structure for analysis and forecasting, and allows the implications of alternative global scenarios and policy developments to be readily analyzed at the macro level.[6] This stage of the analysis assesses the effect of changes in natural gas supply, trade, and prices on gross domestic product (GDP), total industry and manufacturing, competitiveness, consumer and producer prices levels, and the current account.

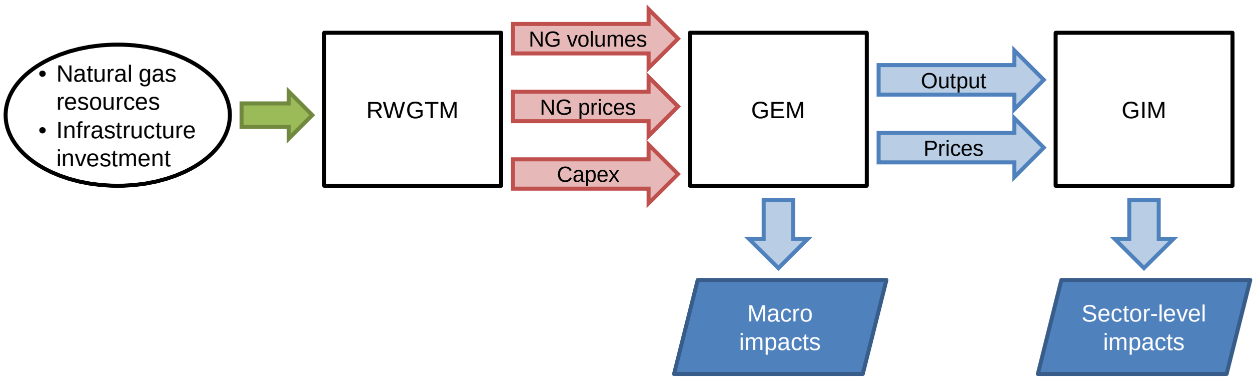
Finally, the macroeconomic outputs from the GEM are then input into the Oxford Economics Global Industry Model (GIM), which models the impact on activity at the sector level. The GIM covers 100 sectors in 67 countries. Forecasts for individual industries are driven by the macroeconomic forecast—consumption, investment, and exports—combined with detailed modeling of industry interactions, such as supply-chain linkages. Improvement in sector competitiveness allows capture of

[5] It should be noted that economic and political influences are not necessarily mutually exclusive, since policy can initiate changes in economic parameters.
[6] It is of note that the GEM is unique among commercial economic consultancies.

greater market share in the domestic and international market, where competitiveness is driven by exchange rate developments, labor costs, and energy prices.

Figure 1 highlights the modeling approach, and a more detailed description of the models used in this study can be found in Annex B.

Figure 1. Modeling Approach



2.2 Macroeconomic Impact Channels

The oil and gas sector is a relatively small component of the U.S. economy overall, accounting for around 1.3 percent of total output and 0.1 percent of non-farm payrolls in 2014. However, despite its relatively small size in the national accounts, energy is a key input in virtually every sector and changes in energy prices affect the entire economy.

An increase in U.S. LNG exports would be expected to impact the U.S. economy[7] through the following key transmission channels:

[7] The impacts described are relative to what would otherwise have happened, i.e., if there was not an increase in U.S. LNG exports.

- Increased gas production directly contributes to GDP, and the export of natural gas will increase export revenue and improve the U.S. current account.
- Increased production will also have positive spillovers to in key suppliers of the sector such as machinery and engineering services, and rising employment in the gas sector also leads to increased demand for goods and services more broadly.
- The incremental investment needed to facilitate higher natural gas production and exports should also boost economic activity in the United States.
- The additional investment will also have multiplier effects through the supply chains of the construction, cement, and metal products sectors that lead to further gains in output and employment.
- Henry Hub prices are higher than they would otherwise be as U.S. LNG exports increase because producers increasingly exploit reserves with higher extraction costs. Higher natural gas prices will erode consumers' purchasing power both directly and indirectly as the impact of higher domestic natural gas prices filters through the supply chains of other sectors causing the prices of other goods and services to rise. This will negatively impact consumption with the energy-intensive sectors being most affected.
- Changes in relative natural gas prices across countries will impact U.S. competiveness. If energy prices in the United States rise relative to energy prices in the rest of the world, this raises production costs for U.S. firms relative to international competitors. This erosion in U.S. competitiveness will weigh on the U.S. trade balance. The tradable energy-intensive sectors such as chemicals and steel will generally be most exposed to shifts in industrial competitiveness.

- Increased production and higher Henry Hub gas prices[8] should generate higher profits for natural gas producers. The improved profitability should, in turn, ultimately raise U.S. income either through the distribution of profits or by increasing equity market value of listed companies.
- Variations in natural gas production and investment outside the United States will also impact U.S. businesses that are dependent on overseas natural gas production and investment activity. Changes to natural gas prices in the rest of the world will also affect global economic activity and impact demand for all U.S. exports.

2.3 Scenario Approach

The study analyzes a comprehensive set of scenarios to understand the impact of higher U.S. LNG exports under a range of circumstances. A wide range of scenarios are analyzed in order to establish conclusions that are not dependent on any particular set of starting conditions for the U.S. or international gas markets. The scenario assumptions fall along two core dimensions. In one dimension, we consider different U.S. domestic market conditions with regard to resources and domestic demand. In the other dimension, we consider specific circumstances that result in different international demand pull for U.S.-sourced LNG for each domestic scenario. Table 1 outlines this approach.

[8] It should be noted that it is assumed that U.S. exporters receive the Henry Hub price rather than the price in the destination market.

Table 1. Study Scenarios

<table>
<tr><th colspan="2"></th><th colspan="4">Domestic Scenarios</th></tr>
<tr><th colspan="2">International Demand Scenarios</th><th>Reference</th><th>High Resource Recovery</th><th>Low Resource Recovery</th><th>High Natural Gas Demand</th></tr>
<tr><td colspan="2">Reference</td><td>Ref_Ref</td><td>Ref_HRR</td><td>Ref_LRR</td><td>Ref_Hi-D</td></tr>
<tr><td colspan="2">Global Demand for U.S. LNG Supports 12 Bcf/d</td><td>LNG12_Ref</td><td>LNG12_HRR</td><td>LNG12_LRR</td><td>LNG12_Hi-D</td></tr>
<tr><td rowspan="3">Global Demand for U.S. LNG Supports 20 Bcf/d</td><td>U.S. LNG Exports 12 Bcf/d</td><td>LNG20_Ref12</td><td>LNG20_HRR12</td><td>LNG20_LRR12</td><td>LNG20_Hi-D12</td></tr>
<tr><td>U.S. LNG Exports 20 Bcf/d</td><td>LNG20_Ref20</td><td>LNG20_HRR20</td><td>LNG20_LRR20</td><td>LNG20_Hi-D20</td></tr>
<tr><td>U.S. LNG Exports Endogenous</td><td>LNG20_Ref</td><td>LNG20_HRR</td><td>LNG20_LRR</td><td>LNG20_Hi-D</td></tr>
</table>

Note that the scenarios are constructed so that there is sufficient international demand to support commercially viable LNG export flows from the United States in accordance with the volumes indicated in each case. Thus, various assumptions are made about the international natural gas market so as to stimulate investment in the U.S. upstream sector and the commensurate development of LNG export infrastructure. The scenarios indicated in Table 1 are defined as follows, moving first from left to right then top to bottom:

- **Ref_Ref** is defined as the Reference international demand case coupled with the Reference domestic case, hence the mnemonic Ref_Ref.
- **Ref_HRR** is defined as the Reference international demand case with a *higher* level of recoverable resource in the United States than in the Ref_Ref case.

- **Ref_LRR** is defined as the Reference international demand case with a *lower* level of recoverable resource in the United States than in the Ref_Ref case.
- **Ref_Hi-D** is defined as the Reference international demand case with a *higher* level of demand in the United States than in the Ref_Ref case.
- **LNG12_Ref** is defined by a *higher* level of international demand for U.S.-sourced LNG where domestic demand is consistent with the Ref_Ref case.
- **LNG20_Ref** is defined by a *significantly higher* level of international demand for U.S.-sourced LNG where domestic demand is consistent with the Ref_Ref case. LNG exports are endogenously determined.
- **LNG20_Ref12** is defined by a *higher* level of international demand for U.S.-sourced LNG where domestic demand is consistent with the Ref_Ref case. This case is, however, set up so that the U.S. exports of LNG do not exceed more than 12 Bcf/d.
- **LNG20_Ref20** is defined by a *higher* level of international demand for U.S.-sourced LNG where domestic demand is consistent with the Ref_Ref case. This case is, however, set up so that the U.S. exports of LNG do not exceed more than 20 Bcf/d.

In general, when reading the case nomenclature in Table 1, we note:

> "N1_N2X" where N1 denotes the name of the international demand scenario, N2 denotes the domestic scenario, and X denotes the level of LNG exports that *can* occur from the United States. Note that if X is not present, then the amount of LNG exports from the United States is fully endogenous to the scenario being considered.

Importantly, in each of the cases, the level of U.S. LNG exports is different if LNG exports are determined in a fully endogenous manner. This is due to the fact that altering the international market outlook through various mechanisms coupled with different assumptions about domestic demand or resource availability naturally leads to different outcomes. As such, the LNG20_Ref12 case can be compared to the LNG20_Ref20 case in a rather straightforward manner because the domestic and international settings are the same in the two cases as only the level of exports varies. By contrast, comparing scenarios with different underlying assumptions about the domestic and international market environments does not facilitate such a straightforward comparison. Therefore, in subsequent sections we generally compare the last three cases within each column in Table 1; so, for example, LNG20_HRR12 is compared to LNG20_HRR20 and LNG20_HRR.

As noted above, the international demand cases indicated in Table 1 are constructed in order to stimulate commercially viable flows of different U.S. LNG export volumes. The assumptions across the cases, so constructed, are detailed in Table 2.

Table 2. Select Natural Gas Market Assumptions Across International Demand Scenarios

		Reference	LNG12	LNG20
Accessible Shale Resource (tcf)	**World**	8,407	6,500	3,542
	Africa	1,918	1,918	0
	Asia and Pacific	2,107	1,075	90
	China	1,285	390	0
	Australia	529	529	90
	Europe	444	0	0
	South America	1,786	1,786	1,260
	North America	1,839	1,839	1,839
	United States	829	829	829
	Canada	498	498	498
	Mexico	513	513	513
	Rest of World	314	86	0
LNG New Build Capability		No limits.	Limited expansion capabilities in selected locations.	Only the United States has expansion capability beyond 2020.
Pipeline New Build Capability		No limits.	No future expansions of Central Asian pipelines to China.	LNG12 plus existing Russia-China pipeline supply agreements dissolve.
Demand		In all scenarios, a CO_2 trading platform is in place in Europe and the United States is assumed to retire 61 GWs of coal by 2030.	Chinese gas demand rises in response to policies to limit coal use; Japanese nukes remain offline.	LNG12 case plus CO_2 reduction protocols targeting coal use in India, Indonesia, South Korea, and a handful of other smaller coal consuming nations.

As indicated in Table 2, the Reference, LNG12, and LNG20 international demand scenarios adjust shale resource availability, pipeline and LNG infrastructure expansion opportunities outside the United States, and natural gas demand in different countries. For example, the capabilities for pipeline expansion to meet growing Asian demand are increasingly limited as we move into the higher international LNG demand cases. Specifically, the LNG12 case assumes there is no future expansion of

Russian pipeline capacity into China and the Far East beyond what has already been contracted. However, in the LNG20 case the existing agreement is assumed to dissolve, and Russia is assumed to never be connected by pipeline to China. Moreover, in both the LNG12 and LNG20 cases, it is assumed that there are no future pipeline expansions from Central Asia to China.

In addition to the above assumptions, we also vary assumptions regarding the domestic resource base and demand. Namely, in constructing these cases, we assume the total U.S. natural gas resource base is 2,525 tcf in the HRR case, 1,831 tcf in the LRR case, and 2,075 tcf in the Reference case. The total resource base is comprised of an accessible shale gas resource totaling 1,182 tcf in the HRR case, 688 tcf in the LRR case, and 829 tcf in the Reference case, with other resources making up the difference. As for domestic demand, in the Hi-D cases we assume 113 GW of coal-fired generation capacity are retired as the Clean Power Plan takes effect, which accounts for an additional 52 GW of retirements above the Reference case.[9]

[9] The distribution of the retirements is distinctly different than in the Reference case as each state must meet a specific target for carbon dioxide emissions reductions. While the exact impact of the Clean Power Plan is not known and highly uncertain, the primary point of the Hi-D scenario is to stimulate greater domestic demand for natural gas.

3 Natural Gas Market Impacts

As outlined in Table 1, there are a total of 20 scenarios that were considered in this analysis. The scenarios consider different domestic and international market conditions so that a robust view of the global natural gas market can be ascertained. In this section, we detail the Ref_Ref case then outline some high level results for the global natural gas markets across all cases, with a particular emphasis on the United States. This will enable a deeper understanding of the macroeconomic results that are detailed in subsequent sections. Detailed results for all cases can be found in the Annexes.

3.1 The Natural Gas Market in the Ref_Ref Case

The Ref_Ref case is the scenario that combines the Reference domestic market conditions with the Reference international market conditions. It assumes current policies in various places around the world—including those setting domestic prices, dictating exports/imports, and/or addressing the environment (for example renewables targets in the United States and internationally)—are persistent throughout the model time horizon, unless there is already action being undertaken. While this is not likely to be true, the Ref_Ref case serves as a benchmark so that shifts in market outcomes can be attributed to particular assumptions across scenarios. In sum, the Ref_Ref case captures geopolitical, contractual, and regulatory constraints that *currently* exist in the global gas market and are not already known to be different into the future. This includes:

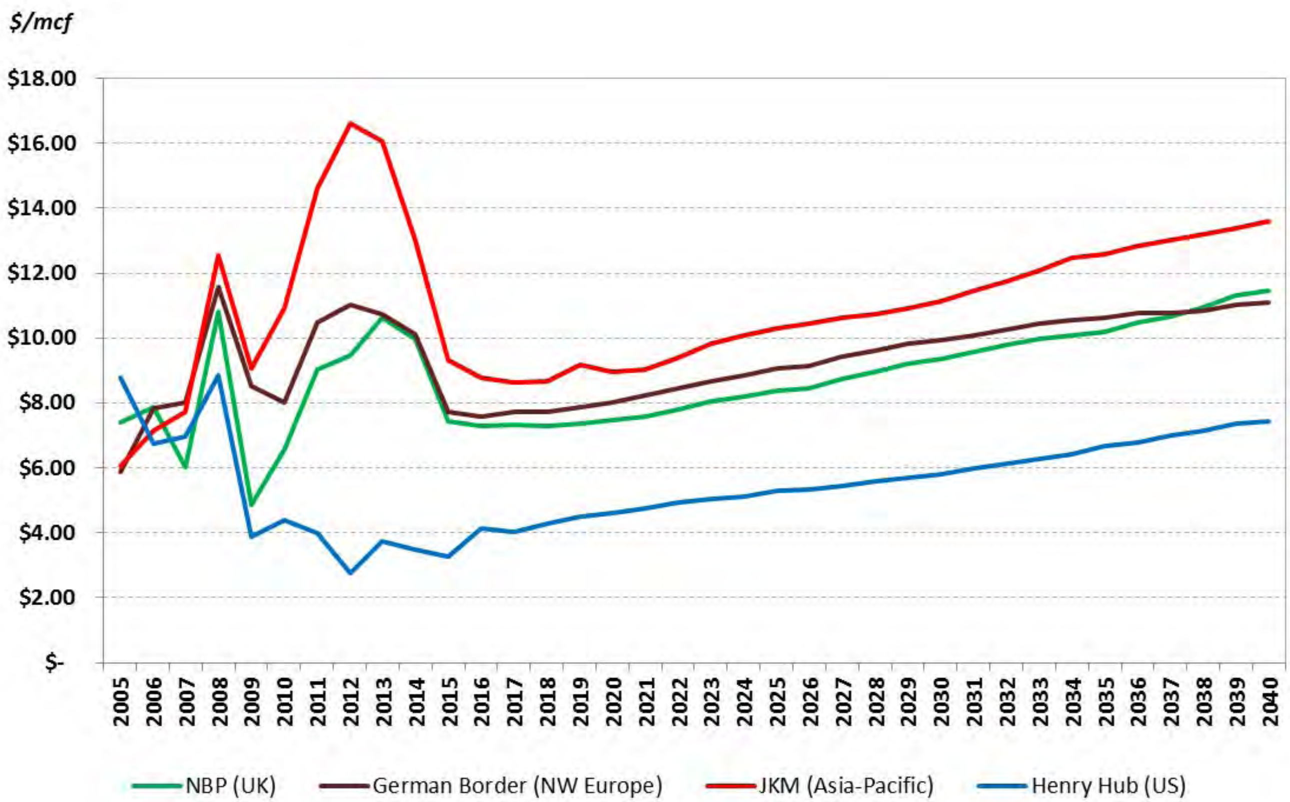
- Current pricing policies and export/import policies across countries remain as they are today throughout the model time horizon, unless there is already concerted action being undertaken to change the internal market.

- The construction of new LNG and pipeline infrastructure is generally allowed to occur according to commercial viability. However, in those countries where investments are hampered by geopolitical considerations, it will be assumed that those burdens are carried forward through the model time horizon. Thus, for example, current sanctions on Iran carry forward (although at the time of this writing this outcome is highly uncertain), and the investment risks associated with developments in countries such as Venezuela and Bolivia are assumed to persist.
- Current assumptions regarding the availability and competitiveness of emerging energy technologies are held fixed. So, there is no effort to accelerate the adoption of technologies that compete with natural gas through policies that have yet to be announced or enacted or through unanticipated innovations that lower the cost of competing energy sources and/or technologies.
- Current environmental policies are assumed to remain in place throughout the model time horizon. So, for example, it is assumed that the European Union (EU) will maintain an active CO_2 trading market but the United States will, collectively, not. While the price of carbon in the EU has fluctuated with policy treatment, it is carried forward in the RWGTM at $10 per tonne. We address current policy intervention addressing domestic CO_2 emissions through the Hi-D scenarios. It is also worth noting that the upcoming climate talks in Paris later this year could alter the policy frameworks in many countries. This possibility is addressed, at least in a rudimentary way, through the international LNG12 and LNG20 scenarios.

- Known natural gas resources, including shale, are developed according to commercial viability in North America and elsewhere. Existing bans on shale-directed activity are assumed to carry forward throughout the model time horizon. Again, there is considerable uncertainty regarding the commercial viability of shale around the world, and we address a potentially diminished role for shale through the domestic LRR scenario and the international LNG12 and LNG20 scenarios. We consider an enhanced role for shale in the domestic HRR setting only.

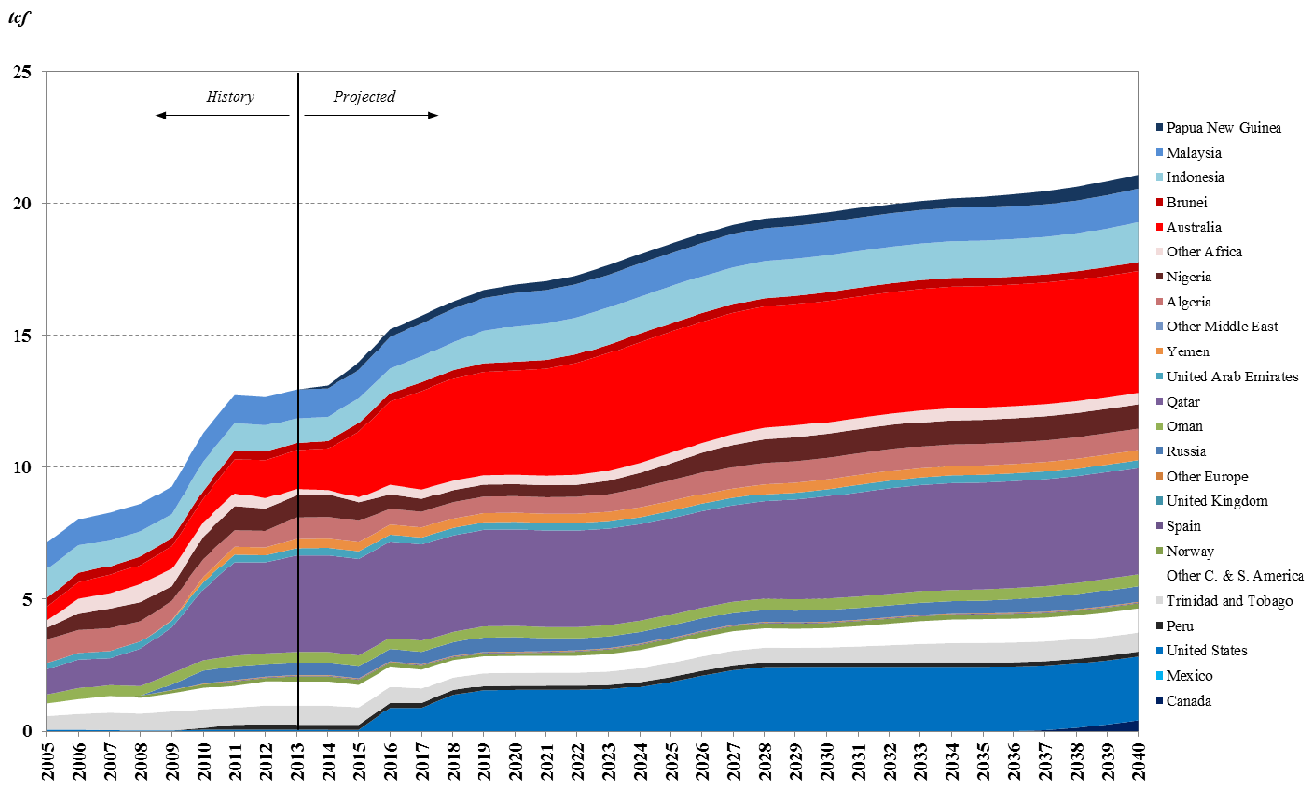
The Ref_Ref case reveals several interesting insights into how the North American, and global, gas market may evolve over the coming decades. To begin, it indicates the North American market will remain a low cost source of supply for natural gas for the foreseeable future. This has implications for regional competitiveness, demand, and international trade. Moreover, as can be highlighted through the scenarios examined in this study, the availability and production of natural gas from shale in the United States and around the world are critical to future market developments.

Figure 2. Select Global Prices (2010$) (Ref_Ref case)



As indicated in Figure 2, the price at Henry Hub remains below the prices in Asia (Japan Korea Marker or JKM) and Europe (National Balancing Point or NBP and German-Austrian Border), although the premium that emerged following the disaster at Fukushima in 2011 dissipates, and the long-term differentials in prices between regions reflects the cost of trade. Moreover, the emergence of new LNG supplies from Australia and the United States drive the total volume of global LNG trade to almost double current levels (see Figures 3 and 4). Importantly, U.S. LNG exports rise in the Ref_Ref case to about 6.5 Bcf/d, making it the third largest LNG exporter in the world, behind Australia and Qatar. A defining difference among the top three LNG exporters is that the United States is the single largest consumer of natural gas and its exports are fueled almost entirely by shale gas development.

Figure 3. Global LNG Exports by Region (Ref_Ref case)[10]

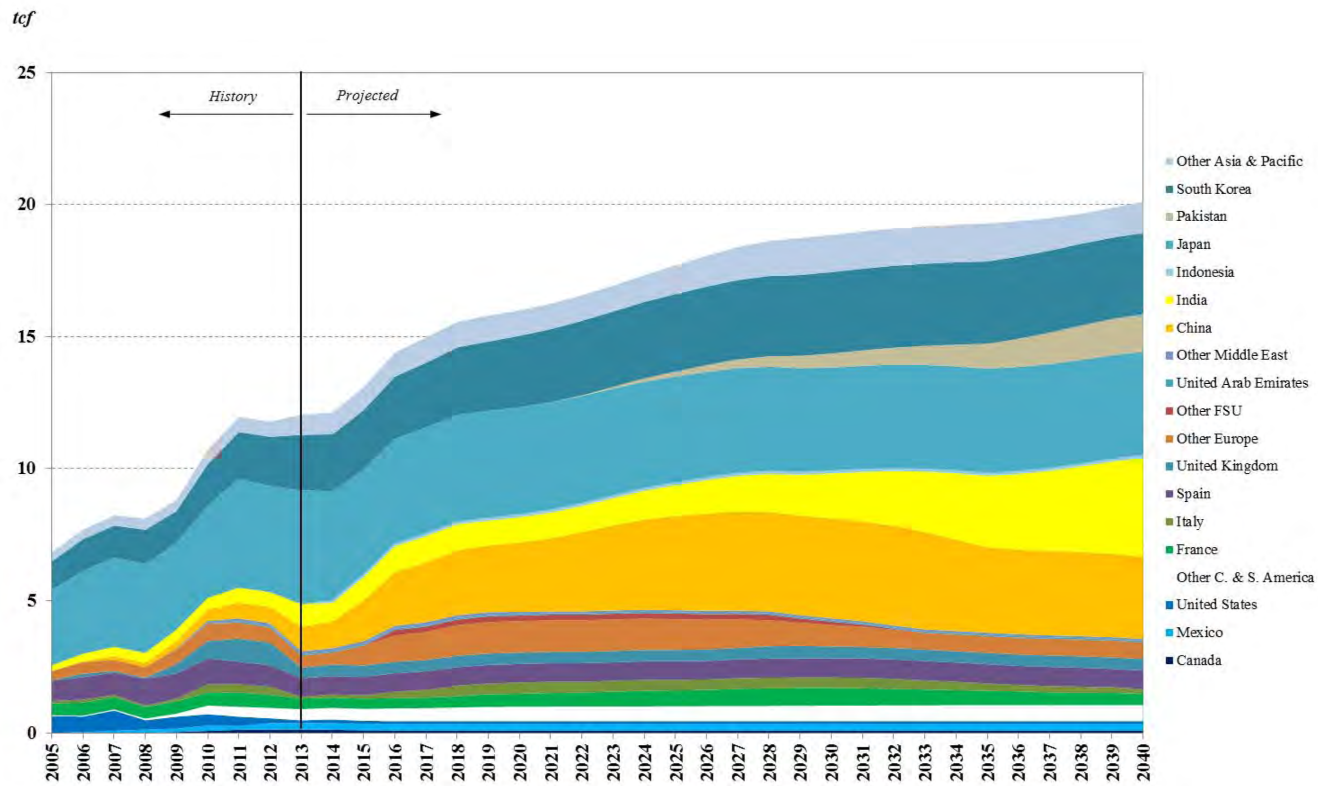


The near term increases in LNG trade indicated in Figures 3 and 4 primarily reflect the amount of LNG export capacity under construction in Australia and the United States. However, the decrease in Asian LNG prices discourages further LNG expansion in the near term. Nevertheless, expanded LNG trade is facilitated by a growing need for waterborne supplies to developing Asian economies (see Figure 5), which is fueled more generally by global demand growth (see Figure 5) that is largely occurring in regions with inadequate domestic resource endowments. This increase in demand, in turn, spawns

[10] The data for exports includes losses during liquefaction.

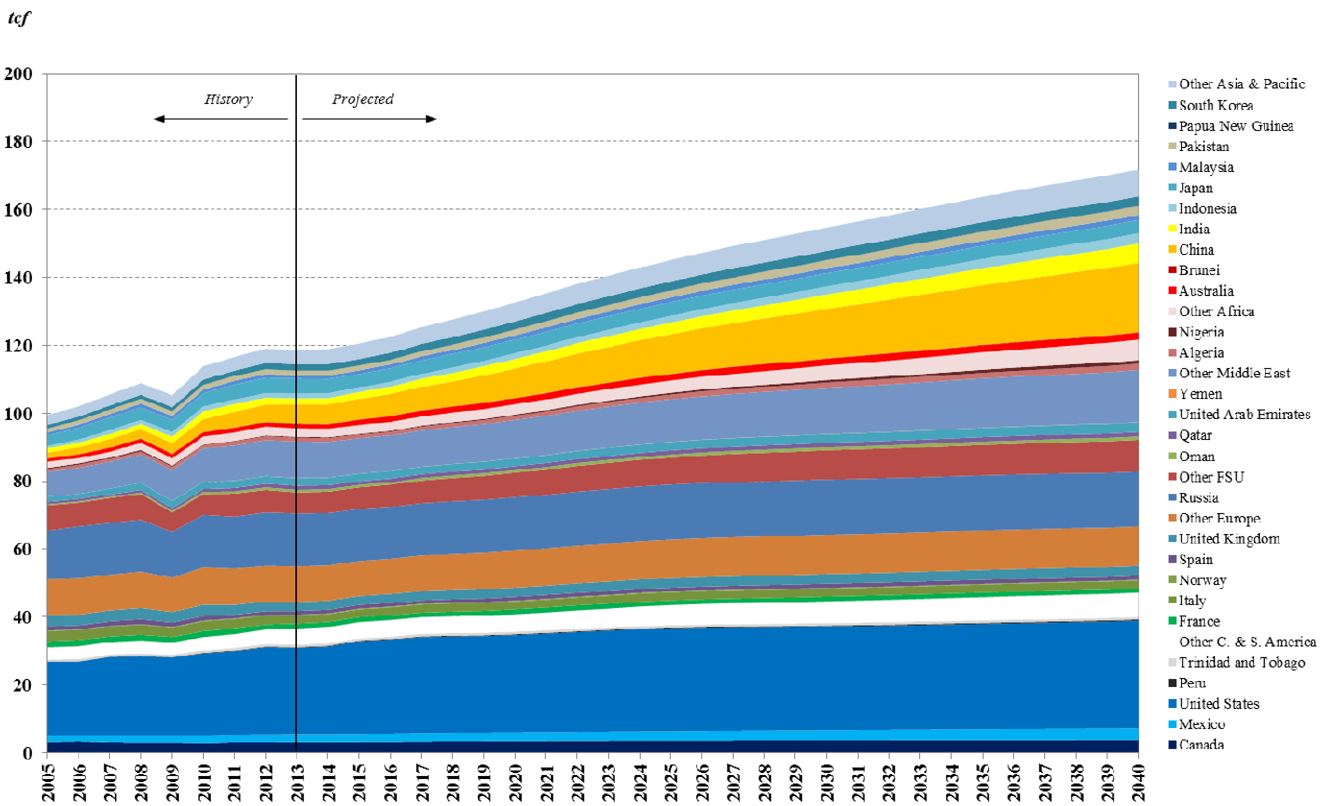
supply growth in regions that can, through trade via both LNG and pipeline, accommodate those new demands.[11]

Figure 4. Global LNG Imports by Region (Ref_Ref case)[12]



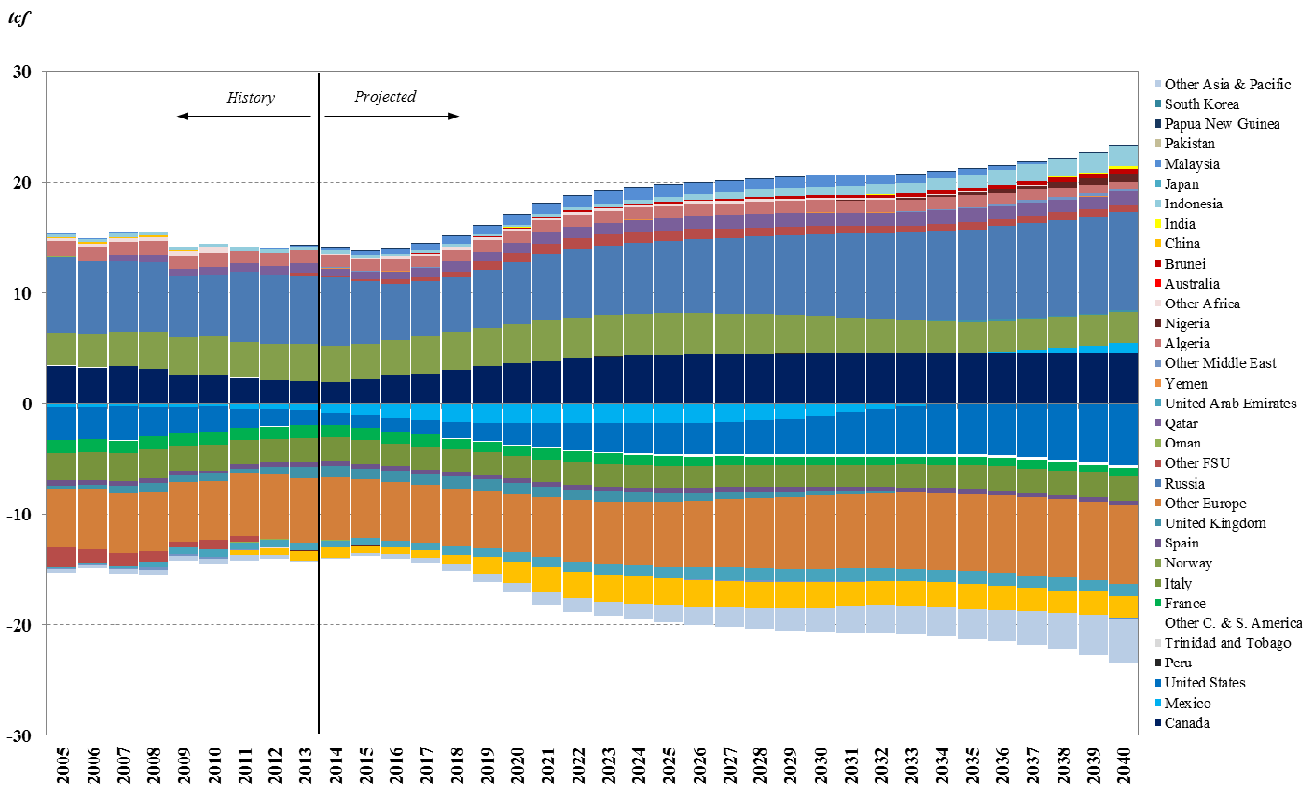
[11] In the results herein, we aggregate countries into geographically defined regions in order to clearly present the results in a coherent manner. More detailed data is presented in Annex D.
[12] The data for imports is less than the reported export data due to losses in liquefaction and shipping.

Figure 5. Global Demand by Region (Ref_Ref case)



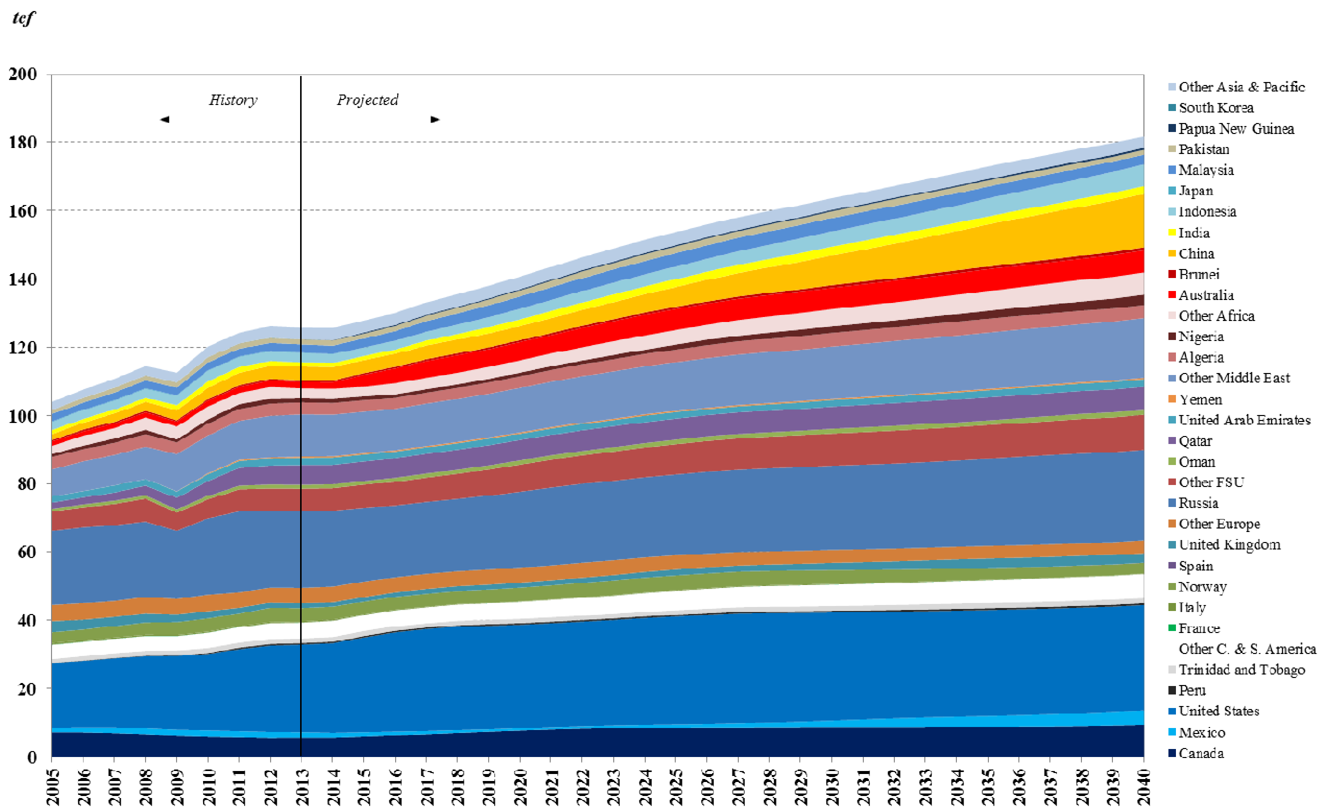
In Figure 5, we see that global demand growth is expected to be fueled primarily by the high population economies of China and India. Europe is not expected to contribute much to the overall global natural gas demand picture, which, in turn, sheds light on the emerging patterns of trade. In particular, as indicated in Figure 5, we see increased flow of LNG to Asia as well as pipeline gas from Russia to Asia (see Figure 6). Long term, the international natural gas trade map is effectively redrawn with a shift in export flows increasingly toward developing Asia.

Figure 6. Global Net Pipeline Trade (Ref_Ref case)



As seen in Figure 6, net global trade via pipeline infrastructure is also expected to grow. Announced projects that result in increased pipeline deliveries present attractive options for meeting long-term demand growth, in particular the development of pipelines between Russia and China. In fact, the persistent relatively robust Russian production seen in Figure 7 is largely facilitated by its larger scale entry in the Asian market. A weak demand outlook for Europe (see Figure 6) is not sufficient to support expanded Russian production, hence Russia turns to Asia. More generally, narrowing international price differentials limit the expansion of LNG infrastructure post-2020 and supporting shorter, continental trade via pipeline.

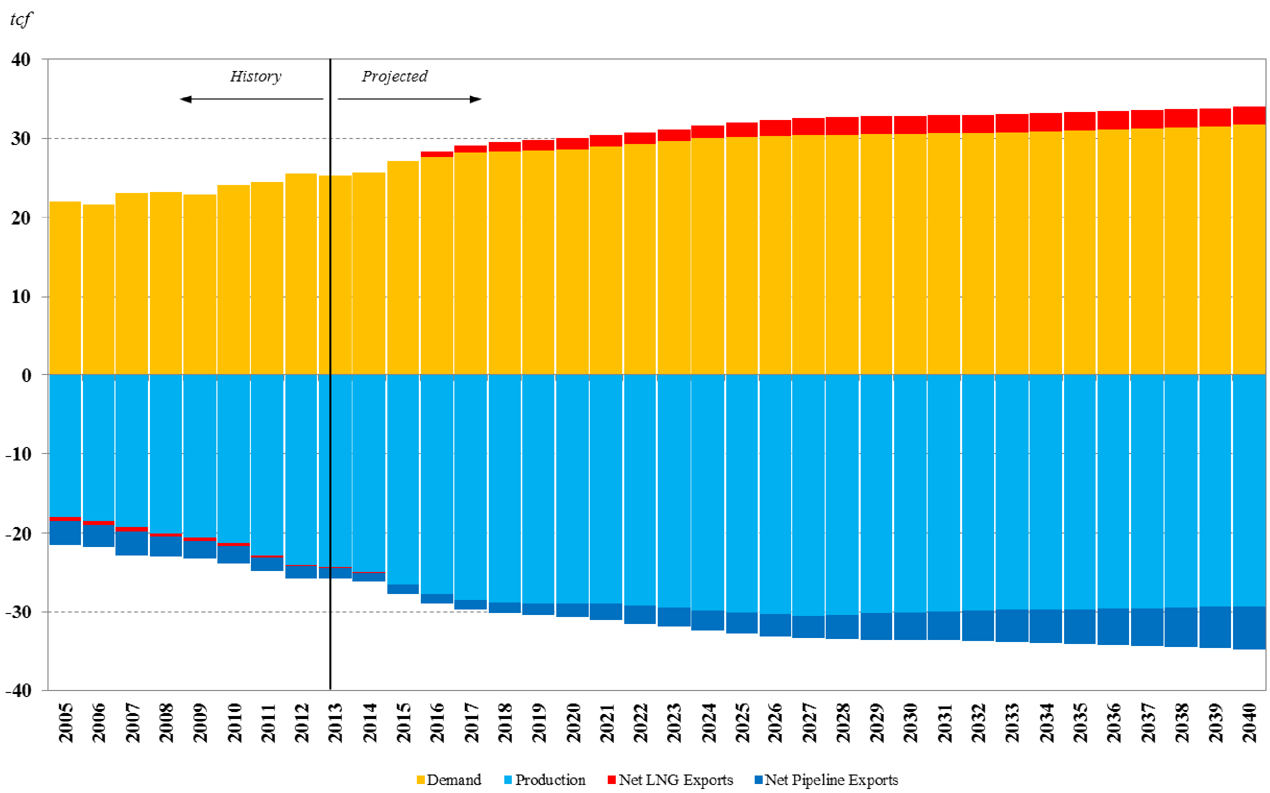
Figure 7. Global Supply (Ref_Ref case)



Also evident from Figure 7 is that Canadian supply expands, fueled primarily by shale gas developments in western Canada. This, in turn, impacts the balance of trade for the United States. As mentioned above, growth in U.S. natural gas production supports LNG exports from the United States of 6.5 Bcf/d, but U.S. LNG exports are also supported by developments in the broader, highly interconnected North American market as the deep interconnectedness of the United States and Canada facilitates the flow of Canadian gas to the United States on already existing infrastructure.

As indicated in Figure 8, Canadian exports via pipeline to the United States increase throughout the time horizon after bottoming out in the early 2010s. The majority of Canadian exports are to western states and the Midwest. Exports to the Mid-Atlantic continue to decline and never recover to any significance, which reflects strong supply growth in the Marcellus shale (see Figure 10).

Figure 8. U.S. Market Balance (Ref_Ref case)



Exports of natural gas via pipeline from the United States to Mexico increase in the near term to about 5.5 Bcf/d in the early 2020s, hold at that level through 2030, then decline through the end of the time horizon as Mexican domestic production begins to climb. The increased connectedness within the North American natural gas market that emerges in the Ref_Ref case reflects a general result that carries significant implications across all scenarios. Namely, Canada, the United States, and Mexico are poised to become more intimately linked through natural gas trade, and, as a result, the impacts of a policy or commercial development in any one country will affect North America more generally.

As indicated in Figures 3 and 8, U.S. LNG exports rise in the Ref_Ref case (and in all cases considered in this study). However, the impact of U.S. LNG exports and other global supply developments on international and domestic prices ultimately places a check on the total volume of U.S. LNG exports. Specifically, the price spreads in the international marketplace weaken to the point that full cost recovery of U.S. LNG export facilities currently under construction is compromised for about a decade. Of course, those facilities operate, but further investment in LNG export capacity is stymied until global demand pull expands to stimulate new capital flows into the U.S. LNG export value chain. Figure 9 highlights the Ref_Ref case price spreads and notes the time periods where price differences are long term supportive of investment in U.S. LNG export capacity.

Figure 9. Price Differentials and LNG Export Capacity Investment (Ref_Ref case)

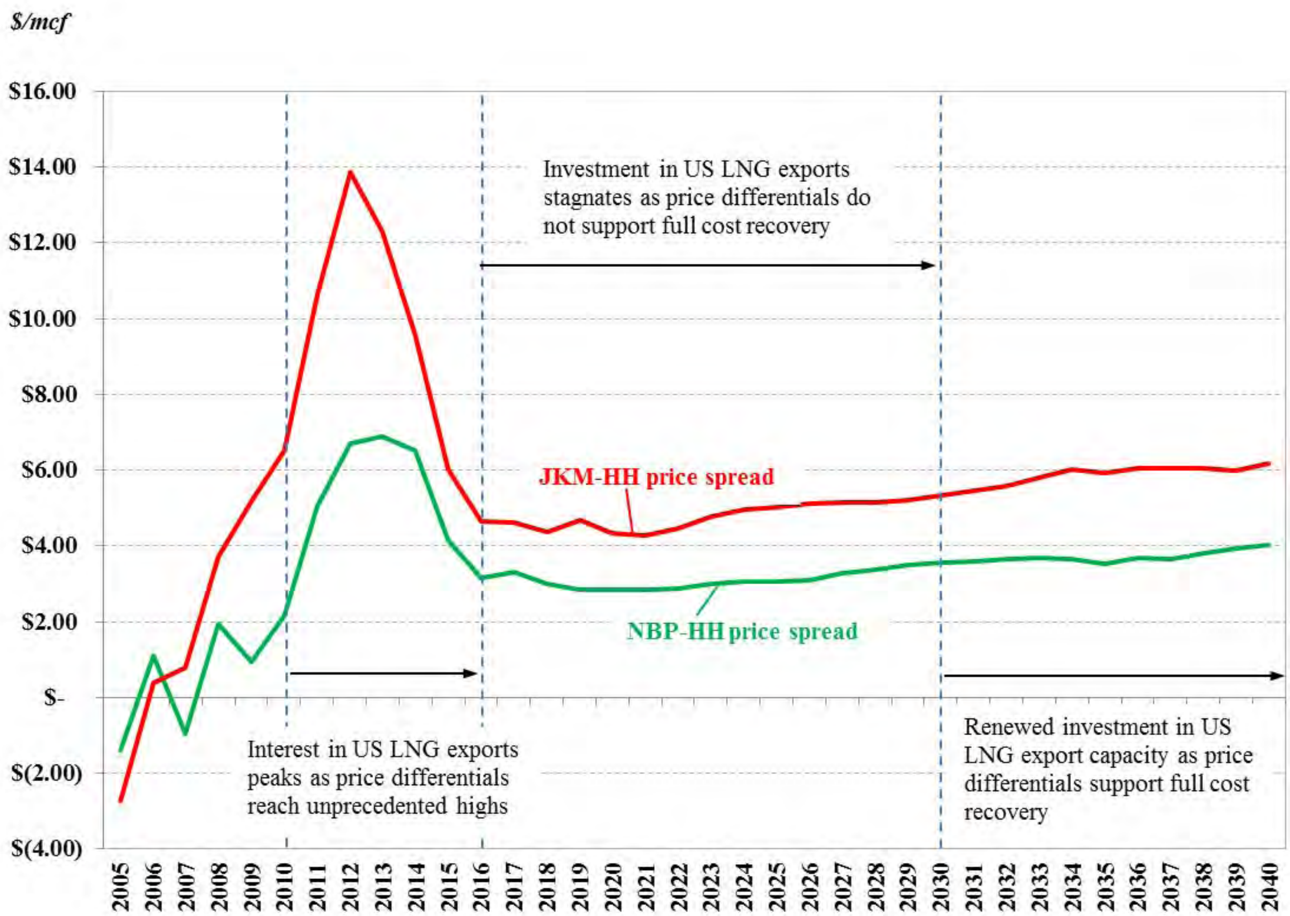
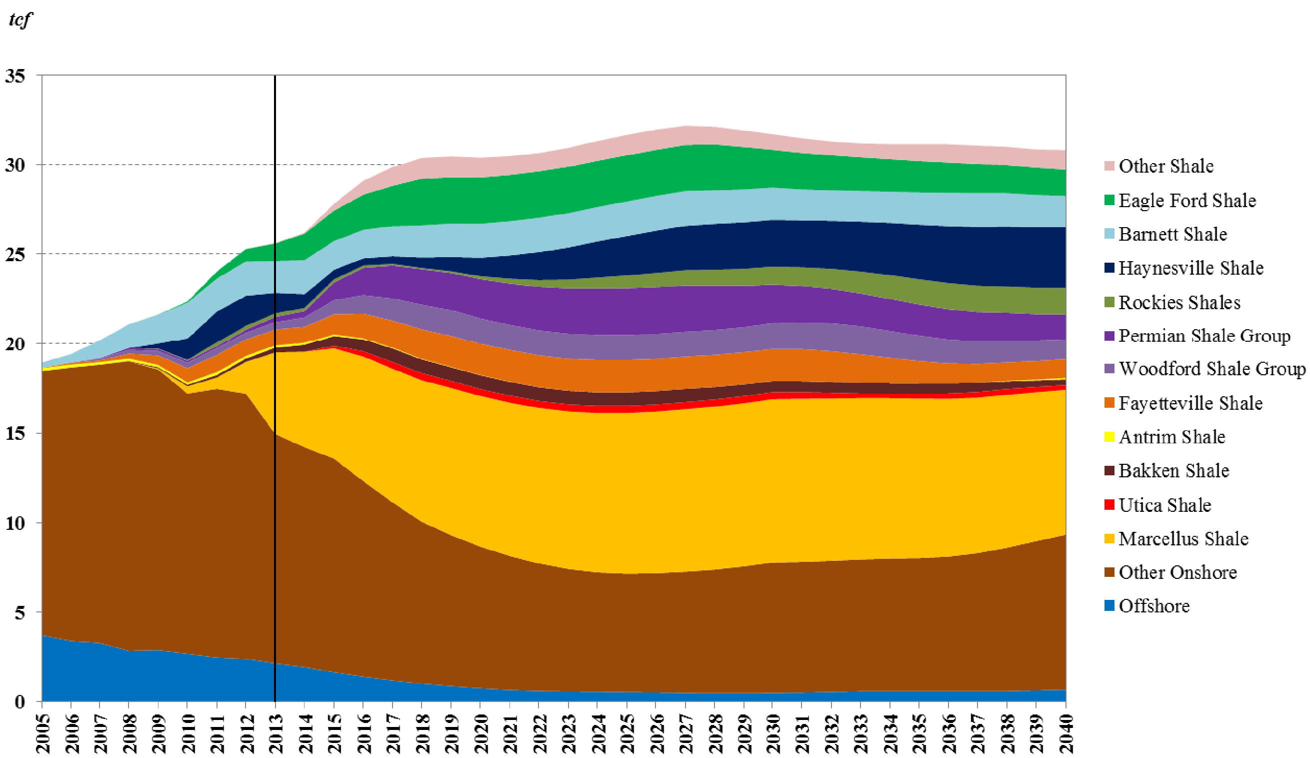


Figure 10 indicates U.S. domestic production by source through 2030. Shale gas production comprises a rising share of U.S. supply, approaching three-quarters of domestic production. The rise in shale production accompanies declines in production from other natural gas resources, both onshore and offshore. The largest producing basin is the Marcellus shale, rising to just over 20 Bcf/d in the late 2020s before beginning to decline. Production from the Haynesville shale is projected to recover in the 2020s due to higher prices and the emergence of a new demand outlet via Gulf Coast LNG export facilities, which attracts upstream capital into northern Louisiana.

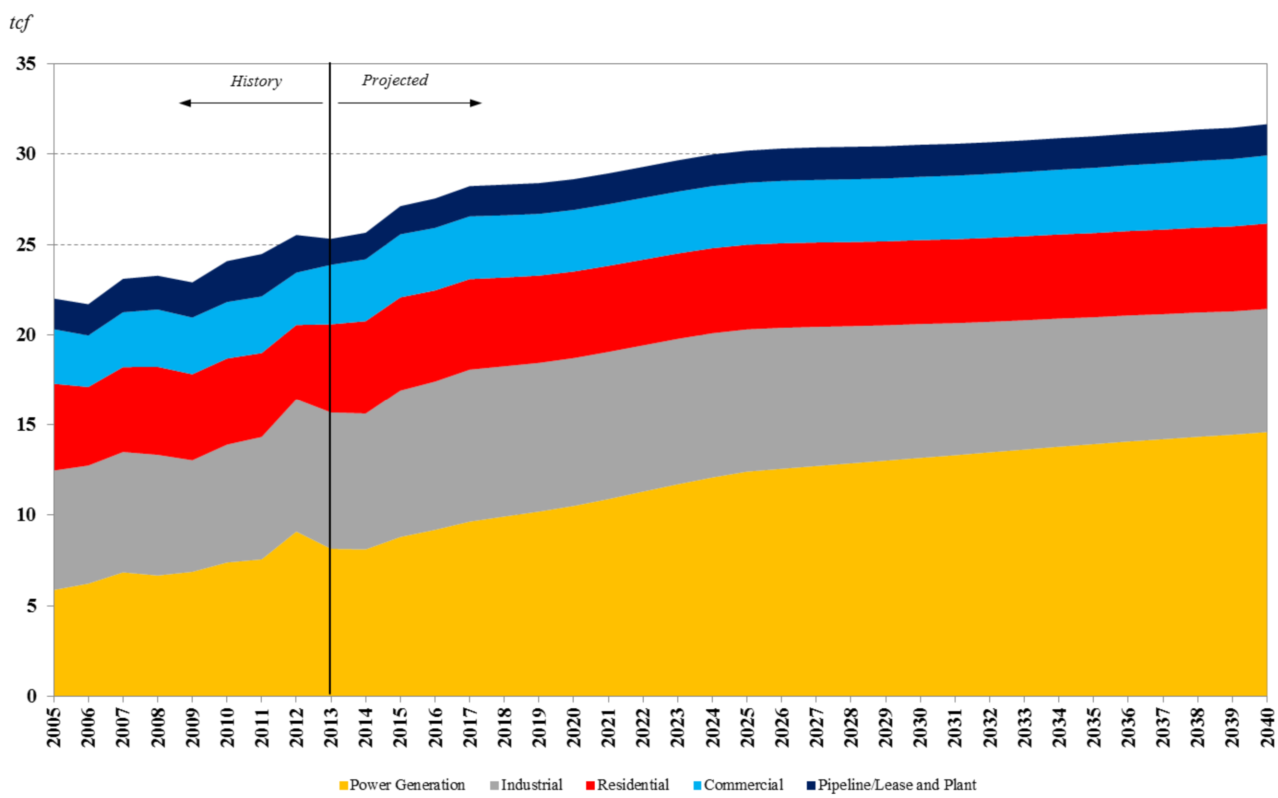
Figure 10. U.S. Supply by Resource and Play (Ref_Ref case)



The projected growth in Canadian production drives an increase in exports via pipeline to the United States, and this occurs as growth in U.S. domestic production flattens. Moreover, Mexican natural gas production begins to increase in the 2020s, meaning total supply throughout the broader North American market is quite robust throughout the time horizon.

Strong North American production facilitates demand growth in the United States, in particular, that is driven by demand in the industrial and power-generation sectors in the near term, and continued growth in power generation longer term (see Figure 11). In fact, the share of natural gas in power generation in the Ref_Ref case is projected to approach 37 percent by 2030, largely driven by emerging environmental policies that target the use of coal. In fact, the power-generation sector is projected to be the most rapidly growing source of domestic demand, rising at an average annual rate of over 3.0 percent through 2020 and 2.3 percent per annum over the entire time horizon. Industrial demand increases at an average annual rate of 2.2 percent through 2020 then is flat to slightly declining after 2020 due to efficiency gains as industrial production continues to increase. The residential and commercial sectors are not projected to see significant growth.

Figure 11. U.S. Demand by End-Use Sector (Ref_Ref case)



The changing U.S. demand and supply portfolio has implications for regional prices. The changing regional price relationships reflect sustained higher levels of production in the Middle Atlantic and Canada longer term, regional patterns of new sources of demand for U.S. natural gas production, such as LNG exports and industrial demands that tend to primarily impact the Gulf Coast, and growth in power-generation demand particularly where coal capacity is retired.[13]

Longer term growth in Canadian production weakens the price in western Canada (AECO Hub) relative to Henry Hub, but price across North America is generally strengthening over time. So, the western Canadian price also strengthens, just more slowly than Henry Hub. In general, the deep interconnectedness of the North American natural gas market and the high degree of fungibility of different sources of natural gas links the prices and in Canada, the United States, and Mexico and prevents any one region from completely dislocating from the other.

3.2 Select Natural Gas Market Highlights Across All Scenarios

In this section, we highlight the differences across cases in prices at Henry Hub, JKM, and NBP. Then, we discuss the differences in U.S. LNG exports across the various scenarios. More detailed results on the changes in domestic and international production and consumption can be found in the Annexes. We focus on these outputs in particular because they form the basis for understanding the impacts on macroeconomic outcomes across the scenarios, which we turn to in section 4.

[13] Note this occurs even with pipeline flow reversals on mainline infrastructure away from the Mid-Atlantic region, which serve to limit the depth to which basis dives longer term.

Figure 12 indicates the price at Henry Hub for each case considered in this study, and Figure 13 indicates the price path of each scenario relative to the Ref_Ref case discussed above. The only two cases not presented in Figure 12 are LNG20_LRR20 and LNG20_Hi-D20. These are not included because they are identical to the scenarios where LNG exports are endogenously determined under the same set of domestic and international market conditions, specifically the LNG20_LRR and LNG20_Hi-D scenarios.

Figures 12 and 13 highlight the breadth of impact on Henry Hub price revealed by the various scenarios. For example, among the cases considered, price is highest in the case where international demand for LNG is highest while domestic resources are lowest (the LNG20_LRR case). Alternatively, price is lowest when international demand for U.S.-sourced LNG is lowest while domestic resources are highest (Ref_HRR). In fact, in moving from Ref_HRR to LNG20_LRR, we see a price spread that approaches $3.60/mcf by 2040. In other words, when international market conditions are such that demand for U.S. LNG exports is at its highest and natural gas resources are relatively scarce, price is considerably higher than when the exact opposite is true.

Figure 12. Henry Hub Price Across Scenarios

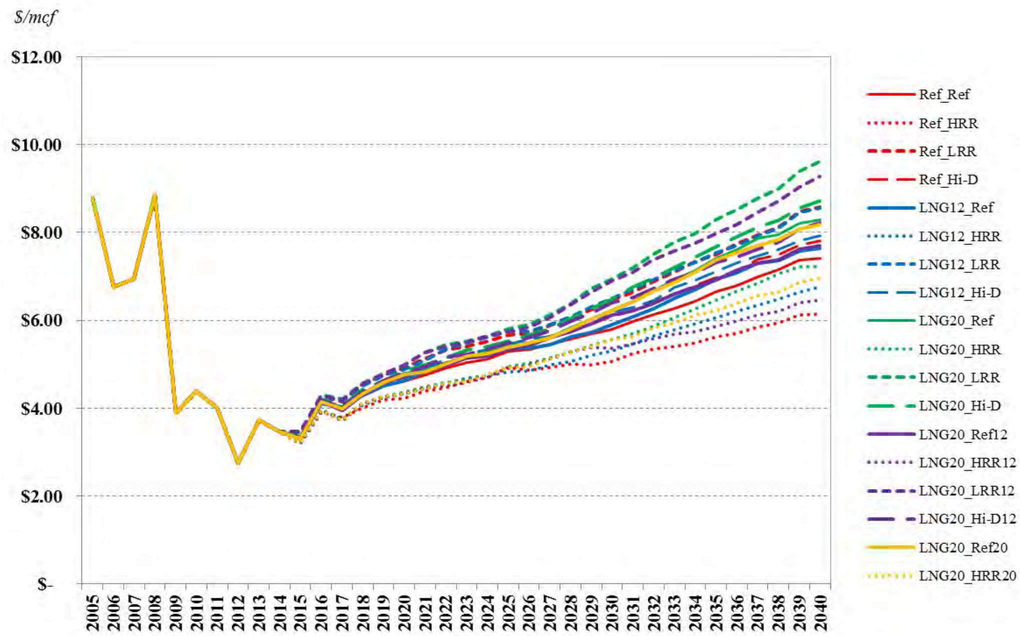
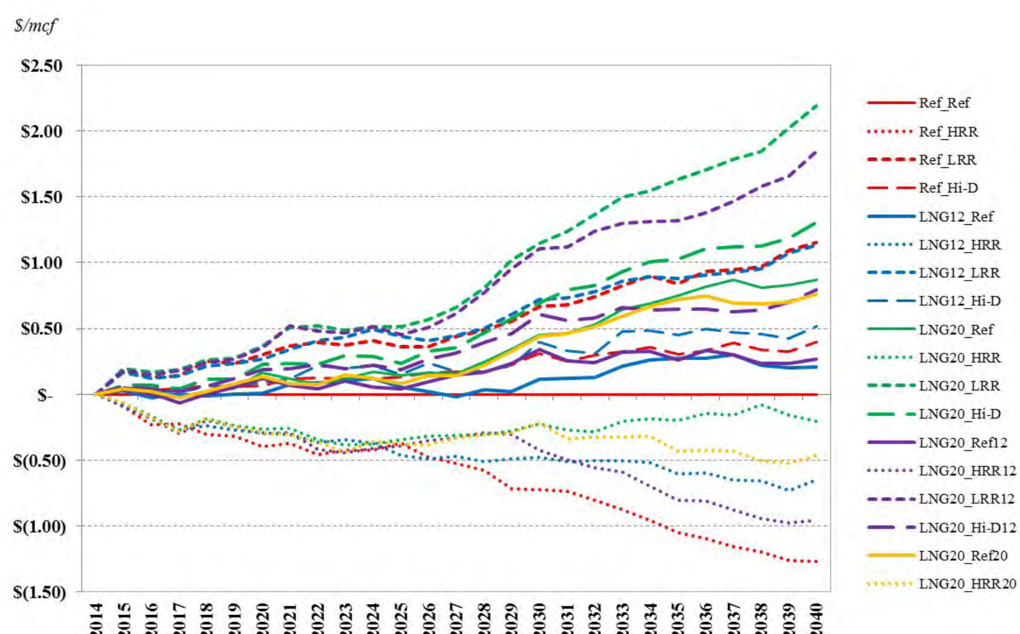


Figure 13. Henry Hub Price Relative to the Ref_Ref Case by Scenario



The other cases collectively reveal a consistent pattern with regard to the Henry Hub price. Namely, as demand for U.S. LNG exports rises, all else equal, the Henry Hub price rises. Moreover, as the availability of U.S. natural gas for export declines, either as resource availability falls or domestic demand rises, the Henry Hub price also rises, all else equal. Therefore, the exact impact of LNG exports on the Henry Hub price depends on both domestic *and* international market considerations. This latter point highlights the basic result that countries become increasingly connected via trade in the Ref_Ref case, and the extent to which this development is reinforced in each scenario plays out in the price at Henry Hub. It also is evident through the manner in which the spreads between Henry Hub and international benchmark prices evolve. Specifically, we see that the spread between Henry Hub and international benchmark prices JKM and NBP narrow as U.S. LNG exports increase within each international demand case, with the majority of the price movement occurring overseas.

Figures 14 and 15 indicate the JKM price and reveal a slightly less diverse picture, but one that is interesting nonetheless. In particular, we see that as international market conditions stimulate greater demand for U.S.-source LNG, the price at JKM rises. This is primarily by construction as the assumptions used to drive up demand for U.S. LNG exports largely target Asia (see Table 2). The price impacts at JKM are exacerbated as U.S. LNG availability is compromised. Notably, the spreads between Henry Hub and JKM (not pictured) are sensitive to both domestic and international drivers. Specifically, we see the spread narrow as more LNG is exported from the United States, all else equal. We return to this point in section 4, but note that the result reinforces the notion that markets become increasingly connected via trade as price signals transmit market information across every region.

Figure 14. JKM Price Across Scenarios

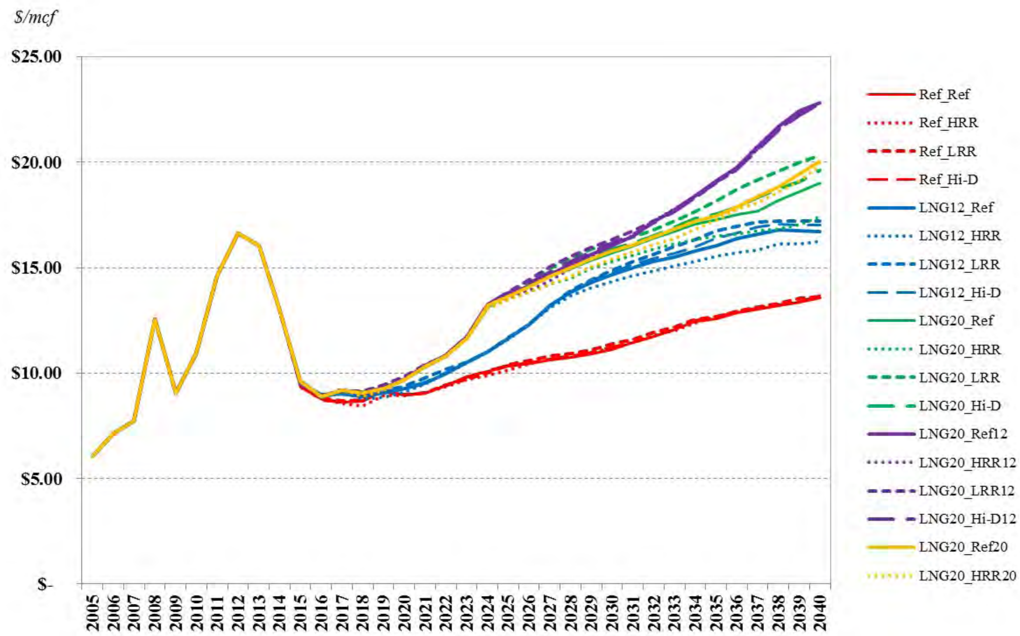


Figure 15. JKM Price Relative to the Ref_Ref Case by Scenario

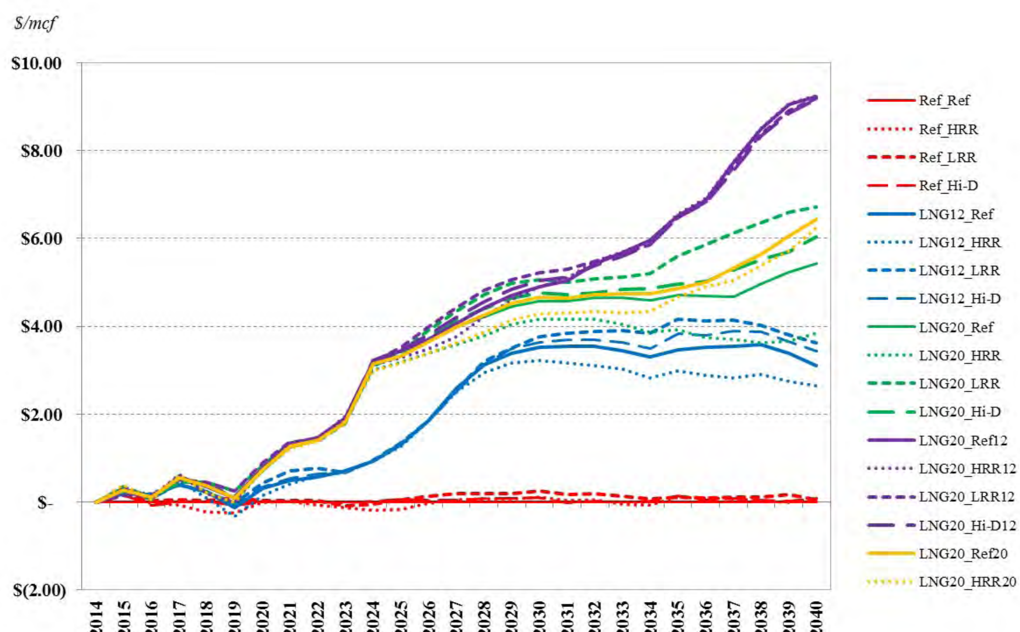


Figure 16. NBP Price Across Scenarios

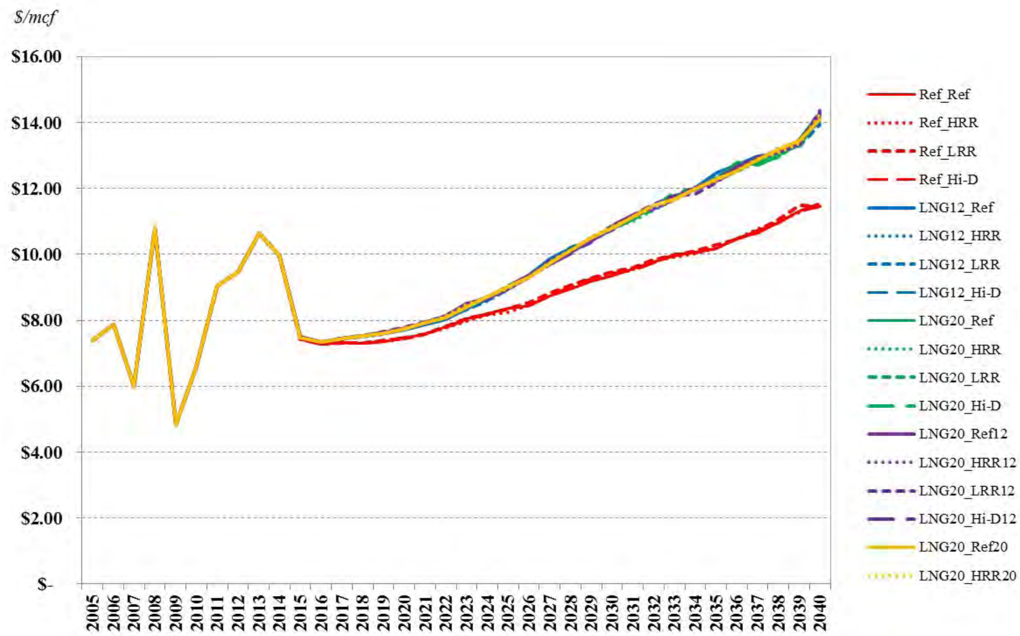
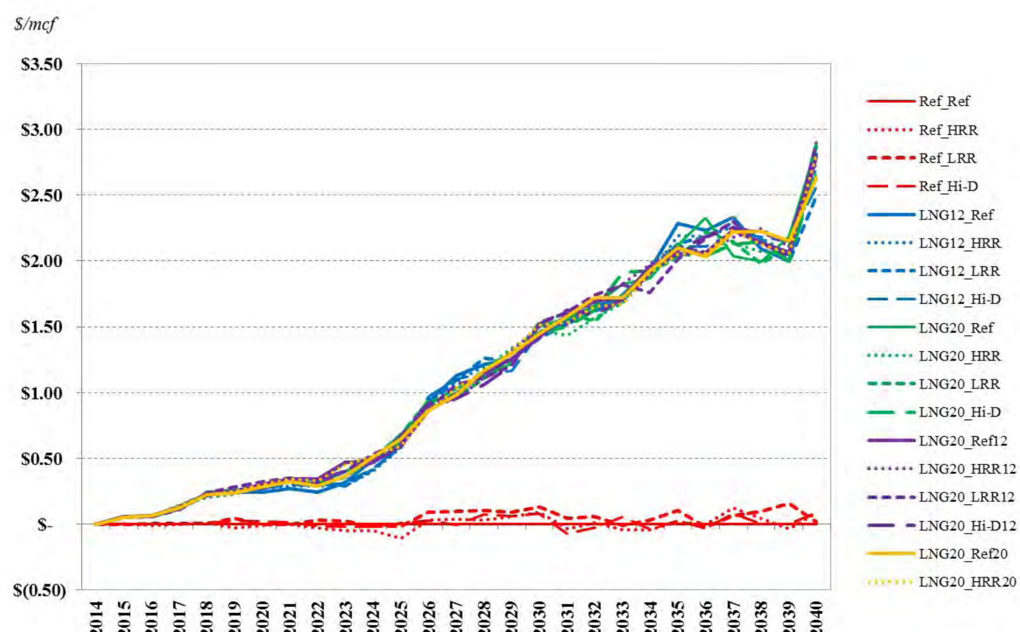


Figure 17. NBP Price Relative to the Ref_Ref Case by Scenario



Figures 16 and 17 detail the pricing results at NBP across the cases. Generally, we see that price is higher in Europe when international market conditions are such that demand for U.S. LNG exports rises. Interestingly, whether or not the increase is to 12 Bcf/d or 20 Bcf/d does not have a significant bearing. This follows because the marginal source of supply to Europe is unchanged beyond the LNG12 international market scenarios and the outlook for total natural gas demand growth in Europe is meager in every case we considered. Thus, the primary sources of supply to northern Europe remain Russia, the North Sea, and LNG primarily from Africa and the Middle East. The price impact is thus driven almost exclusively by deviations in the global LNG market, with modest offsetting responses from traditional pipeline sources of supply, including Russia.

The signal for investments in U.S. LNG export capacity is ultimately contained in the price spreads that emerge across scenarios. Figures 18 and 19 detail the price spreads that are seen between JKM and Henry Hub and NBP and Henry Hub, respectively. The pattern noted above in Figure 9 generally holds across all scenarios. In particular, the global LNG market enters into a period of time where it is relatively well-supplied after 2015. This, in turn, sees price spreads that narrow, and are supportive of LNG exports from the United States through facilities that are already under construction. However, the price spreads post-2015 are generally not supportive of continued investment in new capacity. The stimulus to invest in U.S. LNG export capacity does generally return across the scenarios albeit at different rates. In fact, the higher global LNG demand plus high domestic resource recovery cases see the strongest support for new U.S. LNG export capacity, emerging as soon as the end of this decade, which is about ten years earlier than we see in the Ref_Ref case.

Figure 18. JKM-Henry Hub Price Spreads Across Cases

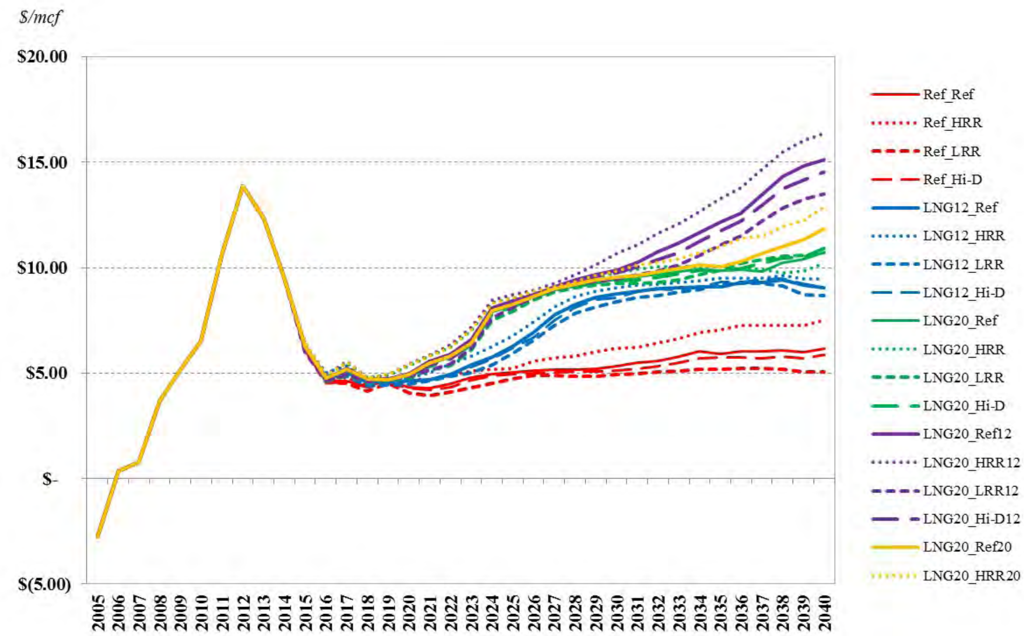


Figure 19. NBP-Henry Hub Price Spreads Across Cases

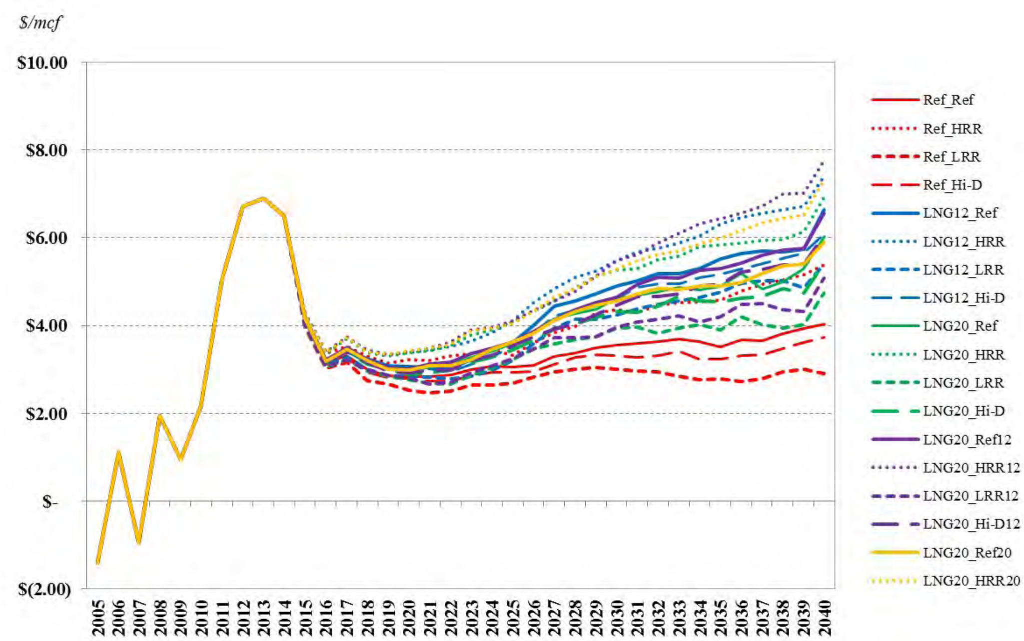
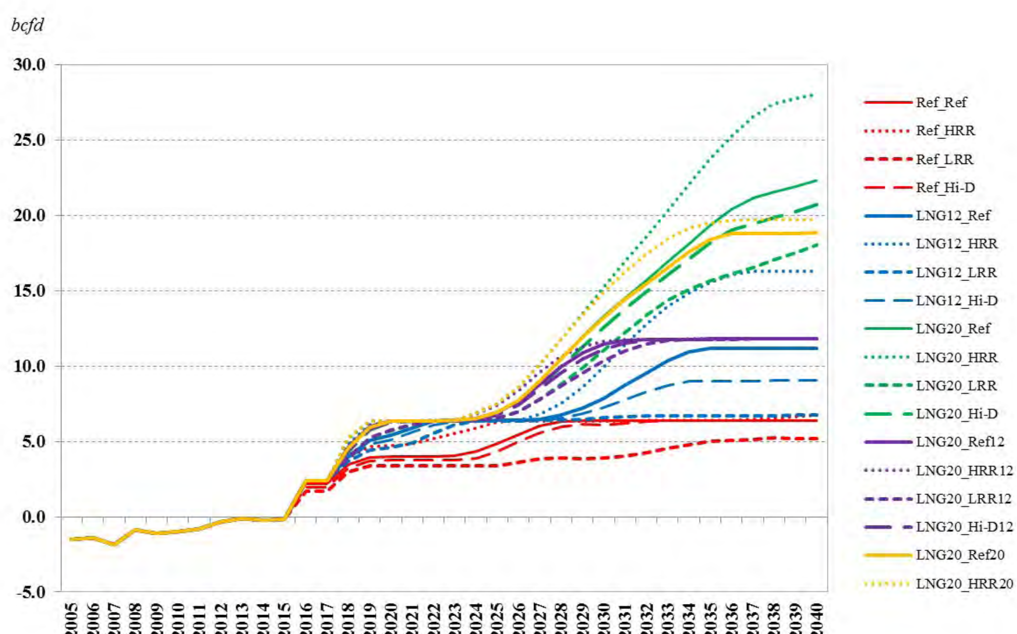


Figure 20 graphs U.S. LNG exports through 2040. Notably, the largest differences emerge after the mid-2020s, a result owing to several factors, including:

- International demand must grow to stimulate investment from new sources of supply. This takes time and generally accompanies economic growth.
- There are a number of planned LNG and pipeline export projects around the world that are already under construction. Thus, absent a very large demand impulse, as in the LNG20 cases, the expansions already underway are sufficient to sate demands for the near term.
- Inhibiting shale resource availability, as in the international LNG12 and LNG20 cases, does not have a material short-term impact because those resources are generally not significant sources of supply even in the international Reference cases until the mid-2020s anyway. So, the supply impact is only felt in the long run.

Figure 20. U.S. LNG Exports Across Scenarios



We see in Figure 20 that the level of U.S. LNG exports approaches 27 Bcf/d in the LNG20_HRR case, which is by far the most aggressive result among the scenarios. This follows from the fact that international market conditions are the most conducive to create demand pull for U.S.-sourced LNG in this case, and the long-term U.S. supply picture is also the most robust. In effect, the international stimulus to total demand for U.S.-sourced natural gas can be met by a very robust supply portfolio.

Table 3. U.S. LNG Exports in 2040 Across Cases (Bcf/d)

		Domestic Scenarios			
International Demand Scenarios		Reference	High Resource Recovery	Low Resource Recovery	High Natural Gas Demand
Reference		6.38	6.74	5.20	6.36
Global Demand for U.S. LNG Supports 12 Bcf/d		11.18	16.30	6.73	9.02
Global Demand for U.S. LNG Supports 20 Bcf/d	U.S. LNG Exports 12 Bcf/d	11.81	11.82	11.80	11.81
	U.S. LNG Exports 20 Bcf/d	18.82	19.74	*	*
	U.S. LNG Exports Endogenous	22.34	28.05	18.02	20.37

Table 3 indicates the level of U.S. LNG exports in 2040 for every case we considered. The results indicate that the largest driver of change in U.S. LNG exports for a given international market circumstance (or reading across Table 3) is domestic resource availability. It is also evident that for a given domestic scenario (or reading vertically in Table 3), different international market conditions have larger impacts on U.S. LNG export volumes than any of the domestic scenarios we considered.

This highlights the importance of considering the issue of U.S. LNG exports in the context of a global analysis. This point is made even more salient when considering the competiveness of natural gas-consuming industries across countries in a broader macroeconomic framework. We turn to this next.

4 Macroeconomic Impact of Increased U.S. LNG Exports

When comparing the macroeconomic outcomes of different LNG export levels it is important to do so against a clear point of reference. Therefore, we detail the macroeconomic outcomes by comparing cases where international market conditions are held constant as the level of U.S. LNG exports increases. In this section, we focus on the cases where the international market supports more than 20 Bcf/d of demand for U.S. LNG exports. We first present a detailed discussion of the results for the Reference domestic scenario (that is, we compare the LNG20_Ref12, LNG20_Ref20, and LNG20_Ref cases) in order to gauge the effect of increasing U.S. LNG exports above 12 Bcf/d. We then assess whether conclusions drawn from the Reference domestic case hold for the alternative domestic cases—High Resource Recovery (HRR), Low Resource Recovery (LRR) and High Gas Demand (Hi-D).

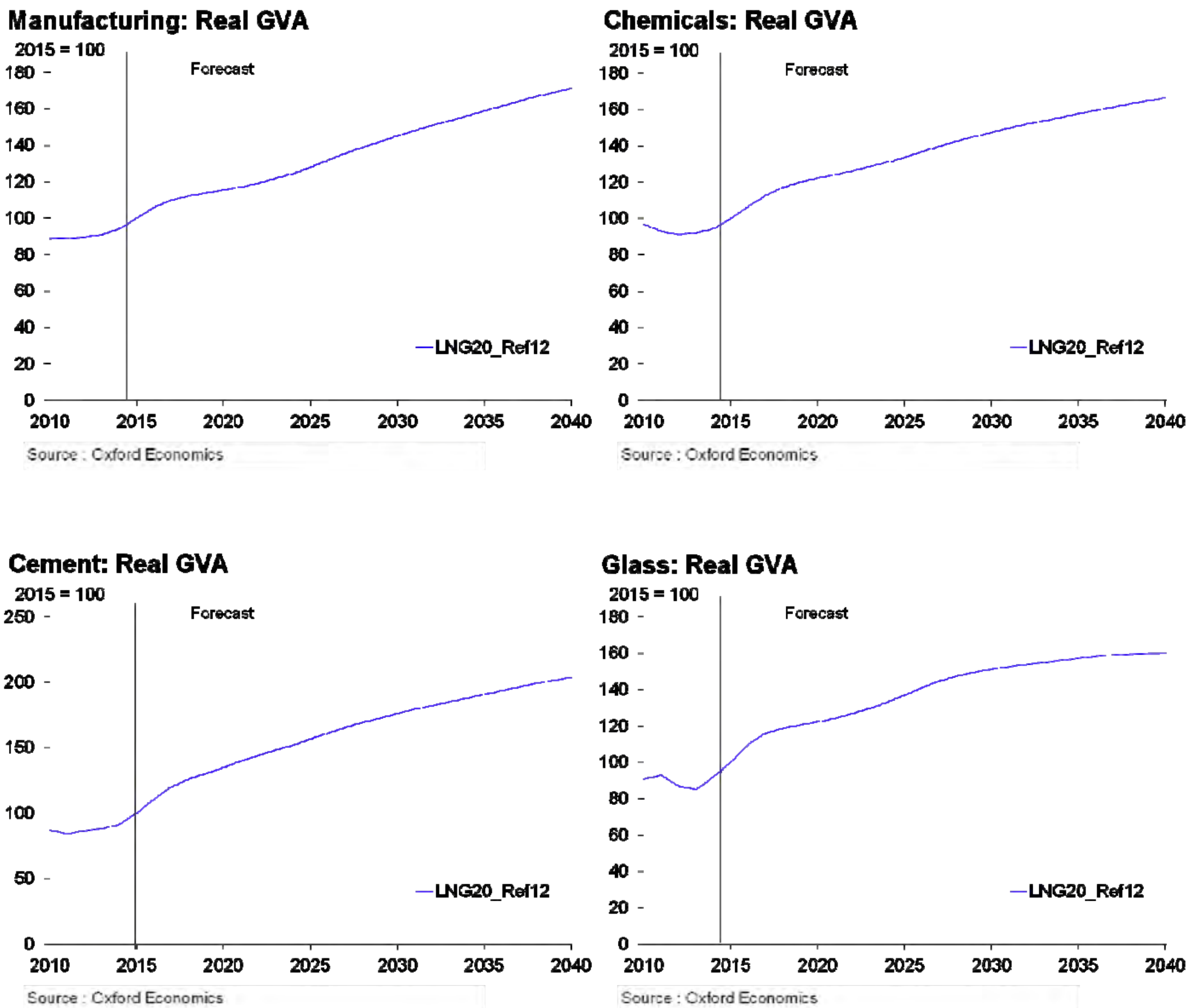
The key assumptions driving the LNG20_Ref12 case (that is, where international demand supports 20 Bcf/d of U.S. LNG exports but capacity does not exceed 12 Bcf/d in the Reference domestic scenario) are as follows:

- As discussed in section 2, in order to ensure international demand is sufficient for 20 Bcf/d of U.S. LNG exports, it is assumed accessible shale resources outside the United States are extremely limited relative to the Ref_Ref case. Total accessible shale resources outside the United States are assumed to be 2,713 tcf, compared with 7,578 tcf in the Ref_Ref scenario. In addition, it is assumed that several large coal-consuming countries, including China, India, Indonesia, and South Korea, reduce coal consumption to limit CO_2 emissions.

- The spread between European and Asian benchmark prices and the Henry Hub price are substantially higher than in the baseline (Ref_Ref) scenario. This follows from diminished supply capabilities outside the United States and ultimately drives an increase in U.S. LNG exports.
- In the LNG20_Ref12 case U.S. GDP growth continues to expand at around 2.6 percent per year on average to 2040.[14] U.S. manufacturing growth continues to expand strongly. Despite higher Henry Hub prices, energy-intensive sectors (EIS) such as chemicals, cement, and glass continue to grow robustly (see Figure 21). Key sectors, such as construction and motor vehicles, continue to drive output in the glass and cement sectors as well as parts of the chemicals sector.

[14] This projection is derived by imposing modeled natural gas market conditions (production and export volumes and prices) on the Ref_Ref baseline. U.S. GDP growth in the Ref_Ref case is based on the EIA 2014 Annual Energy Outlook.

Figure 21. Manufacturing Outlook in LNG20_Ref12 Scenario



Given this backdrop, we compare scenarios in which:

- U.S. LNG exports rise from 12 Bcf/d to a maximum of 20 Bcf/d (that is LNG20_Ref12 vs. LNG20_Ref20).
- U.S. LNG exports rise from 12 Bcf/d to a market-determined level that exceeds 20 Bcf/d (that is LNG20_Ref12 vs. LNG20_Ref).

The rest of this section examines the impact of the scenarios for the natural gas market and the U.S. economy.[15] We begin with a detailed discussion of the results when increasing exports to 20 Bcf/d in the Reference domestic scenario, and then subsequently discuss the impacts in the alternative domestic cases. We then review the impacts of allowing exports to rise to their market-determined level.

4.1 U.S. LNG Exports Increase from 12 Bcf/d to 20 Bcf/d

4.1.1 Natural Gas Market Impacts

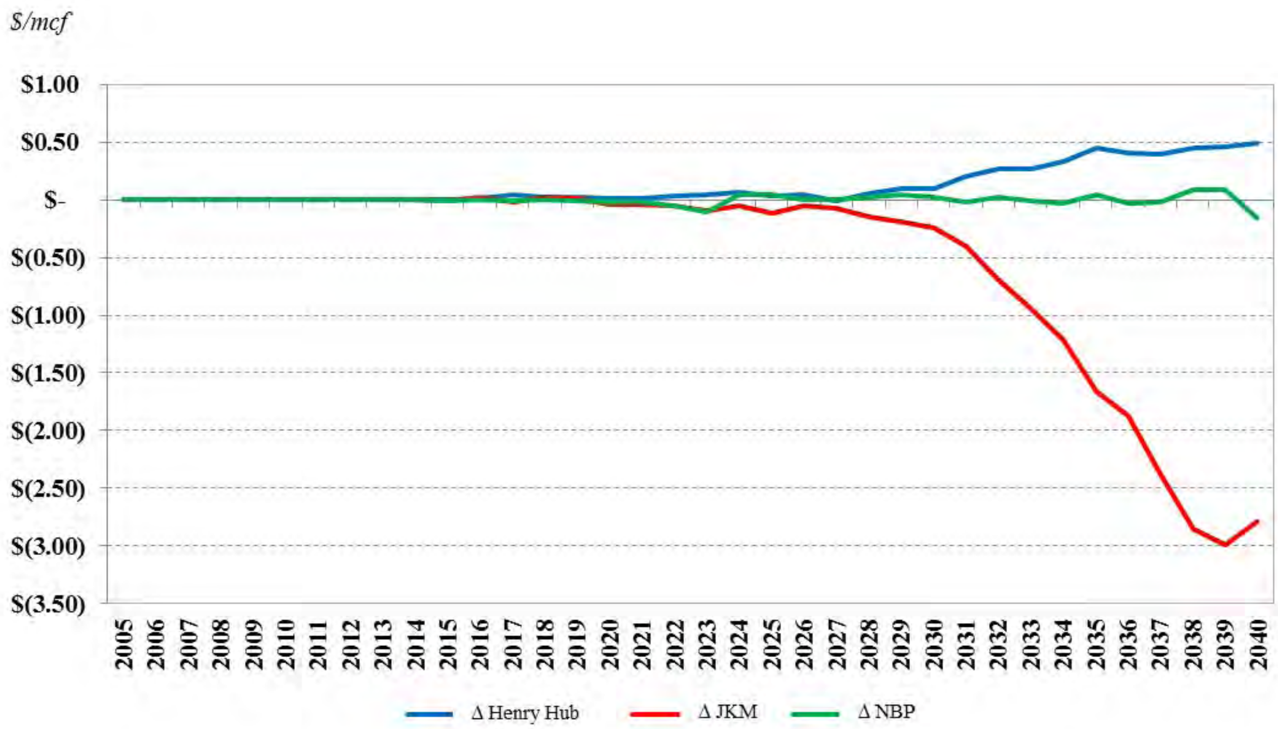
In this section, we highlight the scenarios where international market conditions are supportive of 20 Bcf/d of U.S. LNG exports under the Reference domestic scenario. We begin with the scenario where LNG exports from the United States do not exceed 12 Bcf/d (LNG20_Ref12). Then, we compare this to the case where LNG exports can rise to a maximum of 20 Bcf/d (LNG20_Ref20).

Exports of natural gas overall rise 26 percent, pushing net LNG exports from the United States to 4 Bcf/d from 0.3 Bcf/d in the lower export case. At an aggregate level, the impact on exports, however, is limited, with net fuel exports rising just 0.02 percent of GDP

As indicated in Figure 22, the Henry Hub price rises as LNG exports increase to 20 Bcf/d, while other international benchmark prices decline. This is the result of allowing increased trade from the United States thereby serving to relax the highly constrained supply situation internationally.

[15] Scenario results from the GEM and GIM are presented through 2040, with the focus of analysis covering the period 2026–2040. This is done to highlight the differences across cases. Namely, as indicated in the discussion of the natural gas market results in the previous section, the majority of the differences across scenarios occur after the mid-2020s. Results for the period 2015–2040 and 2015–2025 are given in the Annex. Detailed results for all other modeled scenarios are also available in Annex.

Figure 22. Change in Global Gas Prices (LNG20_Ref20 minus LNG20_Ref12)



Notably, the price response in Asia tends to be greatest as U.S. LNG exports rise to 20 Bcf/d. The JKM price declines in dollar terms by an amount that is roughly six times greater than the price increase at Henry Hub. This is the result of the international market conditions that are simulated in the LNG20 cases. In particular, the LNG demand stimulus is primarily the result of highly constrained supply potentials plus higher demand in Asia. While shale potential is also constrained in Europe in the LNG20 cases, the change relative to the Reference international case is small compared to the change in Asia. In addition, demand is not stimulated in Europe to the same extent as in Asia because the Reference international scenario already assumes policies are in place to reduce CO_2 emissions in Europe. As a result, the European market is simply not as stressed as the Asian market in the LNG20 cases and thus has less to gain from increased availability of U.S. LNG exports.

Figure 23. U.S. Supply by Resource and Play (LNG20_Ref12 case)

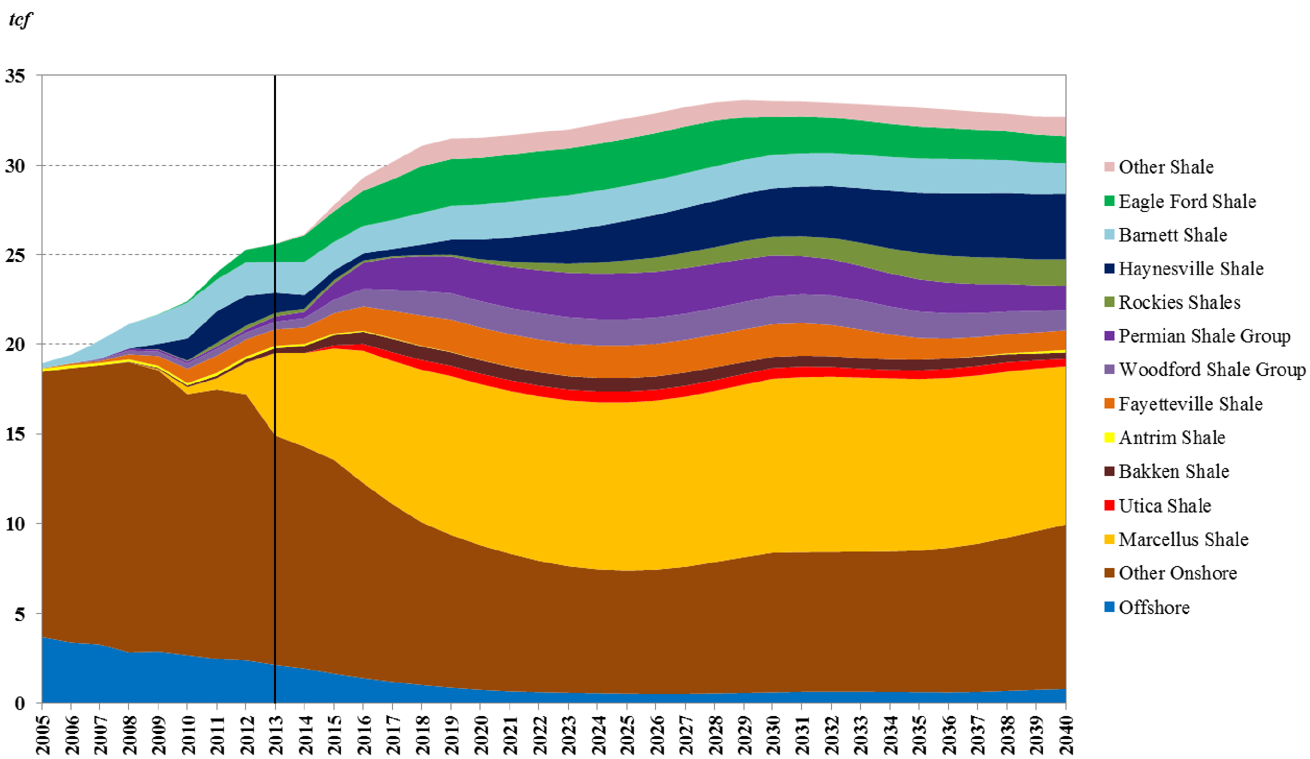
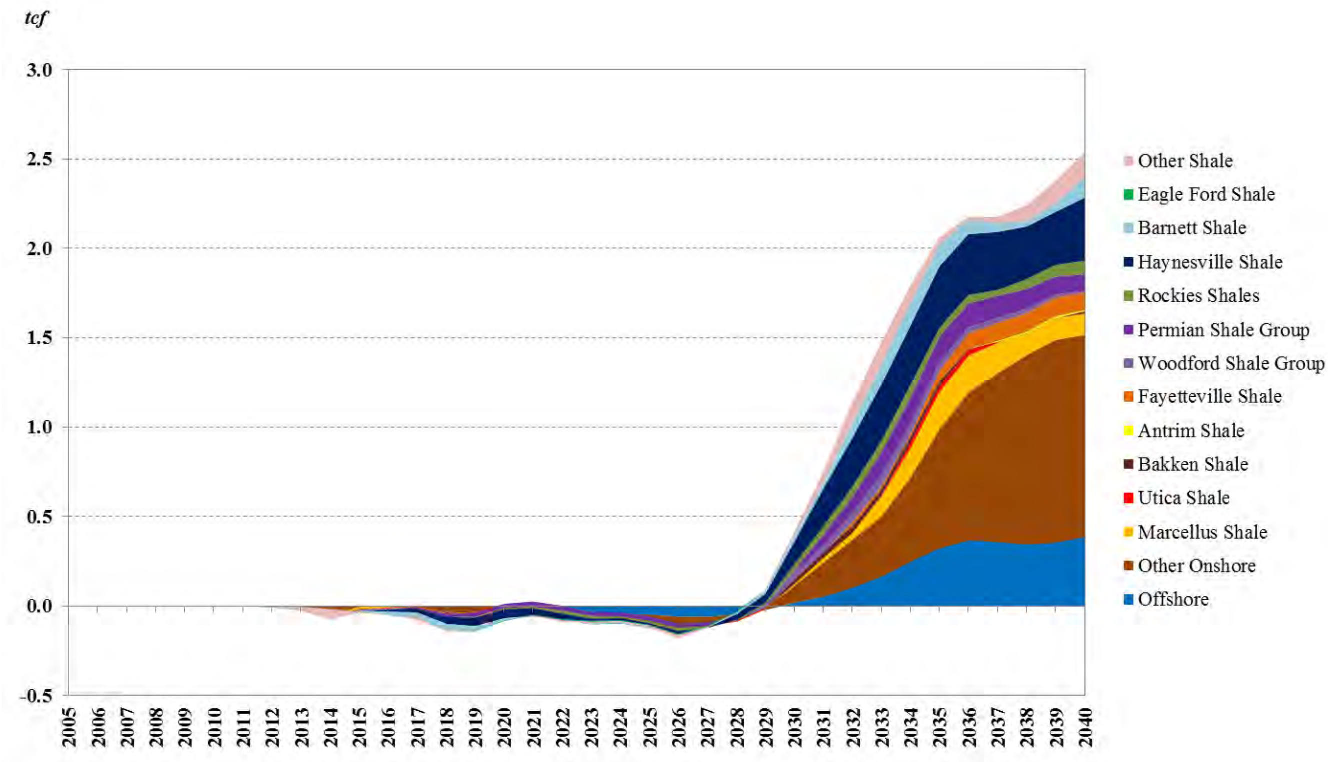


Figure 23 shows that domestic production rises to well over 30 tcf per year by 2030 even when exports are constrained at 12 Bcf/d. While the maximum is only slightly higher than in the Ref_Ref case discussed above in section 3, exports to Mexico via pipeline (not pictured) are lower longer term, which indicates a redirection of supply when international demand pull is greater.

Figure 24. Change in U.S. Production (LNG20_Ref20 minus LNG20_Ref12)



In Figure 24, we see that U.S. production continues to increase through the time horizon when LNG export volumes can expand to 20 Bcf/d, rising 4 percent on average from 2026–2040. Greater LNG exports effectively serve as additional demand for U.S. natural gas, which facilitates additional expansion in the domestic upstream sector.

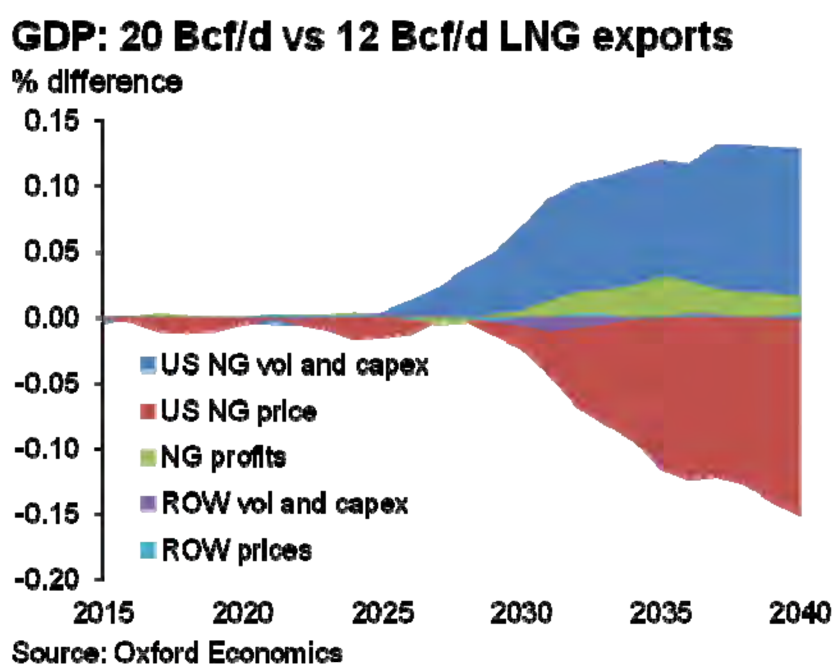
Of course, there are offsetting impacts, but these are relatively small. The majority of the increase in LNG exports is accommodated by expanded production rather than reductions in domestic demand, which declines by about 450 mmcf/d by 2040 with the bulk of the impact split evenly across the power generation and industrial sectors. This fact that the price increase as we move from 12 Bcf/d to

20 Bcf/d of LNG exports slowly climbs to $0.50 by 2040 renders the domestic demand response to be relatively small.

4.1.2 Macroeconomic Impacts in the Domestic Reference Case

The macroeconomic impacts of increasing U.S. LNG exports to 20 Bcf/d from 12 Bcf/d can be decomposed into five main channels identified in section 2.2. When decomposing impacts of greater LNG exports by channel (see Figure 25), the gains from incremental natural gas production and investment in the higher export cases are generally offset to a significant extent by greater increases in U.S. natural gas prices. While U.S. natural gas producers see greater profits, the gains are small relative to the economy as a whole.

Figure 25. GDP Impact by Channel, 20 Bcf/d vs. 12 Bcf/d LNG



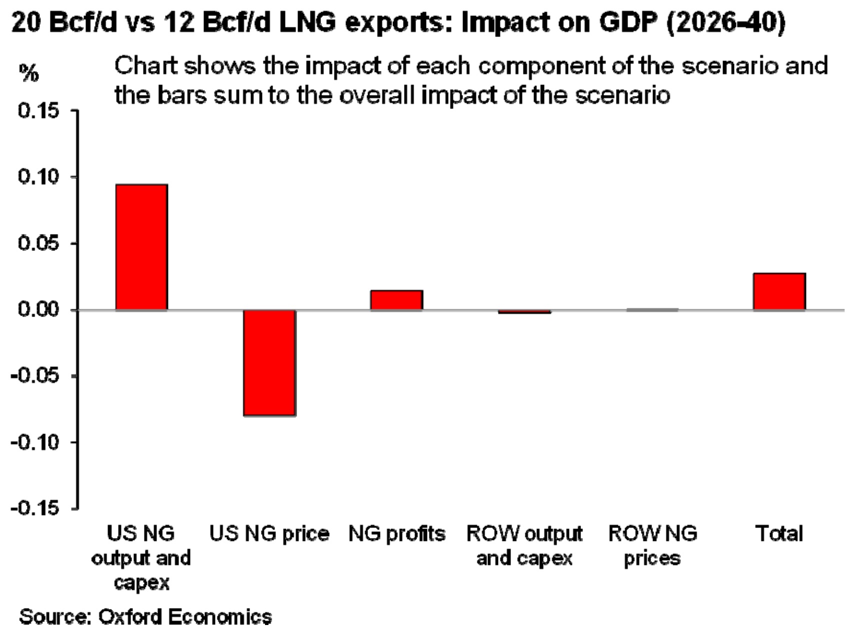


Table 4. Key Scenario Drivers, 12 Bcf/d vs. 20 Bcf/d of LNG Exports (2026–2040 average)

Channel	Indicator	Key Inputs		Change (% or ppts)
		12 Bcf/d	20 Bcf/d	
U.S. LNG Production and Investment	NG production (Bcf/d)	94	97	4.0%
	NG consumption (Bcf/d)	93	93	0.1%
	NG exports (Bcf/d)	17	21	26%
	NG imports (Bcf/d)	16	17	4.2%
	Net fuel exports (% of GDP)*	–	–	0.02%
	Capex (% of GDP)*	–	–	0.06%
U.S. Gas Price	Henry Hub price (2010$/mmBtu)	$6.59	$6.87	4.3%
U.S. Energy Sector Profits	Profits (% of GDP)	0.04%	0.07%	0.03%
Rest of World LNG Production and Investment	Capex (% of GDP)*	–	–	0.00%
Rest of World Gas Prices (2010$/mmBtu)	NBP (UK)	$11.67	$11.68	0.0%
	German Border (NW Europe)	$11.16	$11.16	0.1%
	JKM (Asia-Pacific)	$18.13	$16.89	-6.8%

*Only the change in the value is available and this is applied to more aggregated data

The key drivers of these results are highlighted in Table 4 and are detailed as follows:

- **U.S. LNG Production and Investment**: When U.S. LNG exports rise to 20 Bcf/d from 12 Bcf/d, natural gas production is 4.0 percent higher in the domestic Reference case. This is associated with a rise in net fuel exports of just 0.02 percent of GDP over the period 2026–2040 and additional investment of 0.06 percent of GDP. There are positive multipliers from the extra production and investment, as activity is stimulated in the rest of the economy, and as a result total output is 0.1 percent higher from 2026–2040.
- **U.S. Natural Gas Prices**: The Henry Hub price is, on average, 4.3 percent higher in the 20 Bcf/d export case than the 12 Bcf/d case over the period 2026–2040. As noted above, higher gas prices dampen domestic consumption and erode U.S. export competitiveness. In total, higher prices reduce GDP by 0.1 percent over the period 2026–2040.
- **U.S. Profits**: Profits in the 20 Bcf/d export case are higher given the rise in prices, production and export volumes, but the scale of the impact is small relative to the size of GDP. Profits are 0.03 percent of GDP higher in the 20 Bcf/d case compared with the 12 Bcf/d case. The rise in profit is also modest because it is assumed U.S. producers receive the Henry Hub price on LNG exports rather than the price in the destination market. It assumed that 95 percent of profits are distributed to households and this results in a marginal increase in consumption and GDP over 2026–2040.
- **Rest of World NG Production and Investment**: Production in the rest of the world is little changed when U.S. LNG exports increase to 20 Bcf/d from 12 Bcf/d; international demand conditions remain unchanged, and the addition of incremental U.S. LNG exports displaces very

little supply from the rest of the world. As result, capex needs by the gas sector in the rest of the world remain broadly unchanged when the United States increases LNG exports.

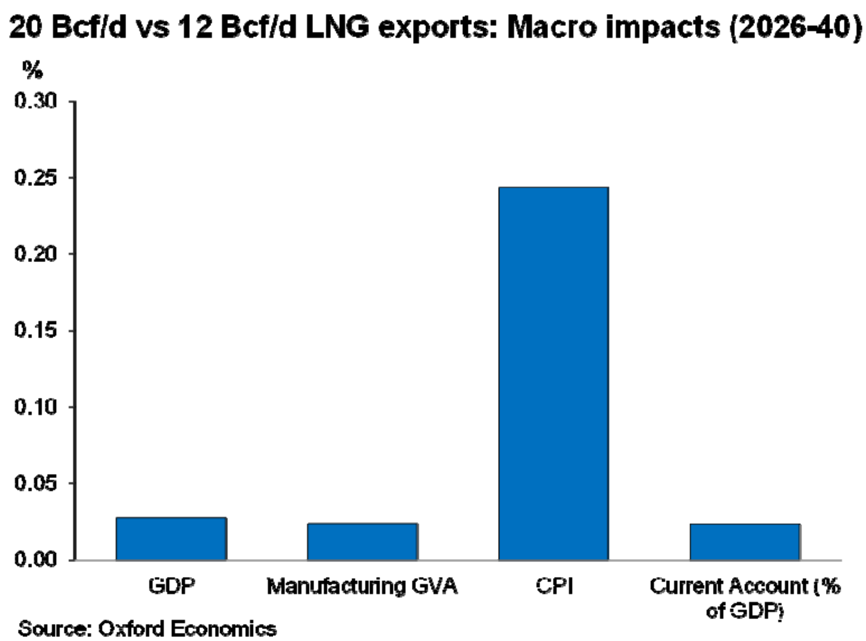
- **Rest of World NG Prices**: The increase in the availability of cheaper U.S. gas exports on the world market dampens NG price increases in Asia, though prices in Europe are little affected. The marginal decline in NG prices both boosts real income in the rest of the world—which boosts demand and is positive for U.S. exports—and boosts the competitiveness of Asian firms relative to U.S. companies, which is negative for U.S. exports. However, the small impact on gas prices and the relative unimportance of natural gas to total energy supply in Asia means that the impact on consumption in Asia is limited as is the competitiveness boost enjoyed by Asian firm from lower gas prices. As result, the overall impact on U.S. GDP through this channel is limited.

The overall macroeconomic impacts of increasing U.S. LNG exports to 20 Bcf/d from 12 Bcf/d are small, reflecting the small size of the shocks relative to the economy overall. In aggregate the size of the economy is little changed in the long run, with GDP less than 0.1 percent ($7.7 billion USD annually in today's prices) higher on average over 2026–2040 than in the 12 Bcf/d export case (see Figure 26).

The United States' current account position is also little impacted by the increase in LNG exports. This is because changes in net exports of LNG are small relative to the size of the economy, and Henry Hub prices are also only modestly higher when the U.S. exports more LNG.

The increase in natural gas prices following an increase in U.S. LNG exports is reflected in a slight increase in the average level of consumer prices, which are 0.25 percent higher on average in the higher export case over the period 2026–2040. However, as this impact is spread over a number of years, so the impact on average inflation is negligible. This modest rise in price level squeezes back some consumer spending and erodes U.S. competitiveness.

Figure 26. Macroeconomic Impact of Increasing LNG Exports to 20 Bcf/d from 12 Bcf/d



At the sector level, firms that supply the natural gas sector and are involved in developing the infrastructure and supply chains needed to increase production and LNG exports benefit. This includes firms in the construction and engineering sectors.

Higher natural gas prices in the United States associated with greater U.S. LNG exports are negative for the energy-intensive manufacturing sectors (see Figure 27), and some sectors—such as glass, cement, and chemicals[16]—see small declines in output (see Figure 28). These are outweighed by gains in manufacturing industries that benefit from increased investment in the natural gas sector and increased construction activity, such as metals, as well as industry gains attributable to the increase in overall demand (i.e., consumer products, food, etc.). As a result, the manufacturing sector in aggregate is little impacted.

Some sectors such as cement and metals are both energy intensive and construction dependent and their relative exposure to these two factors determines whether or not they benefit from an increase in U.S. LNG exports. However across sectors the overall impacts of greater LNG exports are small compared with the expected growth in sector output through 2040.

[16] It should be noted that the analysis does not account for the potential impacts of higher natural gas production on the production of natural gas liquids (NGL) and the potential impacts of changes in NGL production on the domestic petrochemicals industry. The increase in shale gas production in recent years has been associated with a similar rise in NGL production and a decline in prices, which has benefitted the U.S. petrochemical sector (see, for instance, *U.S. NGLs Production and Steam Cracker Substitution*, Oxford Institute for Energy Studies, September 2014). As such it is possible that the increase in gas production associated with rising exports could provide further benefit to the sector and output overall.

Figure 27. EIS vs. Non-EIS Value-Added, 20 Bcf/d vs. 12 Bcf/d of LNG Exports[17]

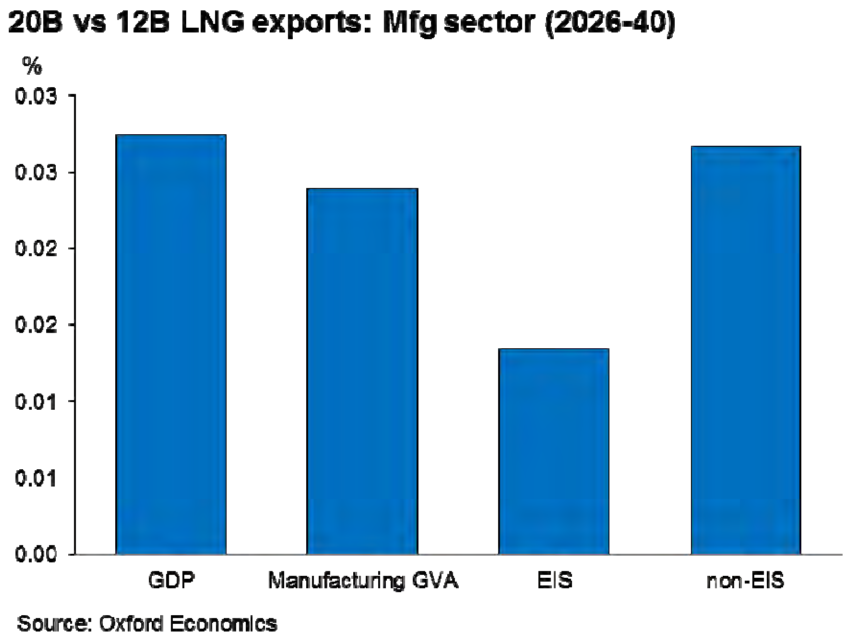
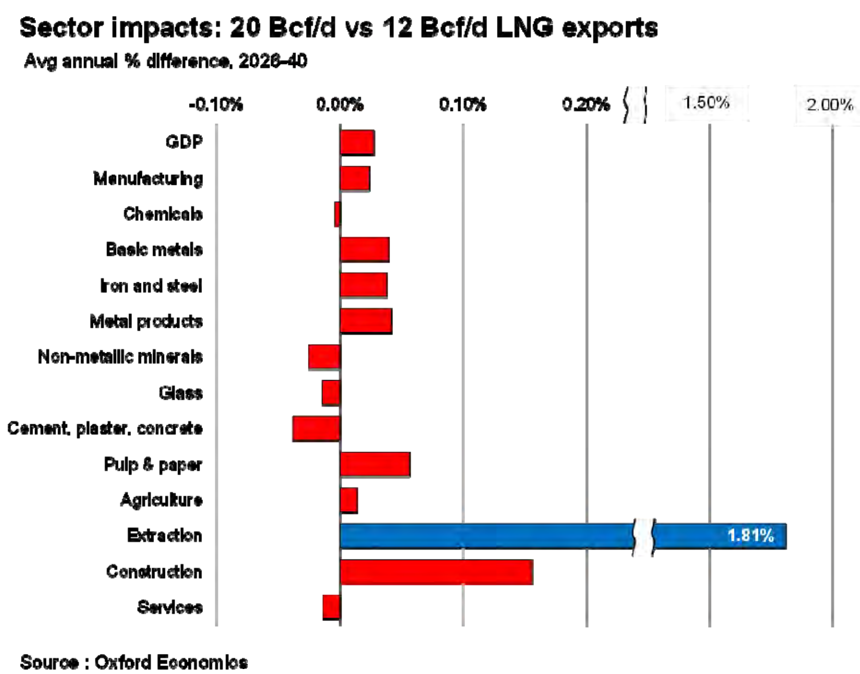
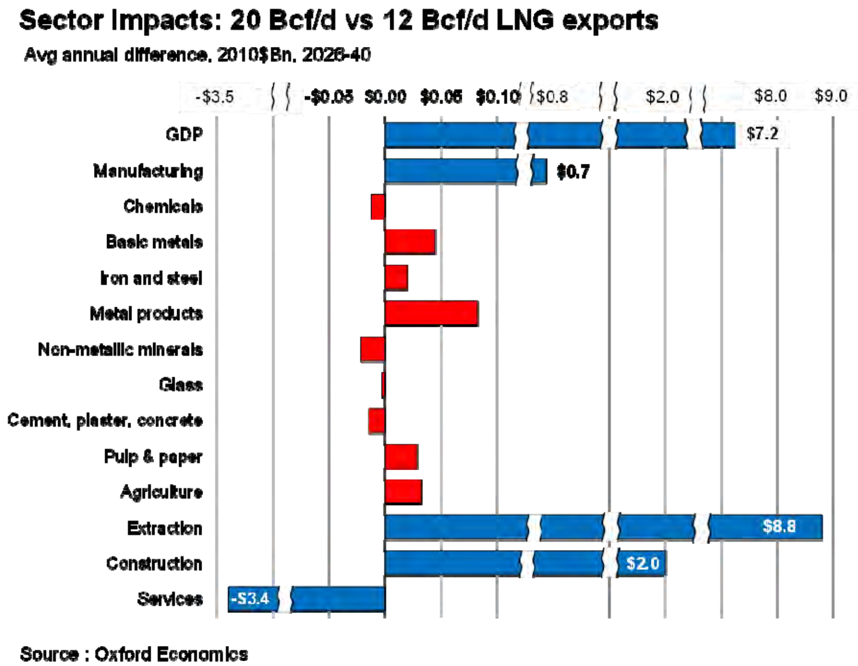


Figure 28. Sector-Level Impacts, 20 Bcf/d vs. 12 Bcf/d LNG Exports



[17] EIS includes chemicals, basic metals and metal products, and non-metallic minerals (which includes cement and glass). These sectors are among the most intensive consumers of natural gas per dollar of output.



4.1.3 Macroeconomic Impacts in the Alternative Domestic Scenarios

The section examines the impact of increasing U.S. LNG exports to 20 Bcf/d from 12 Bcf/d (assuming unchanged international demand) in the HRR case and compares the results to increasing U.S. LNG exports in the Reference domestic case. U.S. exports of LNG do not reach 20 Bcf/d in the LRR scenario and are right at that mark in the Hi-D scenario. Thus, these two alternatives are not assessed here, but are in section 4.2, which examines cases of endogenously determined U.S. LNG exports.

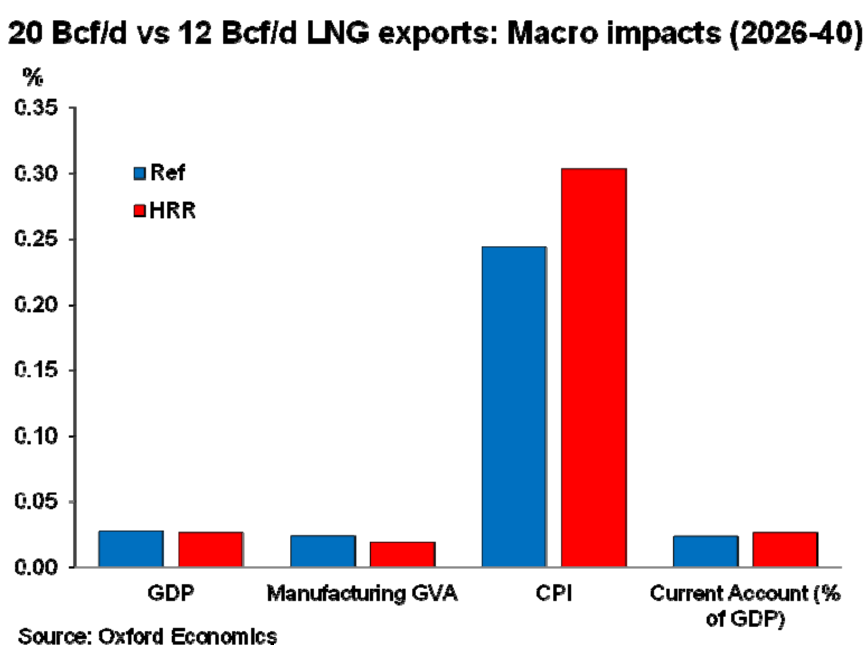
Table 5. Change in Key Scenario Drivers and Scenario Results (2026–2040), 20 Bcf/d vs. 12 Bcf/d LNG Exports Across Domestic Scenarios

	Reference	High Resource
Scenario Drivers		
United States		
NG Production	4.0%	5.1%
NG Consumption	0.1%	0.3%
NG Exports	26%	28%
NG Imports	4.2%	2.4%
Net Fuel Exp. (% of GDP)	0.02%	0.03%
Henry Hub Price	4.3%	4.7%
Capex (% of GDP)	0.06%	0.06%
Profits (% of GDP)	0.03%	0.03%
Rest of World		
Prices:		
NBP (UK)	0.0%	-0.1%
German Border (NW Europe)	0.1%	0.0%
JKM (Asia-Pacific)	-6.8%	-8.4%
Capex (% of GDP)	0.00%	0.00%
Scenario Results		
GDP Change by Channel		
Total	0.03%	0.03%
U.S. NG Output and Capex	0.09%	0.11%
U.S. NG Price	-0.08%	-0.09%
NG Profits	0.01%	0.02%
Rest of World Output and Capex	0.00%	-0.01%
Rest of World NG Prices	0.00%	0.00%
Manufacturing GVA	0.02%	0.02%

Table 5 compares the changes in the key scenario drivers and outputs when LNG exports increase from 12 Bcf/d to 20 Bcf/d in the domestic Reference (LNG20_Ref12 to LNG20_Ref20) and high domestic resource (LNG20_HRR12 to LNG20_HRR20) scenarios. In the HRR scenarios, there is a greater increase in domestic production when LNG exports increase, a result that follows from the assumptions about U.S. resource endowment. In the higher resource case, LNG production is, on average, 5.1 percent higher from 2026 to 2040 when LNG exports increase to 20 Bcf/d compared with 4.0 percent increase in the Reference domestic case. The increase in investment is roughly equal between the two cases, and the impact on domestic natural gas prices is slightly greater when U.S. LNG exports increase in the HRR cases compared to the domestic Reference case.

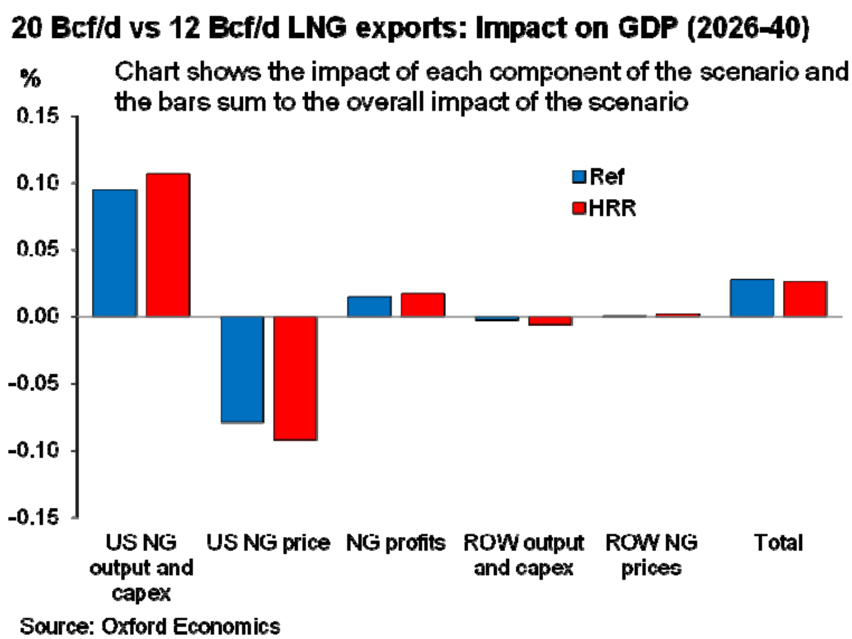
In aggregate, the macroeconomic impacts of increasing export volumes from 12 Bcf/d to 20 Bcf/d in the domestic High Resource scenario are broadly similar to those in the domestic Reference scenario (see Figure 29); GDP is little changed. The higher increase in gas prices has a slightly more pronounced impact on the manufacturing sector. A larger increase in the gas price compared with the reference scenario also results in a bigger impact on the consumer price level and, combined with a slightly larger increase in net gas exports, a slightly larger positive impact on the current account.

Figure 29. Macroeconomic Impacts of Increasing LNG Exports to 20 Bcf/d from 12 Bcf/d in the Domestic Reference and High Resource Scenarios, 2026–2040



Breaking down the results across the different impact channels (see Figure 30), the increase in production and export volumes are slightly higher in the High Resource case, leading to a marginally larger direct impact of rising output in the natural gas sector. However, the increase in prices as LNG exports rise is also slightly larger in the High Resource case, leading to a slightly larger negative macroeconomic impact from this channel. The increase in profits as a share of GDP in each case is the same.

Figure 30. GDP and Manufacturing Sector Impacts, 20 Bcf/d vs. 12 Bcf/d LNG Exports in the Domestic Reference and High Resource Scenarios



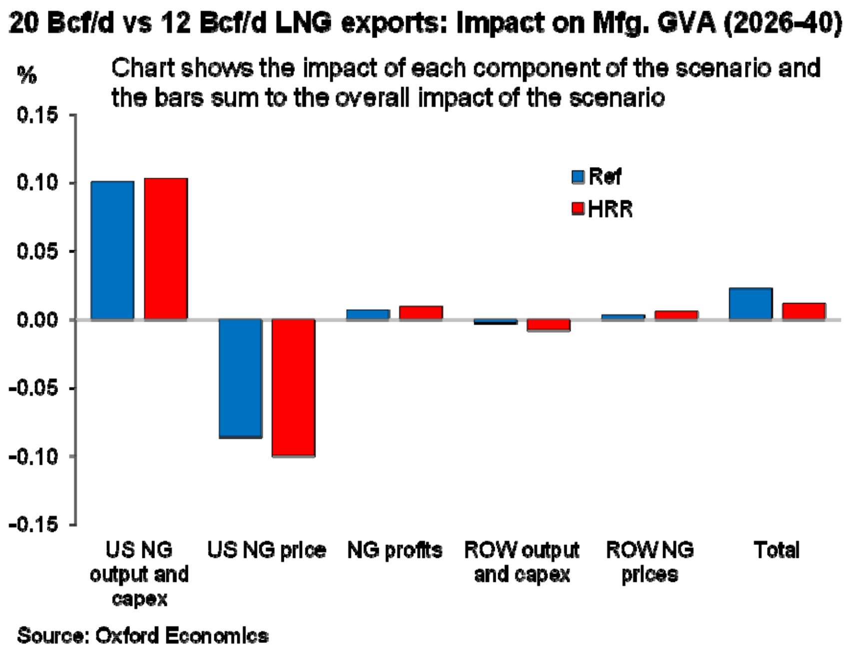


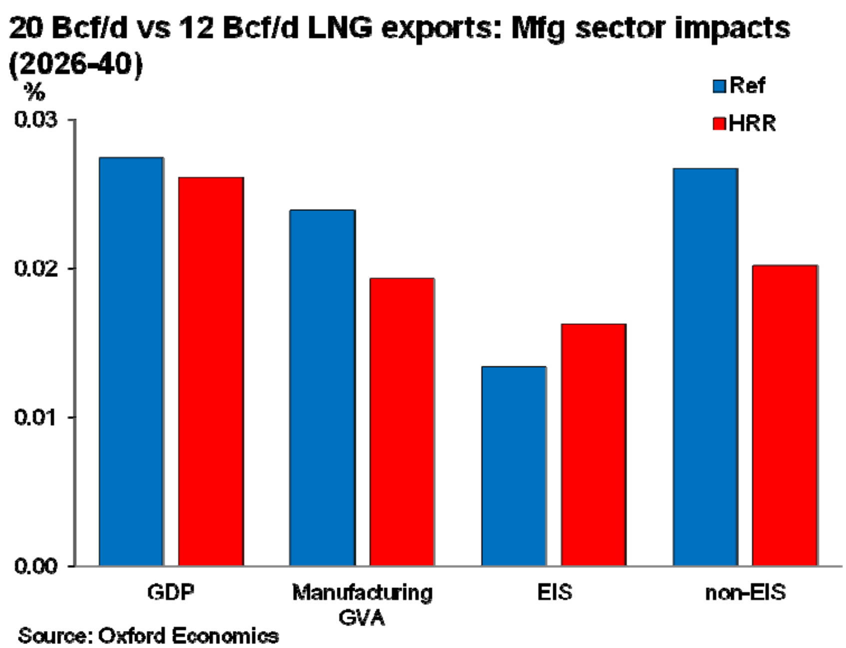
Table 6. Change in Sector Value-Added (2026–2040), 20 Bcf/d vs. 12 Bcf/d LNG Exports

	Reference	High Resource
GDP	0.03%	0.03%
Manufacturing	0.02%	0.02%
Chemicals	0.00%	0.00%
Basic metals	0.04%	0.05%
Iron and Steel	0.04%	0.04%
Metal Products	0.04%	0.05%
Non-Metallic Minerals	-0.03%	-0.04%
Glass	-0.01%	-0.02%
Cement, Plaster, Concrete	-0.04%	-0.05%
Pulp and Paper	0.06%	0.06%
Agriculture	0.01%	0.02%
Extraction	1.81%	2.39%
Construction	0.16%	0.15%
Services	-0.01%	-0.02%

As with the domestic Reference case, impacts from changes in investment and natural gas prices outside of the United States are muted. In aggregate, the increase in LNG exports has little impact on total output in the long run. Impacts on the manufacturing sector in aggregate are similarly limited. Also, the distribution of results at the sector level (see Table 6) across the HRR scenarios is also similar to those across the domestic Reference scenarios.

Manufacturing output overall is marginally higher in the 20 Bcf/d export case, but lags output overall due to the impacts of higher natural gas prices on energy-intensive production. As in the Reference domestic case, some energy-intensive sectors see small declines in output compared with the 12 Bcf/d export case (see Figure 31), and these negative impacts are slightly larger in the High Resource case due to the larger increase in domestic natural gas prices. Nevertheless these are again negligible compared with the projected output growth of these sectors, and have little noticeable effect on the manufacturing sector as a whole.

Figure 31. EIS vs. Non-EIS Value-Added, 20 Bcf/d vs. 12 Bcf/d LNG Exports in the High Domestic Resource Scenario (2026–2040)



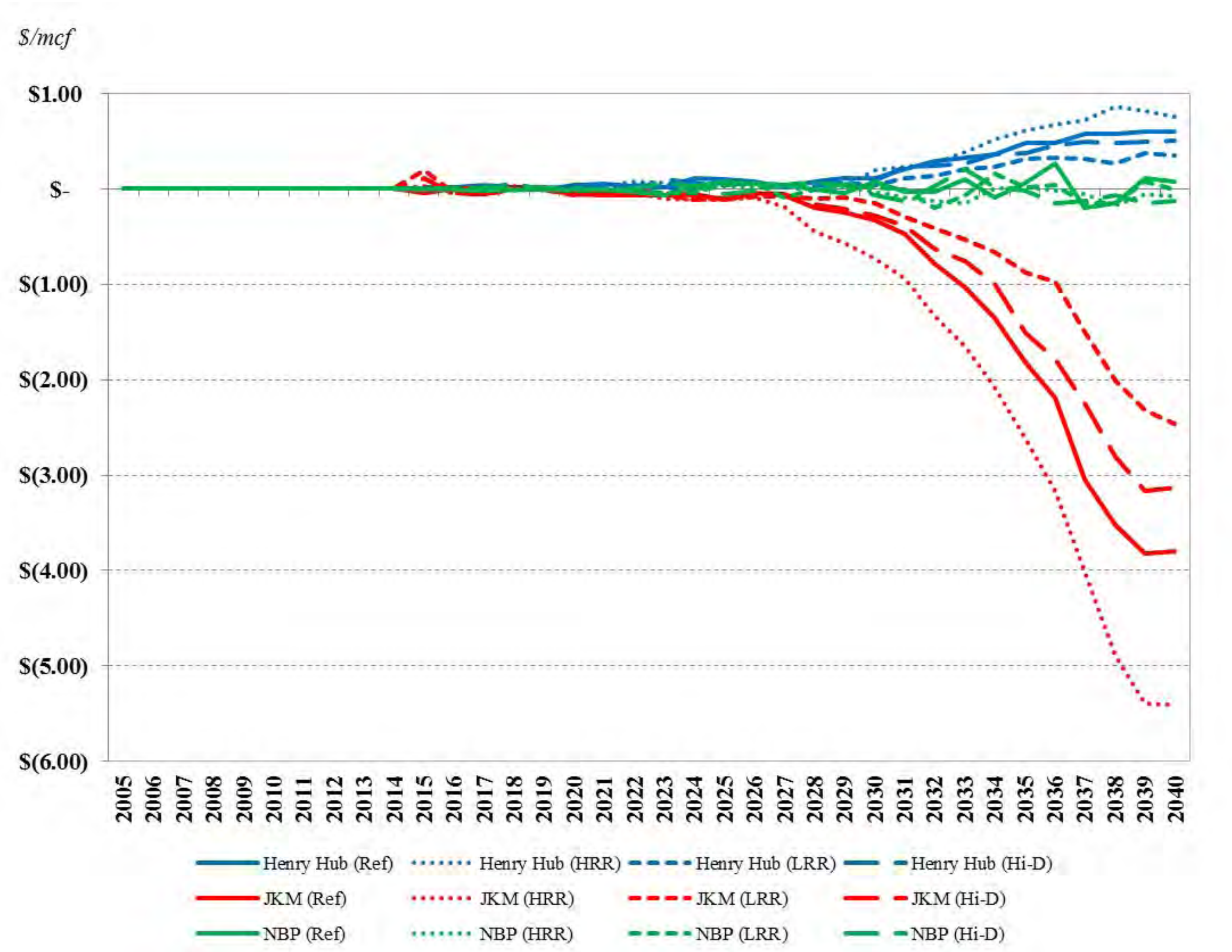
4.2 U.S. LNG Exports Increase from 12 Bcf/d to an Endogenously Determined Level

4.2.1 Natural Gas Market Impacts

In this section, we highlight the scenarios where U.S. LNG exports respond endogenously to demand pull created by international market conditions that are supportive of 20 Bcf/d of U.S. LNG exports under the four different domestic scenarios. We compare these each scenario to the cases where U.S. LNG exports do not exceed 12 Bcf/d (LNG20_Ref12, LNG20_HRR12, LNG20_LRR12, and LNG20_Hi-D12).

As indicated in Figure 32, the Henry Hub price rises as LNG exports increase while other international benchmark prices decline. As in section 4.1, this is the result of allowing increased trade from the United States thereby serving to relax the highly constrained supply situation internationally.

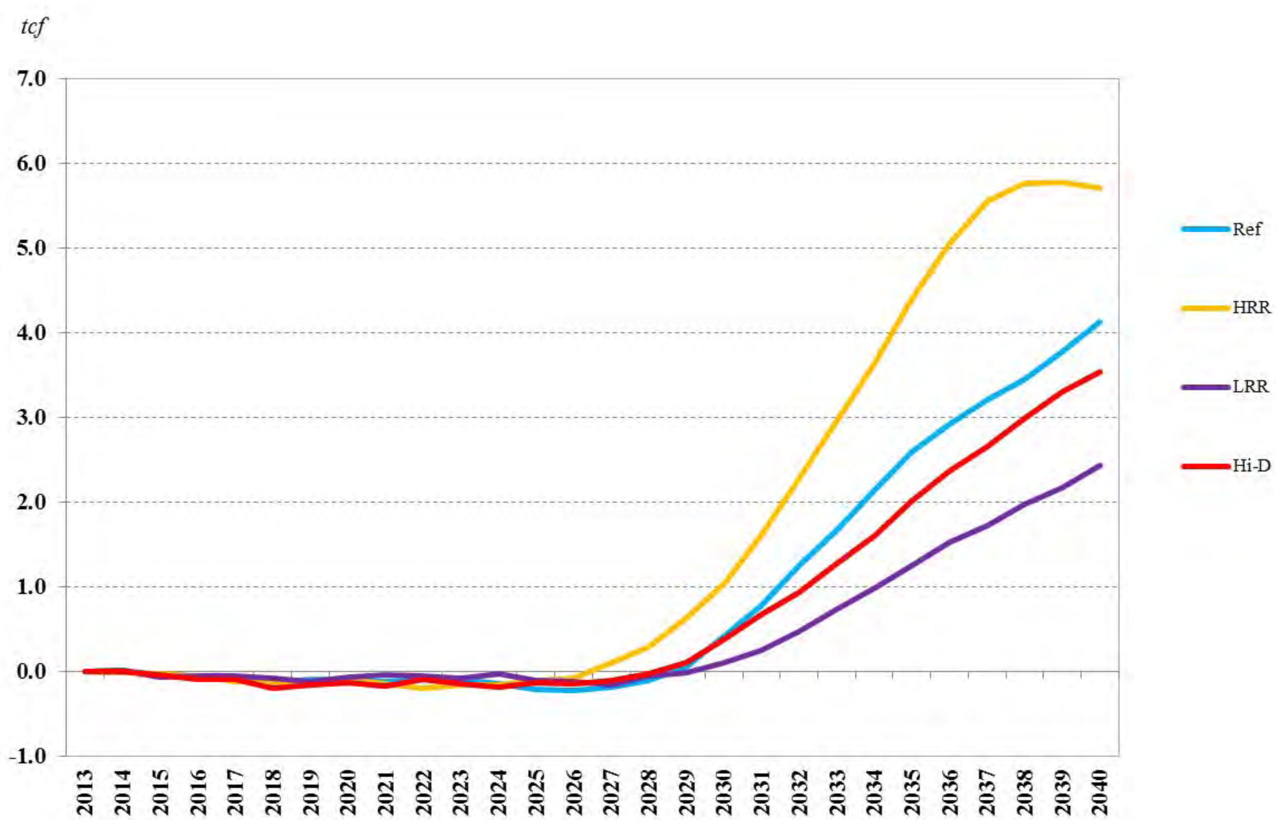
Figure 32. Change in Global Gas Prices
(endogenous exports vs. LNG20 cases where U.S. LNG exports cannot exceed 12 Bcf/d)



As noted in section 4.1, the price response in Asia tends to be greatest as U.S. LNG exports increase. The largest increase in exports occurs in the HRR cases, and it is in these cases where we see the largest increase in Henry Hub (topping out at $0.86 in the late 2030s) and the largest decrease in JKM (approaching $5.50 by 2040). As before, there is virtually no change across the scenarios in the NBP price.

In all cases, as LNG exports increase beyond 12 Bcf/d, U.S. production continues to increase through the time horizon. As indicated in Figure 33, the largest increase in domestic production occurs in the HRR cases, followed by the Ref cases and the Hi-D cases, with the LRR cases seeing the smallest increases in production. Not surprisingly, this is consistent with the change in LNG exports seen across cases and highlighted in section 3.

Figure 33. Changes in Domestic Production
(endogenous exports vs. LNG20 cases where U.S. LNG exports cannot exceed 12 Bcf/d)

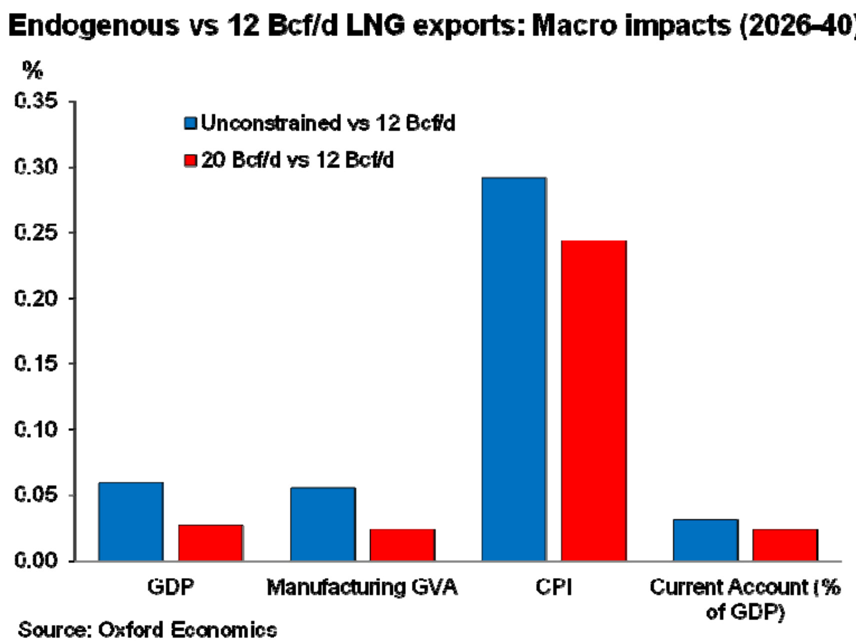


4.2.2 Macroeconomic Impacts

As in the case where LNG exports rise to 20 Bcf/d, the results of increasing exports from 12 Bcf/d to their market-determined level are marginally positive in the Reference domestic scenario. When exports fully respond to international demand conditions we see a larger increase in investment in the natural gas sector than when exports do not exceed 20 Bcf/d. As a result, the endogenous LNG export case produces slightly more positive results than the 20 Bcf/d LNG export case, though the impacts are still very small (see Figure 34).

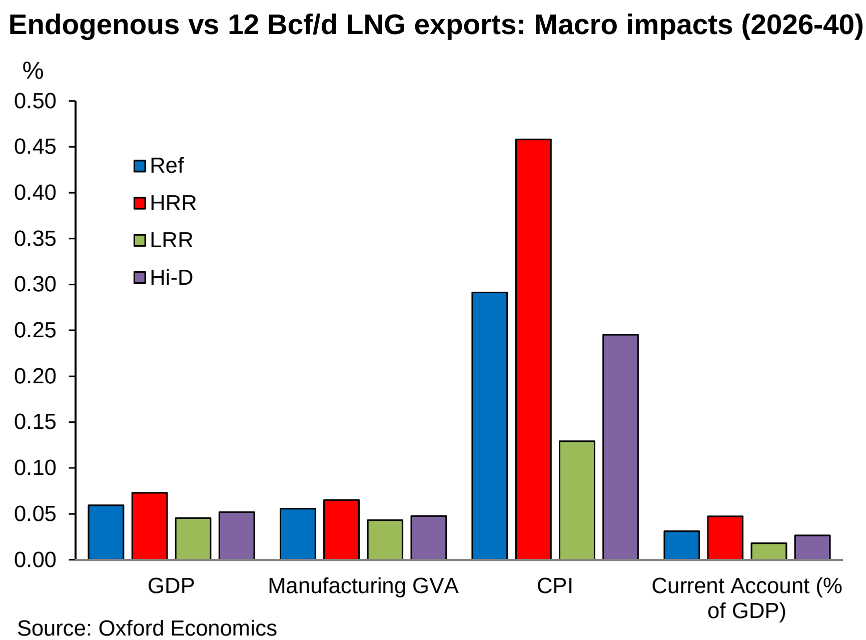
At the same time there is also a greater convergence of domestic natural gas prices with world prices when U.S. LNG exports are allowed to respond fully to global demand conditions as the Henry Hub price increase is greater than in the case where LNG exports could not exceed 20 Bcf/d. Although this helps drive the sector's profits marginally higher, the larger increase in gas prices generates a larger impact on consumer prices in the long run, which offsets some of the positive demand impacts of increased natural gas sector investment by lowering consumption. It should be noted, however, that the price level impacts are small and have little noticeable impact on inflation rates over the forecast horizon. Impacts to the current account are again limited, reflecting both the small direct impact from the increase in net fuel exports and the minor impact of changes in relative natural gas prices on the U.S. export sector overall.

Figure 34. Macroeconomic Impacts of Increasing LNG Exports from 12 Bcf/d, 2026–2040



Results across the alternative domestic scenarios are broadly similar (see Figure 35). In all four cases, impacts on GDP are between 0.05 and 0.07 percent on average over the 2026–2040 period, with the biggest impact in the HRR case where production responds most.

Figure 35. Macroeconomic Impacts of Increasing LNG exports, 2026–2040



General price level impacts vary with the change in natural gas prices, but even in the High Resource case, where the impact on Henry Hub prices is the largest, consumer prices are on average just 0.5 percent above the 12 Bcf/d export case over the period 2026–2040. The current account is also little impacted across the domestic cases given the small net export and gas price impacts. The pattern observed in the channel level impacts is consistent across the scenarios, and consistent with that described in in section 4.1.2. Larger increases in natural gas production and exports, which drive larger direct impacts on GDP, are associated with greater increases in domestic natural gas prices, and these contribute to larger negative impacts on consumption and non-fuel exports (see Table 7). Across all scenarios the impacts on profits are negligible, as are the feedback impacts of changes in the natural gas sector outside the United States. Though there are substantial impacts on Asian natural gas prices, the feedback impacts on the U.S. economy are minimal due to the relatively small share of energy consumption accounted for by gas in Asia.

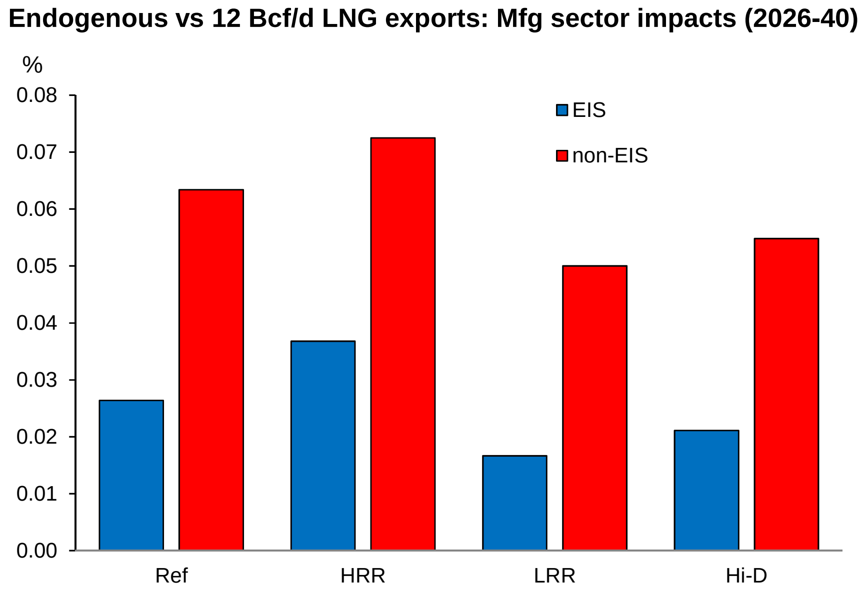
As in the 20 Bcf/d export cases, the energy-intensive sectors generally underperform other downstream sectors (see Figure 36) due to the impacts of higher energy prices.[18]

Table 7. Change in Key Scenario Drivers and Scenario Results (2026–2040), Endogenous LNG Exports vs. 12 Bcf/d LNG Exports

	Reference	High Resource	Low Resource	High Demand
Scenario Drivers				
United States				
NG Production	5.2%	8.5%	2.8%	4.1%
NG Consumption	0.1%	0.5%	0.0%	0.2%
NG Exports	33%	47%	17%	26%
NG Imports	4.3%	4.6%	1.2%	2.6%
Net Fuel Exp. (% of GDP)	0.03%	0.04%	0.01%	0.02%
Henry Hub Price	5.2%	7.5%	2.6%	4.3%
Capex (% of GDP)	0.10%	0.14%	0.07%	0.09%
Profits (% of GDP)	0.04%	0.05%	0.02%	0.03%
Rest of World				
Prices:				
NBP (UK)	0.1%	-0.4%	-0.2%	-0.3%
German Border (NW Europe)	0.1%	-0.1%	-0.1%	0.0%
JKM (Asia-Pacific)	-8.4%	-12.4%	-4.6%	-6.7%
Capex (% of GDP)	0.00%	0.00%	0.00%	0.00%
Scenario Results				
GDP Change by Channel				
Total	0.06%	0.07%	0.05%	0.05%
U.S. NG Output and Capex	0.14%	0.20%	0.09%	0.12%
U.S. NG Price	-0.10%	-0.15%	-0.05%	-0.08%
NG Profits	0.02%	0.03%	0.01%	0.02%
Rest of World Output and Capex	0.00%	-0.01%	0.00%	0.00%
Rest of World NG Prices	0.00%	0.00%	0.00%	0.00%
Manufacturing GVA	0.06%	0.03%	0.04%	0.05%

[18] The lone exception is the High Resource scenario, though the difference is statistically insignificant.

Figure 36. EIS vs. Non-EIS Value-Added, Endogenous vs. 12 Bcf/d LNG Exports (2026–2040)



Source: Oxford Economics

5 Concluding Remarks

The results detailed in this report suggest that the overall macroeconomic impacts of LNG exports are marginally positive. When U.S. LNG exports increase from 12 Bcf/d against the backdrop of an international environment that is consistent with the United States being able to export 20 Bcf/d of LNG, then the overall gain to the U.S. economy is between 0.03 and 0.07 percent of GDP over the period of 2026–2040, or between $7 and $21 billion USD annually in today's prices.

We identified five main channels that determine of the overall economic impact of increasing LNG exports from the United States. These transmission channels are associated production and investment in the natural gas sectors in the United States and the rest of the world, Henry Hub and international natural gas prices, and the profitability of U.S. natural gas producers. The main channel for positive impacts when U.S. LNG exports increase to a higher level, is through higher production and greater investment in the natural gas sector in the United States. This is due to the fact that most of any U.S. LNG exports would be made possible by increased extraction rather than the diversion of natural gas supplies. U.S. production is between 2.8 and 8.5 percent higher on average over the period 2026–2040 when U.S. LNG exports are increased. The resulting economic benefit typically exceeds any drag on the economy from the main negative impact channel of higher domestic natural gas prices, as this extra natural gas production utilizes high cost resources.

However, the impacts on the U.S. economy through these channels are small. Over the period 2026–2040, the capital investment needed to increase U.S. natural gas production and exports averages between 0.06 and 0.14 percent of GDP, while Henry Hub natural gas prices are between 2.6 and 7.5 percent higher compared to when U.S. LNG exports are 12 Bcf/d. The bulk of the macroeconomic impacts are seen in the period 2026–2040, as this is when developments across scenarios in the natural gas market are the most varied.

Similar to previous studies, our results also suggest an increase in LNG exports from the United States will generate small declines in output at the margin for the energy-intensive, trade-exposed industries. The sectors that appear most exposed are cement, concrete, and glass, but the estimated impact on sector output is very small compared to expected sector growth to 2040. Other sectors benefit from increasing U.S. LNG exports, especially the industries that supply the natural gas sector or benefit from the capex needed to increase production. This includes some energy-intensive sectors such as cement and helps offset some of the impact of higher energy prices.

The results are robust to alternative assumptions for the U.S. natural gas market. The gain for the U.S. economy is greatest when higher levels of resource recovery are assumed in the United States, reflecting a larger increase in production, but the overall impact remains positive in cases with lower resource recovery and higher demand for natural gas in the United States.

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Annex A Background and Statement of Work

The Department of Energy's (DOE) Office of Fossil Energy (FE) has received 45 applications requesting long-term authorization to export domestically produced, lower-48 natural gas as liquefied natural gas (LNG) to non-free trade agreement (FTA) countries in a volume totaling the equivalent of 45.1 billion standard cubic feet per day (Bcf/d) of natural gas.[19] Of these, DOE/FE has granted final authorization for ten applications totaling 9.99 Bcf/d. Currently, the Federal Energy Regulatory Commission is reviewing proposed, lower-48, large-scale LNG export facilities totaling 24.325 Bcf/d under the requirements of the National Environmental Policy Act (NEPA), and has granted authorization to construct six other terminals totaling 10.62 Bcf/d.[20] The Natural Gas Act (NGA), 15 U.S.C. § 717b requires DOE to conduct a public interest review of applications to export LNG and to grant the applications unless DOE finds that the proposed exports will not be consistent with the public interest.[21] Under this provision, DOE performs a thorough public interest analysis before acting.[22]

In 2012, when DOE/FE had received only three applications totaling less than 6 Bcf/d to export LNG to non-FTA countries, DOE/FE commissioned two natural gas export studies—one by EIA and one by NERA Economic Consulting. The studies evaluated macroeconomic and other impacts of LNG exports

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[19] As of July 1, 2015.
http://energy.gov/sites/prod/files/2015/07/f24/Summary%20of%20LNG%20Export%20Applications_0.pdf.

[20] As of June 18, 2015. http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-proposed.pdf and http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf.

[21] The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04E issued on April 29, 2011.

[22] Under NGA section 3(c), the import and export of natural gas, including LNG, from and to a nation with which there is in effect an FTA requiring national treatment for trade in natural gas and the import of LNG from other international sources are deemed to be consistent with the public interest and must be granted without modification or delay. Exports of LNG to non-FTA countries have not been deemed in the public interest and require a DOE/FE review.

from 6 to 12 Bcf/d, the results of which have been used by DOE/FE in evaluating export authorizations.[23]

On May 29, 2014, DOE/FE announced its intention to undertake an updated economic study in order to gain a better understanding of how potential U.S. LNG exports between 12 and 20 Bcf/d could affect the public interest. Specifically, DOE/FE commissioned EIA to update its 2012 LNG Export Study using the *Annual Energy Outlook 2014*.[24]

Further, DOE/FE determined that it would follow the EIA LNG Export Study with an additional study that would evaluate macroeconomic impacts of the exports evaluated in the EIA study and directed the National Energy Technology Laboratory (NETL) to facilitate the performance of this additional analysis. The task was to evaluate the macroeconomic impacts of U.S. LNG exports up to 20 Bcf/d determined by international demand based on a variety of domestic and international scenarios. Further, the task was to assess the potential international demand for U.S. LNG and/or the potential level of U.S. exports that could be supported by the global market, and then to evaluate the macroeconomic impacts of U.S. LNG exports on the U.S. economy, using multiple economic indicators, with an emphasis on the energy sector, and natural gas and energy-intensive industries in particular.

DOE specified that the analysis must rely on authoritative economic models of the U.S. and global economies, U.S. industry (particularly the energy-intensive sector), and the international natural gas market. Also, the analysis had to consider a range of scenarios representing varied assumptions

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[23] The EIA and NERA studies can be found at http://www.energy.gov/fe/services/natural-gas-regulation/lng-export-study.
[24] The DOE request can be found here http://energy.gov/fe/downloads/request-update-eia-s-january-2012-study-liquefied-natural-gas-export-scenarios.

regarding export levels, economic growth, global market conditions, and domestic natural gas fundamentals.

NETL directed Leonardo Technologies Inc. (LTI), the prime contractor for its Program and Performance Management Services (PPM) support contract (DE-FE0004002), to carry out the task. LTI determined that it did not have the “authoritative models” called for, nor did it have the economic modeling expertise required to perform this work quickly. Accordingly, it was necessary for LTI to contract with an appropriate subcontractor or subcontractors in order to carry out the work to DOE specifications.

LTI began by compiling a list of known economic consultants with reputations for robust, authoritative modeling of domestic and international energy issues. LTI then cross-walked these firms against a list of companies that had contributed economic analyses as part of the application process followed by companies seeking to export LNG. Many of these companies had either past or present consulting relationships with companies seeking approval from DOE to export LNG and thus were considered to have potential conflicts of interest. For commercial reasons, some companies indicated that they would not be interested in performing this type of public analysis.

LTI determined that the best course of action would be to divide the work into two key subtasks:

- Subtask 1: Determination of international demand for U.S. LNG under different scenarios.
- Subtask 2: Determination of U.S. macroeconomic impacts of various LNG export scenarios consistent with international demand.

Given the need for meeting the criteria listed above, it was determined that separate contractors should be selected for the tasks. After a due diligence evaluation of the capabilities of the available alternatives, LTI selected Dr. Kenneth Medlock with the Center for Energy Studies at Rice University's Baker Institute as the subcontractor for Subtask 1, and Oxford Economics as the subcontractor for Subtask 2.

The final Statement of Work provided to LTI by NETL is found in Annex A.1.

A1. Statement of Work

Study to Assess Macroeconomic Impacts of U.S. Liquefied Natural Gas (LNG) Exports

INTRODUCTION:

The Department of Energy's (DOE) Office of Fossil Energy (FE) has received 36 applications requesting long-term authorization to export domestically produced, lower-48 natural gas as liquefied natural gas (LNG) to non-free trade agreement (non-FTA) countries in a volume totaling the equivalent of 38.06 billion standard cubic feet per day (Bcf/d) of natural gas.[25] Of these, DOE/FE has granted final authorization to three applicants totaling 3.94 Bcf/d. Currently, the Federal Energy Regulatory Commission is reviewing proposed, lower-48, large-scale LNG export facilities totaling 17.47 Bcf/d under the requirements of the National Environmental Policy Act (NEPA), and has granted authorization to construct four other terminals totaling 7.08 Bcf/d.[26] The Natural Gas Act (NGA), 15 U.S.C. § 717b requires DOE to conduct a public interest review of applications to export LNG and to grant the applications unless DOE finds that the proposed exports will not be consistent with the public interest.[27] Under this provision, DOE performs a thorough public interest analysis before acting.[28]

In 2012, when DOE/FE had received only 3 applications totaling less than 6 Bcf/d to export LNG to non-FTA countries, DOE/FE commissioned two natural gas export studies – one by EIA and one by NERA Economic Consulting. The studies evaluated macroeconomic and other impacts of LNG exports from 6 to 12 Bcf/d, the results of which have been used by DOE/FE in evaluating recent export authorizations.

On May 29, 2014, DOE/FE announced its intention to undertake an updated economic study in order to gain a better understanding of how potential U.S. LNG exports between 12 and 20 Bcf/d could affect the public interest. Specifically, DOE/FE commissioned EIA to update its 2012 LNG Export Study using the *Annual Energy Outlook (AEO) 2014*.[29]

DOE/FE and the National Energy Technology Lab (NETL) will follow the EIA LNG Export Study with a study that will evaluate macroeconomic impacts of the exports evaluated in the EIA study. If at any future time the cumulative export authorizations approach the high end of export cases examined,

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[25] As of November 7, 2014.

[26] As of October 14, 2014. http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-proposed.pdf and http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf

[27] The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04E issued on April 29, 2011.

[28] Under NGA section 3(c), the import and export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement (FTA) requiring national treatment for trade in natural gas and the import of LNG from other international sources are deemed to be consistent with the public interest and must be granted without modification or delay. Exports of LNG to non-FTA countries have not been deemed in the public interest and require a DOE/FE review.

[29] DOE/FE's request to EIA, including the study scope can be found at http://www.energy.gov/fe/downloads/request-update-eia-s-january-2012-study-liquefied-natural-gas-export-scenarios

the DOE will conduct additional studies as needed to understand the impact of higher export ranges. At all levels, the cumulative impacts will remain a key criterion in assessing the public interest.

PURPOSE:

The purpose of this task is to evaluate the macroeconomic impacts of U.S. LNG Exports at levels up to 20 billion standard cubic feet per day (Bcf/d) determined by international demand across several scenarios based on domestic and international cases. The analysis will have two elements: first, to assess the potential international demand for U.S. LNG, and second, to evaluate the macroeconomic impacts of U.S. LNG exports on the U.S. economy, using multiple economic indicators, with an emphasis on the energy sector, and natural gas and energy-intensive industries in particular.

To conduct these evaluations, the prime contractor will identify and employ subcontractors with authoritative econometric models of the U.S. and global economies, U.S. industry, particularly the energy-intensive sector, and the international natural gas market. The analysis will consider a range of scenarios representing varied assumptions regarding export levels, economic growth, global market conditions, and domestic natural gas supply and demand.

ANALYSIS TO BE PERFORMED:

To inform the public-interest determinations of LNG export applications, the two tasks will be performed as outlined below.

Task 1: Scenario Analysis of International Demand for U.S. LNG Exports and Market Conditions of the Global Natural Gas Market. This analysis will provide three reasonable scenarios of international demand for U.S. LNG exports over the 2015-2040 timeframe. These demand scenarios will include a range of plausible conditions for the global natural gas market. The contractor will develop a most likely reference case for the global natural gas market and four sensitivity cases that reflect higher levels of international demand for LNG, modeled across a range of domestic resource and demand cases (See Table 1). These cases will be developed with and approved by DOE prior to model runs. The output of this task will be an input to Task 2 described below. At a minimum, the output of this task will address the following characteristics of the global natural gas market over the analysis timeframe in each of the three cases:

a. Demand for U.S. LNG exports segmented by U.S. geographical area of export;
b. Global natural gas production by region;
c. Global natural gas consumption by region;
d. Pricing mechanisms in each region for natural gas;
e. Global wellhead prices by region;
f. Global City Gate prices by region;
g. Global liquefaction costs by region;
h. Global regasification costs by region;

i. Global transportation costs by region;
j. Global supply elasticities by region; and
k. Global demand elasticities by region.

Task 2: U.S. Macroeconomic Impact and Price Response Based on International Demand for U.S. LNG Exports. This analysis will assess the macroeconomic impact of U.S. LNG exports at levels determined by international demand as identified in Task 1 across several scenarios based on domestic and international cases. The price impacts of LNG exports should be incorporated, including a discussion of how domestic natural gas prices are determined and the potential for correlation between domestic and international natural gas prices. This report should include a discussion on fuel demand scenarios, such as demand for natural gas in the power sector, and fuel investment scenarios, such as investment capacity to build the facilities and investment in production scenarios. This analysis should incorporate any spillover effects from the impact of LNG exports on global macroeconomic performance, including discussion of direct, indirect, induced, and catalytic impacts.

a. Timeframe: The timeframe for analysis is from 2015-2040.
b. Domestic Scenarios. The following domestic scenarios will be considered:
    i. A domestic reference case;
    ii. Low oil and gas recoverability case;
    iii. High oil and gas recoverability case; and
    iv. High natural gas demand case.
c. International Scenarios. The international scenarios and assumptions identified in Task 1 will be considered:
    i. The international reference case;
    ii. Sensitivity case 1 with global energy market conditions such that demand for U.S. export volumes is at 12 Bcf/d for the domestic reference case; and
    iii. Sensitivity case 2a with global energy market conditions such that demand for U.S. exports is at 20 Bcf/d for the domestic reference case but U.S. export volumes do not exceed 12 Bcf/d.
    iv. Sensitivity case 2b with global energy market conditions such that demand for U.S. exports is at 20 Bcf/d for the domestic reference case and U.S. export volumes do not exceed 20 Bcf/d.
    v. Sensitivity case 2c with global energy market conditions such that demand for U.S. export volumes is at 20 Bcf/d for the domestic reference case and U.S. export volumes are unconstrained.
d. Indicators. This analysis will consider, at a minimum, the impact of LNG exports using the below economic indicators:
    i. U.S. natural gas prices;
    ii. U.S. Gross Domestic Product (GDP);
    iii. Levels of U.S. employment;

iv. U.S. aggregate consumption;
v. U.S. aggregate investment;
vi. U.S. natural gas export revenues;
vii. U.S. government receipts;
viii. U.S. current account; and
ix. Energy-intensive industry performance.

Table 1: Scenarios to be analyzed in the Macroeconomic Model Based on International Demand for U.S. LNG Exports up to 20 Bcf/d

International Demand Cases		**Domestic Scenarios**			
		Reference	**High Resource Recovery**	**Low Resource Recovery**	**High Natural Gas Demand**
Reference		Ref_Ref	Ref_HRR	Ref_LRR	Ref_Hi-Demand
Sensitivity Case 1 – Global Demand for U.S. LNG at 12 Bcf/d		12B_Ref	12B_HRR	12B_LRR	12B_Hi-Demand
Sensitivity Case 2 – Global Demand for U.S. LNG at 20 Bcf/d	a.US Exports Limited to 12 Bcf/d	20B_Ref_Cap12	20B_HRR_Cap12	20B_LRR_Cap12	20B_Hi-Demand_Cap12
	b.US Exports Limited to 20 Bcf/d	20B_Ref_Cap20	20B_HRR_Cap20	20B_LRR_Cap20	20B_Hi-Demand_Cap20
	c.Endogenous US Export Level	20B_Ref	20B_HRR	20B_LRR	20B_Hi-Demand

e. Macroeconomic performance comparisons will include, among other comparisons to be provided, an analysis of the impact of increasing export volumes from 12 Bcf/d to 20 Bcf/d when there is sufficient global demand for the higher level of exports via the following comparisons:
   i. 20B_Ref_Cap20 case compared to 20B_Ref_Cap12;
   ii. 20B_HRR_Cap20 case compared to 20B_HRR_Cap12;
   iii. 20B_LRR_Cap20 case compared to 20B_LRR_Cap12; and
   iv. 20B_Hi-Demand_Cap20 case compared to 20B_Hi-Demand_Cap12.

<u>DELIVERABLES</u>:

The following deliverables will be provided to DOE/FE/NETL.

1. Kickoff meeting with prime contractor, subcontractors, DOE-FE, and NETL representatives in attendance to formally agree on study objectives, flow, and timing of milestones and deliverables by both subcontractors and prime contractor. Special attention will be paid to the inputs required from the subcontractor for Task 1 required the subcontractor for Task 2.
2. Work plan with schedule and milestones. Within two weeks after the initiation of the study, the contractor will provide DOE/FE/NETL with a work plan that outlines the study approach to include a schedule of key activities and milestones. There is no prescribed format.
3. Weekly status updates. Each week, the prime contractor will provide an update regarding the study's progress to DOE/FE/NETL staff. These updates will typically be conducted as conference calls. The subcontractors may be required to participate as necessary.
4. Working level conference call meetings to discuss the Task 1 model results, their integration with Task 2 modeling, and a review of a broad range of key econometric parameters. This would include confirmation of alignment of the model with the EIA scenarios, and assumptions/results on other key energy and major macroeconomic variables. The subcontractors will be required to participate.
5. Working level meeting to discuss Task 2 model results, and a review of a broad range of key econometric parameters. This would include confirmation of alignment of the model with the EIA scenarios, and assumptions/results on other key energy and major macroeconomic variables. The subcontractors will be required to participate.
6. Preliminary findings report and presentation. The contractor will prepare a preliminary report, integrating individual Task reports provided by subcontractors, that discusses the draft findings of the three areas of analysis and will provide to DOE/FE for review. The prime contractor will prepare an integrated presentation to accompany the preliminary report for use in briefing DOE/FE/NETL and other government officials regarding the study. The prime contractor, together with appropriate representatives from each of the subcontractors, will discuss the preliminary findings with DOE/FE/NETL staff and determine whether the scenarios and assumptions identified are still valid, some cases should be eliminated, and/or other cases added. Should additional work beyond that outlined in this Statement of Work (SOW) be identified, appropriate alterations to this SOW, together with allocated funding adjustments, will be developed and implemented.
7. Final report. The prime contractor will prepare a final report incorporating final reports from both Task 1 and Task 2 subcontractors that explains in detail the findings of the three areas of

analysis and will provide to DOE/FE/NETL. This final report will be released for public comment and published in the public domain.

8. Response to questions. After releasing the study results, at the request of DOE/FE/NETL, the prime contractor, with input from appropriate subcontractors, will prepare written responses to questions about the study raised through public comment or export application proceedings.

Deliverable	Due Date
Kickoff meeting	Upon completion of subcontracts (Feb 3, 2015)
Work plan with schedule and milestones	2 weeks from kickoff meeting
Status updates	Weekly
Discussion of preliminary Task 1 results	4 to 11 weeks from kickoff meeting
Delivery of revised Task 1 results to Task 2 contractor	13 weeks from kickoff meeting
Discussion of preliminary Task 2 results	15 weeks from kickoff meeting (May 19, 2015)
Preliminary findings report	17 weeks from kickoff meeting (June 1, 2015)
Final report	20 weeks from kickoff meeting (June 19, 2015)
Response to questions	TBD following final report

Annex B Modeling Approach

B1. The Rice World Gas Trade Model

The RWGTM is a dynamic spatial partial equilibrium model in which all spatial and temporal arbitrage opportunities in natural gas markets are captured. As such, each point of infrastructure in the gas delivery value chain—field development, pipelines, LNG regasification, LNG shipping, and LNG liquefaction—is modeled as an independent, intertemporal, profit-maximizing entity. Thus, in addition to a host of fixed parameters such as the upfront fixed cost, interest rate on debt, required return on equity, debt-equity ratio, income tax rate, sales tax rate, and royalty, the optimal investment path for field development is dependent on the wellhead price and for transportation infrastructure on the tariff collected. In this manner, the model is solving a classic intertemporal optimization problem for investment in fixed capital infrastructure.[30]

Put another way, the RWGTM proves and develops resources, constructs and utilizes transportation infrastructure, and calculates prices to equate demands and supplies while maximizing the present value of producer profits within a competitive framework. New capital investments in production and delivery infrastructure thus must earn a minimum return for development to occur. The debt-equity ratio is allowed to differ across different categories of investment, such as proving resources, developing wellhead delivery capability, constructing pipelines, and developing LNG infrastructure. By developing supplies, pipelines, and LNG delivery infrastructure, the RWGTM provides a framework for

[30] The initial conditions are calibrated to recent historical data. The terminal value condition must also be specified in order to find an optimal investment path in natural gas production and delivery infrastructure. As such, the transversality condition is modeled by assuming a competing technology, such as solar, becomes available at a specified delivered price to consumers in unlimited quantities. The RWGTM Reference case assumes the competing price is $14 per mcf equivalent in 2020, declining to $9 per mcf equivalent by 2070. We have run scenarios where the adoption of the backstop is accelerated through cost reductions, but that is not germane to this proposed study.

examining the effects of different economic and political influences on the global natural gas market within a framework grounded in geologic data and economic theory. In fact, the RWGTM has been used to this end in multiple studies and published works.[31]

B1a. Demand in the RWGTM

Regions in the RWGTM are defined at the country and sub-country level into 290 regional demand sinks, with extensive representation of natural gas transportation infrastructure. The extent of detail in each region is primarily based on data availability. In addition, demand sinks are situated along transportation networks in order to simulate actual flows of natural gas. Countries and regions with well-developed energy infrastructure, such as the United States, have extensive sub-regional detail, which allows better understanding of the effects that intra-regional capacity constraints and differences in regional policies may have on current and future market developments. Outside the United States, demand is modeled for the power-generation sector and all direct uses, which includes residential, commercial, and industrial demands. In the United States, demand is modeled at the state and sub-state level specifically for the residential, commercial, industrial, and power generation end-use sectors.

In the United States, sub-state demand representation is significant and is located based on data from the U.S. general and Economic Census—for example county-level populations—as well as the location

[31] For example, see Kenneth B. Medlock III, "Modeling the Implications of Expanded U.S. Shale Gas Production," *Energy Strategies Review* No. 1, (2012); Peter Hartley and Kenneth B. Medlock III, "Potential Futures for Russian Natural Gas," *Energy Journal*, Special Issue, "World Natural Gas Markets and Trade: A Multi Modeling Perspective" (2009); Peter Hartley and Kenneth B. Medlock III, "The Baker Institute World Gas Trade Model," in *Natural Gas and Geopolitics: 1970–2040*, edited by David Victor, Amy Jaffe, and Mark Hayes, Cambridge University Press (2006); Peter Hartley and Kenneth B. Medlock III, "Political and Economic Influences on the Future World Market for Natural Gas," in *Natural Gas and Geopolitics: 1970–2040*, edited by David Victor, Amy Jaffe, and Mark Hayes, Cambridge University Press (2006).

of power plants obtained from U.S. EPA NEEDS database. For example, there are 10 regions in Texas, 5 regions in California, 4 regions in Pennsylvania, and 5 regions in New York. Table B1 outlines the sub-regional detail of U.S. demand by state in the RWGTM.

Table B1. Example of Regional Detail in the RWGTM (U.S. Lower 48)

State	# of Regions	State	# of Regions	State	# of Regions
Alabama	2	Maine	1	Ohio	3
Arizona	2	Maryland*	3	Oklahoma	1
Arkansas	1	Massachesetts	2	Oregon	2
California	5	Michigan	2	Pennsylvania	4
Colorado	1	Minnesota	1	Rhode Island	1
Connecticut	2	Mississippi	4	South Carolina	2
Delaware	1	Missouri	1	South Dakota	1
Florida	4	Montana	1	Tennessee	2
Georgia	3	Nebraska	1	Texas	10
Idaho	1	Nevada	2	Utah	1
Illinois	2	New Hampshire	1	Vermont	1
Indiana	2	New Jersey	4	Virginia	3
Iowa	1	New Mexico	2	Washington	2
Kansas	1	New York	5	West Virginia	1
Kentucky	2	North Carolina	2	Wisconsin	1
Louisiana	4	North Dakota	1	Wyoming	3

* - includes Washington DC

Outside the United States, sub-national detail varies depending on infrastructure and data availability. For example, there are 6 regions in India, 8 regions in China, 6 regions in Germany, 4 regions in the UK, 10 regions in Australia, 1 region in Bangladesh, 2 regions in Thailand, etc.[32] In international locations, the distribution of natural gas demands outside the power-generation sector is based on regional populations obtained from the website City Population (http://www.citypopulation.de/). Natural gas demands in the power-generation sector are generally regionalized using the location of

[32] A more extensive detail is available upon request.

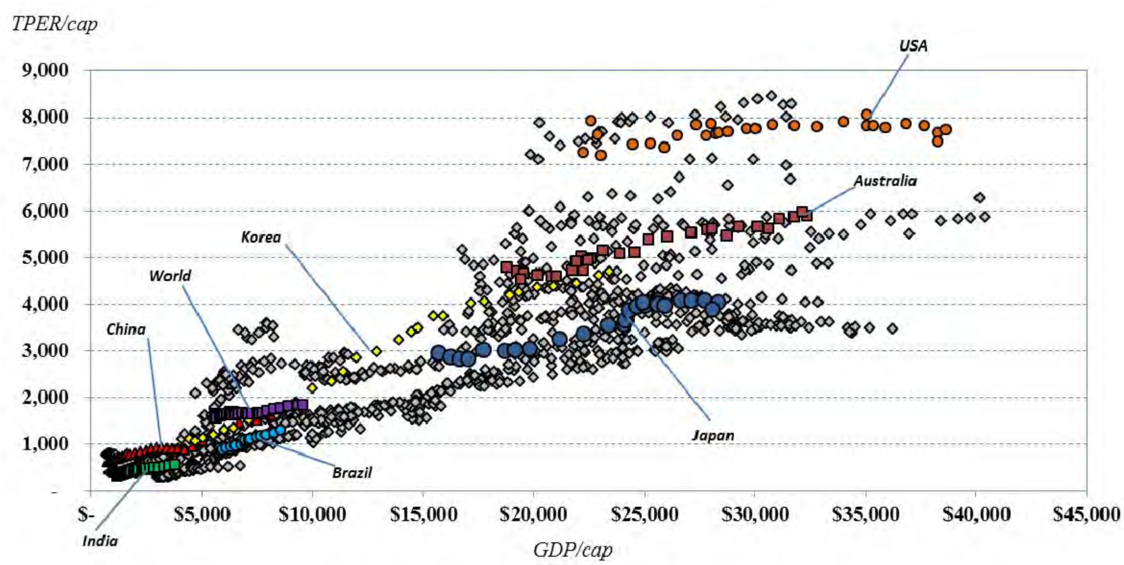
natural gas power plants, which is obtained from several sources, including *Platts* and the *Oil and Gas Journal*.

In order to forecast demand for natural gas, we begin by forecasting total primary energy requirement (TPER) for every country around the world. This is done by econometrically estimating the relationship between energy intensity (defined as TPER divided by GDP) and real (purchasing power parity adjusted) per capita income using a panel of 67 countries covering 1980–2010. This follows a large literature on the subject that has found energy intensity declines as per capita income rises, after rising to a peak generally associated with industrialization of an economy (see, for example, Medlock and Soligo [2001]). Specifically, as continued economic development begets changes in economic structure, and as improvements in end-use energy efficiency occur, energy intensity declines. This tends to drive a decline in the income elasticity of energy demand as per capita income rises.

Figure B1 indicates data for TPER per capita plotted against GDP per capita for 67 countries (in 2010$ USD). This is the data used to estimate the relationship between energy intensity and income. We have highlighted a few select countries for illustrative purposes. As can be seen in Figure B1, energy use increases with GDP. However, perhaps not as obvious, the rate of increase declines as economic development progresses. As referenced above, this is driven by both structural and technical change, and it leads to declining energy intensity.[33]

[33] Medlock (2009) expands on this point in great detail.

Figure B1. Total Primary Energy Requirement Across 67 Countries from 1980–2010



Source: International Energy Agency

Although the number of countries included in the estimation of the energy intensity-income relationship far from captures all countries, the countries included collectively account for over 90 percent of global energy demand. We use the estimated relationship to forecast TPER for all countries. This step requires us to multiply the forecast for energy intensity by a forecast for GDP. For the purpose of this study, GDP forecasts for use in the RWGTM are provided by Oxford Economics.[34] As population growth also matters, population growth rates are adopted from the United Nations mid-trend growth projections. These rates of growth, of course, vary significantly across countries, but we do not consider scenarios with alternative population growth rates in the analysis conducted herein.

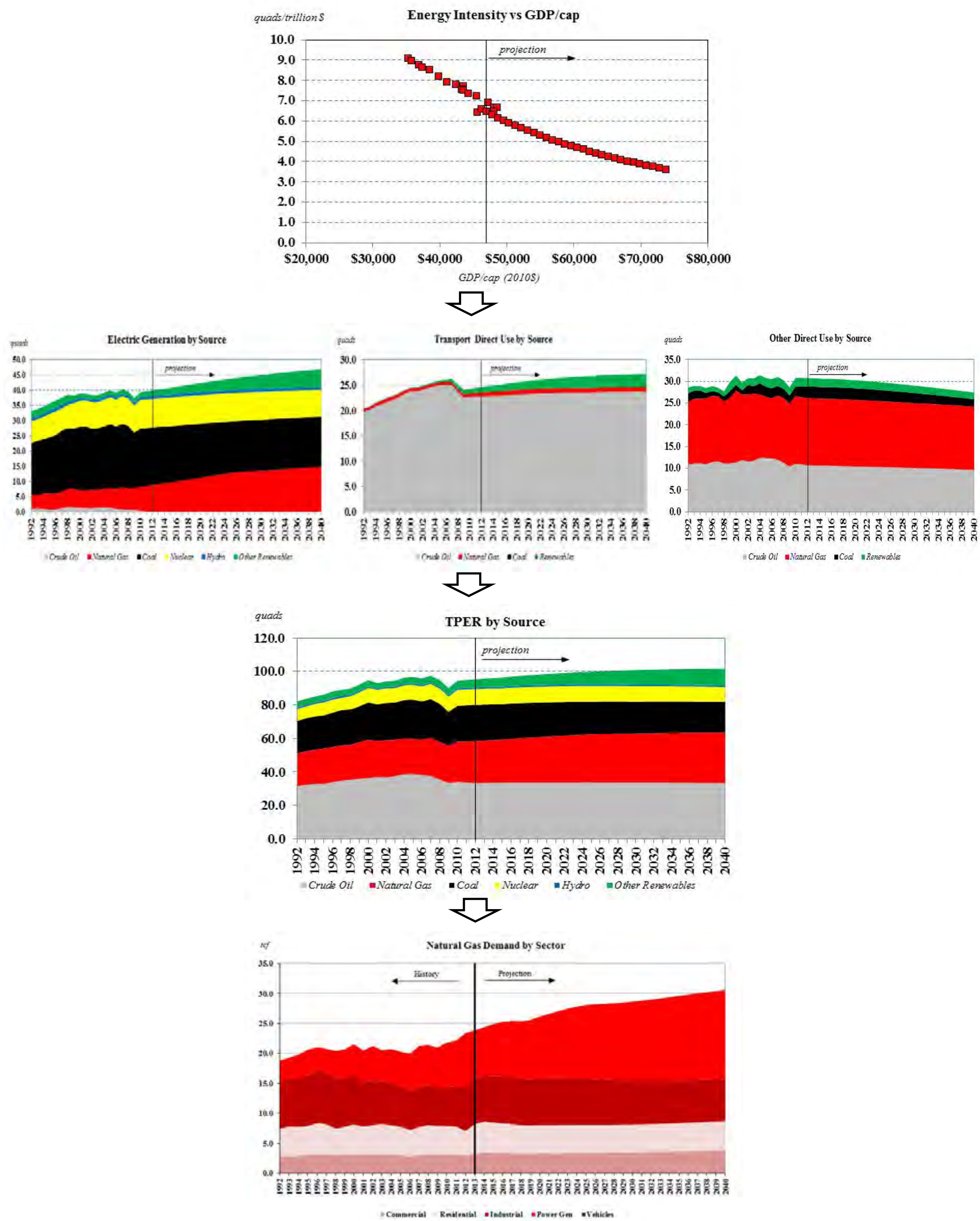
TPER is disaggregated into demand by end-use sector designations—transport, other direct uses, and electric generation—and by component fuel shares—coal, gas, oil, nuclear, hydro, and other renewables. Sector demands are allowed to evolve according to econometrically fit relationships

[34] More detail on the forecasts can be made available upon request.

between electricity intensity of TPER and GDP and transport energy intensity of TPER and income. Other direct uses are modeled as the remainder of TPER.[35] We then incorporate announced policy dictating various forms of energy—such as nuclear, renewables, and hydro—and allow an econometric fit of the residual component shares (all of which are fossil fuels) to determine the mix of crude oil, natural gas, and coal in TPER by sector. The fuel shares are fit using a simultaneous equations framework that includes the effects of relative fuel prices. In addition, the econometric fits indicate that higher incomes reveal an increasing preference for natural gas versus coal, which is consistent with the *relative* preference ordering of environmental attributes increasing with rising incomes. The results of this exercise are depicted for the United States in Figure B2.

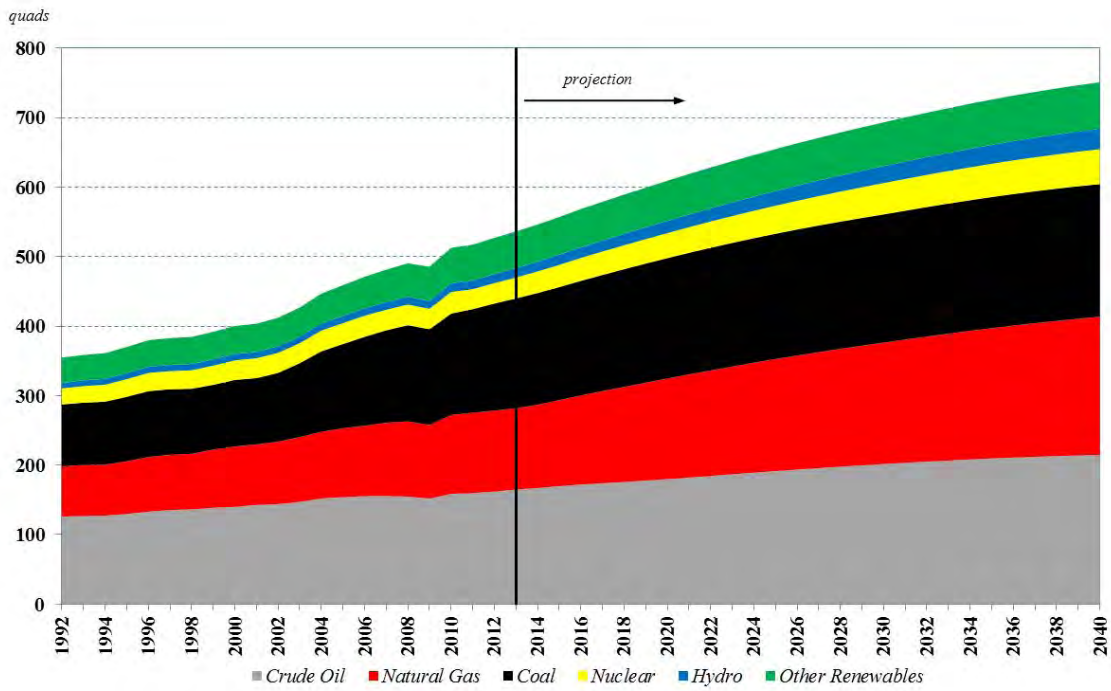
[35] So, we fit the share of electric generation in TPER against per capita income and the share of transportation energy in TPER against per capita income. The residual share is classified as other direct uses. The relationships are all non-linear, and the results generally indicate increasing electrification and transport orientation. Note these are shares, not absolute values.

Figure B2. Illustration of U.S. Demand (1992–2040) Estimation by Step



We generate forecasts for every country in the world in a similar manner. Aggregating across all countries yields the global TPER forecast seen in Figure B3.

Figure B3. Global TPER by Source



In addition, we generate forecasts by fuel source for every country in the world. It is important to point out that the forecast methodology as described is specific to a set of prices. As such, the demands in any given year are just one point along a demand curve. Thus, we call the initial demands that follow from this exercise the RWGTM "reference demand" because it is the demand that is associated with a specific reference price. The reference demand is included in the RWGTM along with the estimated price elasticity thus allowing demand to be price-responsive. As such, if the model-solved price deviates from the reference price, the demand in each end-use sector deviates from the reference demand according to estimated country-specific, sector-specific price elasticity.

Table B2. Implied Price Elasticity of Demand by Country/Region and Sector

Region	Countries	Direct Use	Power Gen
AFRICA	East Africa (Sudan/Ethiopia/Somalia/Kenya/Uganda/Tanzania)	-3.2811	-3.0875
	Algeria	-0.0945	-0.0332
	Egypt	-0.1403	-0.0354
	Libya	-0.2020	-0.0522
	Morocco	-0.5861	-0.1761
	Tunisia	-0.2383	-0.0339
	Southern Africa (South Africa/Namibia/Mozambique/Botswana)	-0.4050	-0.3418
	Angola	-0.1809	-0.4728
	Nigeria	-0.1512	-0.0327
	Northwest Africa	-0.4324	-1.1198
	West Central Coast Africa (Cameroon/Eq Guinea/Gabon/Congo)	-0.8257	-1.4507
ASIA and PACIFIC	Afghanistan	-1.1321	-0.1994
	Bangladesh	-0.1449	-0.0400
	China	-0.5872	-0.2632
	Hong Kong	-2.9761	-0.1080
	India	-0.5816	-0.1572
	Myanmar	-0.1411	-0.0581
	Nepal	-3.4637	-4.8156
	Pakistan	-0.1492	-0.0598
	Sri Lanka	-0.7934	-0.3116
	Thailand	-0.4131	-0.0479
	Vietnam/Laos/Cambodia	-0.5665	-0.0560
	Brunei	-0.0954	-0.0360
	Indonesia	-0.1877	-0.1150
	Japan	-0.7368	-0.0910
	Malaysia	-0.1492	-0.0465
	North Korea	-3.7623	-4.4502
	Philippines	-1.3388	-0.0949
	Singapore	-0.5043	-0.0363
	South Korea	-0.5342	-0.1613
	Taiwan	-1.1917	-0.1456
	Australia	-0.2593	-0.1379
	New Zealand	-0.3012	-0.1133
	Papua New Guinea	-1.2936	-0.2313
CENTRAL AND SOUTH AMERICA	Argentina	-0.1012	-0.0443
	Bolivia	-0.1358	-0.0373
	Brazil	-0.3258	-0.2105
	Central America	-3.5509	-3.7979
	Cuba	-0.5989	-0.1214
	Other Caribbean	-1.1636	-0.1052
	Chile	-0.2773	-0.0779
	Colombia	-0.1459	-0.0766
	Ecuador	-0.6186	-0.0900
	Paraguay	-3.4812	-4.0898
	Peru	-0.2777	-0.0493
	Suriname/Guyana/French Guiana	-0.8787	-0.0587
	Trinidad & Tobago	-0.0498	-0.0328
	Uruguay	-0.8240	-0.3858
	Venezuela	-0.0964	-0.0695

Region	Countries	Direct Use		Power Gen
EUROPE	Austria	-0.2209		-0.0987
	Balkans (Slovenia, Croatia, and Bosnia Herzegovina)	-0.1734		-0.0746
	Balkans (Albania, Macedonia, Serbia, Montenegro)	-0.2881		-0.4974
	Belgium	-0.1835		-0.0825
	Bulgaria	-0.3358		-0.2082
	Czech Republic	-0.2427		-0.3458
	Denmark	-0.2881		-0.1044
	Finland	-0.6130		-0.1504
	France	-0.3137		-0.4616
	Germany	-0.2153		-0.1528
	Greece	-0.6979		-0.1301
	Hungary	-0.1310		-0.0871
	Ireland	-0.2807		-0.0465
	Italy	-0.1386		-0.0495
	Luxembourg	-0.2442		-0.0419
	Netherlands	-0.1201		-0.0487
	Norway	-0.1886		-0.3947
	Poland	-0.2415		-0.4678
	Portugal	-0.3785		-0.0675
	Romania	-0.1430		-0.1049
	Slovakia	-0.1375		-0.2216
	Spain	-0.2352		-0.0682
	Sweden	-1.4161		-0.9198
	Switzerland	-0.3711		-0.9357
	United Kingdom	-0.1373		-0.0714
FORMER SOVIET UNION	Armenia	-0.1415		-0.0869
	Azerbaijan	-0.1337		-0.0362
	Belarus	-0.1408		-0.0388
	Estonia	-0.3546		-0.1936
	Latvia	-0.1765		-0.0465
	Lithuania	-0.2329		-0.0943
	Georgia	-0.1455		-0.0597
	Kazakhstan	-0.1431		-0.1458
	Kyrgyzstan	-0.3291		-0.0839
	Moldova	-0.1322		-0.0387
	Russia	-0.1178		-0.0492
	Tajikistan	-0.3059		-0.1023
	Turkmenistan	-0.0820		-0.0352
	Ukraine	-0.1206		-0.1414
	Uzbekistan	-0.0645		-0.0367
MIDDLE EAST	Bahrain	-0.0693		-0.0311
	Iran	-0.0825		-0.0348
	Iraq	-0.3125		-0.1564
	Israel	-0.6918		-0.0691
	Jordan	-0.7776		-0.0319
	Kuwait	-0.1150		-0.0630
	Lebanon	-1.6106		-0.2203
	Oman	-0.0764		-0.0329
	Qatar	-0.0560		-0.0310
	Saudi Arabia	-0.1317		-0.0394
	Syria	-0.2573		-0.0410
	Turkey	-0.2536		-0.0511
	UAE	-0.0783		-0.0313
	Yemen	-3.7623		-3.8558
NORTH AMERICA	Canada	-0.1133		-0.1864
	Mexico	-0.2271		-0.0517
	United States	-0.1475	*Residential*	-0.1186
		-0.1218	*Commercial*	
		-0.2201	*Industrial*	

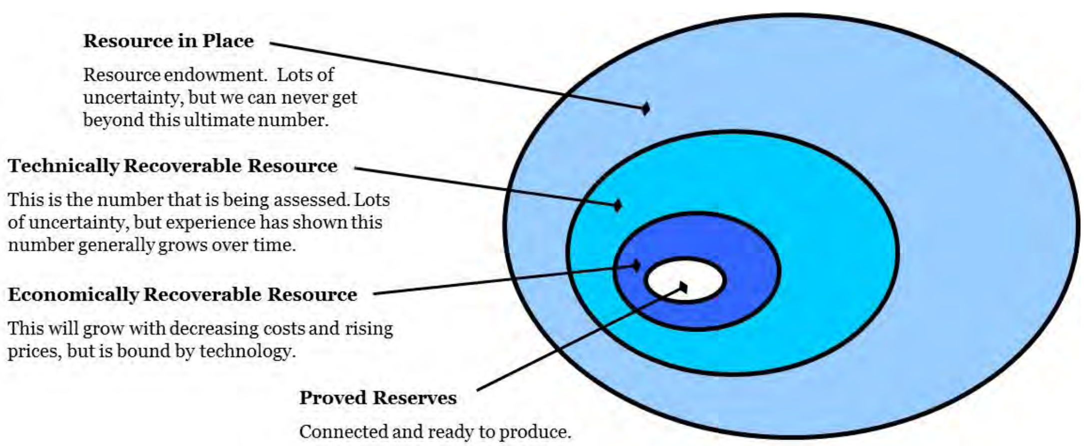
This raises another important point. As a result of the manner in which natural gas demand is estimated as a share of TPER, the price elasticity varies with the share of natural gas in total primary energy. Specifically, as the share of natural gas in total energy approaches zero, the price elasticity rises in absolute value, all else equal. In other words, the natural gas price elasticity of demand is high if a country/region is not currently invested in natural gas-consuming capital. One interpretation of this result from the econometric analysis is that future demand growth in regions where natural gas use is not prevalent would require investment in natural gas-using capital equipment, which would be slow to come if price is high. Moreover, in regions where the natural gas share is already high, natural gas demand has relatively little ability to respond to price because other types of energy-using capital are not prevalent. Table B2 details the short-run price elasticities used in this study. The mid-point elasticities in Table B2 are implied by the estimated equations for the procedure explained above.

Modeling demand in this manner provides flexibility to analyze how different scenarios will impact the demand for natural gas. For example, if the international demand for U.S.-sourced LNG is very high, this acts as an impulse to demand for U.S. natural gas. All else equal, price will be influence upwards, which could crowd out demand from other sectors. However, the extent to which price increases is also a function of the elasticity of domestic supply, which is contingent on domestic resource cost and availability. We now turn our attention to resource quantity and cost assessments in the RWGTM.

B1b. Resources and Production in the RWGTM

Because the RWGTM proves and develops resources, finding and development costs and resource assessments are critical inputs. Both conventional and unconventional resources are characterized across 140 regions into three primary categories: (1) proved reserves, (2) growth in existing fields, and (3) undiscovered resources. Proved reserves and geologic assessments of unproven resources are taken from a number of sources, such as the U.S. Geological Survey (USGS), National Petroleum Council (NPC), Australian Bureau of Agriculture and Resource Economics, and Baker Institute CES research on unconventional resources.

Figure B4. Resources Defined[36]



Production in the RWGTM requires investment in the development of resources, so the finding and development costs of resources are an important input. Even if technically recoverable resources are assessed to be very large, the relevant quantity is the commercially viable subset of what is

[36] Modified from V.E. McKelvey, "Mineral Resource Estimates and Public Policy," *American Scientist* 60, no. 1 (1972): 32–40.

technically recoverable. Technically recoverable resources define the resources that can be recovered with existing technology regardless of cost, whereas economically recoverable resources define what is commercially accessible. Resources that are "proved" are a subset of what is commercially viable, because proved reserves typically refer to resources that can be produced in a relatively short period of time. In sum, large resource in-place estimates do not imply large-scale production will be forthcoming. Productivity improvements, cost reductions, and the price environment all play an important role in defining what is *technically recoverable* and what is *economically recoverable* relative to the *total resource endowment*. Figure B4 illustrates this principle.

North America finding and development (F&D) costs for non-shale resources are based on estimates developed by the NPC in its 2003 report and have been adjusted using data from their 1998–2000 point of reference, using the Bureau of Economic Analysis (BEA) KLEMS database to account for changes in upstream costs, which has varied widely through the years. As explained below, upstream costs are closely correlated to the crude oil and natural gas price environment.

The F&D cost curves are developed by linking data on well development costs to the geologic characteristics of each play in areas where such information is known. The NPC report in 2003 aimed at assessing the future of the North American natural gas market and detailed costs for over 900 plays in North America. That data was utilized to develop an econometric relationship between costs and geology in non-shale resources. Then, the statistically derived information was used to generate costs (via an "out of sample" fit) in regions around the world where geologic characteristics are known, but costs are not. In other words, costs have been econometrically related to play-level geologic characteristics and applied globally to generate costs for all regions of the world. The methodology employed for non-shale gas resources is outlined in detail in Hartley and Medlock (2006).[37]

A note on the long-run cost environment assumed in the RWGTM is important here. In general, upstream costs rise and fall over time. The RWGTM Reference case assumes the cost environment drifts to a long-run average level. Analyzing data available from the KLEMS database from the BEA on the real cost of oil and gas extraction, we are able to differentiate a long-run average cost from short-term peaks and valleys. Of course, there are uncertainties regarding this approach, and although not explicitly addressed in this study, we have executed scenarios in the RWGTM assuming different long-run cost levels. However, an underlying assumption that costs do not change can cement the myopia that is often present in forecasting.[38]

Figure B5 graphs an index of development costs and the price of oil, each in real 2010 values having been adjusted using the GDP deflator. Notably, the two indices generally move together, but neither is a clear leading indicator of the other. This general pattern supports the notion that in some periods costs rise due to "demand pull" occurring when high energy prices encourage greater upstream investment activity, while in other periods price rises due to "cost push" when scarcity of raw materials and qualified personnel drive up development costs.[39] In either case, the cost environment is germane to market conditions, so what one assumes going forward will be very important for the projected time horizon.

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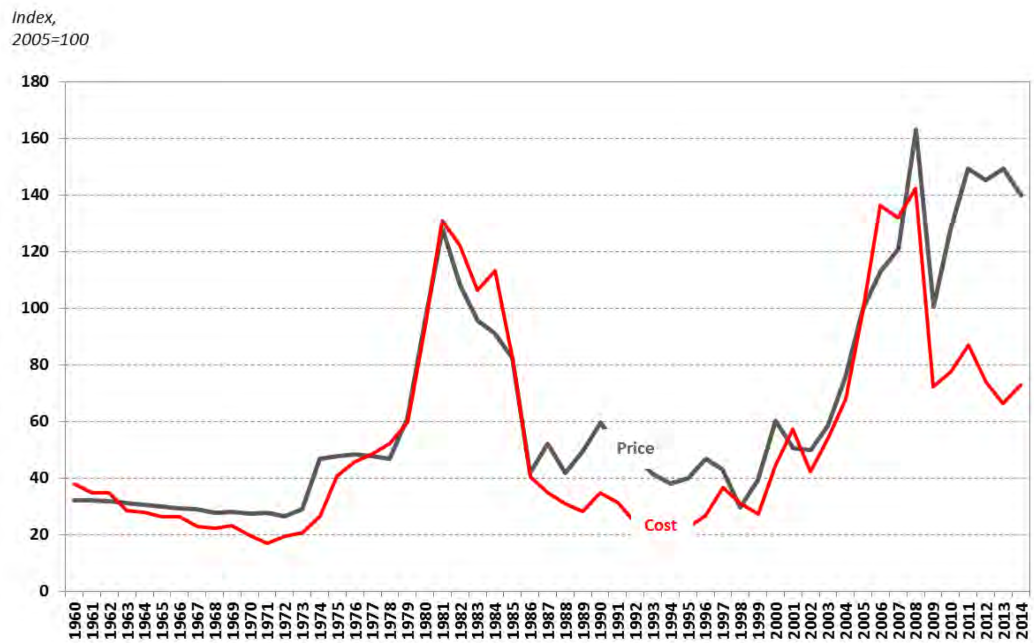
[37] Peter Hartley and Kenneth B. Medlock III, "The Baker Institute World Gas Trade Model" in *Natural Gas and Geopolitics: 1970–2040*, ed. David Victor, Amy Jaffe, and Mark Hayes, Cambridge University Press (2006).

[38] Based on unpublished analysis as part of CES sponsored research, the *QP-Rice International Natural Gas Program*.

[39] Certainly, the latter point has been a concern in the oil and gas industry for the better part of the last two decades. Often referred to as "the great crew change," a graying industry has seen a diminishing availability of qualified individuals to operate technically complex oil and gas mining operations.

Figure B5. Real Development Costs and the Real Price of Oil (1968–2014)



Source: U.S. Bureau of Economic Analysis; U.S. Energy Information Administration

While the average long-run cost is assumed to be the average of the cost levels over the last 25 years, which is generally consistent with a real oil price (in 2010$) of just under $80 per barrel, short-run pressures are allowed to increase costs in any given year above the long-run level. These so-called "short-run adjustment costs" raise F&D costs above their long-run level when development activity rises within a given year. Thus, if a particular scenario in the RWGTM involves, for example, an unexpected demand shock, both short-run cost and price will rise as development activity ramps up to respond.

The RWGTM also contains detailed estimates of resource quantities and development costs for shale resources around the world. The initial assessments of technically recoverable shale resources are taken from the report "Technically Recoverable Shale Oil and Gas Resources: An Assessment of 137

Shale Formations in 41 Countries Outside the United States" by Advanced Resources International for the U.S. Energy Information Administration in June 2013.[40] In developing F&D curves for shale, we also used data from the report "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays" by INTEK, Inc. for the EIA in July 2011,[41] as well as shale gas well production data across regions in the United States collected from DrillingInfo.com.

Geophysical data and well performance data are used to generate finding and development cost curves for an average shale gas well in every assessed basin. Specifically, the *average* expected ultimate recovery (EUR) for play *i* is found using the following relationship

$$\underbrace{EUR_{i,avg}}_{\frac{X}{YZ}\ bcf/well} = \underbrace{TRR_i}_{X\ bcf} / \underbrace{\left(Area_i \cdot WellSpacing_i\right)}_{Y\ miles^2 \cdot Z\ well/miles^2}$$

where the relevant data are taken from the aforementioned ARI report for international locations. For domestic shales the average EUR, and the distribution of EURs, is taken from the INTEK report. The distribution of EURs is fit to the INTEK data for each shale play by estimating

$$EUR_{i,p} = a\ln\left(p\right) + b$$

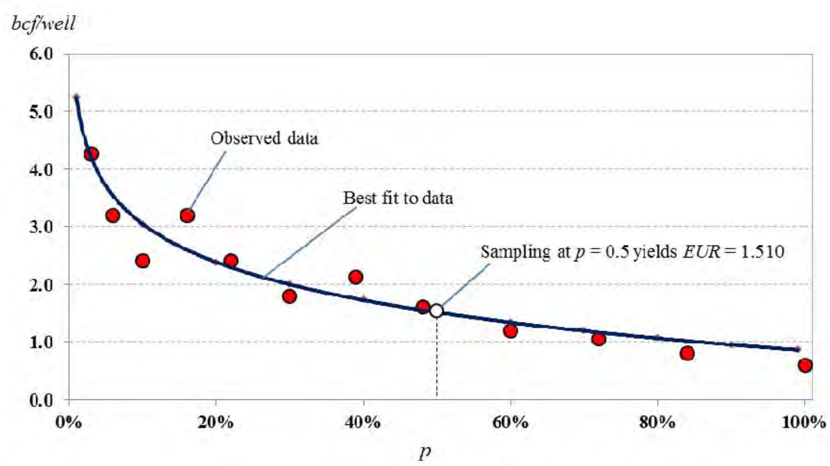
where *p* is the probability of a well's EUR being less than $EUR_{i,p}$. For example, in the Barnett shale we estimate the relationship above to find

$$EUR_{Barnett,p} = -0.9520\ln\left(p\right) + 0.8501$$

[40] Available at http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf.
[41] Available at http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf.

with $R^2 = 0.9118$.[42] This equation then allows us to "sample" at any *p* to obtain an EUR. Figure B6 illustrates this procedure.

Figure B6. Estimating EURs for Known Shale Plays



Next, we determine the cost per unit at each EUR as

$$\underbrace{Cost\ per\ unit_{i,p}}_{\frac{X}{Y}\ \$/mcf} = \underbrace{F\ \&\ D_i}_{X\ million\$/well} \ / \underbrace{EUR_{i,p}}_{Y\ bcf/well} .$$

Specifically, we determine the average per unit cost for each 20th percentile by: (1) assuming wells can be drilled uniformly in available acreage across the areal extent of the shale, (2) sampling from the EUR distribution and determining the total resource in each percentile of the distribution, then (3) taking a volume weighted average of the per unit costs at each percentile in the distribution. Similar steps were taken for every shale play in the United States. Then, the parameters describing the distribution of shale gas well performance for plays in the United States are used to derive EUR

[42] The regressions for the other shales in the United States also fit the data very well, with R^2 ranging between 0.9101 and 0.9963.

distributions for shales around the world. This allows us to "tier" the resources according to cost for every shale in the world.

Where available, we use published data on full cycle finding and development costs. However, this is not available for every location in the world. As such, we estimate drilling costs (*F&D*$_i$) as a function of depth and pressure

$$F\,\&\,D_i \;=\; \underset{(0.8941)}{0.8616} \;+\; \underset{\left(9.0041\times10^{-5}\right)}{3.6605\times10^{-4}}\,TVD_i + \underset{(1.8606)}{3.2192}\,Pressure_i$$

with $R^2 = 0.9016$. Thus, for example, a horizontal well with total vertical depth of 4,000 feet and pressure gradient of 0.5801 psi/ft^2 is estimated to cost \$4.19 million. If EUR is 2.5 Bcf/well, then the cost per mcf is estimated to be \$1.67/mcf. Of course, a return must be earned on capital, and operating costs must also be covered, which is how we arrive at an estimated breakeven cost for the average well in this example. Of course, the income tax rate, severance tax, royalties, and other relevant parameters also come into the calculation when determining the breakeven price. Using the average set of values for these parameters in the RWGTM for the United States would put the breakeven price for this example at \$5.96/mcf. Taking things a step further, this approach allows an evaluation of the relative competitiveness of resources across regions under different tax regimes.

Unless otherwise stated in a specific scenario, we honor "above ground" constraints, such as fracturing moratoria in places like France and the State of New York. Other issues also present impediments to development. For instance, the lack of a well-developed service industry or lack of a competitive upstream sector can raise costs relative to what is seen elsewhere. As a result, costs are higher in these places, with the inputs benchmarked against publically reported well costs. In addition, in countries such as China, water availability for hydraulic fracturing may raise costs and even severely restrict the shale gas potential to varying extents in different basins. Despite constraints faced in some regions due to water scarcity, it is possible that breakthroughs in the use of brackish water from deep-source aquifers, top-side water recycling capability, and/or the use of super-critical nitrogen or liquefied petroleum gas (LPG) to fracture shale will make much of the resource more viable at some point in the future. In the RWGTM, we do not assume any such technological breakthroughs, unless otherwise stated in a particular scenario, so shale development costs are typically higher in regions affected by water shortages as a result.

Figures B7 and B8 indicate the breakeven curves, inclusive of fiscal terms and return to capital, for shale in North America and around the world. The data are also presented in a table in Annex D. One should not interpret the graphs in Figures B7 and B8 as classical long-run supply curves. Rather, they are only *illustrative* of cost largely because the resources are geographically dispersed. Aggregating them ignores transportation costs to a generally accepted pricing location, and the transportation costs are heterogeneous across resources. A prime example is highlighted in the graph for "EUROPE and FSU" in Figure B8. Here, Russian shale is identified (tiers 1 through 4 of the Bazhenov shale to be specific; tier 5 breakeven exceeds $20 so is not illustrated). In order for this resource to be commercially viable in Western Europe, it would need to be transported a long distance via pipeline. Therefore, to a consumer in Europe, a breakeven of just under $5 per mcf is not very relevant because upon including transport costs, that Russian shale is not competitive with several tier 1 shales in Western Europe.

Figure B7. Shale Breakeven Curves for North America by Country

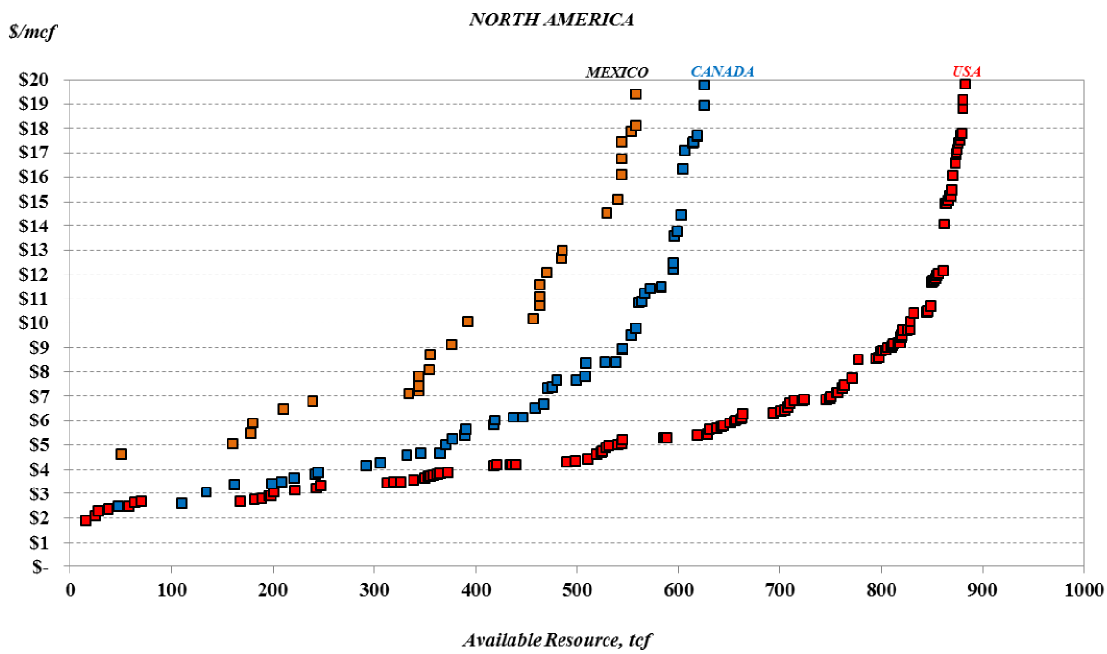
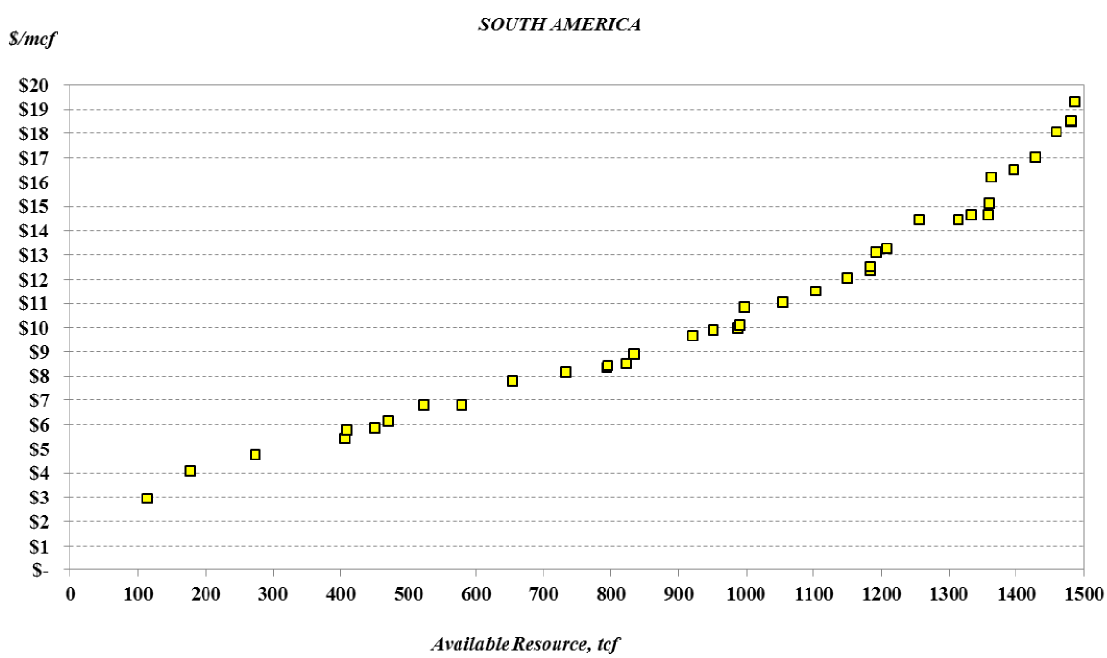
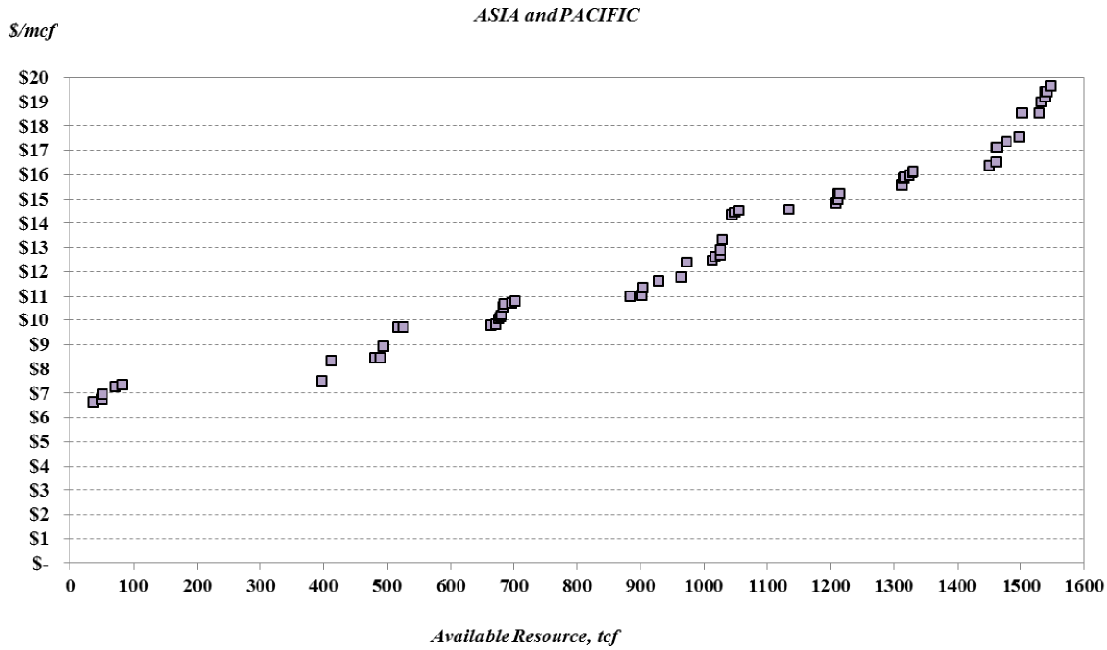


Figure B8. Shale Breakeven Curves for Regions Outside North America




ASIA and PACIFIC
$/mcf
$20
$19
$18
$17
$16
$15
$14
$13
$12
$11
$10
$9
$8
$7
$6
$5
$4
$3
$2
$1
$-
0
100
200
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400
500
600
700
800
900
1000
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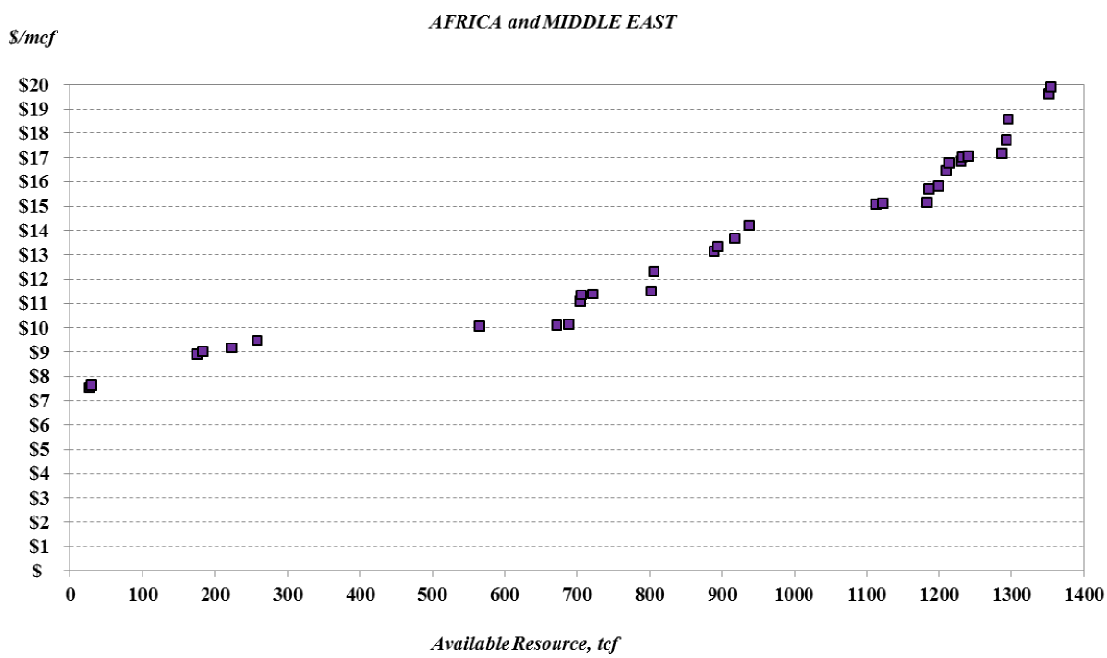
1200
1300
1400
1500
1600
Available Resource, tcf


AFRICA and MIDDLE EAST
$/mcf
$20
$19
$18
$17
$16
$15
$14
$13
$12
$11
$10
$9
$8
$7
$6
$5
$4
$3
$2
$1
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0
100
200
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400
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700
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1000
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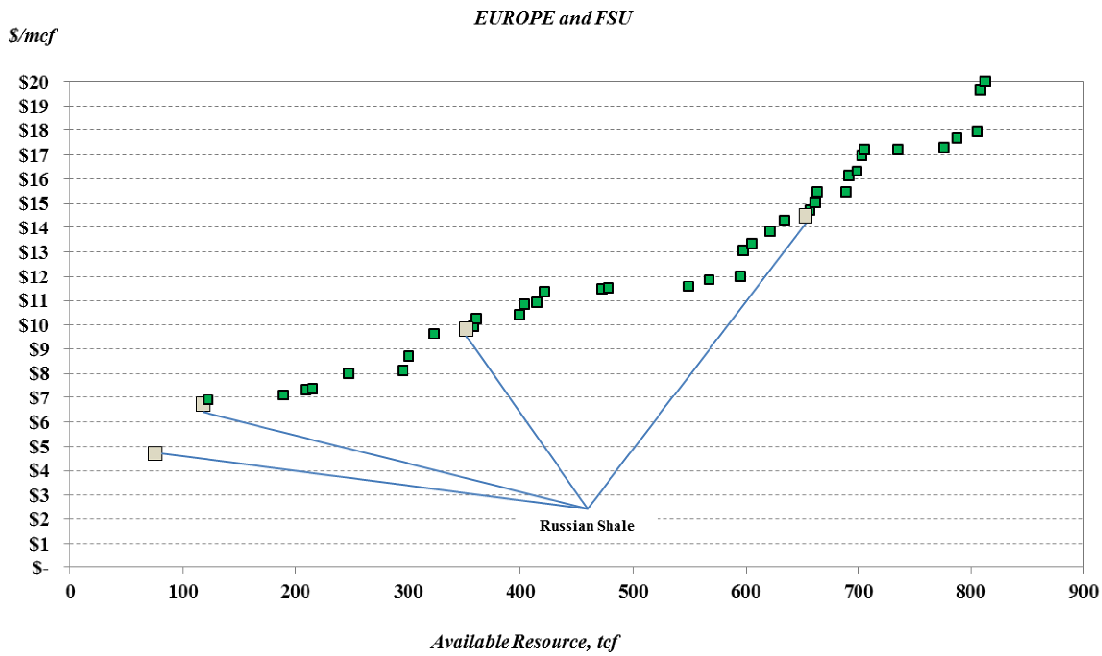
1200
1300
1400
Available Resource, tcf



Many factors influence cost and productivity, which leads to tremendous heterogeneity. For example, shale that is clay-rich is generally not prone to high production rates, which in turn tends to reduce its commercial attractiveness even if the technically recoverable resource assessment is large. Other factors—such as total organic carbon, natural fracturation, isopach, permeability, porosity, and other features—are also critical, which makes the degree of complexity involved in developing cost curves for undeveloped shale resources very high thus imbedding a significant degree of uncertainty.

We must also recognize that estimates of shale gas resources will change over time as more is learned about each play. In addition, as new imaging technologies and new extraction processes are developed, assessments for *economically* recoverable shale gas could increase, particularly as technical advances drive improvements in productivity. As such, estimates of productivity improvement can be important and have significant impacts on upstream activity and price. We allow technical improvements in shale extraction throughout the model time horizon, approaching an overall cost reduction of 10 percent at a rate of 2 percent per year. In the various scenarios considered in this study, we vary shale resource availability to be both higher and lower in the United States and other parts of the world in order to motivate demand for and availability of U.S.-sourced LNG.

As indicated to above, factors other than technical advances can alter development costs. Specifically, various regulatory, policy, and market factors can contribute to heterogeneity in costs. As outlined in Medlock (2014b), geology is a *necessary* condition for successful upstream development, but it is far from *sufficient*, and the recent growth in production in the United States owes to a very unique set of circumstances, including:

- A regulatory and legal apparatus in which upstream firms can negotiate directly with landowners for access to mineral rights on privately owned lands.
- A market where liquid pricing locations, or hubs, are easily accessed due to liberalized transport services that dictate pipeline capacity is unbundled from pipeline ownership.
- A well-developed pipeline network that can facilitate new production volumes as they are brought online.
- A market in which interstate pipeline development is relatively seamless due to a well-established governing body, i.e., the Federal Energy Regulatory Commission (FERC), and a comparatively straightforward regulatory approval process.

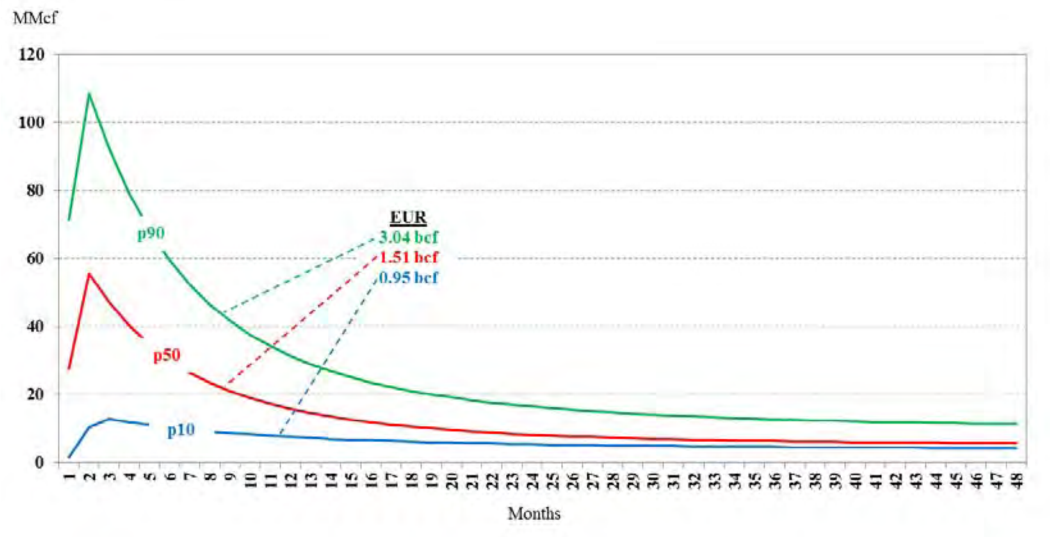
- A market in which demand pull is sufficient, and can materialize with minimal regulatory impediment, to provide the opportunity for new supplies to compete against other supplies or energy sources for market share.
- A market where a well-developed service sector already exists that can facilitate fast-paced drilling activity and provide rapid response to demands in the field.
- A service sector that strives to lower costs and advance technologies in order to gain a competitive advantage.
- A rig fleet that is capable of responding to upstream demands without constraint.
- A deep set of upstream actors—independent producers—that behave as "entrepreneurs" in the upstream, thereby facilitating a flow of capital into the field toward smaller-scale, riskier ventures than those typically engaged by vertically integrated majors.

Many of the above factors are unique to the United States, and their absence in other parts of the world can serve to raise the cost of developing shale (and other) resources. For example, in the absence of a robust upstream sector capable of handling the large-scale demands of shale gas development, scarcity constraints (on labor, rigs, and equipment) can become binding. This has been evidenced in places like Poland, for example, where drilling costs are roughly double those seen for shale production targets at similar depths in the United States. This, all else equal, requires those wells to be about twice as productive to stand on the same commercial footing as a similar well in the United States. However, if upstream activity ramps up in these regions, the availability of rigs, personnel, and equipment should increase. This would, with the development of a deeper supply chain bring costs down. We capture this in the RWGTM by allowing current costs around the world to approach the costs seen in the United States. The transition is parameterized by a learning function that allows costs to fall asymptotically to costs that would be representative of similar activities in the United States.[43] Absent resource development, however, costs remain at their initial higher levels.

Characterizing shale gas decline curves is a very important matter when modeling potential production. The models of physical flow through porous media that are the basis for the classically accepted Arps' equations do not fit observed production data for shale gas wells. Patzek, Male, and Marder (2014) developed an alternative descriptor of decline curves for shale based on the physics of fluid flow in ultralow permeability, ultralow porosity rock media, such as shale. Their analysis resulted in a hypothesis that shale gas wells should decline so that production is inversely proportional to the square root of time. Medlock and Seitlheko (2015) subsequently tested this hypothesis by linearizing their postulated decline curve and econometrically fitting it to a panel of over 16,000 wells in the Barnett shale. They could not reject the hypothesis of Patzek, Male, and Marder at a very high level of significance. This, in turn, allows for the construction of "type" curves, and allows a characterization of the distribution of well performances, which is depicted below in Figure B9 for the Barnett shale.

[43] So, if shale-directed activity in Poland were to increase significantly, the cost to drill a well with vertical depth of 8,500 feet that currently costs just over $16 million would fall over the course of a decade to approach $9 million.

Figure B9. Barnett Shale "Type" Well Decline



Source: Reproduced from Medlock and Seitlheko (2015)

Of particular note in Figure A9 is the fact that the EUR can vary substantially within a play. This, of course, has implications for the economic viability of each well and is a core component in the construction of the productivity tiers discussed above. Importantly, when assessing the long-term potential of a play, individual well economics do not convey the complete story. Virtually every operator has a portfolio of acreage and wells, and the performance of the portfolio is what determines commercial success. As drilling commences, a tremendous amount of information is gathered at the play and the acreage that has the greater proportion of high-performing wells—the so-called "sweet spots"—become better identified. Operators will turn their focus to those regions over time, especially if price is expected to be low. As this occurs, fewer wells are needed to maintain a given play-level production volume because each subsequent well is more productive. This "learning-by-doing" process results in an observed play-level productivity improvement. Importantly, however, this is distinctly different from technologically-driven productivity improvements, which generally tend to lift productivity of all wells regardless of location.

B1c. Other Model Attributes

In the RWGTM, events in one region of the world—economic, political, or otherwise—influence all other regions because commodity movement via pipelines and/or LNG tankers connects markets and transmits both physical commodity volumes and price signals. The costs of constructing new pipelines and LNG facilities in the RWGTM are estimated using data from previous and potential projects available from the Energy Information Administration, International Energy Agency (IEA), and various industry reports. Within the United States, Federal Energy Regulatory Commission (FERC)-filed tariff rates determine pipeline transportation costs. Transportation costs for regions outside the United States are determined by a rate-of-return calculation on existing infrastructure or are based on information obtained from various industry reports, where such information is available.

The transportation infrastructure is characterized to a fine level of detail, reflecting the geographic detail of supply and demand represented in the model. The infrastructure representation in the RWGTM for the U.S. natural gas market replicates interstate and intrastate pipeline networks with great detail. In fact, as noted above, in the lower 48 states there are over 100 demand regions characterized by industrial, power generation, residential, commercial, and transportation demand, with each of these demands connected to supply sources by a highly detailed representation of the North American pipeline network. More generally, the degree of regional detail around the world varies according to the density of pipeline infrastructure and the size of local demand centers.

The RWGTM balances supply and demand through spatial optimization along a given transportation network within a time period, while using intertemporal dynamic optimization to prove resources and develop infrastructure across time periods. This, as noted earlier, allows the model to eliminate all spatial and intertemporal arbitrage opportunities. In other words, the model solves for the optimal investment pathway—through field level upstream development, pipeline construction and utilization, and LNG value chain development and use—to balance supply and demand in each location. This allows us to construct scenarios that consider the effects of different economic and/or geopolitical assumptions on investment and trade.

B2. The Oxford Global Economic Model

Oxford's Global Economic Model (GEM) is the world's leading globally integrated macro model, used by over 100 clients around the world, including finance ministries, leading banks, and blue-chip companies.

The GEM covers 46 countries, including the United States, Canada, the EU, and major emerging markets including China and India. The model provides a rigorous and consistent structure for analysis and forecasting, and allows the implications of alternative global scenarios and policy developments to be analyzed at both the macro and sector level.

Theoretical motivations

Broadly speaking, there are three types of macroeconomic model designed to help economists in forecasting and analysis of the impacts of alternative economic scenarios and policies. At one extreme, there are the purely statistical models known as vector autoregressions (VARs). Their strengths are short-term forecasting (usually six months to a year or so) and the generation of stylized facts. However, they are much less useful for longer-term forecasting and, because they lack any economic structure, they cannot be used for policy analysis.

At the other extreme are the so-called computable general equilibrium models (CGEMs) such as dynamic-stochastic general equilibrium (DSGE) models. These models' equations are derived by assuming private agents solve dynamic optimization problems, and they typically do not have error terms, or residuals, like econometrically-estimated relationships. They are calibrated so that in equilibrium they reproduce historical averages of key macro variables. Their strength is their high degree of rigour, but when econometricians perform statistical tests on them, they typically do badly relative to the traditional models.

The Oxford Economics Global Economic Model (GEM) takes a third approach, which draws elements from both VAR and DSGE models. The GEM is a large-scale macroeconometric model: like a VAR model, behavioral equations in the GEM are estimated using statistical regressions on observable data; the choice of which variables to include in the equations, however, are drawn from economic theory. The main advantage of the macroeconometric approach is that it provides both a forecasting tool and a tool for policy analysis.

Model form, parameter estimation and calibration

The GEM is an error correction model, a form of a multiple time series model that estimates the speed at which a dependent variable returns to its equilibrium after a shock to one or more independent variables. This form of model is useful as estimating both the short and long run effects of variables on the given variable in question. The GEM exhibits 'Keynesian' features in the short run. Factor prices are sticky and output is determined by aggregate demand. In the long-run, its properties are Neoclassical, such that prices adjust fully and the equilibrium is determined by supply factors – productivity, labor and capital – and attempts to raise growth by boosting demand only leads to higher prices.

This explicit division into short and long components does not imply that the long-term steady state solution is independent of the short-term drivers. Rather, the error correction format introduces a feedback loops such that short-run deviations from the equilibrium adjust back to the steady state. In other words, an error correction model combines the long-run equilibrium relationship implied by co-integration with the short run dynamic adjustment mechanism that describes how the variables react when they move out of long-run equilibrium. Intuitively, if forecasts are derived using observed data, then significant and persistent deviations from the historical trend would suggest a change in the underlying drivers of an economic phenomenon.

The GEM is a disaggregated empirical model where behavioral equations are estimated on observable data. Individual country models, and the six regional models which complete the world coverage of the Oxford Global Economic Model, are estimated using the previously described error correction format. Economic theory is used to determine appropriate explanatory variables for behavioral relationships such as prices, exchange rates, productivity, and employment.

Coefficients on behavioral relationships which cannot be estimated using econometric regressions are calibrated using proxy series, established economic theory, or imposed to obtain consistency with an observed empirical relationship. The different approaches for determining coefficients are largely driven by the availability and quality of underlying data. Coefficients on variables in the long-run are imposed using theory, for example the permanent income hypothesis as a driver of long-run consumption.

Overview of country models in the Global Economic Model

The structure of each of the country models is based on the income-expenditure accounting framework. However, the models have a coherent treatment of supply. In the long run, each of the economies behaves like the classic one sector economy under Cobb-Douglas technology. Countries have a natural growth rate, which is determined by capital stock, labor supply adjusted for human capital, and total factor productivity. Output cycles around a deterministic trend, so the level of potential output at any point in time can be defined, along with a corresponding natural rate of unemployment.

Firms are assumed to set prices given output and the capital stock, but the labor market is characterized by imperfect competition. Firms bargain with workers over wages but choose the optimal level of employment. Under this construct, countries with higher real wages demonstrate higher long-run unemployment, while countries with more rigid real wages demonstrate higher unemployment relative to the natural rate.

Inflation is a monetary phenomenon in the long run. All of the models assume a vertical Phillips curve, so expansionary demand policies place upward pressure on inflation. Unchecked, these pressures cause an unbounded acceleration of the price level. Given the negative economic consequences of this (as seen in the 1970s in developed economies and more recently in some emerging markets), most countries have adopted a monetary policy framework which keeps inflation in check. The model mirrors this, by incorporating endogenous monetary policy. For the main advanced economies, monetary policy is underpinned by the Taylor rule, captured using an inflation target, such that interest rates are assumed to rise when inflation is above the target rate, and/or output is above potential. The coefficients in the interest rate reaction function, as well as the inflation target itself, reflect assumptions about how hawkish different countries are about inflation. A by-product of this system is that scenarios under fixed interest rates only make sense in the short-run. A scenario which imposes a fixed interest rate, and therefore assumes a lack of monetary policy, in conjunction with a vertical Phillips curve, would result in accelerating (or decelerating) inflation after several years.

Demand is modeled as a function of real incomes, real financial wealth, real interest rates and inflation. Investment equations are underpinned by the Tobin's Q Ratio, such that the investment rate is determined by the return relative to the opportunity cost, adjusted for taxes and allowances. Countries are assumed to be "infinitely small", in the sense that exports are determined by aggregate demand and a country cannot ultimately determine its own terms of trade. Consequently, exports are a function of world demand and the real exchange rate, and the world trade matrix ensures adding-up consistency across countries. Imports are determined by real domestic demand and competitiveness.

Finally, the model assumes adaptive rather than forward looking expectations because we believe that introducing expectations on the basis of economic theory is more advantageous than using the forward looking assumption ubiquitously. There is disagreement among economists about whether forward looking expectations are consistent with observed data, which become even more acute in light of the difficulties with obtaining accurate data on expectations for model-building purposes. Instead, we adopt adaptive expectations, which are introduced using a framework in which expectations are formed using the actual predicted values from the model. Exogenous variables are assumed to be known a priori. Where appropriate, the model does introduce expectations implicitly and explicitly, therefore accounting for how and extent to which agents respond to information about changes in fundamentals. An example of this includes our derivation of exchange rate forecasts which implicitly capture expectations: in the short-run, the exchange rate is driven by movements in domestic interest rates relative to the United States, therefore accounting for uncovered interest rate parity. Another example is our use of a variable for forward guidance to capture expected movements in interest rates.

Linkages between economies

Individual country models within the GEM are linked in a number of ways:

- Trade (Exports driven by weighted matrix of trading partners' import demand)
- Competitiveness (IMF relative unit labor costs where available, relative prices elsewhere)
- Interest Rates and Exchange Rates
- Commodity Prices (e.g. oil, gas and coal prices depend on supply/demand balance; metal
- prices depend on growth in industry output)
- World Price of Manufactured Goods

Link to sector/industry output

In addition, the Global Economic Model links to the Global Industry Model to break-down of value added and employment by sector. Consistency between the income-expenditure and value-added approaches to output is ensured by scaling value added in each sector up or down to obtain expenditure-based value added as the sum of value added in the sectors.

The sector breakdown reflects the input-output structure of each economy. For each sector we calculate the total demand for that sector as a weighted average of value added in other sectors and final expenditure, with the weights taken from input-output tables. We then use total demand to estimate the value added for that respective sector since in the long run (everything else equal) value added and demand must grow in line with each other. Value added is also affected by competitiveness (measured by relative unit labour costs) to a degree that reflects the international openness of each sector. Employment by sector is derived from value added in that sector and sector-specific productivity trends. As in the case of value added, consistency between the total employment forecast and employment in all sectors is achieved by scaling the sector employment variables up or down.

At the country level, the model's structure is Keynesian in the short run, with output driven by shifts in demand, but in the long run the model is neoclassical, and GDP is determined by the economy's supply-side potential (i.e., the level of output is determined by an economy's labor supply, capital stock, and productive potential). For example, increased demand will lead to higher output and employment initially, but eventually that feeds through into higher wages and prices. Given an inflation target, interest rates have to rise, reducing demand again ("crowding out"). As a result, output returns to its potential level over the long run.

Overview of the Global Economic Model
Consumption—function of real income, wealth, and interest rates
Investment—"q" formulation with accelerator terms
Exports—depend on world demand and relative unit labor costs
Imports—depend on total final expenditure and competitiveness
Real wages depend on productivity and unemployment relative to NAIRU
Prices are a markup on unit costs, with profits margins a function of the output gap
Monetary policy endogenized; options include Taylor rule, fixed money and exchange rate targeting
Exchange rate determined by UIP
Expectations adaptive

At the global level, countries are linked through trade, financial variables, and commodity prices. As a result, the model is able to capture both the direct and indirect impacts of changes in the global natural gas market. The output of the GEM is then the dynamic impact on GDP, interest rates, employment, inflation, and other macro variables.

B3. The Oxford Economics Global Industry Model

Linked to the Global Economic Model is the Oxford Economics Global Industry Model. This model, based upon standard industrial classifications and updated quarterly, has a detailed breakdown of output by sector across 100 sectors and 67 countries. The model includes a particularly detailed breakdown in the manufacturing sector, covering eight key sectors: metals, chemicals, motor vehicles, engineering and metal goods, electronics and computers, textiles and clothing, aerospace, and other intermediate goods. The GIM generates forecasts for both gross output and gross value added (output excluding intermediate consumption).

Forecasts for individual industries are driven by the macroeconomic forecast from the GEM combined with our detailed model of industry interactions. Demand from households, firms, and government is allocated to individual industries using weights based upon national input-output tables. These tables show the percentage of each industry's output that is driven by consumption, investment, exports, and intermediate demand. So, for example, a forecast of economic growth led by strong investment will lead to rapid growth in capital goods sectors. Furthermore, sectors that supply those industries will also benefit through supply-chain linkages (i.e., intermediate levels of demand) also captured in the model. Finally, the industry model takes into account the impacts of changes in competitiveness of a sector's market share both domestically and overseas.

Annex C Scenario Results Tables

Table C1. Impact of Increasing LNG Exports, Annual Avg. Change from 12 Bcf/d, 2015–2040*

	12 Bcf/d to 20 Bcf/d LNG Exports		12 Bcf/d to Market-Determined (endogenous) LNG Export Level			
	Reference	High Resource Recovery	Reference	High Resource Recovery	Low Resource Recovery	High Natural Gas Demand
U.S. Natural Gas Market (Bcf/d)						
NG Production	3.5	4.9	4.6	8.1	2.3	3.8
	2.3%	*3.0%*	*2.9%*	*4.9%*	*1.6%*	*2.3%*
NG Consumption	0.1	0.2	0.0	0.4	-0.1	0.0
	0.0%	*0.2%*	*0.0%*	*0.3%*	*0.0%*	*0.0%*
NG Exports	4.2	5.1	5.3	8.5	2.6	4.2
	16%	*18%*	*20%*	*30%*	*11%*	*16%*
NG Imports	0.8	0.4	0.8	0.8	0.2	0.5
	3.0%	*1.9%*	*3.1%*	*3.5%*	*0.9%*	*1.9%*
Prices (2010$)						
Henry Hub Price	$0.17	$0.15	$0.20	$0.25	$0.12	$0.18
	3.3%	*3.4%*	*4.0%*	*5.6%*	*2.0%*	*3.4%*
NBP (UK)	$0.00	-$0.01	$0.01	-$0.03	-$0.01	-$0.01
	0.0%	*-0.1%*	*0.1%*	*-0.3%*	*-0.1%*	*-0.1%*
German Border (NW Europe)	$0.00	$0.00	$0.01	-$0.01	-$0.01	$0.00
	0.0%	*0.0%*	*0.1%*	*-0.1%*	*-0.1%*	*0.0%*
JKM (Asia-Pacific)	-$0.73	-$0.89	-$0.89	-$1.31	-$0.50	-$0.71
	-4.9%	*-6.0%*	*-6.0%*	*-8.8%*	*-3.3%*	*-4.8%*
Macroeconomic Impacts						
GDP (annual avg., 2014$B)	$3.8	$4.1	$8.5	$11.1	$6.7	$7.4
	0.02%	*0.02%*	*0.03%*	*0.04%*	*0.03%*	*0.03%*
Employment (000s)	3.0	5.6	10.6	17.2	8.6	7.8
	0.00%	*0.00%*	*0.01%*	*0.01%*	*0.01%*	*0.00%*
CPI (level)	0.16%	0.20%	0.19%	0.30%	0.08%	0.16%
Current Account (% of GDP)	0.02	0.03	0.03	0.05	0.02	0.03
Sector Value-Added:						
Manufacturing	0.01%	0.01%	0.03%	0.04%	0.02%	0.02%
EIS	0.00%	0.01%	0.01%	0.02%	0.01%	0.01%
Non-EIS	0.01%	0.01%	0.03%	0.04%	0.03%	0.03%
Agriculture	0.01%	0.01%	0.01%	0.02%	0.01%	0.01%
Extraction	1.00%	1.36%	1.30%	2.23%	0.67%	1.03%
Construction	0.09%	0.09%	0.15%	0.19%	0.10%	0.13%
Services	-0.01%	-0.01%	-0.01%	-0.01%	0.00%	0.00%

***The % rows in this table represent the annual average % difference for the specified time period, between the scenario in question and the 12Bcf/d equivalent – so the % show the percentage equivalent of the change in Bcf/d, US$, '000s, etc.**

Table C2. Impact of Increasing LNG Exports, Annual Avg. Change from 12 Bcf/d, 2015–2025*

	12 Bcf/d to 20 Bcf/d LNG Exports		12 Bcf/d to Market-Determined (endogenous) LNG Export Level			
	Reference	High Resource Recovery	Reference	High Resource Recovery	Low Resource Recovery	High Natural Gas Demand
U.S. Natural Gas Market (Bcf/d)						
NG Production	-0.2	-0.1	-0.2	-0.3	-0.1	-0.3
	-0.3%	*-0.2%*	*-0.4%*	*-0.4%*	*-0.2%*	*-0.4%*
NG Consumption	-0.1	0.0	-0.1	-0.1	-0.1	-0.2
	-0.1%	*0.0%*	*-0.1%*	*-0.1%*	*-0.1%*	*-0.2%*
NG Exports	-0.1	0.0	-0.1	0.0	0.0	-0.1
	-1%	*0%*	*-1%*	*0%*	*-1%*	*-1%*
NG Imports	0.1	0.1	0.1	0.1	0.0	0.1
	0.9%	*1.0%*	*0.9%*	*1.4%*	*0.4%*	*0.6%*
Prices (2010$)						
Henry Hub Price	$0.17	$0.15	$0.20	$0.25	$0.12	$0.18
	0.6%	*0.4%*	*0.9%*	*0.8%*	*0.4%*	*0.8%*
NBP (UK)	$0.00	-$0.01	$0.01	-$0.03	-$0.01	-$0.01
	0.0%	*-0.1%*	*0.1%*	*-0.3%*	*-0.1%*	*-0.1%*
German Border (NW Europe)	$0.00	$0.00	$0.01	-$0.01	-$0.01	$0.00
	0.0%	*0.0%*	*0.1%*	*-0.1%*	*-0.1%*	*0.0%*
JKM (Asia-Pacific)	-$0.73	-$0.89	-$0.89	-$1.31	-$0.50	-$0.71
	-4.9%	*-6.0%*	*-6.0%*	*-8.8%*	*-3.3%*	*-4.8%*
Macroeconomic Impacts						
GDP (annual avg., 2014$B)	-$1.6	-$0.3	-$2.6	-$1.7	-$1.4	-$2.2
	-0.01%	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*	*-0.01%*
Employment (000s)	2.9	5.4	10.2	16.5	8.3	7.5
	0.00%	*0.00%*	*0.01%*	*0.01%*	*0.01%*	*0.00%*
CPI (level)	0.01%	0.01%	0.02%	0.02%	0.01%	0.02%
Current Account (% of GDP)	0.02	0.03	0.03	0.05	0.02	0.03
Sector Value-Added:						
Manufacturing	-0.01%	0.00%	-0.01%	0.00%	-0.01%	-0.01%
EIS	-0.01%	0.00%	-0.01%	-0.01%	-0.01%	-0.01%
Non-EIS	0.00%	0.00%	-0.01%	0.00%	-0.01%	-0.01%
Agriculture	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Extraction	-0.13%	-0.08%	-0.15%	-0.17%	-0.10%	-0.18%
Construction	-0.01%	0.00%	-0.02%	0.00%	-0.01%	-0.01%
Services	0.00%	0.00%	-0.01%	0.00%	0.00%	-0.01%

***The % rows in this table represent the annual average % difference for the specified time period, between the scenario in question and the 12Bcf/d equivalent – so the % show the percentage equivalent of the change in Bcf/d, US$, '000s, etc.**

Annex D RWGTM Results (Price, Demand, Supply, and LNG Trade)[44]

D1. Natural Gas Prices (2010$/mmBtu)[45]

		2005	2010	2015	2020	2025	2030	2035	2040
Henry Hub	Ref_Ref	$ 8.79	$ 4.39	$ 3.28	$ 4.62	$ 5.30	$ 5.79	$ 6.66	$ 7.42
	Ref_HRR	$ 8.79	$ 4.39	$ 3.19	$ 4.23	$ 4.93	$ 5.07	$ 5.62	$ 6.15
	Ref_LRR	$ 8.79	$ 4.39	$ 3.46	$ 4.92	$ 5.66	$ 6.46	$ 7.50	$ 8.57
	Ref_Hi-D	$ 8.79	$ 4.39	$ 3.33	$ 4.69	$ 5.43	$ 6.10	$ 6.97	$ 7.81
	LNG12_Ref	$ 8.79	$ 4.39	$ 3.31	$ 4.63	$ 5.35	$ 5.90	$ 6.94	$ 7.63
	LNG12_HRR	$ 8.79	$ 4.39	$ 3.19	$ 4.34	$ 4.83	$ 5.31	$ 6.06	$ 6.77
	LNG12_LRR	$ 8.79	$ 4.39	$ 3.45	$ 4.89	$ 5.74	$ 6.51	$ 7.54	$ 8.55
	LNG12_Hi-D	$ 8.79	$ 4.39	$ 3.33	$ 4.72	$ 5.45	$ 6.18	$ 7.11	$ 7.93
	LNG20_Ref	$ 8.79	$ 4.39	$ 3.32	$ 4.79	$ 5.44	$ 6.24	$ 7.41	$ 8.29
	LNG20_HRR	$ 8.79	$ 4.39	$ 3.22	$ 4.36	$ 4.95	$ 5.56	$ 6.47	$ 7.21
	LNG20_LRR	$ 8.79	$ 4.39	$ 3.47	$ 4.99	$ 5.81	$ 6.93	$ 8.30	$ 9.61
	LNG20_Hi-D	$ 8.79	$ 4.39	$ 3.35	$ 4.86	$ 5.53	$ 6.48	$ 7.69	$ 8.72
	LNG20_Ref12	$ 8.79	$ 4.39	$ 3.31	$ 4.75	$ 5.34	$ 6.13	$ 6.93	$ 7.69
	LNG20_HRR12	$ 8.79	$ 4.39	$ 3.20	$ 4.33	$ 4.91	$ 5.37	$ 5.86	$ 6.46
	LNG20_LRR12	$ 8.79	$ 4.39	$ 3.46	$ 4.98	$ 5.75	$ 6.89	$ 7.98	$ 9.27
	LNG20_Hi-D12	$ 8.79	$ 4.39	$ 3.34	$ 4.81	$ 5.48	$ 6.40	$ 7.31	$ 8.21
	LNG20_Ref20	$ 8.79	$ 4.39	$ 3.32	$ 4.76	$ 5.38	$ 6.23	$ 7.38	$ 8.18
	LNG20_HRR20	$ 8.79	$ 4.39	$ 3.22	$ 4.34	$ 4.92	$ 5.57	$ 6.23	$ 6.96
NBP	Ref_Ref	$ 7.38	$ 6.56	$ 7.43	$ 7.46	$ 8.36	$ 9.34	$ 10.18	$ 11.46
	Ref_HRR	$ 7.38	$ 6.56	$ 7.43	$ 7.45	$ 8.25	$ 9.43	$ 10.20	$ 11.54
	Ref_LRR	$ 7.38	$ 6.56	$ 7.43	$ 7.46	$ 8.34	$ 9.47	$ 10.28	$ 11.47
	Ref_Hi-D	$ 7.38	$ 6.56	$ 7.43	$ 7.48	$ 8.37	$ 9.42	$ 10.21	$ 11.55
	LNG12_Ref	$ 7.38	$ 6.56	$ 7.49	$ 7.70	$ 8.95	$ 10.80	$ 12.47	$ 14.27
	LNG12_HRR	$ 7.38	$ 6.56	$ 7.49	$ 7.73	$ 8.94	$ 10.80	$ 12.37	$ 14.17
	LNG12_LRR	$ 7.38	$ 6.56	$ 7.49	$ 7.73	$ 8.95	$ 10.76	$ 12.31	$ 13.95
	LNG12_Hi-D	$ 7.38	$ 6.56	$ 7.49	$ 7.73	$ 8.95	$ 10.79	$ 12.28	$ 14.02
	LNG20_Ref	$ 7.38	$ 6.56	$ 7.48	$ 7.75	$ 9.04	$ 10.84	$ 12.30	$ 14.32
	LNG20_HRR	$ 7.38	$ 6.56	$ 7.49	$ 7.75	$ 9.04	$ 10.81	$ 12.31	$ 14.13
	LNG20_LRR	$ 7.38	$ 6.56	$ 7.48	$ 7.77	$ 9.04	$ 10.88	$ 12.20	$ 14.35
	LNG20_Hi-D	$ 7.38	$ 6.56	$ 7.48	$ 7.74	$ 8.98	$ 10.80	$ 12.23	$ 14.14
	LNG20_Ref12	$ 7.38	$ 6.56	$ 7.49	$ 7.76	$ 8.96	$ 10.76	$ 12.23	$ 14.24
	LNG20_HRR12	$ 7.38	$ 6.56	$ 7.49	$ 7.76	$ 9.01	$ 10.84	$ 12.29	$ 14.21
	LNG20_LRR12	$ 7.38	$ 6.56	$ 7.48	$ 7.78	$ 8.99	$ 10.86	$ 12.19	$ 14.35
	LNG20_Hi-D12	$ 7.38	$ 6.56	$ 7.48	$ 7.74	$ 9.03	$ 10.86	$ 12.26	$ 14.27
	LNG20_Ref20	$ 7.38	$ 6.56	$ 7.48	$ 7.74	$ 9.01	$ 10.79	$ 12.28	$ 14.09
	LNG20_HRR20	$ 7.38	$ 6.56	$ 7.48	$ 7.76	$ 8.96	$ 10.86	$ 12.23	$ 14.26
JKM	Ref_Ref	$ 6.05	$ 10.91	$ 9.31	$ 8.95	$ 10.32	$ 11.12	$ 12.57	$ 13.58
	Ref_HRR	$ 6.05	$ 10.91	$ 9.50	$ 8.95	$ 10.15	$ 11.23	$ 12.68	$ 13.65
	Ref_LRR	$ 6.05	$ 10.91	$ 9.46	$ 8.98	$ 10.37	$ 11.38	$ 12.69	$ 13.63
	Ref_Hi-D	$ 6.05	$ 10.91	$ 9.47	$ 8.96	$ 10.37	$ 11.22	$ 12.71	$ 13.66
	LNG12_Ref	$ 6.05	$ 10.91	$ 9.51	$ 9.27	$ 11.62	$ 14.66	$ 16.04	$ 16.69
	LNG12_HRR	$ 6.05	$ 10.91	$ 9.54	$ 9.11	$ 11.59	$ 14.34	$ 15.55	$ 16.23
	LNG12_LRR	$ 6.05	$ 10.91	$ 9.50	$ 9.38	$ 11.66	$ 14.88	$ 16.74	$ 17.21
	LNG12_Hi-D	$ 6.05	$ 10.91	$ 9.62	$ 9.30	$ 11.66	$ 14.75	$ 16.41	$ 17.01
	LNG20_Ref	$ 6.05	$ 10.91	$ 9.55	$ 9.66	$ 13.64	$ 15.70	$ 17.29	$ 19.01
	LNG20_HRR	$ 6.05	$ 10.91	$ 9.67	$ 9.71	$ 13.49	$ 15.30	$ 16.51	$ 17.43
	LNG20_LRR	$ 6.05	$ 10.91	$ 9.66	$ 9.78	$ 13.74	$ 16.18	$ 18.18	$ 20.30
	LNG20_Hi-D	$ 6.05	$ 10.91	$ 9.65	$ 9.70	$ 13.68	$ 15.87	$ 17.54	$ 19.63
	LNG20_Ref12	$ 6.05	$ 10.91	$ 9.60	$ 9.72	$ 13.75	$ 16.03	$ 19.10	$ 22.80
	LNG20_HRR12	$ 6.05	$ 10.91	$ 9.64	$ 9.74	$ 13.61	$ 16.03	$ 19.13	$ 22.83
	LNG20_LRR12	$ 6.05	$ 10.91	$ 9.46	$ 9.84	$ 13.84	$ 16.34	$ 19.05	$ 22.76
	LNG20_Hi-D12	$ 6.05	$ 10.91	$ 9.53	$ 9.70	$ 13.78	$ 16.16	$ 19.06	$ 22.76
	LNG20_Ref20	$ 6.05	$ 10.91	$ 9.59	$ 9.68	$ 13.64	$ 15.78	$ 17.44	$ 20.01
	LNG20_HRR20	$ 6.05	$ 10.91	$ 9.70	$ 9.71	$ 13.48	$ 15.41	$ 17.23	$ 19.81

44 RWGTM outputs are annual and more detailed than indicated. The tables simply reveal trends across scenarios.
45 Only international benchmark prices are presented here to highlight general scenario outcomes.

D2. Demand (tcf)[46]

Ref_Ref Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.750**	**34.643**	**36.561**	**37.177**	**37.924**	**38.871**	**2.02%**	**1.11%**	**0.41%**
Canada	3.144	2.815	3.134	3.372	3.504	3.569	3.632	3.712	-0.03%	1.12%	0.38%
Mexico	1.656	2.286	2.486	2.646	2.854	3.078	3.295	3.489	4.14%	1.39%	1.35%
United States	22.014	24.087	27.130	28.624	30.204	30.530	30.997	31.670	2.11%	1.08%	0.32%
Central & South America	**4.208**	**4.897**	**5.729**	**6.175**	**6.881**	**7.457**	**7.902**	**8.256**	**3.13%**	**1.85%**	**1.22%**
Argentina	1.428	1.529	1.612	1.864	2.036	2.174	2.288	2.386	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.350	1.557	1.744	1.888	2.000	5.82%	3.02%	1.68%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.524	0.562	5.25%	1.27%	1.56%
Peru	0.056	0.194	0.220	0.234	0.265	0.290	0.314	0.328	14.69%	1.91%	1.43%
Trinidad and Tobago	0.575	0.824	0.752	0.760	0.770	0.757	0.742	0.716	2.73%	0.24%	-0.48%
Venezuela	0.828	0.748	1.102	0.980	1.131	1.237	1.301	1.340	2.90%	0.27%	1.13%
Other Central & South America	0.135	0.205	0.264	0.294	0.343	0.394	0.443	0.498	6.96%	2.66%	2.53%
Europe	**20.095**	**20.525**	**17.991**	**18.715**	**19.325**	**19.582**	**19.658**	**19.524**	**-1.10%**	**0.72%**	**0.07%**
Austria	0.354	0.353	0.286	0.295	0.307	0.314	0.318	0.318	-2.10%	0.71%	0.24%
Belgium	0.601	0.700	0.613	0.655	0.696	0.729	0.742	0.746	0.19%	1.29%	0.46%
France	1.740	1.695	1.425	1.440	1.438	1.391	1.349	1.297	-1.98%	0.09%	-0.69%
Germany	3.203	3.329	3.061	3.116	3.176	3.191	3.137	3.048	-0.45%	0.37%	-0.27%
Italy	3.046	2.935	2.324	2.343	2.358	2.359	2.352	2.329	-2.67%	0.15%	-0.08%
Netherlands	1.741	1.937	1.720	1.755	1.759	1.726	1.681	1.616	-0.12%	0.23%	-0.56%
Norway	0.187	0.194	0.223	0.239	0.257	0.238	0.204	0.195	1.77%	1.41%	-1.81%
Poland	0.573	0.606	0.617	0.689	0.759	0.823	0.866	0.900	0.75%	2.09%	1.14%
Portugal	0.152	0.182	0.146	0.153	0.160	0.165	0.169	0.168	-0.43%	0.95%	0.34%
Romania	0.643	0.455	0.454	0.493	0.521	0.529	0.533	0.523	-3.42%	1.39%	0.03%
Spain	1.188	1.265	1.052	1.100	1.144	1.177	1.193	1.206	-1.21%	0.84%	0.36%
Turkey	0.967	1.346	1.533	1.684	1.801	1.879	1.970	2.057	4.72%	1.62%	0.89%
United Kingdom	3.376	3.337	2.648	2.727	2.802	2.847	2.913	2.904	-2.40%	0.57%	0.24%
Other Europe	2.324	2.192	1.890	2.027	2.148	2.213	2.231	2.216	-2.04%	1.29%	0.21%
Eurasia	**21.786**	**21.616**	**21.674**	**22.964**	**24.213**	**24.911**	**25.213**	**25.528**	**-0.05%**	**1.11%**	**0.35%**
Kazakhstan	0.477	0.303	0.474	0.557	0.636	0.692	0.728	0.764	-0.05%	2.97%	1.23%
Russia	14.330	15.471	15.274	15.707	16.173	16.293	16.207	16.095	0.64%	0.57%	-0.03%
Turkmenistan	0.629	0.720	0.765	0.928	1.088	1.217	1.336	1.439	1.98%	3.59%	1.88%
Ukraine	3.079	1.969	1.678	1.771	1.845	1.886	1.895	1.878	-5.89%	0.95%	0.12%
Uzbekistan	1.702	1.614	1.890	2.278	2.621	2.893	3.098	3.404	1.05%	3.33%	1.76%
Other Eurasia	1.569	1.538	1.593	1.723	1.850	1.929	1.948	1.950	0.15%	1.51%	0.35%
Middle East	**9.825**	**13.379**	**14.479**	**15.521**	**17.077**	**18.325**	**19.508**	**20.584**	**3.95%**	**1.66%**	**1.25%**
Iran	3.707	5.106	5.243	5.488	5.929	6.295	6.612	6.936	3.53%	1.24%	1.05%
Qatar	0.660	0.796	1.103	1.142	1.219	1.277	1.313	1.332	5.26%	1.01%	0.59%
Oman	0.324	0.620	0.710	0.780	0.859	0.908	0.939	0.978	8.17%	1.92%	0.87%
Saudi Arabia	2.516	3.096	3.511	3.893	4.422	4.842	5.193	5.471	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.202	2.295	2.463	2.547	2.707	2.836	4.22%	1.13%	0.94%
Other Middle East	1.160	1.614	1.711	1.922	2.185	2.456	2.744	3.032	3.96%	2.48%	2.21%
Africa	**2.979**	**3.535**	**3.893**	**4.597**	**5.542**	**6.591**	**7.721**	**8.867**	**2.71%**	**3.59%**	**3.18%**
Algeria	0.846	1.024	1.086	1.225	1.419	1.591	1.709	1.792	2.53%	2.71%	1.57%
Egypt	1.208	1.630	1.795	2.035	2.360	2.745	3.285	3.859	4.04%	2.77%	3.33%
Nigeria	0.366	0.178	0.257	0.363	0.525	0.716	0.904	1.109	-3.45%	7.39%	5.11%
Other Africa	0.559	0.702	0.755	0.974	1.238	1.538	1.823	2.107	3.06%	5.08%	3.61%
Asia & Oceania	**13.741**	**20.677**	**23.990**	**29.993**	**35.490**	**40.679**	**45.807**	**50.141**	**5.73%**	**3.99%**	**2.33%**
Australia	1.014	1.249	1.543	1.786	1.919	2.002	2.070	2.115	4.29%	2.20%	0.65%
China	1.655	3.769	6.044	8.654	11.656	14.610	17.543	20.394	13.83%	6.79%	3.80%
India	1.269	2.277	1.969	2.800	3.410	4.151	4.949	5.656	4.49%	5.65%	3.43%
Indonesia	0.638	1.397	1.380	1.653	1.987	2.377	2.730	3.051	8.01%	3.71%	2.90%
Japan	3.110	3.861	4.011	4.054	3.996	3.887	3.934	3.891	2.58%	-0.04%	-0.18%
Malaysia	0.914	1.145	1.084	1.289	1.420	1.496	1.531	1.533	1.72%	2.74%	0.51%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.266	0.332	0.399	-2.04%	6.14%	4.17%
Pakistan	1.088	1.400	1.333	1.679	2.023	2.354	2.592	2.632	2.05%	4.26%	1.77%
Singapore	0.233	0.297	0.370	0.409	0.417	0.416	0.409	0.393	4.72%	1.21%	-0.40%
South Korea	1.076	1.524	1.975	2.407	2.636	2.779	2.813	2.765	6.26%	2.93%	0.32%
Thailand	1.150	1.592	1.839	2.133	2.306	2.387	2.512	2.581	4.81%	2.29%	0.75%
Other Asia & Oceania	1.447	2.051	2.324	2.966	3.504	3.953	4.393	4.729	4.85%	4.19%	2.02%
World	**99.448**	**113.816**	**120.506**	**132.609**	**145.089**	**154.722**	**163.732**	**171.770**	**1.94%**	**1.87%**	**1.13%**

[46] Demand includes Lease and Plant Use and Pipeline Fuel. Historical data match those reported by EIA.

Ref_HRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.881**	**35.118**	**37.060**	**37.972**	**38.922**	**40.021**	**2.06%**	**1.20%**	**0.51%**
Canada	3.144	2.815	3.125	3.322	3.480	3.591	3.669	3.762	-0.06%	1.08%	0.52%
Mexico	1.656	2.286	2.499	2.652	2.851	3.042	3.244	3.433	4.20%	1.33%	1.24%
United States	22.014	24.087	27.258	29.144	30.729	31.339	32.009	32.827	2.16%	1.21%	0.44%
Central & South America	**4.208**	**4.897**	**5.729**	**6.176**	**6.883**	**7.464**	**7.889**	**8.286**	**3.13%**	**1.85%**	**1.24%**
Argentina	1.428	1.529	1.611	1.863	2.035	2.175	2.286	2.391	1.21%	2.36%	1.08%
Brazil	0.657	0.890	1.156	1.350	1.556	1.744	1.887	2.005	5.81%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.426	-2.39%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.445	0.493	0.521	0.562	5.25%	1.26%	1.57%
Peru	0.056	0.194	0.221	0.234	0.265	0.290	0.313	0.331	14.73%	1.85%	1.50%
Trinidad and Tobago	0.575	0.824	0.752	0.760	0.772	0.759	0.741	0.716	2.72%	0.27%	-0.50%
Venezuela	0.828	0.748	1.102	0.981	1.133	1.238	1.295	1.358	2.90%	0.28%	1.22%
Other Central & South America	0.135	0.205	0.263	0.295	0.343	0.394	0.444	0.496	6.94%	2.68%	2.50%
Europe	**20.095**	**20.525**	**17.989**	**18.726**	**19.360**	**19.551**	**19.642**	**19.481**	**-1.10%**	**0.74%**	**0.04%**
Austria	0.354	0.353	0.286	0.296	0.308	0.314	0.318	0.317	-2.11%	0.74%	0.21%
Belgium	0.601	0.700	0.613	0.655	0.697	0.728	0.741	0.745	0.19%	1.30%	0.44%
France	1.740	1.695	1.425	1.443	1.446	1.387	1.346	1.293	-1.98%	0.15%	-0.74%
Germany	3.203	3.329	3.060	3.117	3.182	3.185	3.134	3.039	-0.45%	0.39%	-0.31%
Italy	3.046	2.935	2.323	2.344	2.360	2.357	2.351	2.327	-2.67%	0.16%	-0.09%
Netherlands	1.741	1.937	1.720	1.755	1.761	1.724	1.681	1.616	-0.12%	0.23%	-0.57%
Norway	0.187	0.194	0.223	0.237	0.255	0.238	0.206	0.195	1.77%	1.35%	-1.76%
Poland	0.573	0.606	0.618	0.689	0.761	0.817	0.860	0.885	0.75%	2.11%	1.01%
Portugal	0.152	0.182	0.146	0.153	0.160	0.165	0.168	0.168	-0.42%	0.98%	0.32%
Romania	0.643	0.455	0.454	0.493	0.521	0.528	0.533	0.522	-3.42%	1.40%	0.01%
Spain	1.188	1.265	1.052	1.102	1.147	1.176	1.192	1.206	-1.21%	0.87%	0.34%
Turkey	0.967	1.346	1.533	1.686	1.804	1.878	1.970	2.053	4.72%	1.64%	0.86%
United Kingdom	3.376	3.337	2.648	2.728	2.803	2.844	2.913	2.904	-2.40%	0.57%	0.23%
Other Europe	2.324	2.192	1.889	2.028	2.154	2.209	2.230	2.210	-2.05%	1.32%	0.17%
Eurasia	**21.786**	**21.616**	**21.674**	**22.974**	**24.234**	**24.909**	**25.207**	**25.482**	**-0.05%**	**1.12%**	**0.34%**
Kazakhstan	0.477	0.303	0.474	0.557	0.636	0.692	0.729	0.760	-0.05%	2.98%	1.19%
Russia	14.330	15.471	15.275	15.713	16.184	16.291	16.203	16.060	0.64%	0.58%	-0.05%
Turkmenistan	0.629	0.720	0.765	0.928	1.090	1.220	1.337	1.437	1.98%	3.61%	1.86%
Ukraine	3.079	1.969	1.677	1.772	1.847	1.884	1.894	1.875	-5.89%	0.97%	0.10%
Uzbekistan	1.702	1.614	1.890	2.280	2.625	2.893	3.096	3.401	1.05%	3.34%	1.74%
Other Eurasia	1.569	1.538	1.593	1.724	1.852	1.929	1.949	1.949	0.15%	1.52%	0.34%
Middle East	**9.825**	**13.379**	**14.479**	**15.524**	**17.088**	**18.338**	**19.509**	**20.573**	**3.95%**	**1.67%**	**1.25%**
Iran	3.707	5.106	5.243	5.490	5.935	6.301	6.603	6.923	3.53%	1.25%	1.03%
Qatar	0.660	0.796	1.102	1.142	1.219	1.279	1.312	1.332	5.26%	1.01%	0.59%
Oman	0.324	0.620	0.710	0.780	0.859	0.908	0.939	0.977	8.17%	1.92%	0.86%
Saudi Arabia	2.516	3.096	3.510	3.894	4.425	4.842	5.206	5.490	3.39%	2.34%	1.45%
United Arab Emirates	1.457	2.147	2.203	2.296	2.464	2.556	2.708	2.839	4.22%	1.13%	0.95%
Other Middle East	1.160	1.614	1.711	1.922	2.186	2.453	2.741	3.011	3.96%	2.48%	2.16%
Africa	**2.979**	**3.535**	**3.894**	**4.597**	**5.539**	**6.596**	**7.726**	**8.872**	**2.71%**	**3.59%**	**3.19%**
Algeria	0.846	1.024	1.086	1.225	1.420	1.589	1.707	1.793	2.53%	2.72%	1.57%
Egypt	1.208	1.630	1.795	2.034	2.353	2.746	3.287	3.855	4.04%	2.74%	3.35%
Nigeria	0.366	0.178	0.258	0.363	0.526	0.721	0.904	1.107	-3.45%	7.41%	5.08%
Other Africa	0.559	0.702	0.755	0.975	1.240	1.539	1.828	2.116	3.06%	5.09%	3.63%
Asia & Oceania	**13.741**	**20.677**	**23.987**	**29.988**	**35.545**	**40.608**	**45.768**	**50.056**	**5.73%**	**4.01%**	**2.31%**
Australia	1.014	1.249	1.544	1.781	1.919	1.998	2.068	2.108	4.29%	2.20%	0.63%
China	1.655	3.769	6.043	8.652	11.668	14.567	17.522	20.361	13.83%	6.80%	3.78%
India	1.269	2.277	1.968	2.800	3.419	4.148	4.941	5.648	4.49%	5.68%	3.40%
Indonesia	0.638	1.397	1.380	1.652	1.985	2.376	2.729	3.048	8.01%	3.70%	2.90%
Japan	3.110	3.861	4.011	4.054	4.010	3.882	3.931	3.888	2.58%	0.00%	-0.21%
Malaysia	0.914	1.145	1.083	1.287	1.420	1.493	1.534	1.531	1.72%	2.74%	0.50%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.266	0.332	0.397	-2.04%	6.14%	4.15%
Pakistan	1.088	1.400	1.333	1.679	2.034	2.349	2.588	2.644	2.05%	4.32%	1.76%
Singapore	0.233	0.297	0.370	0.409	0.418	0.416	0.409	0.393	4.72%	1.21%	-0.41%
South Korea	1.076	1.524	1.975	2.407	2.644	2.776	2.809	2.760	6.26%	2.96%	0.28%
Thailand	1.150	1.592	1.838	2.133	2.307	2.387	2.512	2.574	4.80%	2.30%	0.73%
Other Asia & Oceania	1.447	2.051	2.323	2.970	3.505	3.949	4.393	4.705	4.85%	4.20%	1.98%
World	**99.448**	**113.816**	**120.633**	**133.104**	**145.710**	**155.438**	**164.664**	**172.771**	**1.95%**	**1.91%**	**1.14%**

Ref_LRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.506**	**34.361**	**36.156**	**36.532**	**37.288**	**38.114**	**1.94%**	**1.07%**	**0.35%**
Canada	3.144	2.815	3.134	3.390	3.496	3.551	3.611	3.692	-0.03%	1.10%	0.36%
Mexico	1.656	2.286	2.476	2.631	2.874	3.103	3.344	3.521	4.10%	1.50%	1.36%
United States	22.014	24.087	26.896	28.340	29.786	29.878	30.332	30.902	2.02%	1.03%	0.25%
Central & South America	**4.208**	**4.897**	**5.730**	**6.170**	**6.883**	**7.456**	**7.890**	**8.264**	**3.13%**	**1.85%**	**1.23%**
Argentina	1.428	1.529	1.612	1.863	2.035	2.175	2.287	2.388	1.22%	2.36%	1.07%
Brazil	0.657	0.890	1.157	1.349	1.556	1.744	1.887	2.002	5.82%	3.01%	1.69%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.425	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.403	0.446	0.491	0.521	0.561	5.25%	1.27%	1.55%
Peru	0.056	0.194	0.220	0.234	0.265	0.289	0.313	0.333	14.68%	1.88%	1.54%
Trinidad and Tobago	0.575	0.824	0.753	0.757	0.772	0.758	0.741	0.714	2.74%	0.25%	-0.52%
Venezuela	0.828	0.748	1.102	0.978	1.134	1.235	1.296	1.345	2.90%	0.29%	1.15%
Other Central & South America	0.135	0.205	0.263	0.296	0.342	0.393	0.445	0.495	6.93%	2.66%	2.50%
Europe	**20.095**	**20.525**	**17.992**	**18.714**	**19.328**	**19.529**	**19.623**	**19.518**	**-1.10%**	**0.72%**	**0.07%**
Austria	0.354	0.353	0.286	0.295	0.307	0.313	0.318	0.318	-2.10%	0.72%	0.23%
Belgium	0.601	0.700	0.613	0.655	0.696	0.727	0.741	0.746	0.19%	1.29%	0.46%
France	1.740	1.695	1.425	1.437	1.436	1.381	1.344	1.296	-1.98%	0.07%	-0.68%
Germany	3.203	3.329	3.061	3.115	3.176	3.182	3.131	3.047	-0.45%	0.37%	-0.28%
Italy	3.046	2.935	2.324	2.342	2.358	2.355	2.349	2.329	-2.67%	0.15%	-0.08%
Netherlands	1.741	1.937	1.720	1.756	1.760	1.724	1.679	1.616	-0.12%	0.23%	-0.57%
Norway	0.187	0.194	0.223	0.240	0.257	0.238	0.204	0.196	1.78%	1.42%	-1.79%
Poland	0.573	0.606	0.618	0.689	0.760	0.819	0.862	0.899	0.76%	2.09%	1.13%
Portugal	0.152	0.182	0.145	0.153	0.160	0.164	0.168	0.168	-0.43%	0.94%	0.35%
Romania	0.643	0.455	0.454	0.493	0.521	0.528	0.533	0.523	-3.42%	1.39%	0.03%
Spain	1.188	1.265	1.052	1.099	1.142	1.172	1.191	1.206	-1.21%	0.83%	0.36%
Turkey	0.967	1.346	1.533	1.687	1.802	1.874	1.968	2.055	4.72%	1.63%	0.88%
United Kingdom	3.376	3.337	2.647	2.728	2.804	2.845	2.909	2.904	-2.40%	0.58%	0.23%
Other Europe	2.324	2.192	1.890	2.026	2.149	2.205	2.226	2.215	-2.05%	1.29%	0.20%
Eurasia	**21.786**	**21.616**	**21.674**	**22.970**	**24.225**	**24.886**	**25.212**	**25.504**	**-0.05%**	**1.12%**	**0.34%**
Kazakhstan	0.477	0.303	0.474	0.557	0.637	0.691	0.731	0.764	-0.05%	2.99%	1.23%
Russia	14.330	15.471	15.274	15.710	16.178	16.277	16.208	16.074	0.64%	0.58%	-0.04%
Turkmenistan	0.629	0.720	0.765	0.929	1.088	1.215	1.335	1.435	1.98%	3.59%	1.86%
Ukraine	3.079	1.969	1.678	1.771	1.847	1.885	1.894	1.879	-5.89%	0.97%	0.12%
Uzbekistan	1.702	1.614	1.890	2.279	2.623	2.890	3.096	3.402	1.05%	3.33%	1.75%
Other Eurasia	1.569	1.538	1.593	1.724	1.852	1.928	1.948	1.949	0.15%	1.52%	0.34%
Middle East	**9.825**	**13.379**	**14.479**	**15.527**	**17.080**	**18.351**	**19.527**	**20.597**	**3.95%**	**1.67%**	**1.26%**
Iran	3.707	5.106	5.243	5.495	5.931	6.308	6.625	6.922	3.53%	1.24%	1.04%
Qatar	0.660	0.796	1.102	1.142	1.219	1.277	1.312	1.345	5.26%	1.01%	0.66%
Oman	0.324	0.620	0.710	0.780	0.859	0.909	0.943	0.973	8.17%	1.92%	0.84%
Saudi Arabia	2.516	3.096	3.510	3.892	4.422	4.848	5.202	5.488	3.39%	2.34%	1.45%
United Arab Emirates	1.457	2.147	2.203	2.296	2.464	2.554	2.703	2.845	4.22%	1.13%	0.96%
Other Middle East	1.160	1.614	1.710	1.921	2.186	2.455	2.743	3.023	3.95%	2.48%	2.19%
Africa	**2.979**	**3.535**	**3.894**	**4.598**	**5.550**	**6.588**	**7.716**	**8.877**	**2.72%**	**3.61%**	**3.18%**
Algeria	0.846	1.024	1.086	1.225	1.420	1.590	1.704	1.789	2.53%	2.71%	1.56%
Egypt	1.208	1.630	1.795	2.035	2.362	2.742	3.280	3.859	4.04%	2.78%	3.33%
Nigeria	0.366	0.178	0.258	0.362	0.530	0.720	0.911	1.110	-3.42%	7.44%	5.06%
Other Africa	0.559	0.702	0.755	0.975	1.239	1.536	1.821	2.118	3.06%	5.08%	3.64%
Asia & Oceania	**13.741**	**20.677**	**23.989**	**29.985**	**35.478**	**40.573**	**45.778**	**50.001**	**5.73%**	**3.99%**	**2.31%**
Australia	1.014	1.249	1.544	1.788	1.920	2.000	2.068	2.109	4.29%	2.20%	0.63%
China	1.655	3.769	6.044	8.647	11.663	14.561	17.548	20.335	13.83%	6.79%	3.78%
India	1.269	2.277	1.969	2.798	3.410	4.142	4.935	5.637	4.49%	5.65%	3.41%
Indonesia	0.638	1.397	1.380	1.654	1.987	2.379	2.731	3.052	8.01%	3.71%	2.90%
Japan	3.110	3.861	4.011	4.052	3.992	3.874	3.929	3.890	2.58%	-0.05%	-0.17%
Malaysia	0.914	1.145	1.084	1.287	1.420	1.495	1.529	1.531	1.72%	2.74%	0.50%
Myanmar	0.146	0.114	0.119	0.165	0.215	0.265	0.332	0.397	-2.05%	6.12%	4.18%
Pakistan	1.088	1.400	1.333	1.679	2.021	2.342	2.585	2.625	2.05%	4.25%	1.76%
Singapore	0.233	0.297	0.370	0.409	0.417	0.416	0.408	0.393	4.72%	1.20%	-0.40%
South Korea	1.076	1.524	1.975	2.405	2.633	2.769	2.804	2.757	6.26%	2.92%	0.31%
Thailand	1.150	1.592	1.838	2.132	2.302	2.385	2.512	2.577	4.80%	2.27%	0.76%
Other Asia & Oceania	1.447	2.051	2.322	2.969	3.499	3.946	4.396	4.697	4.84%	4.19%	1.98%
World	**99.448**	**113.816**	**120.263**	**132.325**	**144.700**	**153.914**	**163.034**	**170.875**	**1.92%**	**1.87%**	**1.11%**

Ref_Hi-D Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.838**	**35.538**	**38.173**	**39.441**	**40.216**	**41.102**	**2.05%**	**1.52%**	**0.49%**
Canada	3.144	2.815	3.132	3.381	3.502	3.561	3.622	3.703	-0.04%	1.12%	0.37%
Mexico	1.656	2.286	2.485	2.640	2.859	3.091	3.303	3.508	4.14%	1.41%	1.37%
United States	22.014	24.087	27.221	29.517	31.812	32.789	33.291	33.891	2.15%	1.57%	0.42%
Central & South America	**4.208**	**4.897**	**5.729**	**6.173**	**6.885**	**7.461**	**7.894**	**8.252**	**3.13%**	**1.86%**	**1.22%**
Argentina	1.428	1.529	1.611	1.863	2.036	2.176	2.286	2.391	1.22%	2.37%	1.08%
Brazil	0.657	0.890	1.157	1.349	1.557	1.745	1.887	2.004	5.82%	3.02%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.73%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.524	0.561	5.25%	1.28%	1.54%
Peru	0.056	0.194	0.219	0.233	0.266	0.291	0.313	0.331	14.66%	1.96%	1.47%
Trinidad and Tobago	0.575	0.824	0.752	0.760	0.770	0.757	0.740	0.712	2.73%	0.24%	-0.52%
Venezuela	0.828	0.748	1.102	0.981	1.134	1.234	1.300	1.340	2.90%	0.29%	1.12%
Other Central & South America	0.135	0.205	0.263	0.294	0.342	0.397	0.442	0.487	6.95%	2.66%	2.37%
Europe	**20.095**	**20.525**	**17.991**	**18.709**	**19.319**	**19.557**	**19.647**	**19.483**	**-1.10%**	**0.71%**	**0.06%**
Austria	0.354	0.353	0.286	0.295	0.307	0.314	0.318	0.317	-2.10%	0.71%	0.23%
Belgium	0.601	0.700	0.613	0.655	0.696	0.728	0.741	0.745	0.19%	1.28%	0.45%
France	1.740	1.695	1.425	1.438	1.436	1.388	1.346	1.293	-1.98%	0.07%	-0.70%
Germany	3.203	3.329	3.061	3.114	3.174	3.186	3.135	3.041	-0.45%	0.36%	-0.29%
Italy	3.046	2.935	2.324	2.342	2.357	2.357	2.351	2.327	-2.67%	0.14%	-0.09%
Netherlands	1.741	1.937	1.720	1.755	1.760	1.724	1.681	1.615	-0.12%	0.23%	-0.57%
Norway	0.187	0.194	0.223	0.239	0.257	0.238	0.205	0.194	1.77%	1.43%	-1.86%
Poland	0.573	0.606	0.618	0.688	0.760	0.822	0.865	0.897	0.75%	2.09%	1.11%
Portugal	0.152	0.182	0.145	0.153	0.160	0.165	0.168	0.168	-0.43%	0.95%	0.34%
Romania	0.643	0.455	0.454	0.493	0.521	0.529	0.533	0.522	-3.42%	1.39%	0.02%
Spain	1.188	1.265	1.052	1.100	1.143	1.176	1.192	1.205	-1.21%	0.83%	0.35%
Turkey	0.967	1.346	1.533	1.686	1.799	1.878	1.968	2.052	4.72%	1.61%	0.88%
United Kingdom	3.376	3.337	2.648	2.726	2.802	2.844	2.913	2.898	-2.40%	0.57%	0.22%
Other Europe	2.324	2.192	1.890	2.026	2.147	2.209	2.229	2.209	-2.05%	1.29%	0.19%
Eurasia	**21.786**	**21.616**	**21.674**	**22.968**	**24.209**	**24.897**	**25.194**	**25.479**	**-0.05%**	**1.11%**	**0.34%**
Kazakhstan	0.477	0.303	0.474	0.557	0.635	0.691	0.730	0.763	-0.05%	2.95%	1.23%
Russia	14.330	15.471	15.274	15.708	16.167	16.282	16.192	16.055	0.64%	0.57%	-0.05%
Turkmenistan	0.629	0.720	0.765	0.929	1.090	1.218	1.335	1.436	1.98%	3.60%	1.86%
Ukraine	3.079	1.969	1.678	1.771	1.845	1.885	1.894	1.875	-5.89%	0.96%	0.11%
Uzbekistan	1.702	1.614	1.890	2.280	2.622	2.892	3.096	3.401	1.05%	3.33%	1.75%
Other Eurasia	1.569	1.538	1.593	1.723	1.851	1.930	1.948	1.949	0.15%	1.51%	0.35%
Middle East	**9.825**	**13.379**	**14.477**	**15.518**	**17.082**	**18.346**	**19.509**	**20.598**	**3.95%**	**1.67%**	**1.26%**
Iran	3.707	5.106	5.243	5.487	5.932	6.301	6.617	6.925	3.53%	1.24%	1.04%
Qatar	0.660	0.796	1.102	1.142	1.219	1.279	1.312	1.328	5.26%	1.01%	0.57%
Oman	0.324	0.620	0.710	0.780	0.859	0.909	0.940	0.982	8.17%	1.92%	0.90%
Saudi Arabia	2.516	3.096	3.511	3.892	4.422	4.853	5.204	5.487	3.39%	2.34%	1.45%
United Arab Emirates	1.457	2.147	2.202	2.296	2.465	2.549	2.700	2.858	4.22%	1.13%	0.99%
Other Middle East	1.160	1.614	1.708	1.921	2.184	2.456	2.736	3.018	3.94%	2.49%	2.18%
Africa	**2.979**	**3.535**	**3.895**	**4.597**	**5.541**	**6.595**	**7.721**	**8.877**	**2.72%**	**3.59%**	**3.19%**
Algeria	0.846	1.024	1.086	1.226	1.421	1.591	1.709	1.790	2.53%	2.73%	1.55%
Egypt	1.208	1.630	1.795	2.034	2.355	2.745	3.285	3.854	4.04%	2.75%	3.34%
Nigeria	0.366	0.178	0.259	0.363	0.527	0.721	0.904	1.123	-3.41%	7.37%	5.17%
Other Africa	0.559	0.702	0.755	0.975	1.239	1.538	1.822	2.110	3.06%	5.08%	3.62%
Asia & Oceania	**13.741**	**20.677**	**23.991**	**29.992**	**35.464**	**40.610**	**45.733**	**50.039**	**5.73%**	**3.99%**	**2.32%**
Australia	1.014	1.249	1.544	1.785	1.921	1.999	2.065	2.107	4.29%	2.21%	0.62%
China	1.655	3.769	6.045	8.653	11.652	14.571	17.506	20.350	13.83%	6.78%	3.79%
India	1.269	2.277	1.969	2.798	3.403	4.144	4.939	5.645	4.49%	5.63%	3.43%
Indonesia	0.638	1.397	1.380	1.654	1.987	2.375	2.726	3.043	8.01%	3.71%	2.88%
Japan	3.110	3.861	4.011	4.053	3.992	3.883	3.930	3.887	2.58%	-0.05%	-0.18%
Malaysia	0.914	1.145	1.084	1.288	1.420	1.494	1.531	1.529	1.72%	2.74%	0.50%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.266	0.332	0.398	-2.05%	6.13%	4.18%
Pakistan	1.088	1.400	1.333	1.679	2.019	2.352	2.587	2.643	2.05%	4.24%	1.81%
Singapore	0.233	0.297	0.370	0.409	0.417	0.416	0.408	0.393	4.72%	1.21%	-0.40%
South Korea	1.076	1.524	1.975	2.406	2.633	2.776	2.808	2.759	6.26%	2.92%	0.31%
Thailand	1.150	1.592	1.838	2.133	2.304	2.385	2.510	2.574	4.80%	2.28%	0.74%
Other Asia & Oceania	1.447	2.051	2.324	2.970	3.501	3.948	4.389	4.711	4.85%	4.18%	2.00%
World	**99.448**	**113.816**	**120.594**	**133.495**	**146.674**	**156.909**	**165.914**	**173.831**	**1.95%**	**1.98%**	**1.14%**

LNG12_Ref Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.721**	**34.763**	**36.660**	**37.292**	**38.113**	**39.078**	**2.01%**	**1.14%**	**0.43%**
Canada	3.144	2.815	3.128	3.364	3.511	3.585	3.667	3.722	-0.05%	1.16%	0.39%
Mexico	1.656	2.286	2.487	2.644	2.849	3.074	3.294	3.509	4.15%	1.37%	1.40%
United States	22.014	24.087	27.106	28.755	30.301	30.634	31.151	31.846	2.10%	1.12%	0.33%
Central & South America	**4.208**	**4.897**	**5.725**	**6.170**	**6.888**	**7.455**	**7.876**	**8.173**	**3.13%**	**1.87%**	**1.15%**
Argentina	1.428	1.529	1.612	1.862	2.037	2.175	2.289	2.384	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.348	1.556	1.746	1.886	2.004	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.446	0.490	0.522	0.559	5.25%	1.27%	1.52%
Peru	0.056	0.194	0.218	0.234	0.265	0.291	0.312	0.331	14.61%	1.95%	1.50%
Trinidad and Tobago	0.575	0.824	0.750	0.761	0.775	0.761	0.738	0.706	2.70%	0.33%	-0.62%
Venezuela	0.828	0.748	1.102	0.981	1.135	1.234	1.306	1.334	2.90%	0.30%	1.08%
Other Central & South America	0.135	0.205	0.263	0.292	0.341	0.388	0.423	0.429	6.93%	2.66%	1.54%
Europe	**20.095**	**20.525**	**17.967**	**18.614**	**19.115**	**19.234**	**19.244**	**19.026**	**-1.11%**	**0.62%**	**-0.03%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.314	0.314	-2.11%	0.66%	0.19%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.728	0.730	0.18%	1.20%	0.38%
France	1.740	1.695	1.421	1.419	1.396	1.329	1.288	1.243	-2.01%	-0.17%	-0.77%
Germany	3.203	3.329	3.057	3.095	3.139	3.147	3.078	2.976	-0.47%	0.27%	-0.35%
Italy	3.046	2.935	2.322	2.337	2.349	2.344	2.339	2.317	-2.68%	0.12%	-0.09%
Netherlands	1.741	1.937	1.717	1.739	1.733	1.683	1.635	1.578	-0.14%	0.09%	-0.62%
Norway	0.187	0.194	0.225	0.247	0.263	0.256	0.239	0.225	1.86%	1.58%	-1.03%
Poland	0.573	0.606	0.618	0.681	0.735	0.770	0.783	0.780	0.75%	1.75%	0.40%
Portugal	0.152	0.182	0.145	0.152	0.158	0.161	0.166	0.167	-0.46%	0.83%	0.41%
Romania	0.643	0.455	0.454	0.492	0.519	0.528	0.532	0.518	-3.42%	1.35%	-0.01%
Spain	1.188	1.265	1.050	1.093	1.129	1.153	1.179	1.207	-1.23%	0.73%	0.45%
Turkey	0.967	1.346	1.530	1.682	1.792	1.872	1.966	2.053	4.70%	1.60%	0.91%
United Kingdom	3.376	3.337	2.645	2.717	2.781	2.783	2.806	2.752	-2.41%	0.50%	-0.07%
Other Europe	2.324	2.192	1.887	2.015	2.127	2.179	2.191	2.165	-2.06%	1.20%	0.12%
Eurasia	**21.786**	**21.616**	**21.673**	**22.917**	**24.215**	**24.910**	**25.193**	**25.422**	**-0.05%**	**1.12%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.556	0.638	0.692	0.732	0.766	-0.05%	3.00%	1.23%
Russia	14.330	15.471	15.275	15.673	16.167	16.289	16.198	16.016	0.64%	0.57%	-0.06%
Turkmenistan	0.629	0.720	0.765	0.928	1.094	1.230	1.347	1.452	1.98%	3.64%	1.90%
Ukraine	3.079	1.969	1.676	1.766	1.844	1.885	1.887	1.861	-5.90%	0.96%	0.06%
Uzbekistan	1.702	1.614	1.890	2.273	2.620	2.886	3.088	3.388	1.05%	3.32%	1.73%
Other Eurasia	1.569	1.538	1.593	1.721	1.852	1.926	1.942	1.939	0.15%	1.52%	0.31%
Middle East	**9.825**	**13.379**	**14.478**	**15.518**	**17.074**	**18.352**	**19.528**	**20.571**	**3.95%**	**1.66%**	**1.25%**
Iran	3.707	5.106	5.244	5.486	5.922	6.306	6.605	6.934	3.53%	1.22%	1.06%
Qatar	0.660	0.796	1.102	1.142	1.225	1.285	1.315	1.336	5.26%	1.06%	0.58%
Oman	0.324	0.620	0.710	0.780	0.860	0.909	0.948	0.974	8.17%	1.93%	0.83%
Saudi Arabia	2.516	3.096	3.510	3.892	4.419	4.844	5.202	5.465	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.203	2.296	2.464	2.550	2.706	2.835	4.22%	1.13%	0.94%
Other Middle East	1.160	1.614	1.709	1.921	2.185	2.457	2.753	3.027	3.95%	2.49%	2.20%
Africa	**2.979**	**3.535**	**3.895**	**4.599**	**5.562**	**6.594**	**7.723**	**8.886**	**2.72%**	**3.63%**	**3.17%**
Algeria	0.846	1.024	1.087	1.227	1.426	1.592	1.700	1.784	2.53%	2.75%	1.51%
Egypt	1.208	1.630	1.795	2.033	2.355	2.743	3.286	3.857	4.04%	2.75%	3.34%
Nigeria	0.366	0.178	0.259	0.364	0.538	0.718	0.909	1.117	-3.40%	7.59%	4.99%
Other Africa	0.559	0.702	0.755	0.975	1.243	1.541	1.829	2.129	3.05%	5.12%	3.65%
Asia & Oceania	**13.741**	**20.677**	**24.175**	**30.428**	**35.696**	**39.988**	**43.479**	**44.379**	**5.81%**	**3.97%**	**1.46%**
Australia	1.014	1.249	1.545	1.803	1.922	2.002	2.072	2.156	4.30%	2.21%	0.77%
China	1.655	3.769	6.018	8.784	11.687	14.201	16.103	16.975	13.78%	6.86%	2.52%
India	1.269	2.277	1.959	2.689	3.279	3.923	4.498	4.686	4.44%	5.29%	2.41%
Indonesia	0.638	1.397	1.383	1.656	1.990	2.381	2.738	3.024	8.04%	3.71%	2.83%
Japan	3.110	3.861	4.236	4.473	4.367	4.173	4.105	3.869	3.14%	0.30%	-0.80%
Malaysia	0.914	1.145	1.083	1.287	1.419	1.498	1.525	1.516	1.72%	2.74%	0.44%
Myanmar	0.146	0.114	0.119	0.164	0.216	0.276	0.339	0.371	-2.03%	6.13%	3.68%
Pakistan	1.088	1.400	1.332	1.679	2.034	2.218	2.373	2.455	2.04%	4.33%	1.26%
Singapore	0.233	0.297	0.370	0.409	0.417	0.414	0.406	0.390	4.72%	1.19%	-0.44%
South Korea	1.076	1.524	1.966	2.381	2.591	2.654	2.667	2.577	6.21%	2.80%	-0.04%
Thailand	1.150	1.592	1.838	2.130	2.301	2.366	2.482	2.321	4.80%	2.27%	0.06%
Other Asia & Oceania	1.447	2.051	2.324	2.973	3.473	3.883	4.172	4.038	4.85%	4.10%	1.01%
World	**99.448**	**113.816**	**120.633**	**133.009**	**145.210**	**153.825**	**161.156**	**165.535**	**1.95%**	**1.87%**	**0.88%**

LNG12_HRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.877**	**35.072**	**37.122**	**37.928**	**38.956**	**40.023**	**2.06%**	**1.22%**	**0.50%**
Canada	3.144	2.815	3.126	3.328	3.490	3.595	3.687	3.749	-0.06%	1.11%	0.48%
Mexico	1.656	2.286	2.497	2.650	2.849	3.058	3.273	3.472	4.19%	1.33%	1.33%
United States	22.014	24.087	27.255	29.093	30.783	31.274	31.995	32.802	2.16%	1.22%	0.42%
Central & South America	**4.208**	**4.897**	**5.729**	**6.179**	**6.890**	**7.456**	**7.862**	**8.201**	**3.13%**	**1.86%**	**1.17%**
Argentina	1.428	1.529	1.612	1.863	2.037	2.175	2.288	2.386	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.557	1.746	1.886	2.007	5.82%	3.02%	1.71%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.520	0.562	5.25%	1.28%	1.54%
Peru	0.056	0.194	0.220	0.234	0.265	0.291	0.313	0.334	14.71%	1.87%	1.55%
Trinidad and Tobago	0.575	0.824	0.752	0.766	0.776	0.761	0.737	0.712	2.72%	0.32%	-0.57%
Venezuela	0.828	0.748	1.102	0.981	1.133	1.235	1.292	1.342	2.90%	0.28%	1.13%
Other Central & South America	0.135	0.205	0.263	0.293	0.342	0.388	0.426	0.433	6.94%	2.65%	1.59%
Europe	**20.095**	**20.525**	**17.967**	**18.619**	**19.123**	**19.233**	**19.264**	**19.052**	**-1.11%**	**0.63%**	**-0.02%**
Austria	0.354	0.353	0.285	0.294	0.305	0.311	0.315	0.314	-2.12%	0.67%	0.19%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.729	0.730	0.18%	1.20%	0.38%
France	1.740	1.695	1.421	1.420	1.397	1.329	1.291	1.247	-2.01%	-0.17%	-0.75%
Germany	3.203	3.329	3.057	3.095	3.140	3.146	3.083	2.981	-0.47%	0.27%	-0.34%
Italy	3.046	2.935	2.322	2.338	2.351	2.344	2.341	2.318	-2.68%	0.12%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.734	1.683	1.635	1.578	-0.14%	0.10%	-0.63%
Norway	0.187	0.194	0.225	0.247	0.264	0.255	0.238	0.224	1.86%	1.59%	-1.07%
Poland	0.573	0.606	0.618	0.682	0.735	0.770	0.784	0.783	0.76%	1.75%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.158	0.161	0.167	0.168	-0.46%	0.83%	0.41%
Romania	0.643	0.455	0.454	0.492	0.519	0.528	0.532	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.093	1.129	1.152	1.181	1.208	-1.23%	0.73%	0.45%
Turkey	0.967	1.346	1.530	1.684	1.793	1.872	1.966	2.053	4.70%	1.60%	0.91%
United Kingdom	3.376	3.337	2.644	2.716	2.782	2.785	2.809	2.760	-2.41%	0.51%	-0.05%
Other Europe	2.324	2.192	1.887	2.015	2.128	2.179	2.194	2.169	-2.06%	1.20%	0.13%
Eurasia	**21.786**	**21.616**	**21.673**	**22.928**	**24.227**	**24.912**	**25.216**	**25.460**	**-0.05%**	**1.12%**	**0.33%**
Kazakhstan	0.477	0.303	0.474	0.557	0.640	0.692	0.731	0.766	-0.05%	3.03%	1.21%
Russia	14.330	15.471	15.275	15.680	16.173	16.290	16.210	16.042	0.64%	0.57%	-0.05%
Turkmenistan	0.629	0.720	0.765	0.928	1.095	1.233	1.352	1.455	1.98%	3.66%	1.91%
Ukraine	3.079	1.969	1.676	1.766	1.846	1.885	1.889	1.863	-5.90%	0.97%	0.06%
Uzbekistan	1.702	1.614	1.890	2.275	2.621	2.885	3.090	3.393	1.05%	3.33%	1.74%
Other Eurasia	1.569	1.538	1.592	1.722	1.852	1.926	1.944	1.941	0.15%	1.52%	0.31%
Middle East	**9.825**	**13.379**	**14.477**	**15.515**	**17.081**	**18.348**	**19.518**	**20.599**	**3.95%**	**1.67%**	**1.26%**
Iran	3.707	5.106	5.243	5.484	5.925	6.301	6.604	6.964	3.53%	1.23%	1.08%
Qatar	0.660	0.796	1.103	1.143	1.226	1.285	1.312	1.330	5.26%	1.07%	0.54%
Oman	0.324	0.620	0.710	0.780	0.860	0.905	0.950	0.981	8.17%	1.93%	0.88%
Saudi Arabia	2.516	3.096	3.510	3.893	4.420	4.848	5.203	5.469	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.202	2.295	2.463	2.549	2.702	2.841	4.22%	1.12%	0.96%
Other Middle East	1.160	1.614	1.708	1.920	2.188	2.459	2.747	3.015	3.94%	2.50%	2.16%
Africa	**2.979**	**3.535**	**3.897**	**4.604**	**5.566**	**6.609**	**7.720**	**8.875**	**2.72%**	**3.63%**	**3.16%**
Algeria	0.846	1.024	1.087	1.228	1.426	1.590	1.708	1.784	2.53%	2.75%	1.51%
Egypt	1.208	1.630	1.795	2.035	2.360	2.744	3.288	3.856	4.04%	2.77%	3.33%
Nigeria	0.366	0.178	0.260	0.365	0.536	0.732	0.893	1.102	-3.35%	7.50%	4.92%
Other Africa	0.559	0.702	0.755	0.976	1.244	1.543	1.831	2.133	3.05%	5.12%	3.66%
Asia & Oceania	**13.741**	**20.677**	**24.180**	**30.475**	**35.724**	**40.202**	**43.827**	**44.579**	**5.81%**	**3.98%**	**1.49%**
Australia	1.014	1.249	1.546	1.804	1.918	2.000	2.070	2.149	4.31%	2.18%	0.76%
China	1.655	3.769	6.021	8.810	11.707	14.335	16.214	17.036	13.79%	6.88%	2.53%
India	1.269	2.277	1.959	2.689	3.283	3.945	4.604	4.712	4.44%	5.30%	2.44%
Indonesia	0.638	1.397	1.384	1.657	1.991	2.383	2.740	3.037	8.04%	3.70%	2.86%
Japan	3.110	3.861	4.236	4.483	4.367	4.185	4.177	3.883	3.14%	0.31%	-0.78%
Malaysia	0.914	1.145	1.084	1.286	1.419	1.499	1.526	1.520	1.72%	2.73%	0.46%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.277	0.339	0.374	-2.03%	6.12%	3.73%
Pakistan	1.088	1.400	1.332	1.679	2.036	2.236	2.399	2.471	2.04%	4.34%	1.30%
Singapore	0.233	0.297	0.370	0.409	0.417	0.415	0.406	0.392	4.72%	1.19%	-0.42%
South Korea	1.076	1.524	1.966	2.388	2.591	2.666	2.679	2.589	6.21%	2.80%	-0.01%
Thailand	1.150	1.592	1.838	2.130	2.300	2.370	2.487	2.366	4.80%	2.26%	0.19%
Other Asia & Oceania	1.447	2.051	2.324	2.976	3.479	3.892	4.186	4.049	4.85%	4.12%	1.02%
World	**99.448**	**113.816**	**120.799**	**133.391**	**145.733**	**154.687**	**162.363**	**166.789**	**1.96%**	**1.89%**	**0.90%**

LNG12_LRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.530**	**34.486**	**36.324**	**36.725**	**37.446**	**38.304**	**1.95%**	**1.11%**	**0.35%**
Canada	3.144	2.815	3.131	3.389	3.510	3.572	3.642	3.694	-0.04%	1.15%	0.34%
Mexico	1.656	2.286	2.477	2.629	2.877	3.106	3.350	3.549	4.11%	1.51%	1.41%
United States	22.014	24.087	26.923	28.468	29.937	30.046	30.454	31.062	2.03%	1.07%	0.25%
Central & South America	**4.208**	**4.897**	**5.728**	**6.179**	**6.886**	**7.455**	**7.864**	**8.184**	**3.13%**	**1.86%**	**1.16%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.175	2.289	2.386	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.556	1.746	1.886	2.007	5.82%	3.01%	1.71%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.426	-2.40%	3.72%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.524	0.562	5.25%	1.27%	1.56%
Peru	0.056	0.194	0.219	0.234	0.265	0.291	0.314	0.332	14.66%	1.90%	1.52%
Trinidad and Tobago	0.575	0.824	0.752	0.766	0.776	0.759	0.738	0.707	2.73%	0.31%	-0.61%
Venezuela	0.828	0.748	1.102	0.982	1.133	1.234	1.297	1.334	2.90%	0.28%	1.09%
Other Central & South America	0.135	0.205	0.263	0.293	0.341	0.389	0.413	0.430	6.94%	2.63%	1.55%
Europe	**20.095**	**20.525**	**17.967**	**18.614**	**19.117**	**19.240**	**19.275**	**19.113**	**-1.11%**	**0.62%**	**0.00%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.315	-2.11%	0.66%	0.21%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.729	0.732	0.18%	1.20%	0.40%
France	1.740	1.695	1.421	1.417	1.396	1.330	1.292	1.253	-2.01%	-0.17%	-0.72%
Germany	3.203	3.329	3.057	3.094	3.139	3.148	3.085	2.988	-0.46%	0.27%	-0.33%
Italy	3.046	2.935	2.322	2.337	2.350	2.344	2.340	2.320	-2.68%	0.12%	-0.08%
Netherlands	1.741	1.937	1.717	1.740	1.734	1.684	1.635	1.580	-0.14%	0.10%	-0.62%
Norway	0.187	0.194	0.225	0.249	0.263	0.255	0.241	0.226	1.87%	1.57%	-0.99%
Poland	0.573	0.606	0.618	0.681	0.734	0.770	0.784	0.786	0.75%	1.75%	0.45%
Portugal	0.152	0.182	0.145	0.152	0.158	0.161	0.166	0.168	-0.46%	0.83%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.532	0.520	-3.42%	1.35%	0.01%
Spain	1.188	1.265	1.050	1.092	1.129	1.153	1.180	1.209	-1.23%	0.73%	0.46%
Turkey	0.967	1.346	1.530	1.683	1.792	1.872	1.970	2.064	4.70%	1.59%	0.95%
United Kingdom	3.376	3.337	2.644	2.717	2.783	2.786	2.809	2.776	-2.41%	0.51%	-0.02%
Other Europe	2.324	2.192	1.888	2.015	2.126	2.180	2.196	2.177	-2.06%	1.20%	0.16%
Eurasia	**21.786**	**21.616**	**21.674**	**22.932**	**24.223**	**24.916**	**25.228**	**25.491**	**-0.05%**	**1.12%**	**0.34%**
Kazakhstan	0.477	0.303	0.474	0.557	0.640	0.693	0.732	0.767	-0.05%	3.04%	1.22%
Russia	14.330	15.471	15.276	15.683	16.175	16.292	16.216	16.057	0.64%	0.57%	-0.05%
Turkmenistan	0.629	0.720	0.765	0.929	1.094	1.233	1.352	1.457	1.99%	3.64%	1.93%
Ukraine	3.079	1.969	1.677	1.766	1.844	1.885	1.889	1.867	-5.90%	0.96%	0.08%
Uzbekistan	1.702	1.614	1.890	2.276	2.621	2.886	3.091	3.398	1.05%	3.32%	1.75%
Other Eurasia	1.569	1.538	1.592	1.721	1.850	1.927	1.947	1.944	0.15%	1.51%	0.33%
Middle East	**9.825**	**13.379**	**14.477**	**15.520**	**17.082**	**18.361**	**19.528**	**20.567**	**3.95%**	**1.67%**	**1.25%**
Iran	3.707	5.106	5.243	5.489	5.926	6.308	6.606	6.921	3.53%	1.23%	1.04%
Qatar	0.660	0.796	1.102	1.142	1.227	1.286	1.316	1.335	5.26%	1.08%	0.56%
Oman	0.324	0.620	0.710	0.781	0.861	0.908	0.946	0.978	8.17%	1.94%	0.85%
Saudi Arabia	2.516	3.096	3.509	3.893	4.419	4.849	5.206	5.481	3.38%	2.33%	1.45%
United Arab Emirates	1.457	2.147	2.203	2.296	2.464	2.554	2.703	2.812	4.22%	1.13%	0.88%
Other Middle East	1.160	1.614	1.709	1.920	2.185	2.457	2.752	3.042	3.95%	2.49%	2.23%
Africa	**2.979**	**3.535**	**3.897**	**4.603**	**5.561**	**6.600**	**7.750**	**8.915**	**2.72%**	**3.62%**	**3.20%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.593	1.709	1.788	2.53%	2.76%	1.52%
Egypt	1.208	1.630	1.795	2.032	2.357	2.743	3.291	3.855	4.04%	2.76%	3.33%
Nigeria	0.366	0.178	0.260	0.367	0.534	0.723	0.911	1.141	-3.34%	7.44%	5.20%
Other Africa	0.559	0.702	0.755	0.976	1.243	1.540	1.838	2.131	3.05%	5.12%	3.66%
Asia & Oceania	**13.741**	**20.677**	**24.177**	**30.415**	**35.682**	**39.881**	**43.285**	**44.296**	**5.81%**	**3.97%**	**1.45%**
Australia	1.014	1.249	1.546	1.811	1.919	2.001	2.082	2.172	4.31%	2.18%	0.83%
China	1.655	3.769	6.019	8.774	11.697	14.122	16.023	16.926	13.78%	6.87%	2.49%
India	1.269	2.277	1.959	2.689	3.280	3.910	4.450	4.657	4.43%	5.29%	2.36%
Indonesia	0.638	1.397	1.384	1.658	1.991	2.387	2.745	3.034	8.05%	3.70%	2.85%
Japan	3.110	3.861	4.236	4.467	4.365	4.164	4.064	3.855	3.14%	0.30%	-0.82%
Malaysia	0.914	1.145	1.084	1.286	1.417	1.499	1.527	1.522	1.72%	2.72%	0.47%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.277	0.340	0.371	-2.03%	6.13%	3.66%
Pakistan	1.088	1.400	1.332	1.677	2.020	2.210	2.348	2.438	2.04%	4.26%	1.26%
Singapore	0.233	0.297	0.370	0.409	0.417	0.414	0.405	0.390	4.72%	1.19%	-0.45%
South Korea	1.076	1.524	1.966	2.376	2.591	2.646	2.651	2.565	6.21%	2.80%	-0.07%
Thailand	1.150	1.592	1.838	2.130	2.299	2.365	2.483	2.330	4.80%	2.26%	0.09%
Other Asia & Oceania	1.447	2.051	2.324	2.974	3.469	3.886	4.168	4.036	4.85%	4.09%	1.01%
World	**99.448**	**113.816**	**120.451**	**132.751**	**144.875**	**153.178**	**160.375**	**164.870**	**1.93%**	**1.86%**	**0.87%**

LNG12_Hi-D Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.844**	**35.640**	**38.346**	**39.597**	**40.486**	**41.375**	**2.05%**	**1.56%**	**0.51%**
Canada	3.144	2.815	3.130	3.374	3.515	3.580	3.663	3.713	-0.05%	1.17%	0.37%
Mexico	1.656	2.286	2.485	2.639	2.858	3.085	3.310	3.532	4.14%	1.41%	1.42%
United States	22.014	24.087	27.230	29.627	31.972	32.932	33.513	34.131	2.15%	1.62%	0.44%
Central & South America	**4.208**	**4.897**	**5.728**	**6.179**	**6.885**	**7.462**	**7.875**	**8.189**	**3.13%**	**1.86%**	**1.16%**
Argentina	1.428	1.529	1.612	1.864	2.035	2.174	2.289	2.390	1.22%	2.36%	1.08%
Brazil	0.657	0.890	1.157	1.349	1.556	1.745	1.887	2.009	5.82%	3.01%	1.72%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.427	-2.40%	3.71%	1.67%
Colombia	0.236	0.321	0.393	0.403	0.445	0.493	0.523	0.562	5.25%	1.25%	1.56%
Peru	0.056	0.194	0.220	0.233	0.264	0.291	0.314	0.331	14.69%	1.87%	1.52%
Trinidad and Tobago	0.575	0.824	0.752	0.765	0.779	0.760	0.740	0.705	2.72%	0.36%	-0.66%
Venezuela	0.828	0.748	1.102	0.982	1.132	1.239	1.301	1.338	2.90%	0.27%	1.12%
Other Central & South America	0.135	0.205	0.263	0.293	0.341	0.390	0.420	0.428	6.93%	2.63%	1.53%
Europe	**20.095**	**20.525**	**17.967**	**18.614**	**19.111**	**19.231**	**19.274**	**19.083**	**-1.11%**	**0.62%**	**-0.01%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.66%	0.20%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.729	0.731	0.18%	1.19%	0.40%
France	1.740	1.695	1.421	1.417	1.396	1.328	1.293	1.250	-2.01%	-0.18%	-0.73%
Germany	3.203	3.329	3.057	3.094	3.138	3.146	3.085	2.984	-0.46%	0.26%	-0.34%
Italy	3.046	2.935	2.322	2.337	2.349	2.344	2.341	2.319	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.734	1.682	1.636	1.579	-0.14%	0.10%	-0.62%
Norway	0.187	0.194	0.225	0.248	0.264	0.256	0.239	0.227	1.86%	1.62%	-1.00%
Poland	0.573	0.606	0.618	0.682	0.734	0.769	0.785	0.784	0.75%	1.74%	0.44%
Portugal	0.152	0.182	0.145	0.152	0.158	0.161	0.167	0.168	-0.46%	0.83%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.533	0.518	-3.42%	1.34%	0.00%
Spain	1.188	1.265	1.050	1.092	1.129	1.152	1.181	1.208	-1.23%	0.73%	0.45%
Turkey	0.967	1.346	1.530	1.683	1.790	1.871	1.965	2.056	4.70%	1.58%	0.93%
United Kingdom	3.376	3.337	2.644	2.716	2.782	2.786	2.812	2.772	-2.41%	0.51%	-0.02%
Other Europe	2.324	2.192	1.887	2.015	2.125	2.179	2.195	2.173	-2.06%	1.19%	0.15%
Eurasia	**21.786**	**21.616**	**21.673**	**22.937**	**24.203**	**24.908**	**25.223**	**25.456**	**-0.05%**	**1.11%**	**0.34%**
Kazakhstan	0.477	0.303	0.474	0.557	0.638	0.693	0.734	0.768	-0.05%	3.01%	1.24%
Russia	14.330	15.471	15.276	15.688	16.160	16.288	16.215	16.035	0.64%	0.56%	-0.05%
Turkmenistan	0.629	0.720	0.765	0.928	1.092	1.229	1.350	1.453	1.98%	3.62%	1.92%
Ukraine	3.079	1.969	1.676	1.766	1.845	1.886	1.888	1.864	-5.90%	0.96%	0.07%
Uzbekistan	1.702	1.614	1.890	2.276	2.618	2.885	3.091	3.395	1.05%	3.32%	1.75%
Other Eurasia	1.569	1.538	1.592	1.722	1.850	1.927	1.945	1.942	0.15%	1.51%	0.32%
Middle East	**9.825**	**13.379**	**14.481**	**15.520**	**17.080**	**18.356**	**19.519**	**20.574**	**3.96%**	**1.66%**	**1.25%**
Iran	3.707	5.106	5.244	5.489	5.925	6.304	6.605	6.947	3.53%	1.23%	1.07%
Qatar	0.660	0.796	1.102	1.142	1.227	1.286	1.316	1.325	5.26%	1.08%	0.52%
Oman	0.324	0.620	0.710	0.780	0.860	0.908	0.948	0.976	8.17%	1.93%	0.85%
Saudi Arabia	2.516	3.096	3.510	3.893	4.419	4.845	5.203	5.465	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.203	2.296	2.464	2.553	2.699	2.837	4.22%	1.13%	0.94%
Other Middle East	1.160	1.614	1.711	1.920	2.184	2.461	2.748	3.023	3.96%	2.47%	2.19%
Africa	**2.979**	**3.535**	**3.896**	**4.602**	**5.563**	**6.591**	**7.737**	**8.889**	**2.72%**	**3.62%**	**3.17%**
Algeria	0.846	1.024	1.087	1.228	1.426	1.592	1.708	1.786	2.53%	2.75%	1.51%
Egypt	1.208	1.630	1.795	2.033	2.354	2.741	3.292	3.858	4.04%	2.75%	3.35%
Nigeria	0.366	0.178	0.260	0.366	0.540	0.717	0.903	1.112	-3.36%	7.58%	4.94%
Other Africa	0.559	0.702	0.755	0.976	1.244	1.541	1.834	2.133	3.05%	5.12%	3.66%
Asia & Oceania	**13.741**	**20.677**	**24.177**	**30.436**	**35.705**	**39.945**	**43.380**	**44.314**	**5.81%**	**3.98%**	**1.45%**
Australia	1.014	1.249	1.546	1.810	1.921	2.000	2.077	2.163	4.31%	2.19%	0.79%
China	1.655	3.769	6.019	8.786	11.698	14.167	16.061	16.951	13.79%	6.87%	2.50%
India	1.269	2.277	1.959	2.689	3.281	3.916	4.469	4.666	4.44%	5.29%	2.38%
Indonesia	0.638	1.397	1.384	1.658	1.993	2.385	2.746	3.033	8.04%	3.71%	2.84%
Japan	3.110	3.861	4.236	4.471	4.365	4.169	4.075	3.861	3.14%	0.30%	-0.82%
Malaysia	0.914	1.145	1.084	1.287	1.418	1.501	1.529	1.517	1.72%	2.72%	0.45%
Myanmar	0.146	0.114	0.119	0.165	0.216	0.277	0.339	0.371	-2.02%	6.15%	3.66%
Pakistan	1.088	1.400	1.332	1.678	2.034	2.219	2.360	2.444	2.04%	4.33%	1.23%
Singapore	0.233	0.297	0.370	0.409	0.417	0.414	0.405	0.390	4.72%	1.20%	-0.44%
South Korea	1.076	1.524	1.966	2.379	2.590	2.650	2.658	2.570	6.21%	2.80%	-0.05%
Thailand	1.150	1.592	1.838	2.130	2.301	2.366	2.482	2.316	4.80%	2.27%	0.04%
Other Asia & Oceania	1.447	2.051	2.324	2.975	3.472	3.882	4.178	4.033	4.85%	4.10%	1.00%
World	**99.448**	**113.816**	**120.767**	**133.929**	**146.892**	**156.090**	**163.494**	**167.880**	**1.96%**	**1.98%**	**0.89%**

LNG20_Ref Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.700**	**34.667**	**36.600**	**37.238**	**38.118**	**39.053**	**2.00%**	**1.13%**	**0.43%**
Canada	3.144	2.815	3.129	3.368	3.511	3.579	3.641	3.692	-0.05%	1.16%	0.34%
Mexico	1.656	2.286	2.485	2.641	2.859	3.098	3.329	3.519	4.14%	1.41%	1.40%
United States	22.014	24.087	27.086	28.658	30.229	30.561	31.148	31.841	2.10%	1.10%	0.35%
Central & South America	**4.208**	**4.897**	**5.729**	**6.182**	**6.887**	**7.453**	**7.856**	**8.182**	**3.13%**	**1.86%**	**1.16%**
Argentina	1.428	1.529	1.612	1.863	2.037	2.175	2.288	2.386	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.557	1.745	1.885	2.006	5.82%	3.01%	1.71%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.73%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.521	0.561	5.25%	1.28%	1.53%
Peru	0.056	0.194	0.220	0.234	0.264	0.291	0.314	0.333	14.72%	1.81%	1.58%
Trinidad and Tobago	0.575	0.824	0.752	0.770	0.778	0.759	0.738	0.712	2.72%	0.35%	-0.59%
Venezuela	0.828	0.748	1.102	0.980	1.133	1.236	1.297	1.331	2.90%	0.28%	1.08%
Other Central & South America	0.135	0.205	0.263	0.293	0.340	0.386	0.411	0.427	6.93%	2.59%	1.54%
Europe	**20.095**	**20.525**	**17.964**	**18.599**	**19.088**	**19.214**	**19.265**	**19.038**	**-1.11%**	**0.61%**	**-0.02%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.65%	0.21%
Belgium	0.601	0.700	0.612	0.651	0.688	0.717	0.729	0.729	0.18%	1.18%	0.39%
France	1.740	1.695	1.421	1.415	1.387	1.327	1.292	1.244	-2.01%	-0.24%	-0.72%
Germany	3.203	3.329	3.057	3.090	3.133	3.145	3.086	2.986	-0.46%	0.25%	-0.32%
Italy	3.046	2.935	2.322	2.334	2.348	2.341	2.335	2.317	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.741	1.733	1.681	1.635	1.576	-0.14%	0.09%	-0.63%
Norway	0.187	0.194	0.225	0.248	0.264	0.254	0.239	0.224	1.85%	1.64%	-1.11%
Poland	0.573	0.606	0.617	0.684	0.737	0.771	0.786	0.786	0.74%	1.79%	0.42%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.532	0.519	-3.41%	1.34%	0.01%
Spain	1.188	1.265	1.050	1.092	1.127	1.151	1.180	1.207	-1.23%	0.72%	0.46%
Turkey	0.967	1.346	1.526	1.676	1.785	1.864	1.965	2.055	4.67%	1.58%	0.94%
United Kingdom	3.376	3.337	2.645	2.717	2.779	2.783	2.809	2.744	-2.41%	0.50%	-0.09%
Other Europe	2.324	2.192	1.887	2.013	2.125	2.179	2.197	2.170	-2.06%	1.19%	0.14%
Eurasia	**21.786**	**21.616**	**21.673**	**22.926**	**24.191**	**24.845**	**25.151**	**25.360**	**-0.05%**	**1.10%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.638	0.690	0.730	0.764	-0.05%	3.00%	1.21%
Russia	14.330	15.471	15.275	15.678	16.140	16.232	16.148	15.945	0.64%	0.55%	-0.08%
Turkmenistan	0.629	0.720	0.765	0.927	1.091	1.223	1.345	1.448	1.98%	3.61%	1.91%
Ukraine	3.079	1.969	1.677	1.764	1.844	1.885	1.889	1.867	-5.90%	0.96%	0.08%
Uzbekistan	1.702	1.614	1.890	2.277	2.624	2.887	3.093	3.393	1.05%	3.34%	1.73%
Other Eurasia	1.569	1.538	1.592	1.724	1.855	1.928	1.946	1.943	0.15%	1.54%	0.31%
Middle East	**9.825**	**13.379**	**14.479**	**15.516**	**17.078**	**18.353**	**19.518**	**20.595**	**3.95%**	**1.66%**	**1.26%**
Iran	3.707	5.106	5.243	5.489	5.929	6.300	6.601	6.941	3.53%	1.24%	1.06%
Qatar	0.660	0.796	1.103	1.143	1.228	1.285	1.314	1.337	5.26%	1.08%	0.57%
Oman	0.324	0.620	0.710	0.780	0.858	0.908	0.946	0.979	8.17%	1.91%	0.88%
Saudi Arabia	2.516	3.096	3.510	3.893	4.420	4.848	5.201	5.465	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.202	2.296	2.456	2.551	2.708	2.834	4.22%	1.10%	0.96%
Other Middle East	1.160	1.614	1.711	1.914	2.187	2.460	2.747	3.039	3.96%	2.48%	2.22%
Africa	**2.979**	**3.535**	**3.898**	**4.609**	**5.565**	**6.603**	**7.741**	**8.855**	**2.73%**	**3.62%**	**3.15%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.592	1.710	1.786	2.53%	2.76%	1.51%
Egypt	1.208	1.630	1.795	2.029	2.355	2.741	3.280	3.815	4.04%	2.75%	3.27%
Nigeria	0.366	0.178	0.262	0.375	0.539	0.725	0.923	1.142	-3.30%	7.49%	5.13%
Other Africa	0.559	0.702	0.755	0.976	1.244	1.545	1.828	2.112	3.05%	5.13%	3.59%
Asia & Oceania	**13.741**	**20.677**	**24.171**	**31.091**	**36.280**	**40.994**	**44.777**	**45.578**	**5.81%**	**4.14%**	**1.53%**
Australia	1.014	1.249	1.545	1.819	1.920	2.000	2.076	2.122	4.30%	2.20%	0.67%
China	1.655	3.769	6.021	9.098	12.089	14.897	17.222	18.183	13.79%	7.22%	2.76%
India	1.269	2.277	1.959	2.805	3.374	3.997	4.586	4.766	4.44%	5.59%	2.33%
Indonesia	0.638	1.397	1.384	1.658	1.990	2.389	2.740	3.020	8.04%	3.70%	2.82%
Japan	3.110	3.861	4.233	4.453	4.276	4.108	4.051	3.808	3.13%	0.10%	-0.77%
Malaysia	0.914	1.145	1.084	1.309	1.445	1.535	1.559	1.484	1.72%	2.92%	0.18%
Myanmar	0.146	0.114	0.119	0.164	0.215	0.281	0.337	0.360	-2.03%	6.08%	3.50%
Pakistan	1.088	1.400	1.331	1.677	2.024	2.218	2.331	2.372	2.04%	4.28%	1.06%
Singapore	0.233	0.297	0.370	0.418	0.426	0.423	0.413	0.396	4.72%	1.41%	-0.49%
South Korea	1.076	1.524	1.965	2.430	2.597	2.699	2.719	2.607	6.20%	2.83%	0.03%
Thailand	1.150	1.592	1.838	2.184	2.350	2.428	2.503	2.295	4.80%	2.49%	-0.16%
Other Asia & Oceania	1.447	2.051	2.322	3.077	3.574	4.019	4.240	4.164	4.84%	4.41%	1.02%
World	**99.448**	**113.816**	**120.615**	**133.588**	**145.688**	**154.700**	**162.426**	**166.660**	**1.95%**	**1.91%**	**0.90%**

LNG20_HRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.843**	**35.060**	**37.045**	**37.875**	**38.935**	**40.003**	**2.05%**	**1.21%**	**0.51%**
Canada	3.144	2.815	3.124	3.333	3.491	3.599	3.662	3.725	-0.06%	1.12%	0.43%
Mexico	1.656	2.286	2.494	2.652	2.846	3.065	3.290	3.493	4.18%	1.33%	1.37%
United States	22.014	24.087	27.224	29.075	30.708	31.210	31.983	32.786	2.15%	1.21%	0.44%
Central & South America	**4.208**	**4.897**	**5.726**	**6.180**	**6.881**	**7.445**	**7.858**	**8.208**	**3.13%**	**1.86%**	**1.18%**
Argentina	1.428	1.529	1.612	1.863	2.034	2.171	2.287	2.391	1.22%	2.36%	1.08%
Brazil	0.657	0.890	1.157	1.349	1.555	1.743	1.885	2.011	5.82%	3.00%	1.73%
Chile	0.295	0.187	0.231	0.290	0.333	0.369	0.401	0.426	-2.39%	3.71%	1.66%
Colombia	0.236	0.321	0.393	0.403	0.445	0.491	0.521	0.562	5.25%	1.26%	1.56%
Peru	0.056	0.194	0.218	0.234	0.264	0.291	0.314	0.333	14.62%	1.92%	1.56%
Trinidad and Tobago	0.575	0.824	0.750	0.768	0.777	0.758	0.739	0.707	2.70%	0.36%	-0.63%
Venezuela	0.828	0.748	1.102	0.980	1.133	1.233	1.295	1.349	2.90%	0.28%	1.17%
Other Central & South America	0.135	0.205	0.263	0.293	0.340	0.388	0.415	0.428	6.93%	2.59%	1.55%
Europe	**20.095**	**20.525**	**17.963**	**18.599**	**19.088**	**19.221**	**19.268**	**19.064**	**-1.12%**	**0.61%**	**-0.01%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.65%	0.20%
Belgium	0.601	0.700	0.612	0.651	0.688	0.717	0.729	0.730	0.18%	1.18%	0.40%
France	1.740	1.695	1.421	1.415	1.387	1.328	1.293	1.248	-2.01%	-0.24%	-0.71%
Germany	3.203	3.329	3.057	3.090	3.133	3.146	3.086	2.985	-0.46%	0.25%	-0.32%
Italy	3.046	2.935	2.322	2.334	2.348	2.341	2.336	2.316	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.733	1.683	1.635	1.578	-0.14%	0.09%	-0.62%
Norway	0.187	0.194	0.225	0.251	0.264	0.255	0.237	0.226	1.87%	1.60%	-1.02%
Poland	0.573	0.606	0.617	0.684	0.737	0.772	0.786	0.785	0.74%	1.79%	0.42%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.167	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.532	0.519	-3.42%	1.34%	0.00%
Spain	1.188	1.265	1.050	1.092	1.127	1.152	1.181	1.207	-1.23%	0.72%	0.46%
Turkey	0.967	1.346	1.526	1.676	1.784	1.864	1.965	2.055	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.645	2.716	2.780	2.783	2.809	2.761	-2.41%	0.50%	-0.04%
Other Europe	2.324	2.192	1.887	2.013	2.125	2.180	2.196	2.172	-2.06%	1.20%	0.15%
Eurasia	**21.786**	**21.616**	**21.674**	**22.922**	**24.193**	**24.856**	**25.155**	**25.337**	**-0.05%**	**1.11%**	**0.31%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.730	0.761	-0.05%	3.00%	1.19%
Russia	14.330	15.471	15.275	15.676	16.140	16.235	16.154	15.931	0.64%	0.55%	-0.09%
Turkmenistan	0.629	0.720	0.765	0.928	1.093	1.227	1.342	1.444	1.99%	3.63%	1.87%
Ukraine	3.079	1.969	1.677	1.764	1.845	1.886	1.888	1.865	-5.90%	0.96%	0.07%
Uzbekistan	1.702	1.614	1.890	2.277	2.624	2.889	3.094	3.392	1.05%	3.33%	1.73%
Other Eurasia	1.569	1.538	1.592	1.723	1.854	1.928	1.947	1.944	0.15%	1.53%	0.32%
Middle East	**9.825**	**13.379**	**14.477**	**15.510**	**17.079**	**18.351**	**19.527**	**20.561**	**3.95%**	**1.67%**	**1.24%**
Iran	3.707	5.106	5.243	5.486	5.926	6.304	6.607	6.936	3.53%	1.23%	1.06%
Qatar	0.660	0.796	1.102	1.143	1.230	1.286	1.316	1.328	5.26%	1.10%	0.51%
Oman	0.324	0.620	0.710	0.780	0.858	0.907	0.951	0.978	8.17%	1.90%	0.88%
Saudi Arabia	2.516	3.096	3.510	3.893	4.419	4.847	5.202	5.471	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.202	2.295	2.460	2.553	2.704	2.824	4.22%	1.11%	0.92%
Other Middle East	1.160	1.614	1.708	1.913	2.186	2.455	2.747	3.024	3.94%	2.50%	2.19%
Africa	**2.979**	**3.535**	**3.897**	**4.610**	**5.569**	**6.587**	**7.721**	**8.843**	**2.72%**	**3.63%**	**3.13%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.592	1.711	1.786	2.53%	2.76%	1.51%
Egypt	1.208	1.630	1.795	2.032	2.359	2.738	3.277	3.818	4.04%	2.77%	3.26%
Nigeria	0.366	0.178	0.261	0.374	0.540	0.718	0.909	1.133	-3.31%	7.52%	5.07%
Other Africa	0.559	0.702	0.755	0.975	1.244	1.539	1.825	2.105	3.05%	5.13%	3.57%
Asia & Oceania	**13.741**	**20.677**	**24.164**	**31.100**	**36.323**	**41.129**	**45.015**	**46.116**	**5.81%**	**4.16%**	**1.60%**
Australia	1.014	1.249	1.546	1.819	1.921	2.000	2.075	2.123	4.31%	2.19%	0.67%
China	1.655	3.769	6.017	9.103	12.114	14.956	17.342	18.448	13.78%	7.25%	2.84%
India	1.269	2.277	1.959	2.806	3.377	4.030	4.636	4.876	4.44%	5.60%	2.48%
Indonesia	0.638	1.397	1.384	1.659	1.989	2.388	2.736	3.026	8.04%	3.70%	2.84%
Japan	3.110	3.861	4.231	4.450	4.282	4.136	4.076	3.849	3.13%	0.12%	-0.71%
Malaysia	0.914	1.145	1.084	1.309	1.445	1.538	1.558	1.475	1.72%	2.92%	0.14%
Myanmar	0.146	0.114	0.119	0.164	0.214	0.282	0.338	0.363	-2.03%	6.02%	3.59%
Pakistan	1.088	1.400	1.332	1.678	2.031	2.209	2.360	2.425	2.04%	4.31%	1.19%
Singapore	0.233	0.297	0.370	0.418	0.426	0.424	0.413	0.398	4.72%	1.41%	-0.45%
South Korea	1.076	1.524	1.963	2.428	2.601	2.712	2.737	2.643	6.19%	2.85%	0.11%
Thailand	1.150	1.592	1.838	2.184	2.351	2.429	2.508	2.293	4.80%	2.49%	-0.17%
Other Asia & Oceania	1.447	2.051	2.321	3.081	3.573	4.025	4.236	4.197	4.84%	4.41%	1.08%
World	**99.448**	**113.816**	**120.744**	**133.981**	**146.177**	**155.464**	**163.478**	**168.131**	**1.96%**	**1.93%**	**0.94%**

LNG20_LRR Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.504**	**34.433**	**36.244**	**36.627**	**37.308**	**38.071**	**1.94%**	**1.10%**	**0.33%**
Canada	3.144	2.815	3.133	3.392	3.511	3.562	3.611	3.665	-0.04%	1.15%	0.29%
Mexico	1.656	2.286	2.479	2.639	2.886	3.129	3.364	3.505	4.11%	1.53%	1.30%
United States	22.014	24.087	26.893	28.401	29.847	29.937	30.333	30.900	2.02%	1.05%	0.23%
Central & South America	**4.208**	**4.897**	**5.728**	**6.180**	**6.883**	**7.446**	**7.857**	**8.185**	**3.13%**	**1.85%**	**1.16%**
Argentina	1.428	1.529	1.612	1.864	2.036	2.174	2.289	2.384	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.350	1.556	1.744	1.886	2.005	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.525	0.563	5.25%	1.27%	1.57%
Peru	0.056	0.194	0.219	0.233	0.263	0.291	0.314	0.331	14.65%	1.86%	1.53%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.776	0.758	0.735	0.707	2.73%	0.32%	-0.62%
Venezuela	0.828	0.748	1.102	0.980	1.133	1.235	1.299	1.335	2.90%	0.28%	1.10%
Other Central & South America	0.135	0.205	0.262	0.292	0.339	0.383	0.408	0.434	6.91%	2.60%	1.67%
Europe	**20.095**	**20.525**	**17.964**	**18.584**	**19.084**	**19.206**	**19.287**	**19.031**	**-1.11%**	**0.61%**	**-0.02%**
Austria	0.354	0.353	0.286	0.293	0.305	0.311	0.315	0.314	-2.11%	0.65%	0.20%
Belgium	0.601	0.700	0.612	0.650	0.688	0.717	0.730	0.729	0.18%	1.18%	0.38%
France	1.740	1.695	1.421	1.412	1.387	1.326	1.295	1.243	-2.01%	-0.24%	-0.73%
Germany	3.203	3.329	3.057	3.087	3.133	3.144	3.090	2.985	-0.46%	0.25%	-0.32%
Italy	3.046	2.935	2.322	2.333	2.348	2.339	2.336	2.316	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.732	1.681	1.636	1.575	-0.14%	0.09%	-0.63%
Norway	0.187	0.194	0.225	0.251	0.265	0.254	0.239	0.226	1.87%	1.63%	-1.05%
Poland	0.573	0.606	0.617	0.684	0.737	0.771	0.787	0.785	0.74%	1.79%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.492	0.519	0.527	0.532	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.091	1.127	1.150	1.181	1.206	-1.23%	0.72%	0.45%
Turkey	0.967	1.346	1.527	1.674	1.783	1.864	1.967	2.055	4.67%	1.56%	0.95%
United Kingdom	3.376	3.337	2.644	2.716	2.779	2.782	2.813	2.741	-2.41%	0.50%	-0.09%
Other Europe	2.324	2.192	1.887	2.010	2.124	2.178	2.199	2.169	-2.06%	1.19%	0.14%
Eurasia	**21.786**	**21.616**	**21.673**	**22.911**	**24.183**	**24.850**	**25.171**	**25.362**	**-0.05%**	**1.10%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.729	0.764	-0.05%	3.00%	1.22%
Russia	14.330	15.471	15.274	15.668	16.135	16.235	16.166	15.951	0.64%	0.55%	-0.08%
Turkmenistan	0.629	0.720	0.765	0.928	1.091	1.223	1.345	1.446	1.98%	3.61%	1.90%
Ukraine	3.079	1.969	1.677	1.762	1.844	1.885	1.890	1.865	-5.90%	0.95%	0.08%
Uzbekistan	1.702	1.614	1.890	2.275	2.622	2.887	3.095	3.394	1.05%	3.33%	1.74%
Other Eurasia	1.569	1.538	1.592	1.723	1.854	1.928	1.946	1.941	0.15%	1.53%	0.31%
Middle East	**9.825**	**13.379**	**14.479**	**15.511**	**17.070**	**18.366**	**19.534**	**20.621**	**3.95%**	**1.66%**	**1.27%**
Iran	3.707	5.106	5.243	5.487	5.926	6.309	6.606	6.958	3.53%	1.23%	1.08%
Qatar	0.660	0.796	1.103	1.143	1.228	1.285	1.311	1.340	5.26%	1.08%	0.59%
Oman	0.324	0.620	0.710	0.780	0.856	0.910	0.945	0.973	8.17%	1.88%	0.86%
Saudi Arabia	2.516	3.096	3.511	3.893	4.421	4.852	5.206	5.470	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.202	2.296	2.455	2.554	2.711	2.841	4.22%	1.09%	0.98%
Other Middle East	1.160	1.614	1.710	1.912	2.184	2.456	2.755	3.038	3.96%	2.47%	2.23%
Africa	**2.979**	**3.535**	**3.898**	**4.610**	**5.567**	**6.604**	**7.733**	**8.846**	**2.73%**	**3.63%**	**3.14%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.594	1.716	1.783	2.53%	2.76%	1.49%
Egypt	1.208	1.630	1.795	2.030	2.358	2.742	3.275	3.811	4.04%	2.77%	3.25%
Nigeria	0.366	0.178	0.262	0.376	0.539	0.722	0.912	1.139	-3.29%	7.49%	5.11%
Other Africa	0.559	0.702	0.755	0.975	1.242	1.547	1.829	2.113	3.05%	5.11%	3.60%
Asia & Oceania	**13.741**	**20.677**	**24.173**	**31.040**	**36.239**	**40.827**	**44.536**	**45.079**	**5.81%**	**4.13%**	**1.47%**
Australia	1.014	1.249	1.545	1.820	1.921	2.004	2.077	2.117	4.30%	2.20%	0.65%
China	1.655	3.769	6.019	9.073	12.077	14.839	17.089	17.943	13.79%	7.21%	2.67%
India	1.269	2.277	1.959	2.803	3.367	3.958	4.545	4.694	4.44%	5.56%	2.24%
Indonesia	0.638	1.397	1.384	1.658	1.989	2.388	2.755	3.034	8.04%	3.69%	2.86%
Japan	3.110	3.861	4.235	4.443	4.274	4.074	4.024	3.778	3.14%	0.09%	-0.82%
Malaysia	0.914	1.145	1.084	1.308	1.445	1.534	1.561	1.431	1.72%	2.92%	-0.07%
Myanmar	0.146	0.114	0.119	0.164	0.215	0.281	0.338	0.357	-2.04%	6.07%	3.46%
Pakistan	1.088	1.400	1.331	1.675	2.013	2.209	2.299	2.333	2.04%	4.22%	0.99%
Singapore	0.233	0.297	0.370	0.419	0.426	0.423	0.413	0.391	4.72%	1.40%	-0.56%
South Korea	1.076	1.524	1.966	2.422	2.595	2.686	2.699	2.581	6.21%	2.81%	-0.04%
Thailand	1.150	1.592	1.838	2.184	2.350	2.422	2.507	2.282	4.80%	2.49%	-0.20%
Other Asia & Oceania	1.447	2.051	2.322	3.073	3.569	4.008	4.229	4.139	4.84%	4.39%	0.99%
World	**99.448**	**113.816**	**120.419**	**133.269**	**145.269**	**153.926**	**161.427**	**165.195**	**1.93%**	**1.89%**	**0.86%**

LNG20_Hi-D Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.823**	**35.558**	**38.272**	**39.545**	**40.396**	**41.257**	**2.04%**	**1.55%**	**0.50%**
Canada	3.144	2.815	3.131	3.381	3.512	3.571	3.635	3.687	-0.04%	1.15%	0.33%
Mexico	1.656	2.286	2.483	2.634	2.869	3.101	3.349	3.512	4.13%	1.46%	1.36%
United States	22.014	24.087	27.208	29.544	31.891	32.873	33.412	34.058	2.14%	1.60%	0.44%
Central & South America	**4.208**	**4.897**	**5.727**	**6.179**	**6.882**	**7.458**	**7.865**	**8.206**	**3.13%**	**1.85%**	**1.18%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.175	2.289	2.391	1.22%	2.37%	1.08%
Brazil	0.657	0.890	1.157	1.349	1.557	1.745	1.888	2.008	5.82%	3.01%	1.71%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.402	0.427	-2.40%	3.72%	1.67%
Colombia	0.236	0.321	0.393	0.402	0.445	0.494	0.523	0.561	5.25%	1.25%	1.56%
Peru	0.056	0.194	0.219	0.234	0.263	0.292	0.314	0.333	14.64%	1.88%	1.58%
Trinidad and Tobago	0.575	0.824	0.751	0.769	0.776	0.758	0.737	0.706	2.72%	0.32%	-0.63%
Venezuela	0.828	0.748	1.102	0.980	1.133	1.240	1.302	1.347	2.90%	0.28%	1.16%
Other Central & South America	0.135	0.205	0.262	0.292	0.339	0.384	0.411	0.433	6.91%	2.58%	1.65%
Europe	**20.095**	**20.525**	**17.965**	**18.602**	**19.102**	**19.223**	**19.276**	**19.067**	**-1.11%**	**0.62%**	**-0.01%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.65%	0.20%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.730	0.730	0.18%	1.19%	0.39%
France	1.740	1.695	1.421	1.415	1.390	1.328	1.294	1.248	-2.01%	-0.22%	-0.71%
Germany	3.203	3.329	3.057	3.091	3.136	3.147	3.088	2.987	-0.46%	0.26%	-0.32%
Italy	3.046	2.935	2.322	2.334	2.348	2.341	2.336	2.316	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.741	1.734	1.682	1.636	1.578	-0.14%	0.10%	-0.63%
Norway	0.187	0.194	0.225	0.249	0.265	0.255	0.240	0.225	1.86%	1.64%	-1.08%
Poland	0.573	0.606	0.617	0.685	0.737	0.772	0.786	0.786	0.74%	1.79%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.533	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.092	1.128	1.151	1.179	1.207	-1.23%	0.72%	0.45%
Turkey	0.967	1.346	1.526	1.676	1.785	1.865	1.965	2.056	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.644	2.716	2.782	2.785	2.812	2.761	-2.41%	0.51%	-0.05%
Other Europe	2.324	2.192	1.888	2.013	2.127	2.180	2.198	2.172	-2.06%	1.20%	0.14%
Eurasia	**21.786**	**21.616**	**21.674**	**22.935**	**24.191**	**24.847**	**25.147**	**25.365**	**-0.05%**	**1.10%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.690	0.729	0.763	-0.05%	2.99%	1.21%
Russia	14.330	15.471	15.275	15.684	16.140	16.232	16.150	15.957	0.64%	0.55%	-0.08%
Turkmenistan	0.629	0.720	0.765	0.929	1.092	1.224	1.343	1.446	1.98%	3.62%	1.89%
Ukraine	3.079	1.969	1.677	1.764	1.845	1.886	1.888	1.863	-5.90%	0.96%	0.07%
Uzbekistan	1.702	1.614	1.890	2.278	2.623	2.887	3.092	3.393	1.05%	3.33%	1.73%
Other Eurasia	1.569	1.538	1.592	1.724	1.854	1.928	1.945	1.943	0.15%	1.53%	0.31%
Middle East	**9.825**	**13.379**	**14.477**	**15.517**	**17.077**	**18.361**	**19.524**	**20.590**	**3.95%**	**1.67%**	**1.26%**
Iran	3.707	5.106	5.243	5.491	5.930	6.310	6.609	6.921	3.53%	1.24%	1.04%
Qatar	0.660	0.796	1.102	1.142	1.229	1.285	1.313	1.324	5.26%	1.09%	0.50%
Oman	0.324	0.620	0.710	0.781	0.855	0.910	0.947	0.982	8.17%	1.88%	0.92%
Saudi Arabia	2.516	3.096	3.510	3.894	4.420	4.846	5.209	5.478	3.39%	2.33%	1.44%
United Arab Emirates	1.457	2.147	2.203	2.296	2.457	2.553	2.697	2.837	4.22%	1.10%	0.96%
Other Middle East	1.160	1.614	1.709	1.913	2.186	2.457	2.749	3.048	3.95%	2.49%	2.24%
Africa	**2.979**	**3.535**	**3.898**	**4.611**	**5.565**	**6.601**	**7.724**	**8.859**	**2.73%**	**3.62%**	**3.15%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.594	1.711	1.786	2.53%	2.76%	1.51%
Egypt	1.208	1.630	1.795	2.031	2.354	2.741	3.275	3.819	4.04%	2.75%	3.28%
Nigeria	0.366	0.178	0.262	0.375	0.540	0.722	0.913	1.139	-3.29%	7.51%	5.10%
Other Africa	0.559	0.702	0.755	0.976	1.244	1.544	1.825	2.114	3.06%	5.13%	3.60%
Asia & Oceania	**13.741**	**20.677**	**24.169**	**31.088**	**36.255**	**40.926**	**44.708**	**45.330**	**5.81%**	**4.14%**	**1.50%**
Australia	1.014	1.249	1.546	1.819	1.920	2.002	2.075	2.120	4.31%	2.19%	0.66%
China	1.655	3.769	6.018	9.098	12.081	14.874	17.176	18.067	13.78%	7.22%	2.72%
India	1.269	2.277	1.959	2.804	3.373	3.981	4.574	4.719	4.44%	5.58%	2.26%
Indonesia	0.638	1.397	1.384	1.659	1.989	2.390	2.746	3.028	8.04%	3.70%	2.84%
Japan	3.110	3.861	4.233	4.452	4.275	4.096	4.043	3.794	3.13%	0.10%	-0.79%
Malaysia	0.914	1.145	1.084	1.308	1.444	1.536	1.560	1.461	1.72%	2.91%	0.08%
Myanmar	0.146	0.114	0.119	0.164	0.215	0.281	0.338	0.358	-2.03%	6.06%	3.47%
Pakistan	1.088	1.400	1.331	1.676	2.014	2.210	2.322	2.354	2.04%	4.22%	1.05%
Singapore	0.233	0.297	0.370	0.419	0.426	0.423	0.413	0.396	4.72%	1.41%	-0.49%
South Korea	1.076	1.524	1.965	2.429	2.596	2.694	2.713	2.595	6.20%	2.83%	0.00%
Thailand	1.150	1.592	1.838	2.184	2.350	2.426	2.505	2.287	4.80%	2.49%	-0.18%
Other Asia & Oceania	1.447	2.051	2.321	3.078	3.573	4.012	4.243	4.152	4.84%	4.41%	1.01%
World	**99.448**	**113.816**	**120.734**	**134.491**	**147.344**	**156.960**	**164.639**	**168.674**	**1.96%**	**2.01%**	**0.91%**

LNG20_Ref12 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.709**	**34.699**	**36.694**	**37.271**	**38.133**	**39.053**	**2.01%**	**1.16%**	**0.42%**
Canada	3.144	2.815	3.128	3.365	3.516	3.580	3.644	3.700	-0.05%	1.17%	0.34%
Mexico	1.656	2.286	2.486	2.641	2.859	3.089	3.309	3.515	4.14%	1.41%	1.39%
United States	22.014	24.087	27.095	28.693	30.319	30.602	31.180	31.837	2.10%	1.13%	0.33%
Central & South America	**4.208**	**4.897**	**5.727**	**6.180**	**6.889**	**7.450**	**7.861**	**8.176**	**3.13%**	**1.86%**	**1.15%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.175	2.288	2.388	1.22%	2.37%	1.07%
Brazil	0.657	0.890	1.157	1.349	1.557	1.745	1.885	2.006	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.72%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.448	0.490	0.524	0.561	5.25%	1.31%	1.52%
Peru	0.056	0.194	0.218	0.234	0.264	0.292	0.314	0.334	14.62%	1.91%	1.58%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.779	0.759	0.738	0.702	2.73%	0.36%	-0.69%
Venezuela	0.828	0.748	1.102	0.981	1.133	1.235	1.300	1.324	2.90%	0.28%	1.04%
Other Central & South America	0.135	0.205	0.262	0.293	0.339	0.383	0.411	0.435	6.91%	2.59%	1.68%
Europe	**20.095**	**20.525**	**17.964**	**18.592**	**19.110**	**19.234**	**19.285**	**19.045**	**-1.11%**	**0.62%**	**-0.02%**
Austria	0.354	0.353	0.286	0.293	0.305	0.311	0.315	0.314	-2.11%	0.66%	0.20%
Belgium	0.601	0.700	0.612	0.650	0.689	0.718	0.730	0.730	0.18%	1.19%	0.38%
France	1.740	1.695	1.421	1.414	1.390	1.330	1.294	1.245	-2.01%	-0.22%	-0.73%
Germany	3.203	3.329	3.057	3.089	3.138	3.149	3.090	2.986	-0.46%	0.26%	-0.33%
Italy	3.046	2.935	2.322	2.334	2.349	2.342	2.336	2.316	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.739	1.734	1.683	1.636	1.576	-0.14%	0.10%	-0.63%
Norway	0.187	0.194	0.225	0.250	0.264	0.255	0.238	0.227	1.87%	1.61%	-1.00%
Poland	0.573	0.606	0.617	0.684	0.738	0.772	0.788	0.786	0.74%	1.80%	0.42%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.83%	0.40%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.533	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.091	1.129	1.152	1.180	1.206	-1.23%	0.73%	0.44%
Turkey	0.967	1.346	1.526	1.675	1.786	1.865	1.967	2.051	4.67%	1.58%	0.93%
United Kingdom	3.376	3.337	2.644	2.716	2.783	2.785	2.811	2.751	-2.41%	0.51%	-0.08%
Other Europe	2.324	2.192	1.887	2.012	2.128	2.182	2.200	2.170	-2.06%	1.21%	0.13%
Eurasia	**21.786**	**21.616**	**21.674**	**22.922**	**24.204**	**24.860**	**25.172**	**25.366**	**-0.05%**	**1.11%**	**0.31%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.731	0.763	-0.05%	2.99%	1.21%
Russia	14.330	15.471	15.276	15.675	16.146	16.242	16.165	15.954	0.64%	0.56%	-0.08%
Turkmenistan	0.629	0.720	0.765	0.928	1.093	1.223	1.345	1.447	1.98%	3.63%	1.89%
Ukraine	3.079	1.969	1.677	1.763	1.847	1.887	1.891	1.864	-5.90%	0.97%	0.06%
Uzbekistan	1.702	1.614	1.890	2.277	2.625	2.888	3.095	3.394	1.06%	3.34%	1.73%
Other Eurasia	1.569	1.538	1.592	1.723	1.855	1.929	1.947	1.943	0.15%	1.54%	0.31%
Middle East	**9.825**	**13.379**	**14.477**	**15.516**	**17.078**	**18.357**	**19.547**	**20.591**	**3.95%**	**1.67%**	**1.25%**
Iran	3.707	5.106	5.243	5.490	5.930	6.304	6.618	6.919	3.53%	1.24%	1.03%
Qatar	0.660	0.796	1.102	1.143	1.229	1.285	1.314	1.326	5.26%	1.09%	0.51%
Oman	0.324	0.620	0.710	0.780	0.856	0.909	0.946	0.977	8.17%	1.88%	0.89%
Saudi Arabia	2.516	3.096	3.510	3.893	4.418	4.848	5.213	5.492	3.39%	2.33%	1.46%
United Arab Emirates	1.457	2.147	2.203	2.296	2.457	2.556	2.702	2.855	4.22%	1.10%	1.01%
Other Middle East	1.160	1.614	1.709	1.914	2.188	2.456	2.755	3.022	3.95%	2.50%	2.18%
Africa	**2.979**	**3.535**	**3.897**	**4.607**	**5.565**	**6.612**	**7.728**	**8.852**	**2.72%**	**3.63%**	**3.14%**
Algeria	0.846	1.024	1.087	1.230	1.427	1.597	1.716	1.785	2.53%	2.76%	1.50%
Egypt	1.208	1.630	1.795	2.030	2.358	2.745	3.272	3.817	4.04%	2.77%	3.26%
Nigeria	0.366	0.178	0.261	0.373	0.537	0.725	0.913	1.139	-3.32%	7.49%	5.13%
Other Africa	0.559	0.702	0.755	0.975	1.243	1.546	1.827	2.110	3.05%	5.11%	3.59%
Asia & Oceania	**13.741**	**20.677**	**24.170**	**31.068**	**36.223**	**40.888**	**44.212**	**44.544**	**5.81%**	**4.13%**	**1.39%**
Australia	1.014	1.249	1.546	1.819	1.919	2.002	2.076	2.115	4.30%	2.19%	0.65%
China	1.655	3.769	6.018	9.087	12.080	14.852	16.905	17.669	13.78%	7.22%	2.57%
India	1.269	2.277	1.959	2.804	3.365	3.978	4.504	4.640	4.43%	5.56%	2.17%
Indonesia	0.638	1.397	1.384	1.658	1.988	2.388	2.765	3.039	8.05%	3.69%	2.87%
Japan	3.110	3.861	4.235	4.450	4.273	4.093	3.996	3.725	3.13%	0.09%	-0.91%
Malaysia	0.914	1.145	1.084	1.307	1.443	1.535	1.558	1.421	1.72%	2.90%	-0.10%
Myanmar	0.146	0.114	0.119	0.164	0.214	0.283	0.336	0.355	-2.04%	6.04%	3.44%
Pakistan	1.088	1.400	1.331	1.673	2.008	2.210	2.269	2.258	2.04%	4.20%	0.79%
Singapore	0.233	0.297	0.370	0.418	0.426	0.423	0.413	0.388	4.72%	1.40%	-0.61%
South Korea	1.076	1.524	1.966	2.428	2.596	2.689	2.680	2.535	6.21%	2.82%	-0.16%
Thailand	1.150	1.592	1.838	2.184	2.349	2.425	2.501	2.279	4.80%	2.48%	-0.20%
Other Asia & Oceania	1.447	2.051	2.322	3.076	3.563	4.011	4.210	4.121	4.84%	4.38%	0.97%
World	**99.448**	**113.816**	**120.619**	**133.584**	**145.762**	**154.673**	**161.938**	**165.626**	**1.95%**	**1.91%**	**0.86%**

LNG20_HRR12 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.859**	**35.068**	**37.115**	**37.953**	**38.932**	**39.948**	**2.05%**	**1.23%**	**0.49%**
Canada	3.144	2.815	3.124	3.326	3.487	3.596	3.667	3.731	-0.06%	1.10%	0.45%
Mexico	1.656	2.286	2.496	2.648	2.851	3.057	3.267	3.443	4.18%	1.34%	1.27%
United States	22.014	24.087	27.239	29.094	30.777	31.301	31.998	32.774	2.15%	1.23%	0.42%
Central & South America	**4.208**	**4.897**	**5.729**	**6.180**	**6.884**	**7.450**	**7.852**	**8.163**	**3.13%**	**1.85%**	**1.14%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.174	2.287	2.385	1.22%	2.36%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.556	1.744	1.885	2.005	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.72%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.521	0.559	5.25%	1.28%	1.51%
Peru	0.056	0.194	0.220	0.234	0.264	0.292	0.314	0.333	14.70%	1.84%	1.55%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.775	0.760	0.738	0.706	2.73%	0.31%	-0.62%
Venezuela	0.828	0.748	1.102	0.981	1.134	1.236	1.295	1.314	2.90%	0.29%	0.99%
Other Central & South America	0.135	0.205	0.263	0.293	0.339	0.383	0.412	0.435	6.93%	2.59%	1.66%
Europe	**20.095**	**20.525**	**17.964**	**18.591**	**19.096**	**19.214**	**19.272**	**19.080**	**-1.11%**	**0.61%**	**-0.01%**
Austria	0.354	0.353	0.286	0.293	0.305	0.311	0.315	0.315	-2.11%	0.65%	0.21%
Belgium	0.601	0.700	0.612	0.650	0.689	0.717	0.729	0.730	0.18%	1.19%	0.39%
France	1.740	1.695	1.421	1.413	1.388	1.327	1.293	1.248	-2.01%	-0.23%	-0.71%
Germany	3.203	3.329	3.057	3.089	3.135	3.145	3.088	2.992	-0.46%	0.25%	-0.31%
Italy	3.046	2.935	2.322	2.334	2.348	2.340	2.336	2.318	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.733	1.682	1.636	1.576	-0.14%	0.09%	-0.63%
Norway	0.187	0.194	0.225	0.250	0.264	0.255	0.238	0.228	1.86%	1.62%	-0.99%
Poland	0.573	0.606	0.617	0.684	0.738	0.772	0.787	0.788	0.74%	1.80%	0.44%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.492	0.519	0.528	0.533	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.091	1.128	1.151	1.180	1.208	-1.23%	0.72%	0.46%
Turkey	0.967	1.346	1.527	1.675	1.785	1.864	1.965	2.060	4.68%	1.57%	0.96%
United Kingdom	3.376	3.337	2.645	2.716	2.780	2.782	2.809	2.754	-2.41%	0.50%	-0.06%
Other Europe	2.324	2.192	1.887	2.011	2.126	2.179	2.197	2.176	-2.06%	1.20%	0.16%
Eurasia	**21.786**	**21.616**	**21.673**	**22.918**	**24.204**	**24.849**	**25.163**	**25.411**	**-0.05%**	**1.11%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.730	0.762	-0.05%	3.00%	1.20%
Russia	14.330	15.471	15.275	15.673	16.147	16.229	16.158	15.993	0.64%	0.56%	-0.06%
Turkmenistan	0.629	0.720	0.765	0.928	1.093	1.226	1.345	1.446	1.98%	3.63%	1.89%
Ukraine	3.079	1.969	1.677	1.764	1.846	1.887	1.888	1.865	-5.90%	0.97%	0.07%
Uzbekistan	1.702	1.614	1.890	2.276	2.625	2.888	3.095	3.399	1.05%	3.34%	1.74%
Other Eurasia	1.569	1.538	1.592	1.723	1.855	1.928	1.946	1.945	0.15%	1.54%	0.32%
Middle East	**9.825**	**13.379**	**14.480**	**15.510**	**17.078**	**18.356**	**19.487**	**20.625**	**3.96%**	**1.66%**	**1.27%**
Iran	3.707	5.106	5.244	5.485	5.924	6.301	6.579	6.967	3.53%	1.23%	1.09%
Qatar	0.660	0.796	1.102	1.143	1.228	1.286	1.310	1.332	5.26%	1.09%	0.54%
Oman	0.324	0.620	0.710	0.780	0.858	0.908	0.943	0.976	8.17%	1.91%	0.86%
Saudi Arabia	2.516	3.096	3.511	3.893	4.423	4.850	5.200	5.473	3.39%	2.34%	1.43%
United Arab Emirates	1.457	2.147	2.203	2.296	2.457	2.555	2.709	2.832	4.22%	1.10%	0.95%
Other Middle East	1.160	1.614	1.710	1.913	2.186	2.456	2.746	3.046	3.95%	2.49%	2.23%
Africa	**2.979**	**3.535**	**3.897**	**4.607**	**5.562**	**6.606**	**7.745**	**8.868**	**2.72%**	**3.62%**	**3.16%**
Algeria	0.846	1.024	1.087	1.229	1.426	1.592	1.716	1.788	2.53%	2.76%	1.52%
Egypt	1.208	1.630	1.795	2.030	2.357	2.742	3.270	3.818	4.04%	2.76%	3.27%
Nigeria	0.366	0.178	0.261	0.373	0.536	0.725	0.924	1.140	-3.32%	7.46%	5.15%
Other Africa	0.559	0.702	0.755	0.975	1.242	1.546	1.834	2.122	3.05%	5.11%	3.64%
Asia & Oceania	**13.741**	**20.677**	**24.167**	**31.065**	**36.256**	**40.863**	**44.207**	**44.544**	**5.81%**	**4.14%**	**1.38%**
Australia	1.014	1.249	1.545	1.819	1.918	2.003	2.076	2.114	4.30%	2.19%	0.65%
China	1.655	3.769	6.016	9.089	12.101	14.842	16.894	17.667	13.78%	7.24%	2.55%
India	1.269	2.277	1.959	2.803	3.368	3.975	4.504	4.640	4.43%	5.57%	2.16%
Indonesia	0.638	1.397	1.384	1.658	1.989	2.387	2.767	3.039	8.04%	3.69%	2.87%
Japan	3.110	3.861	4.234	4.449	4.279	4.091	3.995	3.724	3.13%	0.11%	-0.92%
Malaysia	0.914	1.145	1.084	1.308	1.443	1.534	1.559	1.423	1.72%	2.90%	-0.09%
Myanmar	0.146	0.114	0.119	0.164	0.214	0.283	0.336	0.355	-2.04%	6.02%	3.45%
Pakistan	1.088	1.400	1.331	1.672	2.006	2.205	2.269	2.259	2.04%	4.19%	0.79%
Singapore	0.233	0.297	0.370	0.418	0.426	0.423	0.413	0.388	4.72%	1.40%	-0.61%
South Korea	1.076	1.524	1.965	2.427	2.601	2.689	2.680	2.535	6.21%	2.84%	-0.17%
Thailand	1.150	1.592	1.838	2.184	2.349	2.423	2.503	2.278	4.80%	2.48%	-0.20%
Other Asia & Oceania	1.447	2.051	2.322	3.074	3.564	4.009	4.213	4.121	4.84%	4.38%	0.97%
World	**99.448**	**113.816**	**120.771**	**133.940**	**146.194**	**155.291**	**162.658**	**166.638**	**1.96%**	**1.93%**	**0.88%**

LNG20_LRR12 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.515**	**34.438**	**36.283**	**36.655**	**37.338**	**38.064**	**1.95%**	**1.10%**	**0.32%**
Canada	3.144	2.815	3.131	3.390	3.510	3.565	3.616	3.665	-0.04%	1.15%	0.29%
Mexico	1.656	2.286	2.478	2.636	2.884	3.129	3.361	3.511	4.11%	1.53%	1.32%
United States	22.014	24.087	26.906	28.412	29.889	29.961	30.360	30.887	2.03%	1.06%	0.22%
Central & South America	**4.208**	**4.897**	**5.729**	**6.177**	**6.884**	**7.449**	**7.849**	**8.178**	**3.13%**	**1.85%**	**1.16%**
Argentina	1.428	1.529	1.612	1.862	2.036	2.175	2.288	2.385	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.556	1.746	1.886	2.005	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.39%	3.71%	1.65%
Colombia	0.236	0.321	0.393	0.403	0.447	0.489	0.522	0.560	5.25%	1.30%	1.52%
Peru	0.056	0.194	0.220	0.233	0.264	0.292	0.311	0.332	14.70%	1.85%	1.53%
Trinidad and Tobago	0.575	0.824	0.752	0.768	0.775	0.758	0.737	0.703	2.73%	0.31%	-0.65%
Venezuela	0.828	0.748	1.102	0.980	1.133	1.234	1.292	1.336	2.90%	0.28%	1.11%
Other Central & South America	0.135	0.205	0.263	0.293	0.339	0.384	0.411	0.432	6.93%	2.58%	1.62%
Europe	**20.095**	**20.525**	**17.965**	**18.581**	**19.102**	**19.209**	**19.290**	**19.044**	**-1.11%**	**0.62%**	**-0.02%**
Austria	0.354	0.353	0.286	0.293	0.305	0.311	0.315	0.314	-2.11%	0.66%	0.20%
Belgium	0.601	0.700	0.612	0.650	0.689	0.717	0.730	0.729	0.18%	1.19%	0.38%
France	1.740	1.695	1.421	1.411	1.389	1.326	1.296	1.244	-2.01%	-0.22%	-0.73%
Germany	3.203	3.329	3.057	3.087	3.136	3.145	3.090	2.988	-0.46%	0.26%	-0.32%
Italy	3.046	2.935	2.322	2.332	2.349	2.339	2.336	2.317	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.733	1.681	1.636	1.576	-0.14%	0.09%	-0.63%
Norway	0.187	0.194	0.225	0.249	0.264	0.253	0.241	0.226	1.84%	1.62%	-1.04%
Poland	0.573	0.606	0.617	0.684	0.737	0.772	0.787	0.787	0.74%	1.79%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.40%
Romania	0.643	0.455	0.454	0.492	0.519	0.528	0.533	0.519	-3.42%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.091	1.128	1.150	1.180	1.207	-1.23%	0.72%	0.45%
Turkey	0.967	1.346	1.527	1.674	1.786	1.864	1.967	2.058	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.645	2.716	2.781	2.782	2.813	2.740	-2.41%	0.50%	-0.10%
Other Europe	2.324	2.192	1.887	2.010	2.127	2.179	2.200	2.172	-2.06%	1.20%	0.14%
Eurasia	**21.786**	**21.616**	**21.675**	**22.917**	**24.196**	**24.852**	**25.164**	**25.380**	**-0.05%**	**1.11%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.730	0.764	-0.05%	3.00%	1.22%
Russia	14.330	15.471	15.276	15.672	16.139	16.235	16.161	15.962	0.64%	0.55%	-0.07%
Turkmenistan	0.629	0.720	0.766	0.928	1.094	1.224	1.342	1.447	1.99%	3.64%	1.88%
Ukraine	3.079	1.969	1.677	1.763	1.847	1.886	1.890	1.864	-5.90%	0.97%	0.06%
Uzbekistan	1.702	1.614	1.890	2.276	2.624	2.888	3.094	3.398	1.06%	3.33%	1.74%
Other Eurasia	1.569	1.538	1.592	1.723	1.856	1.928	1.946	1.944	0.15%	1.54%	0.31%
Middle East	**9.825**	**13.379**	**14.479**	**15.514**	**17.073**	**18.360**	**19.522**	**20.633**	**3.95%**	**1.66%**	**1.27%**
Iran	3.707	5.106	5.244	5.488	5.925	6.308	6.579	6.950	3.53%	1.23%	1.07%
Qatar	0.660	0.796	1.102	1.142	1.229	1.287	1.316	1.328	5.26%	1.09%	0.52%
Oman	0.324	0.620	0.710	0.781	0.859	0.908	0.945	0.975	8.17%	1.92%	0.85%
Saudi Arabia	2.516	3.096	3.510	3.894	4.417	4.846	5.213	5.494	3.38%	2.33%	1.47%
United Arab Emirates	1.457	2.147	2.203	2.297	2.456	2.553	2.707	2.845	4.22%	1.09%	0.99%
Other Middle East	1.160	1.614	1.710	1.912	2.188	2.459	2.762	3.041	3.96%	2.49%	2.22%
Africa	**2.979**	**3.535**	**3.898**	**4.608**	**5.566**	**6.606**	**7.743**	**8.842**	**2.73%**	**3.62%**	**3.13%**
Algeria	0.846	1.024	1.087	1.230	1.428	1.594	1.717	1.785	2.53%	2.77%	1.50%
Egypt	1.208	1.630	1.795	2.028	2.357	2.742	3.277	3.814	4.04%	2.76%	3.26%
Nigeria	0.366	0.178	0.262	0.375	0.537	0.724	0.921	1.139	-3.29%	7.45%	5.14%
Other Africa	0.559	0.702	0.755	0.975	1.243	1.546	1.828	2.104	3.05%	5.12%	3.57%
Asia & Oceania	**13.741**	**20.677**	**24.171**	**31.034**	**36.202**	**40.784**	**44.220**	**44.534**	**5.81%**	**4.12%**	**1.39%**
Australia	1.014	1.249	1.545	1.820	1.920	2.002	2.078	2.125	4.30%	2.20%	0.68%
China	1.655	3.769	6.018	9.070	12.064	14.820	16.894	17.666	13.78%	7.20%	2.58%
India	1.269	2.277	1.959	2.802	3.360	3.952	4.508	4.643	4.43%	5.55%	2.18%
Indonesia	0.638	1.397	1.384	1.658	1.989	2.388	2.764	3.033	8.05%	3.69%	2.85%
Japan	3.110	3.861	4.235	4.442	4.271	4.067	3.998	3.726	3.14%	0.08%	-0.91%
Malaysia	0.914	1.145	1.083	1.308	1.444	1.533	1.558	1.409	1.72%	2.91%	-0.17%
Myanmar	0.146	0.114	0.119	0.164	0.214	0.283	0.336	0.354	-2.04%	6.03%	3.42%
Pakistan	1.088	1.400	1.331	1.673	2.007	2.208	2.273	2.259	2.04%	4.19%	0.79%
Singapore	0.233	0.297	0.370	0.419	0.426	0.423	0.413	0.385	4.72%	1.40%	-0.67%
South Korea	1.076	1.524	1.966	2.422	2.593	2.682	2.681	2.536	6.21%	2.81%	-0.15%
Thailand	1.150	1.592	1.838	2.184	2.349	2.422	2.502	2.277	4.80%	2.48%	-0.21%
Other Asia & Oceania	1.447	2.051	2.322	3.073	3.565	4.004	4.215	4.122	4.84%	4.38%	0.97%
World	**99.448**	**113.816**	**120.432**	**133.269**	**145.305**	**153.915**	**161.126**	**164.675**	**1.93%**	**1.90%**	**0.84%**

LNG20_Hi-D12 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.842**	**35.601**	**38.311**	**39.581**	**40.421**	**41.271**	**2.05%**	**1.55%**	**0.50%**
Canada	3.144	2.815	3.131	3.378	3.511	3.574	3.637	3.689	-0.04%	1.15%	0.33%
Mexico	1.656	2.286	2.484	2.635	2.866	3.099	3.332	3.521	4.14%	1.44%	1.38%
United States	22.014	24.087	27.227	29.588	31.934	32.909	33.452	34.061	2.15%	1.61%	0.43%
Central & South America	**4.208**	**4.897**	**5.728**	**6.179**	**6.883**	**7.452**	**7.834**	**8.198**	**3.13%**	**1.85%**	**1.17%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.175	2.287	2.384	1.22%	2.36%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.556	1.746	1.886	2.005	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.402	0.446	0.491	0.518	0.558	5.25%	1.28%	1.50%
Peru	0.056	0.194	0.219	0.234	0.264	0.291	0.313	0.333	14.64%	1.89%	1.56%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.775	0.759	0.736	0.709	2.72%	0.31%	-0.59%
Venezuela	0.828	0.748	1.102	0.979	1.133	1.236	1.284	1.352	2.90%	0.28%	1.18%
Other Central & South America	0.135	0.205	0.263	0.292	0.339	0.384	0.409	0.433	6.92%	2.59%	1.64%
Europe	**20.095**	**20.525**	**17.964**	**18.600**	**19.091**	**19.208**	**19.276**	**19.054**	**-1.11%**	**0.61%**	**-0.01%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.65%	0.21%
Belgium	0.601	0.700	0.612	0.651	0.688	0.717	0.729	0.730	0.18%	1.18%	0.39%
France	1.740	1.695	1.421	1.415	1.388	1.326	1.294	1.245	-2.01%	-0.24%	-0.72%
Germany	3.203	3.329	3.057	3.091	3.134	3.144	3.088	2.988	-0.46%	0.25%	-0.32%
Italy	3.046	2.935	2.322	2.334	2.348	2.340	2.336	2.316	-2.68%	0.11%	-0.09%
Netherlands	1.741	1.937	1.717	1.741	1.733	1.681	1.635	1.577	-0.14%	0.09%	-0.63%
Norway	0.187	0.194	0.225	0.250	0.264	0.255	0.238	0.226	1.86%	1.62%	-1.03%
Poland	0.573	0.606	0.617	0.684	0.737	0.771	0.786	0.786	0.74%	1.79%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.533	0.519	-3.42%	1.34%	0.01%
Spain	1.188	1.265	1.050	1.092	1.127	1.151	1.180	1.206	-1.23%	0.72%	0.45%
Turkey	0.967	1.346	1.527	1.676	1.786	1.864	1.966	2.057	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.644	2.717	2.779	2.782	2.812	2.749	-2.41%	0.50%	-0.07%
Other Europe	2.324	2.192	1.887	2.013	2.125	2.178	2.198	2.173	-2.06%	1.20%	0.15%
Eurasia	**21.786**	**21.616**	**21.673**	**22.921**	**24.195**	**24.843**	**25.162**	**25.383**	**-0.05%**	**1.11%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.638	0.691	0.730	0.763	-0.05%	3.00%	1.20%
Russia	14.330	15.471	15.275	15.674	16.140	16.227	16.157	15.967	0.64%	0.55%	-0.07%
Turkmenistan	0.629	0.720	0.765	0.927	1.092	1.225	1.346	1.448	1.98%	3.63%	1.90%
Ukraine	3.079	1.969	1.677	1.764	1.846	1.886	1.888	1.865	-5.90%	0.96%	0.07%
Uzbekistan	1.702	1.614	1.890	2.277	2.624	2.887	3.095	3.396	1.05%	3.34%	1.73%
Other Eurasia	1.569	1.538	1.592	1.724	1.855	1.927	1.946	1.944	0.15%	1.54%	0.31%
Middle East	**9.825**	**13.379**	**14.481**	**15.516**	**17.084**	**18.363**	**19.530**	**20.592**	**3.96%**	**1.67%**	**1.25%**
Iran	3.707	5.106	5.244	5.490	5.931	6.302	6.598	6.936	3.53%	1.24%	1.05%
Qatar	0.660	0.796	1.102	1.142	1.229	1.287	1.315	1.329	5.26%	1.09%	0.52%
Oman	0.324	0.620	0.710	0.781	0.856	0.910	0.947	0.973	8.17%	1.88%	0.86%
Saudi Arabia	2.516	3.096	3.511	3.892	4.422	4.853	5.211	5.479	3.39%	2.33%	1.44%
United Arab Emirates	1.457	2.147	2.203	2.297	2.457	2.554	2.704	2.840	4.22%	1.10%	0.97%
Other Middle East	1.160	1.614	1.711	1.913	2.190	2.457	2.755	3.035	3.96%	2.50%	2.20%
Africa	**2.979**	**3.535**	**3.898**	**4.611**	**5.565**	**6.603**	**7.735**	**8.845**	**2.73%**	**3.62%**	**3.14%**
Algeria	0.846	1.024	1.087	1.230	1.427	1.595	1.715	1.784	2.53%	2.76%	1.50%
Egypt	1.208	1.630	1.795	2.030	2.355	2.742	3.273	3.808	4.04%	2.75%	3.26%
Nigeria	0.366	0.178	0.262	0.376	0.540	0.722	0.918	1.143	-3.29%	7.50%	5.12%
Other Africa	0.559	0.702	0.755	0.975	1.244	1.544	1.829	2.110	3.05%	5.12%	3.59%
Asia & Oceania	**13.741**	**20.677**	**24.170**	**31.073**	**36.216**	**40.844**	**44.221**	**44.541**	**5.81%**	**4.13%**	**1.39%**
Australia	1.014	1.249	1.546	1.819	1.920	2.002	2.078	2.122	4.30%	2.19%	0.67%
China	1.655	3.769	6.017	9.091	12.071	14.836	16.905	17.672	13.78%	7.21%	2.57%
India	1.269	2.277	1.959	2.803	3.363	3.967	4.506	4.642	4.43%	5.56%	2.17%
Indonesia	0.638	1.397	1.384	1.658	1.989	2.387	2.765	3.036	8.04%	3.69%	2.86%
Japan	3.110	3.861	4.235	4.451	4.272	4.082	3.997	3.726	3.14%	0.09%	-0.91%
Malaysia	0.914	1.145	1.084	1.310	1.445	1.534	1.558	1.410	1.72%	2.92%	-0.16%
Myanmar	0.146	0.114	0.119	0.164	0.214	0.283	0.335	0.355	-2.04%	6.03%	3.44%
Pakistan	1.088	1.400	1.331	1.673	2.008	2.212	2.271	2.259	2.04%	4.20%	0.79%
Singapore	0.233	0.297	0.370	0.419	0.426	0.423	0.413	0.385	4.72%	1.41%	-0.66%
South Korea	1.076	1.524	1.966	2.429	2.595	2.686	2.681	2.536	6.21%	2.81%	-0.15%
Thailand	1.150	1.592	1.838	2.184	2.349	2.424	2.502	2.277	4.80%	2.48%	-0.21%
Other Asia & Oceania	1.447	2.051	2.322	3.075	3.566	4.008	4.210	4.120	4.84%	4.38%	0.97%
World	**99.448**	**113.816**	**120.757**	**134.502**	**147.345**	**156.895**	**164.179**	**167.884**	**1.96%**	**2.01%**	**0.87%**

LNG20_Ref20 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.703**	**34.687**	**36.651**	**37.249**	**38.132**	**39.020**	**2.00%**	**1.15%**	**0.42%**
Canada	3.144	2.815	3.129	3.368	3.516	3.579	3.641	3.698	-0.05%	1.17%	0.34%
Mexico	1.656	2.286	2.485	2.638	2.861	3.099	3.335	3.519	4.14%	1.42%	1.39%
United States	22.014	24.087	27.088	28.681	30.275	30.570	31.155	31.804	2.10%	1.12%	0.33%
Central & South America	**4.208**	**4.897**	**5.728**	**6.181**	**6.885**	**7.446**	**7.844**	**8.188**	**3.13%**	**1.86%**	**1.16%**
Argentina	1.428	1.529	1.612	1.863	2.035	2.173	2.286	2.387	1.22%	2.36%	1.07%
Brazil	0.657	0.890	1.157	1.349	1.556	1.744	1.884	2.007	5.82%	3.01%	1.71%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.71%	1.66%
Colombia	0.236	0.321	0.393	0.402	0.446	0.490	0.523	0.562	5.25%	1.28%	1.56%
Peru	0.056	0.194	0.219	0.234	0.264	0.291	0.314	0.333	14.68%	1.86%	1.55%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.780	0.758	0.739	0.707	2.72%	0.37%	-0.66%
Venezuela	0.828	0.748	1.102	0.981	1.132	1.236	1.291	1.337	2.90%	0.27%	1.12%
Other Central & South America	0.135	0.205	0.262	0.292	0.340	0.385	0.407	0.430	6.91%	2.61%	1.59%
Europe	**20.095**	**20.525**	**17.965**	**18.599**	**19.094**	**19.229**	**19.270**	**19.088**	**-1.11%**	**0.61%**	**0.00%**
Austria	0.354	0.353	0.286	0.293	0.305	0.311	0.315	0.315	-2.11%	0.65%	0.21%
Belgium	0.601	0.700	0.612	0.651	0.689	0.717	0.729	0.731	0.18%	1.18%	0.40%
France	1.740	1.695	1.421	1.415	1.388	1.329	1.293	1.251	-2.01%	-0.23%	-0.69%
Germany	3.203	3.329	3.057	3.091	3.135	3.148	3.087	2.991	-0.46%	0.25%	-0.31%
Italy	3.046	2.935	2.322	2.334	2.348	2.342	2.335	2.318	-2.68%	0.11%	-0.08%
Netherlands	1.741	1.937	1.717	1.741	1.733	1.682	1.635	1.579	-0.14%	0.09%	-0.62%
Norway	0.187	0.194	0.225	0.249	0.264	0.255	0.238	0.224	1.84%	1.63%	-1.09%
Poland	0.573	0.606	0.617	0.684	0.737	0.772	0.786	0.788	0.74%	1.79%	0.44%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.82%	0.41%
Romania	0.643	0.455	0.454	0.492	0.519	0.528	0.533	0.519	-3.42%	1.35%	0.01%
Spain	1.188	1.265	1.050	1.092	1.128	1.152	1.179	1.208	-1.23%	0.72%	0.46%
Turkey	0.967	1.346	1.526	1.676	1.784	1.865	1.966	2.056	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.645	2.717	2.781	2.784	2.810	2.767	-2.41%	0.50%	-0.03%
Other Europe	2.324	2.192	1.887	2.013	2.126	2.181	2.197	2.176	-2.06%	1.20%	0.15%
Eurasia	**21.786**	**21.616**	**21.675**	**22.924**	**24.192**	**24.857**	**25.156**	**25.384**	**-0.05%**	**1.10%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.730	0.764	-0.05%	2.99%	1.22%
Russia	14.330	15.471	15.275	15.677	16.139	16.237	16.155	15.965	0.64%	0.55%	-0.07%
Turkmenistan	0.629	0.720	0.766	0.929	1.094	1.225	1.340	1.446	1.99%	3.63%	1.88%
Ukraine	3.079	1.969	1.677	1.764	1.846	1.886	1.890	1.866	-5.90%	0.96%	0.07%
Uzbekistan	1.702	1.614	1.890	2.276	2.623	2.890	3.093	3.398	1.06%	3.33%	1.74%
Other Eurasia	1.569	1.538	1.592	1.723	1.854	1.929	1.948	1.944	0.15%	1.53%	0.32%
Middle East	**9.825**	**13.379**	**14.478**	**15.511**	**17.073**	**18.348**	**19.491**	**20.626**	**3.95%**	**1.66%**	**1.27%**
Iran	3.707	5.106	5.243	5.486	5.923	6.302	6.589	6.952	3.53%	1.23%	1.07%
Qatar	0.660	0.796	1.103	1.143	1.229	1.286	1.313	1.332	5.26%	1.09%	0.54%
Oman	0.324	0.620	0.710	0.780	0.858	0.907	0.941	0.989	8.17%	1.91%	0.95%
Saudi Arabia	2.516	3.096	3.510	3.893	4.419	4.846	5.198	5.460	3.39%	2.33%	1.42%
United Arab Emirates	1.457	2.147	2.202	2.295	2.457	2.550	2.696	2.855	4.22%	1.10%	1.00%
Other Middle East	1.160	1.614	1.709	1.913	2.187	2.456	2.754	3.038	3.95%	2.49%	2.21%
Africa	**2.979**	**3.535**	**3.897**	**4.609**	**5.567**	**6.602**	**7.726**	**8.861**	**2.72%**	**3.63%**	**3.15%**
Algeria	0.846	1.024	1.087	1.229	1.426	1.595	1.711	1.788	2.53%	2.76%	1.52%
Egypt	1.208	1.630	1.795	2.031	2.357	2.744	3.274	3.820	4.04%	2.76%	3.27%
Nigeria	0.366	0.178	0.261	0.373	0.541	0.719	0.915	1.138	-3.32%	7.57%	5.08%
Other Africa	0.559	0.702	0.755	0.975	1.242	1.544	1.825	2.115	3.05%	5.11%	3.61%
Asia & Oceania	**13.741**	**20.677**	**24.172**	**31.083**	**36.276**	**40.944**	**44.760**	**45.208**	**5.81%**	**4.14%**	**1.48%**
Australia	1.014	1.249	1.546	1.818	1.921	2.003	2.081	2.121	4.31%	2.19%	0.66%
China	1.655	3.769	6.019	9.096	12.088	14.885	17.195	18.000	13.78%	7.22%	2.69%
India	1.269	2.277	1.959	2.803	3.372	3.990	4.578	4.700	4.44%	5.58%	2.24%
Indonesia	0.638	1.397	1.384	1.658	1.989	2.388	2.746	3.033	8.04%	3.69%	2.85%
Japan	3.110	3.861	4.234	4.452	4.276	4.103	4.047	3.785	3.13%	0.10%	-0.81%
Malaysia	0.914	1.145	1.084	1.309	1.446	1.535	1.561	1.455	1.72%	2.92%	0.04%
Myanmar	0.146	0.114	0.119	0.164	0.215	0.280	0.337	0.359	-2.03%	6.07%	3.49%
Pakistan	1.088	1.400	1.331	1.675	2.022	2.205	2.326	2.343	2.04%	4.27%	0.99%
Singapore	0.233	0.297	0.370	0.419	0.426	0.423	0.413	0.395	4.72%	1.41%	-0.49%
South Korea	1.076	1.524	1.965	2.429	2.597	2.697	2.715	2.587	6.21%	2.83%	-0.03%
Thailand	1.150	1.592	1.838	2.184	2.351	2.424	2.508	2.286	4.80%	2.49%	-0.19%
Other Asia & Oceania	1.447	2.051	2.322	3.077	3.573	4.013	4.253	4.145	4.84%	4.41%	0.99%
World	**99.448**	**113.816**	**120.616**	**133.593**	**145.739**	**154.675**	**162.379**	**166.376**	**1.95%**	**1.91%**	**0.89%**

LNG20_HRR20 Case (Demand)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**26.814**	**29.188**	**32.840**	**35.079**	**37.078**	**37.913**	**38.945**	**39.945**	**2.05%**	**1.22%**	**0.50%**
Canada	3.144	2.815	3.124	3.332	3.491	3.596	3.668	3.728	-0.06%	1.12%	0.44%
Mexico	1.656	2.286	2.494	2.654	2.849	3.063	3.275	3.471	4.18%	1.34%	1.32%
United States	22.014	24.087	27.221	29.092	30.738	31.254	32.002	32.746	2.15%	1.22%	0.42%
Central & South America	**4.208**	**4.897**	**5.727**	**6.181**	**6.887**	**7.452**	**7.856**	**8.219**	**3.13%**	**1.86%**	**1.19%**
Argentina	1.428	1.529	1.612	1.863	2.036	2.174	2.288	2.385	1.22%	2.37%	1.06%
Brazil	0.657	0.890	1.157	1.349	1.556	1.745	1.886	2.005	5.82%	3.01%	1.70%
Chile	0.295	0.187	0.231	0.290	0.333	0.370	0.401	0.426	-2.40%	3.72%	1.65%
Colombia	0.236	0.321	0.393	0.403	0.446	0.491	0.524	0.565	5.25%	1.27%	1.59%
Peru	0.056	0.194	0.218	0.234	0.264	0.291	0.315	0.332	14.61%	1.92%	1.55%
Trinidad and Tobago	0.575	0.824	0.752	0.769	0.778	0.758	0.738	0.707	2.73%	0.34%	-0.64%
Venezuela	0.828	0.748	1.102	0.981	1.133	1.236	1.297	1.368	2.90%	0.28%	1.26%
Other Central & South America	0.135	0.205	0.262	0.293	0.341	0.387	0.408	0.432	6.91%	2.64%	1.59%
Europe	**20.095**	**20.525**	**17.965**	**18.593**	**19.112**	**19.217**	**19.280**	**19.051**	**-1.11%**	**0.62%**	**-0.02%**
Austria	0.354	0.353	0.286	0.294	0.305	0.311	0.315	0.314	-2.11%	0.66%	0.20%
Belgium	0.601	0.700	0.612	0.650	0.689	0.717	0.730	0.730	0.18%	1.19%	0.38%
France	1.740	1.695	1.421	1.414	1.391	1.327	1.294	1.245	-2.01%	-0.21%	-0.74%
Germany	3.203	3.329	3.057	3.089	3.138	3.146	3.089	2.988	-0.46%	0.26%	-0.33%
Italy	3.046	2.935	2.322	2.334	2.349	2.341	2.335	2.316	-2.68%	0.12%	-0.09%
Netherlands	1.741	1.937	1.717	1.740	1.734	1.682	1.636	1.576	-0.14%	0.10%	-0.64%
Norway	0.187	0.194	0.225	0.249	0.265	0.253	0.240	0.225	1.85%	1.64%	-1.08%
Poland	0.573	0.606	0.617	0.684	0.738	0.772	0.787	0.787	0.75%	1.80%	0.43%
Portugal	0.152	0.182	0.145	0.152	0.157	0.161	0.166	0.167	-0.46%	0.83%	0.40%
Romania	0.643	0.455	0.454	0.493	0.519	0.528	0.533	0.519	-3.41%	1.35%	0.00%
Spain	1.188	1.265	1.050	1.091	1.129	1.152	1.178	1.207	-1.23%	0.73%	0.45%
Turkey	0.967	1.346	1.527	1.676	1.786	1.865	1.968	2.057	4.67%	1.58%	0.95%
United Kingdom	3.376	3.337	2.645	2.716	2.783	2.782	2.811	2.750	-2.41%	0.51%	-0.08%
Other Europe	2.324	2.192	1.887	2.012	2.129	2.180	2.199	2.172	-2.06%	1.21%	0.13%
Eurasia	**21.786**	**21.616**	**21.674**	**22.920**	**24.204**	**24.850**	**25.167**	**25.379**	**-0.05%**	**1.11%**	**0.32%**
Kazakhstan	0.477	0.303	0.474	0.555	0.637	0.691	0.731	0.765	-0.05%	3.00%	1.22%
Russia	14.330	15.471	15.275	15.674	16.148	16.235	16.161	15.962	0.64%	0.56%	-0.08%
Turkmenistan	0.629	0.720	0.765	0.928	1.092	1.222	1.343	1.448	1.99%	3.62%	1.90%
Ukraine	3.079	1.969	1.677	1.763	1.847	1.887	1.888	1.864	-5.90%	0.97%	0.06%
Uzbekistan	1.702	1.614	1.890	2.276	2.624	2.888	3.096	3.397	1.05%	3.34%	1.74%
Other Eurasia	1.569	1.538	1.592	1.724	1.855	1.928	1.947	1.943	0.15%	1.54%	0.31%
Middle East	**9.825**	**13.379**	**14.476**	**15.510**	**17.068**	**18.358**	**19.527**	**20.650**	**3.95%**	**1.66%**	**1.28%**
Iran	3.707	5.106	5.242	5.485	5.920	6.309	6.601	6.975	3.53%	1.22%	1.10%
Qatar	0.660	0.796	1.102	1.142	1.229	1.285	1.317	1.327	5.26%	1.09%	0.52%
Oman	0.324	0.620	0.710	0.780	0.857	0.908	0.945	0.980	8.17%	1.90%	0.90%
Saudi Arabia	2.516	3.096	3.510	3.894	4.419	4.845	5.201	5.470	3.39%	2.33%	1.43%
United Arab Emirates	1.457	2.147	2.203	2.296	2.457	2.551	2.709	2.854	4.22%	1.10%	1.00%
Other Middle East	1.160	1.614	1.708	1.913	2.186	2.460	2.754	3.044	3.94%	2.50%	2.23%
Africa	**2.979**	**3.535**	**3.897**	**4.608**	**5.569**	**6.597**	**7.717**	**8.845**	**2.72%**	**3.63%**	**3.13%**
Algeria	0.846	1.024	1.087	1.229	1.427	1.593	1.708	1.787	2.53%	2.76%	1.51%
Egypt	1.208	1.630	1.795	2.031	2.359	2.743	3.270	3.814	4.04%	2.77%	3.26%
Nigeria	0.366	0.178	0.261	0.373	0.539	0.722	0.914	1.139	-3.33%	7.53%	5.11%
Other Africa	0.559	0.702	0.755	0.975	1.244	1.539	1.825	2.105	3.05%	5.12%	3.57%
Asia & Oceania	**13.741**	**20.677**	**24.169**	**31.090**	**36.307**	**41.063**	**44.806**	**45.285**	**5.81%**	**4.15%**	**1.48%**
Australia	1.014	1.249	1.546	1.818	1.919	2.000	2.077	2.119	4.31%	2.19%	0.66%
China	1.655	3.769	6.019	9.099	12.118	14.942	17.215	18.052	13.79%	7.25%	2.69%
India	1.269	2.277	1.959	2.803	3.373	4.019	4.587	4.707	4.44%	5.59%	2.25%
Indonesia	0.638	1.397	1.384	1.658	1.990	2.386	2.745	3.028	8.04%	3.70%	2.84%
Japan	3.110	3.861	4.233	4.451	4.282	4.131	4.052	3.789	3.13%	0.11%	-0.81%
Malaysia	0.914	1.145	1.084	1.310	1.445	1.535	1.562	1.463	1.72%	2.92%	0.08%
Myanmar	0.146	0.114	0.119	0.164	0.213	0.280	0.338	0.360	-2.03%	6.01%	3.54%
Pakistan	1.088	1.400	1.331	1.676	2.016	2.199	2.331	2.350	2.04%	4.23%	1.03%
Singapore	0.233	0.297	0.370	0.418	0.426	0.423	0.413	0.395	4.72%	1.41%	-0.49%
South Korea	1.076	1.524	1.965	2.428	2.602	2.706	2.720	2.591	6.20%	2.85%	-0.03%
Thailand	1.150	1.592	1.838	2.184	2.352	2.425	2.508	2.286	4.80%	2.49%	-0.19%
Other Asia & Oceania	1.447	2.051	2.321	3.080	3.572	4.017	4.258	4.146	4.84%	4.40%	1.00%
World	**99.448**	**113.816**	**120.748**	**133.981**	**146.224**	**155.452**	**163.298**	**167.374**	**1.96%**	**1.93%**	**0.90%**

D3. Supply (tcf)[47]

Ref_Ref Case (Supply)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.996**	**38.740**	**41.131**	**42.312**	**43.034**	**44.467**	**2.45%**	**1.63%**	**0.52%**
Canada	7.185	5.909	5.936	7.687	8.591	8.770	8.846	9.392	-1.89%	3.77%	0.60%
Mexico	1.349	1.799	1.251	0.683	0.895	1.863	3.060	4.274	-0.74%	-3.30%	10.99%
United States	18.927	22.382	27.809	30.370	31.645	31.679	31.128	30.802	3.92%	1.30%	-0.18%
Central & South America	**5.318**	**6.267**	**6.517**	**6.700**	**7.510**	**8.125**	**8.714**	**9.087**	**2.05%**	**1.43%**	**1.28%**
Argentina	1.753	1.585	1.386	2.475	3.117	3.557	3.859	4.099	-2.32%	8.44%	1.84%
Brazil	0.432	0.570	0.762	0.338	0.158	0.097	0.048	0.024	5.84%	-14.59%	-11.91%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.79%
Colombia	0.253	0.454	0.502	0.427	0.315	0.224	0.191	0.318	7.08%	-4.55%	0.07%
Peru	0.073	0.291	0.442	0.453	0.486	0.511	0.533	0.540	19.65%	0.96%	0.70%
Trinidad and Tobago	1.094	1.512	1.448	1.270	1.362	1.382	1.539	1.526	2.84%	-0.61%	0.76%
Venezuela	1.172	1.201	1.253	1.223	1.546	1.804	1.925	1.870	0.66%	2.13%	1.27%
Other Central & South America	0.472	0.589	0.699	0.503	0.520	0.547	0.568	0.635	4.00%	-2.91%	1.34%
Europe	**11.723**	**11.155**	**9.793**	**9.983**	**10.357**	**10.230**	**10.043**	**9.740**	**-1.78%**	**0.56%**	**-0.41%**
Austria	0.061	0.064	0.041	0.028	0.030	0.018	0.011	0.007	-3.93%	-3.02%	-9.14%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.003	0.020	0.014	0.009	-14.60%	-14.47%	8.33%
Germany	0.689	0.526	0.330	0.164	0.200	0.203	0.471	0.524	-7.09%	-4.89%	6.63%
Italy	0.426	0.297	0.239	0.120	0.193	0.239	0.171	0.109	-5.63%	-2.08%	-3.76%
Netherlands	2.773	3.131	3.166	3.078	2.643	2.057	1.435	0.885	1.33%	-1.79%	-7.03%
Norway	3.196	3.849	3.705	3.979	4.284	3.958	3.350	3.199	1.49%	1.46%	-1.93%
Poland	0.214	0.215	0.191	0.215	0.312	0.663	1.037	1.591	-1.14%	5.06%	11.47%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.352	0.448	0.449	0.332	0.324	0.299	-1.60%	2.47%	-2.67%
Spain	0.006	0.002	0.001	0.001	0.000	0.007	0.010	0.060	-13.89%	-9.71%	38.07%
Turkey	0.032	0.024	0.054	0.117	0.150	0.139	0.090	0.031	5.44%	10.77%	-10.04%
United Kingdom	3.275	2.124	1.328	1.471	1.733	2.206	2.782	2.749	-8.63%	2.70%	3.13%
Other Europe	0.574	0.502	0.374	0.355	0.361	0.388	0.348	0.277	-4.20%	-0.36%	-1.75%
Eurasia	**27.386**	**27.903**	**28.402**	**30.205**	**32.584**	**34.057**	**35.381**	**36.891**	**0.36%**	**1.38%**	**0.83%**
Kazakhstan	0.428	0.441	0.631	1.038	1.338	1.476	1.490	1.605	3.96%	7.81%	1.22%
Russia	21.698	22.372	21.607	22.250	23.724	24.621	25.528	26.602	-0.04%	0.94%	0.77%
Turkmenistan	2.225	1.600	2.559	3.153	3.708	4.223	5.106	5.929	1.41%	3.78%	3.18%
Ukraine	0.685	0.684	0.604	0.292	0.280	0.552	0.817	0.943	-1.25%	-7.39%	8.42%
Uzbekistan	2.119	2.130	2.445	3.088	3.088	2.530	1.697	1.070	1.44%	2.36%	-6.82%
Other Eurasia	0.232	0.677	0.556	0.385	0.447	0.655	0.743	0.743	9.11%	-2.15%	3.45%
Middle East	**12.334**	**18.699**	**21.349**	**22.477**	**24.018**	**25.488**	**27.122**	**28.346**	**5.64%**	**1.19%**	**1.11%**
Iran	3.818	6.031	6.405	6.723	7.111	7.453	7.753	8.050	5.31%	1.05%	0.83%
Qatar	1.826	4.359	5.707	5.931	6.212	6.535	6.743	6.766	12.07%	0.85%	0.57%
Oman	0.748	1.035	1.132	1.226	1.306	1.356	1.414	1.453	4.23%	1.44%	0.71%
Saudi Arabia	2.860	3.424	3.916	4.303	4.849	5.318	5.740	6.202	3.19%	2.16%	1.65%
United Arab Emirates	1.828	1.992	2.005	1.887	1.860	1.906	2.086	2.216	0.93%	-0.75%	1.17%
Other Middle East	1.255	1.858	2.183	2.407	2.680	2.919	3.387	3.659	5.70%	2.07%	2.10%
Africa	**6.877**	**8.553**	**7.371**	**8.048**	**9.457**	**10.918**	**12.134**	**13.363**	**0.70%**	**2.52%**	**2.33%**
Algeria	3.613	3.465	3.413	3.349	3.727	4.000	4.040	3.741	-0.57%	0.89%	0.02%
Egypt	1.610	2.284	1.748	1.929	2.060	1.971	2.318	2.892	0.82%	1.66%	2.29%
Nigeria	0.862	1.317	1.172	1.105	1.472	1.950	2.342	3.101	3.13%	2.30%	5.10%
Other Africa	0.792	1.486	1.038	1.666	2.198	2.998	3.434	3.629	2.74%	7.79%	3.40%
Asia & Oceania	**12.907**	**17.527**	**19.368**	**24.557**	**28.655**	**32.515**	**36.498**	**39.742**	**4.14%**	**3.99%**	**2.20%**
Australia	1.266	1.708	3.518	5.323	6.149	6.280	6.389	6.474	10.76%	5.74%	0.34%
China	1.763	3.334	3.814	4.166	5.821	8.752	12.309	15.672	8.02%	4.32%	6.83%
India	1.153	1.848	1.179	1.943	2.316	2.556	2.347	2.297	0.22%	6.98%	-0.05%
Indonesia	2.406	3.047	2.472	3.070	3.646	4.432	5.249	6.308	0.27%	3.97%	3.72%
Japan	0.191	0.171	0.072	0.020	0.018	0.011	0.008	0.005	-9.31%	-13.03%	-8.48%
Malaysia	2.147	2.347	2.635	3.625	3.962	3.950	3.511	2.884	2.07%	4.16%	-2.10%
Myanmar	0.479	0.437	0.410	0.489	0.559	0.612	1.030	1.310	-1.54%	3.15%	5.84%
Pakistan	1.194	1.484	1.432	1.779	1.938	1.937	1.772	1.347	1.83%	3.08%	-2.40%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.013	0.003	0.004	0.002	0.001	0.000	-3.08%	-10.02%	-14.21%
Thailand	0.925	1.378	1.524	1.366	1.160	0.820	0.904	0.897	5.12%	-2.69%	-1.70%
Other Asia & Oceania	1.366	1.739	2.301	2.772	3.081	3.162	2.977	2.548	5.35%	2.96%	-1.26%
World	**104.006**	**120.194**	**127.797**	**140.711**	**153.713**	**163.644**	**172.927**	**181.637**	**2.08%**	**1.86%**	**1.12%**

[47] Supply is marketed production. Historical data match those reported by EIA.

Ref_HRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.109**	**39.585**	**42.280**	**43.265**	**44.228**	**45.970**	**2.49%**	**1.88%**	**0.56%**
Canada	7.185	5.909	5.680	6.512	7.884	8.469	8.787	9.435	-2.32%	3.33%	1.20%
Mexico	1.349	1.799	1.251	0.666	0.870	1.060	1.928	3.006	-0.75%	-3.57%	8.62%
United States	18.927	22.382	28.177	32.408	33.526	33.736	33.513	33.529	4.06%	1.75%	0.00%
Central & South America	**5.318**	**6.267**	**6.510**	**6.682**	**7.482**	**8.155**	**8.714**	**9.096**	**2.04%**	**1.40%**	**1.31%**
Argentina	1.753	1.585	1.386	2.451	3.113	3.559	3.854	4.110	-2.32%	8.43%	1.87%
Brazil	0.432	0.570	0.762	0.338	0.159	0.097	0.049	0.024	5.84%	-14.49%	-11.97%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.81%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.200	0.308	7.08%	-4.56%	-0.15%
Peru	0.073	0.291	0.442	0.454	0.483	0.506	0.532	0.521	19.66%	0.90%	0.50%
Trinidad and Tobago	1.094	1.512	1.445	1.269	1.341	1.421	1.545	1.527	2.82%	-0.75%	0.87%
Venezuela	1.172	1.201	1.253	1.224	1.547	1.809	1.904	1.901	0.66%	2.13%	1.38%
Other Central & South America	0.472	0.589	0.694	0.506	0.518	0.539	0.579	0.630	3.92%	-2.88%	1.31%
Europe	**11.723**	**11.155**	**9.794**	**9.923**	**10.246**	**10.186**	**10.048**	**9.636**	**-1.78%**	**0.45%**	**-0.41%**
Austria	0.061	0.064	0.041	0.028	0.031	0.018	0.011	0.007	-3.85%	-2.86%	-9.30%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.003	0.020	0.013	0.009	-14.57%	-14.50%	8.25%
Germany	0.689	0.526	0.330	0.158	0.195	0.200	0.466	0.519	-7.11%	-5.14%	6.76%
Italy	0.426	0.297	0.239	0.112	0.178	0.244	0.179	0.112	-5.63%	-2.88%	-3.03%
Netherlands	2.773	3.131	3.164	3.059	2.638	2.052	1.433	0.910	1.33%	-1.80%	-6.85%
Norway	3.196	3.849	3.704	3.954	4.255	3.961	3.379	3.204	1.49%	1.40%	-1.87%
Poland	0.214	0.215	0.190	0.209	0.309	0.610	0.980	1.428	-1.19%	5.00%	10.74%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.354	0.447	0.448	0.336	0.328	0.301	-1.54%	2.39%	-2.63%
Spain	0.006	0.002	0.001	0.001	0.000	0.010	0.010	0.058	-13.89%	-13.37%	41.53%
Turkey	0.032	0.024	0.053	0.124	0.144	0.141	0.088	0.032	5.33%	10.48%	-9.50%
United Kingdom	3.275	2.124	1.333	1.475	1.697	2.201	2.796	2.772	-8.60%	2.44%	3.33%
Other Europe	0.574	0.502	0.373	0.352	0.348	0.393	0.364	0.285	-4.23%	-0.69%	-1.32%
Eurasia	**27.386**	**27.903**	**28.399**	**30.186**	**32.558**	**34.084**	**35.369**	**36.463**	**0.36%**	**1.38%**	**0.76%**
Kazakhstan	0.428	0.441	0.630	1.035	1.327	1.473	1.508	1.552	3.94%	7.74%	1.05%
Russia	21.698	22.372	21.602	22.224	23.674	24.607	25.490	26.207	-0.04%	0.92%	0.68%
Turkmenistan	2.225	1.600	2.561	3.145	3.737	4.262	5.117	5.924	1.42%	3.85%	3.12%
Ukraine	0.685	0.684	0.604	0.289	0.270	0.561	0.823	0.948	-1.25%	-7.73%	8.72%
Uzbekistan	2.119	2.130	2.447	3.108	3.099	2.519	1.679	1.083	1.45%	2.39%	-6.77%
Other Eurasia	0.232	0.677	0.555	0.385	0.450	0.662	0.752	0.750	9.10%	-2.07%	3.46%
Middle East	**12.334**	**18.699**	**21.353**	**22.486**	**24.034**	**25.523**	**27.124**	**28.331**	**5.64%**	**1.19%**	**1.10%**
Iran	3.818	6.031	6.406	6.725	7.117	7.458	7.746	8.039	5.31%	1.06%	0.82%
Qatar	1.826	4.359	5.705	5.927	6.214	6.562	6.741	6.767	12.07%	0.86%	0.57%
Oman	0.748	1.035	1.132	1.226	1.306	1.356	1.414	1.452	4.23%	1.44%	0.71%
Saudi Arabia	2.860	3.424	3.916	4.304	4.850	5.315	5.762	6.231	3.19%	2.16%	1.68%
United Arab Emirates	1.828	1.992	2.007	1.891	1.858	1.915	2.089	2.219	0.94%	-0.77%	1.19%
Other Middle East	1.255	1.858	2.187	2.412	2.689	2.916	3.372	3.622	5.71%	2.09%	2.01%
Africa	**6.877**	**8.553**	**7.384**	**8.022**	**9.345**	**10.939**	**12.178**	**13.408**	**0.71%**	**2.38%**	**2.44%**
Algeria	3.613	3.465	3.414	3.343	3.693	3.999	4.021	3.748	-0.56%	0.79%	0.10%
Egypt	1.610	2.284	1.755	1.915	2.012	1.978	2.329	2.881	0.86%	1.37%	2.42%
Nigeria	0.862	1.317	1.175	1.102	1.432	1.957	2.360	3.098	3.15%	2.00%	5.28%
Other Africa	0.792	1.486	1.039	1.663	2.209	3.005	3.469	3.681	2.75%	7.83%	3.46%
Asia & Oceania	**12.907**	**17.527**	**19.376**	**24.435**	**28.445**	**32.237**	**36.268**	**39.370**	**4.15%**	**3.91%**	**2.19%**
Australia	1.266	1.708	3.533	5.288	6.133	6.222	6.334	6.414	10.81%	5.67%	0.30%
China	1.763	3.334	3.812	4.108	5.705	8.564	12.102	15.465	8.02%	4.11%	6.87%
India	1.153	1.848	1.178	1.937	2.285	2.568	2.369	2.281	0.21%	6.85%	-0.01%
Indonesia	2.406	3.047	2.469	3.048	3.645	4.429	5.256	6.197	0.26%	3.97%	3.60%
Japan	0.191	0.171	0.072	0.021	0.016	0.012	0.008	0.005	-9.33%	-13.94%	-7.88%
Malaysia	2.147	2.347	2.637	3.625	3.937	3.918	3.490	2.889	2.08%	4.09%	-2.04%
Myanmar	0.479	0.437	0.411	0.491	0.557	0.609	1.029	1.314	-1.51%	3.09%	5.89%
Pakistan	1.194	1.484	1.432	1.779	1.922	1.920	1.777	1.360	1.84%	2.99%	-2.28%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.013	0.003	0.004	0.002	0.001	0.000	-3.09%	-10.60%	-13.83%
Thailand	0.925	1.378	1.524	1.363	1.162	0.825	0.893	0.897	5.11%	-2.67%	-1.71%
Other Asia & Oceania	1.366	1.739	2.298	2.773	3.079	3.166	3.009	2.547	5.34%	2.97%	-1.26%
World	**104.006**	**120.194**	**127.924**	**141.320**	**154.391**	**164.389**	**173.929**	**182.274**	**2.09%**	**1.90%**	**1.11%**

Ref_LRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.662**	**38.199**	**40.093**	**40.523**	**41.785**	**43.271**	**2.36%**	**1.47%**	**0.51%**
Canada	7.185	5.909	6.148	8.151	8.726	8.778	8.869	9.505	-1.55%	3.56%	0.57%
Mexico	1.349	1.799	1.251	0.786	1.348	2.733	4.224	5.089	-0.74%	0.75%	9.26%
United States	18.927	22.382	27.263	29.262	30.019	29.013	28.691	28.676	3.72%	0.97%	-0.30%
Central & South America	**5.318**	**6.267**	**6.518**	**6.712**	**7.555**	**8.186**	**8.745**	**9.107**	**2.05%**	**1.49%**	**1.25%**
Argentina	1.753	1.585	1.386	2.484	3.116	3.558	3.855	4.105	-2.32%	8.44%	1.86%
Brazil	0.432	0.570	0.762	0.338	0.157	0.096	0.048	0.023	5.84%	-14.63%	-11.99%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.76%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.205	0.307	7.08%	-4.56%	-0.16%
Peru	0.073	0.291	0.441	0.456	0.485	0.505	0.534	0.568	19.64%	0.95%	1.05%
Trinidad and Tobago	1.094	1.512	1.453	1.266	1.413	1.460	1.544	1.523	2.87%	-0.28%	0.50%
Venezuela	1.172	1.201	1.253	1.224	1.546	1.801	1.915	1.887	0.66%	2.12%	1.34%
Other Central & South America	0.472	0.589	0.695	0.506	0.519	0.540	0.594	0.618	3.94%	-2.88%	1.17%
Europe	**11.723**	**11.155**	**9.795**	**10.048**	**10.404**	**10.274**	**9.977**	**9.721**	**-1.78%**	**0.60%**	**-0.45%**
Austria	0.061	0.064	0.041	0.029	0.031	0.018	0.011	0.007	-3.84%	-2.79%	-9.16%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.004	0.019	0.013	0.009	-14.61%	-10.47%	5.03%
Germany	0.689	0.526	0.329	0.163	0.206	0.202	0.467	0.525	-7.11%	-4.60%	6.44%
Italy	0.426	0.297	0.239	0.121	0.194	0.240	0.171	0.112	-5.63%	-2.06%	-3.57%
Netherlands	2.773	3.131	3.170	3.087	2.646	2.066	1.413	0.875	1.35%	-1.79%	-7.11%
Norway	3.196	3.849	3.709	3.995	4.293	3.961	3.356	3.214	1.50%	1.47%	-1.91%
Poland	0.214	0.215	0.192	0.210	0.312	0.649	1.011	1.580	-1.08%	4.98%	11.42%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.351	0.447	0.450	0.336	0.324	0.307	-1.63%	2.52%	-2.51%
Spain	0.006	0.002	0.001	0.001	0.003	0.010	0.009	0.050	-13.88%	7.61%	21.27%
Turkey	0.032	0.024	0.054	0.152	0.144	0.135	0.081	0.031	5.53%	10.22%	-9.64%
United Kingdom	3.275	2.124	1.322	1.477	1.750	2.245	2.775	2.739	-8.67%	2.85%	3.03%
Other Europe	0.574	0.502	0.374	0.359	0.372	0.393	0.347	0.272	-4.20%	-0.06%	-2.05%
Eurasia	**27.386**	**27.903**	**28.392**	**30.234**	**32.617**	**34.151**	**35.495**	**36.715**	**0.36%**	**1.40%**	**0.79%**
Kazakhstan	0.428	0.441	0.630	1.045	1.344	1.482	1.538	1.627	3.94%	7.88%	1.28%
Russia	21.698	22.372	21.598	22.244	23.696	24.659	25.611	26.401	-0.05%	0.93%	0.72%
Turkmenistan	2.225	1.600	2.562	3.161	3.713	4.198	5.088	5.884	1.42%	3.78%	3.12%
Ukraine	0.685	0.684	0.604	0.291	0.301	0.589	0.831	0.966	-1.25%	-6.73%	8.08%
Uzbekistan	2.119	2.130	2.444	3.101	3.101	2.536	1.678	1.088	1.44%	2.41%	-6.74%
Other Eurasia	0.232	0.677	0.555	0.392	0.462	0.688	0.748	0.748	9.10%	-1.82%	3.27%
Middle East	**12.334**	**18.699**	**21.351**	**22.489**	**24.023**	**25.590**	**27.154**	**28.352**	**5.64%**	**1.19%**	**1.11%**
Iran	3.818	6.031	6.406	6.728	7.107	7.464	7.765	8.041	5.31%	1.04%	0.83%
Qatar	1.826	4.359	5.705	5.925	6.212	6.595	6.741	6.780	12.07%	0.86%	0.58%
Oman	0.748	1.035	1.132	1.226	1.306	1.358	1.418	1.452	4.23%	1.44%	0.71%
Saudi Arabia	2.860	3.424	3.916	4.302	4.850	5.326	5.754	6.226	3.19%	2.16%	1.68%
United Arab Emirates	1.828	1.992	2.007	1.894	1.861	1.914	2.083	2.226	0.94%	-0.75%	1.20%
Other Middle East	1.255	1.858	2.184	2.414	2.686	2.934	3.393	3.626	5.70%	2.09%	2.02%
Africa	**6.877**	**8.553**	**7.381**	**8.078**	**9.578**	**10.931**	**12.141**	**13.404**	**0.71%**	**2.64%**	**2.27%**
Algeria	3.613	3.465	3.413	3.356	3.741	4.007	4.002	3.705	-0.57%	0.92%	-0.06%
Egypt	1.610	2.284	1.748	1.931	2.074	1.978	2.313	2.896	0.82%	1.73%	2.25%
Nigeria	0.862	1.317	1.183	1.104	1.569	1.959	2.387	3.132	3.22%	2.86%	4.72%
Other Africa	0.792	1.486	1.038	1.688	2.195	2.986	3.438	3.671	2.74%	7.77%	3.49%
Asia & Oceania	**12.907**	**17.527**	**19.372**	**24.656**	**28.903**	**32.858**	**36.708**	**39.579**	**4.14%**	**4.08%**	**2.12%**
Australia	1.266	1.708	3.523	5.360	6.137	6.242	6.340	6.378	10.78%	5.71%	0.26%
China	1.763	3.334	3.816	4.184	5.978	8.977	12.472	15.598	8.03%	4.59%	6.60%
India	1.153	1.848	1.181	1.955	2.330	2.609	2.343	2.300	0.24%	7.03%	-0.09%
Indonesia	2.406	3.047	2.473	3.092	3.664	4.473	5.303	6.370	0.28%	4.01%	3.76%
Japan	0.191	0.171	0.072	0.021	0.019	0.012	0.008	0.005	-9.30%	-12.54%	-8.90%
Malaysia	2.147	2.347	2.639	3.629	3.989	3.963	3.498	2.865	2.08%	4.22%	-2.18%
Myanmar	0.479	0.437	0.408	0.492	0.555	0.608	1.030	1.303	-1.57%	3.11%	5.86%
Pakistan	1.194	1.484	1.431	1.779	1.973	1.971	1.769	1.340	1.83%	3.26%	-2.55%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.013	0.003	0.005	0.002	0.001	0.000	-3.06%	-9.80%	-14.36%
Thailand	0.925	1.378	1.521	1.357	1.169	0.833	0.910	0.885	5.10%	-2.60%	-1.84%
Other Asia & Oceania	1.366	1.739	2.295	2.785	3.085	3.167	3.033	2.535	5.32%	3.00%	-1.30%
World	**104.006**	**120.194**	**127.472**	**140.417**	**153.173**	**162.513**	**172.003**	**180.150**	**2.06%**	**1.85%**	**1.09%**

Ref_Hi-D Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.067**	**39.653**	**42.638**	**44.584**	**45.425**	**46.828**	**2.48%**	**1.97%**	**0.63%**
Canada	7.185	5.909	5.979	7.897	8.693	8.781	8.854	9.411	-1.82%	3.81%	0.53%
Mexico	1.349	1.799	1.251	0.708	0.982	2.251	3.418	4.850	-0.74%	-2.39%	11.23%
United States	18.927	22.382	27.836	31.048	32.962	33.551	33.153	32.567	3.93%	1.70%	-0.08%
Central & South America	**5.318**	**6.267**	**6.515**	**6.706**	**7.526**	**8.116**	**8.725**	**9.101**	**2.05%**	**1.45%**	**1.28%**
Argentina	1.753	1.585	1.386	2.479	3.117	3.561	3.855	4.110	-2.32%	8.44%	1.86%
Brazil	0.432	0.570	0.762	0.338	0.159	0.097	0.048	0.024	5.84%	-14.54%	-11.80%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.77%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.199	0.311	7.08%	-4.56%	-0.08%
Peru	0.073	0.291	0.441	0.453	0.487	0.512	0.534	0.554	19.63%	0.99%	0.86%
Trinidad and Tobago	1.094	1.512	1.448	1.269	1.383	1.396	1.535	1.521	2.84%	-0.46%	0.64%
Venezuela	1.172	1.201	1.253	1.219	1.542	1.782	1.923	1.883	0.66%	2.10%	1.34%
Other Central & South America	0.472	0.589	0.697	0.509	0.519	0.543	0.581	0.623	3.98%	-2.90%	1.22%
Europe	**11.723**	**11.155**	**9.796**	**10.005**	**10.392**	**10.191**	**10.065**	**9.682**	**-1.78%**	**0.59%**	**-0.47%**
Austria	0.061	0.064	0.041	0.029	0.029	0.018	0.011	0.007	-3.83%	-3.54%	-8.90%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.004	0.019	0.013	0.009	-14.60%	-11.88%	5.88%
Germany	0.689	0.526	0.330	0.162	0.200	0.193	0.467	0.520	-7.11%	-4.85%	6.56%
Italy	0.426	0.297	0.239	0.122	0.196	0.239	0.172	0.110	-5.63%	-1.96%	-3.77%
Netherlands	2.773	3.131	3.169	3.076	2.662	2.037	1.429	0.885	1.34%	-1.73%	-7.08%
Norway	3.196	3.849	3.706	3.987	4.297	3.961	3.371	3.183	1.49%	1.49%	-1.98%
Poland	0.214	0.215	0.192	0.214	0.317	0.662	1.037	1.581	-1.09%	5.15%	11.31%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.351	0.447	0.448	0.339	0.332	0.305	-1.61%	2.47%	-2.54%
Spain	0.006	0.002	0.001	0.001	0.003	0.009	0.009	0.057	-13.89%	7.79%	22.18%
Turkey	0.032	0.024	0.053	0.140	0.138	0.133	0.086	0.032	5.38%	9.92%	-9.35%
United Kingdom	3.275	2.124	1.326	1.466	1.735	2.196	2.792	2.722	-8.64%	2.72%	3.05%
Other Europe	0.574	0.502	0.375	0.356	0.364	0.385	0.347	0.272	-4.18%	-0.29%	-1.92%
Eurasia	**27.386**	**27.903**	**28.392**	**30.216**	**32.563**	**34.009**	**35.274**	**36.447**	**0.36%**	**1.38%**	**0.75%**
Kazakhstan	0.428	0.441	0.630	1.045	1.315	1.465	1.523	1.601	3.94%	7.64%	1.32%
Russia	21.698	22.372	21.595	22.224	23.661	24.546	25.412	26.162	-0.05%	0.92%	0.67%
Turkmenistan	2.225	1.600	2.564	3.159	3.743	4.234	5.085	5.901	1.43%	3.86%	3.08%
Ukraine	0.685	0.684	0.604	0.298	0.284	0.550	0.816	0.948	-1.25%	-7.26%	8.36%
Uzbekistan	2.119	2.130	2.444	3.103	3.103	2.532	1.684	1.081	1.44%	2.42%	-6.79%
Other Eurasia	0.232	0.677	0.555	0.388	0.456	0.682	0.753	0.754	9.10%	-1.95%	3.41%
Middle East	**12.334**	**18.699**	**21.348**	**22.481**	**24.034**	**25.532**	**27.125**	**28.351**	**5.64%**	**1.19%**	**1.11%**
Iran	3.818	6.031	6.406	6.723	7.117	7.462	7.760	8.041	5.31%	1.06%	0.82%
Qatar	1.826	4.359	5.705	5.928	6.209	6.550	6.742	6.761	12.07%	0.85%	0.57%
Oman	0.748	1.035	1.132	1.226	1.307	1.357	1.415	1.458	4.23%	1.44%	0.73%
Saudi Arabia	2.860	3.424	3.917	4.302	4.852	5.331	5.755	6.222	3.19%	2.16%	1.67%
United Arab Emirates	1.828	1.992	2.007	1.890	1.866	1.910	2.080	2.240	0.94%	-0.72%	1.23%
Other Middle East	1.255	1.858	2.181	2.411	2.685	2.922	3.374	3.629	5.68%	2.10%	2.03%
Africa	**6.877**	**8.553**	**7.380**	**8.063**	**9.518**	**10.930**	**12.144**	**13.380**	**0.71%**	**2.58%**	**2.30%**
Algeria	3.613	3.465	3.413	3.358	3.761	3.999	4.045	3.747	-0.57%	0.97%	-0.02%
Egypt	1.610	2.284	1.749	1.920	2.029	1.964	2.324	2.883	0.83%	1.50%	2.37%
Nigeria	0.862	1.317	1.181	1.104	1.521	1.967	2.343	3.125	3.20%	2.56%	4.92%
Other Africa	0.792	1.486	1.037	1.681	2.207	3.000	3.432	3.626	2.73%	7.85%	3.36%
Asia & Oceania	**12.907**	**17.527**	**19.376**	**24.600**	**28.679**	**32.394**	**36.279**	**39.427**	**4.15%**	**4.00%**	**2.14%**
Australia	1.266	1.708	3.522	5.341	6.143	6.217	6.311	6.336	10.78%	5.72%	0.21%
China	1.763	3.334	3.818	4.174	5.846	8.692	12.121	15.585	8.03%	4.35%	6.76%
India	1.153	1.848	1.180	1.942	2.314	2.547	2.352	2.293	0.23%	6.96%	-0.06%
Indonesia	2.406	3.047	2.471	3.086	3.652	4.428	5.245	6.229	0.27%	3.98%	3.62%
Japan	0.191	0.171	0.072	0.021	0.018	0.011	0.008	0.005	-9.30%	-12.77%	-8.76%
Malaysia	2.147	2.347	2.643	3.630	3.963	3.954	3.514	2.864	2.10%	4.13%	-2.14%
Myanmar	0.479	0.437	0.410	0.489	0.558	0.611	1.030	1.321	-1.53%	3.14%	5.91%
Pakistan	1.194	1.484	1.432	1.779	1.934	1.934	1.771	1.358	1.83%	3.06%	-2.33%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.013	0.003	0.005	0.002	0.001	0.000	-3.10%	-9.80%	-14.34%
Thailand	0.925	1.378	1.519	1.358	1.165	0.829	0.910	0.881	5.08%	-2.62%	-1.85%
Other Asia & Oceania	1.366	1.739	2.296	2.776	3.080	3.169	3.017	2.554	5.33%	2.98%	-1.24%
World	**104.006**	**120.194**	**127.873**	**141.724**	**155.350**	**165.756**	**175.038**	**183.216**	**2.09%**	**1.97%**	**1.11%**

LNG12_Ref Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.950**	**39.311**	**41.905**	**42.808**	**44.955**	**46.386**	**2.44%**	**1.83%**	**0.68%**
Canada	7.185	5.909	5.871	7.453	8.541	8.798	9.254	9.347	-2.00%	3.82%	0.60%
Mexico	1.349	1.799	1.251	0.688	0.904	1.844	3.259	4.850	-0.74%	-3.20%	11.85%
United States	18.927	22.382	27.828	31.169	32.461	32.166	32.442	32.190	3.93%	1.55%	-0.06%
Central & South America	**5.318**	**6.267**	**6.504**	**6.750**	**7.745**	**8.352**	**8.937**	**9.061**	**2.03%**	**1.76%**	**1.05%**
Argentina	1.753	1.585	1.386	2.484	3.123	3.563	3.860	4.115	-2.32%	8.46%	1.86%
Brazil	0.432	0.570	0.762	0.338	0.157	0.096	0.048	0.023	5.84%	-14.62%	-11.96%
Chile	0.068	0.065	0.025	0.011	0.005	0.003	0.049	0.075	-9.34%	-15.00%	19.76%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.205	0.268	7.08%	-4.56%	-1.08%
Peru	0.073	0.291	0.440	0.455	0.486	0.523	0.567	0.578	19.61%	0.99%	1.16%
Trinidad and Tobago	1.094	1.512	1.440	1.300	1.543	1.560	1.546	1.530	2.79%	0.69%	-0.06%
Venezuela	1.172	1.201	1.253	1.222	1.588	1.819	2.054	1.848	0.66%	2.40%	1.02%
Other Central & South America	0.472	0.589	0.695	0.512	0.529	0.565	0.608	0.624	3.94%	-2.70%	1.11%
Europe	**11.723**	**11.155**	**9.767**	**9.930**	**10.065**	**9.335**	**8.495**	**7.454**	**-1.81%**	**0.30%**	**-1.98%**
Austria	0.061	0.064	0.042	0.029	0.030	0.018	0.011	0.007	-3.77%	-3.13%	-8.95%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.009	0.019	0.012	0.026	-14.42%	-4.39%	7.80%
Germany	0.689	0.526	0.329	0.165	0.226	0.444	0.583	0.454	-7.13%	-3.70%	4.77%
Italy	0.426	0.297	0.239	0.137	0.226	0.237	0.154	0.101	-5.63%	-0.54%	-5.20%
Netherlands	2.773	3.131	3.126	2.889	2.357	1.572	0.929	0.585	1.21%	-2.79%	-8.87%
Norway	3.196	3.849	3.741	4.120	4.407	4.275	3.989	3.750	1.59%	1.65%	-1.07%
Poland	0.214	0.215	0.179	0.151	0.091	0.053	0.091	0.114	-1.74%	-6.55%	1.49%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.354	0.455	0.456	0.373	0.367	0.298	-1.52%	2.54%	-2.79%
Spain	0.006	0.002	0.001	0.001	0.005	0.013	0.038	0.181	-13.55%	13.73%	27.04%
Turkey	0.032	0.024	0.054	0.134	0.152	0.150	0.073	0.026	5.47%	10.94%	-11.05%
United Kingdom	3.275	2.124	1.310	1.461	1.706	1.781	1.897	1.644	-8.76%	2.68%	-0.25%
Other Europe	0.574	0.502	0.378	0.383	0.400	0.401	0.351	0.268	-4.09%	0.56%	-2.64%
Eurasia	**27.386**	**27.903**	**28.436**	**30.420**	**33.350**	**35.450**	**36.542**	**37.664**	**0.38%**	**1.61%**	**0.81%**
Kazakhstan	0.428	0.441	0.630	1.055	1.382	1.514	1.587	1.701	3.94%	8.18%	1.40%
Russia	21.698	22.372	21.624	22.341	24.015	25.428	26.245	26.901	-0.03%	1.05%	0.76%
Turkmenistan	2.225	1.600	2.571	3.180	3.854	4.493	5.346	6.250	1.46%	4.13%	3.28%
Ukraine	0.685	0.684	0.604	0.297	0.401	0.757	0.952	0.995	-1.25%	-4.02%	6.25%
Uzbekistan	2.119	2.130	2.450	3.133	3.136	2.527	1.666	1.064	1.47%	2.50%	-6.95%
Other Eurasia	0.232	0.677	0.557	0.414	0.563	0.731	0.747	0.754	9.14%	0.10%	1.97%
Middle East	**12.334**	**18.699**	**21.346**	**22.493**	**24.135**	**25.807**	**27.287**	**28.530**	**5.64%**	**1.24%**	**1.12%**
Iran	3.818	6.031	6.406	6.727	7.117	7.474	7.755	8.027	5.31%	1.06%	0.81%
Qatar	1.826	4.359	5.702	5.931	6.307	6.705	6.749	6.768	12.06%	1.01%	0.47%
Oman	0.748	1.035	1.134	1.227	1.310	1.386	1.421	1.455	4.25%	1.45%	0.70%
Saudi Arabia	2.860	3.424	3.917	4.302	4.853	5.341	5.746	6.187	3.19%	2.16%	1.63%
United Arab Emirates	1.828	1.992	2.004	1.884	1.859	1.910	2.086	2.211	0.92%	-0.74%	1.16%
Other Middle East	1.255	1.858	2.184	2.422	2.689	2.991	3.529	3.882	5.70%	2.10%	2.48%
Africa	**6.877**	**8.553**	**7.386**	**8.181**	**9.934**	**11.195**	**12.667**	**14.355**	**0.72%**	**3.01%**	**2.48%**
Algeria	3.613	3.465	3.427	3.433	3.818	4.068	4.076	3.804	-0.53%	1.09%	-0.02%
Egypt	1.610	2.284	1.750	1.929	2.081	2.087	2.542	3.119	0.83%	1.75%	2.74%
Nigeria	0.862	1.317	1.176	1.110	1.742	1.959	2.443	3.261	3.16%	4.01%	4.27%
Other Africa	0.792	1.486	1.033	1.709	2.293	3.082	3.607	4.170	2.69%	8.30%	4.07%
Asia & Oceania	**12.907**	**17.527**	**19.425**	**23.592**	**26.207**	**29.098**	**30.753**	**30.656**	**4.17%**	**3.04%**	**1.05%**
Australia	1.266	1.708	3.511	5.731	6.187	6.269	6.375	7.314	10.74%	5.83%	1.12%
China	1.763	3.334	3.796	2.815	3.206	4.317	4.995	5.429	7.97%	-1.67%	3.57%
India	1.153	1.848	1.209	1.462	1.586	1.943	2.184	1.673	0.47%	2.75%	0.36%
Indonesia	2.406	3.047	2.531	3.154	3.754	4.814	6.091	6.934	0.50%	4.02%	4.17%
Japan	0.191	0.171	0.078	0.026	0.025	0.016	0.008	0.005	-8.53%	-10.77%	-10.51%
Malaysia	2.147	2.347	2.633	3.590	4.026	4.206	3.690	3.094	2.06%	4.34%	-1.74%
Myanmar	0.479	0.437	0.414	0.536	0.620	0.904	1.434	1.402	-1.44%	4.13%	5.59%
Pakistan	1.194	1.484	1.431	1.781	2.145	2.256	1.839	1.252	1.83%	4.13%	-3.52%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.005	0.005	0.002	0.001	0.000	-1.91%	-9.85%	-15.00%
Thailand	0.925	1.378	1.521	1.362	1.192	0.829	1.008	0.869	5.10%	-2.41%	-2.09%
Other Asia & Oceania	1.366	1.739	2.287	3.131	3.460	3.541	3.127	2.682	5.29%	4.23%	-1.68%
World	**104.006**	**120.194**	**127.814**	**140.678**	**153.341**	**162.045**	**169.635**	**174.106**	**2.08%**	**1.84%**	**0.85%**

LNG12_HRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.126**	**40.248**	**42.425**	**44.745**	**48.465**	**50.357**	**2.49%**	**1.91%**	**1.15%**
Canada	7.185	5.909	5.709	6.666	7.988	8.597	9.205	9.310	-2.27%	3.42%	1.03%
Mexico	1.349	1.799	1.251	0.660	0.868	1.198	2.710	3.841	-0.75%	-3.60%	10.43%
United States	18.927	22.382	28.166	32.923	33.569	34.951	36.550	37.206	4.06%	1.77%	0.69%
Central & South America	**5.318**	**6.267**	**6.532**	**6.816**	**7.735**	**8.324**	**8.740**	**9.125**	**2.08%**	**1.71%**	**1.11%**
Argentina	1.753	1.585	1.386	2.484	3.121	3.559	3.855	4.102	-2.32%	8.46%	1.84%
Brazil	0.432	0.570	0.762	0.338	0.157	0.097	0.048	0.023	5.84%	-14.63%	-11.96%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.076	-9.34%	-15.00%	19.84%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.205	0.307	7.08%	-4.56%	-0.17%
Peru	0.073	0.291	0.441	0.459	0.491	0.512	0.546	0.599	19.64%	1.06%	1.34%
Trinidad and Tobago	1.094	1.512	1.465	1.359	1.565	1.561	1.543	1.526	2.97%	0.66%	-0.17%
Venezuela	1.172	1.201	1.253	1.223	1.548	1.800	1.884	1.882	0.66%	2.14%	1.31%
Other Central & South America	0.472	0.589	0.696	0.514	0.534	0.571	0.609	0.610	3.96%	-2.61%	0.89%
Europe	**11.723**	**11.155**	**9.782**	**9.970**	**10.132**	**9.332**	**8.444**	**7.395**	**-1.79%**	**0.35%**	**-2.08%**
Austria	0.061	0.064	0.041	0.029	0.031	0.019	0.011	0.007	-3.85%	-2.81%	-9.36%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.011	0.018	0.012	0.032	-14.41%	-2.01%	7.35%
Germany	0.689	0.526	0.329	0.168	0.229	0.429	0.585	0.453	-7.11%	-3.58%	4.66%
Italy	0.426	0.297	0.239	0.143	0.237	0.234	0.148	0.097	-5.63%	-0.09%	-5.77%
Netherlands	2.773	3.131	3.133	2.900	2.375	1.571	0.911	0.566	1.23%	-2.73%	-9.12%
Norway	3.196	3.849	3.742	4.125	4.415	4.270	3.962	3.735	1.59%	1.67%	-1.11%
Poland	0.214	0.215	0.182	0.152	0.091	0.052	0.078	0.116	-1.61%	-6.73%	1.64%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.357	0.458	0.458	0.371	0.361	0.297	-1.45%	2.52%	-2.85%
Spain	0.006	0.002	0.001	0.001	0.007	0.012	0.033	0.179	-13.54%	17.83%	24.02%
Turkey	0.032	0.024	0.057	0.155	0.151	0.150	0.071	0.027	5.98%	10.28%	-10.78%
United Kingdom	3.275	2.124	1.306	1.446	1.721	1.808	1.921	1.624	-8.78%	2.79%	-0.39%
Other Europe	0.574	0.502	0.381	0.389	0.408	0.399	0.351	0.263	-4.02%	0.67%	-2.88%
Eurasia	**27.386**	**27.903**	**28.430**	**30.434**	**33.563**	**35.486**	**36.576**	**37.714**	**0.37%**	**1.67%**	**0.78%**
Kazakhstan	0.428	0.441	0.630	1.065	1.417	1.516	1.569	1.693	3.94%	8.44%	1.20%
Russia	21.698	22.372	21.625	22.336	24.135	25.415	26.205	26.924	-0.03%	1.10%	0.73%
Turkmenistan	2.225	1.600	2.564	3.174	3.864	4.550	5.422	6.286	1.43%	4.19%	3.30%
Ukraine	0.685	0.684	0.604	0.296	0.428	0.758	0.963	0.984	-1.25%	-3.40%	5.72%
Uzbekistan	2.119	2.130	2.450	3.144	3.144	2.520	1.661	1.070	1.47%	2.52%	-6.94%
Other Eurasia	0.232	0.677	0.557	0.419	0.576	0.728	0.756	0.756	9.13%	0.35%	1.83%
Middle East	**12.334**	**18.699**	**21.346**	**22.494**	**24.172**	**25.782**	**27.212**	**28.512**	**5.64%**	**1.25%**	**1.11%**
Iran	3.818	6.031	6.405	6.720	7.112	7.469	7.742	8.080	5.31%	1.05%	0.85%
Qatar	1.826	4.359	5.707	5.935	6.340	6.715	6.747	6.769	12.07%	1.06%	0.44%
Oman	0.748	1.035	1.134	1.227	1.309	1.381	1.425	1.457	4.24%	1.45%	0.72%
Saudi Arabia	2.860	3.424	3.916	4.303	4.847	5.324	5.748	6.198	3.19%	2.16%	1.65%
United Arab Emirates	1.828	1.992	2.005	1.888	1.863	1.922	2.080	2.223	0.93%	-0.73%	1.18%
Other Middle East	1.255	1.858	2.180	2.422	2.701	2.971	3.470	3.786	5.68%	2.16%	2.28%
Africa	**6.877**	**8.553**	**7.414**	**8.187**	**9.986**	**11.245**	**12.625**	**14.171**	**0.75%**	**3.02%**	**2.36%**
Algeria	3.613	3.465	3.429	3.409	3.816	4.063	4.071	3.776	-0.52%	1.08%	-0.07%
Egypt	1.610	2.284	1.748	1.934	2.120	2.106	2.527	3.104	0.82%	1.95%	2.57%
Nigeria	0.862	1.317	1.200	1.135	1.747	1.983	2.383	3.167	3.36%	3.83%	4.05%
Other Africa	0.792	1.486	1.037	1.709	2.302	3.093	3.644	4.124	2.73%	8.30%	3.96%
Asia & Oceania	**12.907**	**17.527**	**19.474**	**23.696**	**26.591**	**29.109**	**30.201**	**29.771**	**4.20%**	**3.16%**	**0.76%**
Australia	1.266	1.708	3.525	5.728	6.136	6.245	6.350	7.057	10.78%	5.70%	0.94%
China	1.763	3.334	3.809	2.897	3.558	4.328	4.667	5.078	8.01%	-0.68%	2.40%
India	1.153	1.848	1.207	1.457	1.668	1.988	2.144	1.598	0.46%	3.29%	-0.29%
Indonesia	2.406	3.047	2.543	3.162	3.760	4.777	6.046	6.860	0.55%	3.99%	4.09%
Japan	0.191	0.171	0.079	0.024	0.025	0.015	0.008	0.004	-8.47%	-10.67%	-11.04%
Malaysia	2.147	2.347	2.642	3.598	4.024	4.182	3.662	3.066	2.10%	4.30%	-1.80%
Myanmar	0.479	0.437	0.415	0.541	0.615	0.911	1.414	1.395	-1.42%	4.01%	5.62%
Pakistan	1.194	1.484	1.431	1.779	2.138	2.269	1.819	1.247	1.83%	4.10%	-3.53%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.005	0.005	0.002	0.001	0.000	-1.95%	-9.82%	-15.00%
Thailand	0.925	1.378	1.522	1.365	1.193	0.828	1.002	0.868	5.10%	-2.41%	-2.10%
Other Asia & Oceania	1.366	1.739	2.288	3.141	3.470	3.564	3.088	2.597	5.30%	4.25%	-1.91%
World	**104.006**	**120.194**	**128.104**	**141.846**	**154.603**	**164.024**	**172.264**	**177.044**	**2.11%**	**1.90%**	**0.91%**

LNG12_LRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.743**	**38.822**	**41.484**	**41.940**	**43.279**	**44.643**	**2.38%**	**1.79%**	**0.49%**
Canada	7.185	5.909	6.081	8.021	8.717	8.912	9.284	9.351	-1.65%	3.67%	0.47%
Mexico	1.349	1.799	1.251	0.752	1.472	2.770	4.437	5.827	-0.74%	1.64%	9.61%
United States	18.927	22.382	27.411	30.050	31.294	30.257	29.557	29.464	3.77%	1.33%	-0.40%
Central & South America	**5.318**	**6.267**	**6.531**	**6.853**	**7.723**	**8.314**	**8.743**	**9.133**	**2.08%**	**1.69%**	**1.12%**
Argentina	1.753	1.585	1.386	2.483	3.113	3.554	3.855	4.095	-2.32%	8.42%	1.84%
Brazil	0.432	0.570	0.762	0.338	0.157	0.097	0.048	0.023	5.84%	-14.64%	-11.88%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.81%
Colombia	0.253	0.454	0.502	0.427	0.314	0.223	0.198	0.314	7.08%	-4.57%	-0.02%
Peru	0.073	0.291	0.441	0.454	0.486	0.512	0.569	0.600	19.63%	0.98%	1.41%
Trinidad and Tobago	1.094	1.512	1.464	1.395	1.564	1.560	1.547	1.521	2.96%	0.66%	-0.18%
Venezuela	1.172	1.201	1.253	1.225	1.550	1.800	1.908	1.869	0.66%	2.15%	1.26%
Other Central & South America	0.472	0.589	0.697	0.519	0.535	0.566	0.568	0.636	3.97%	-2.61%	1.16%
Europe	**11.723**	**11.155**	**9.776**	**10.063**	**10.152**	**9.357**	**8.477**	**7.426**	**-1.80%**	**0.38%**	**-2.06%**
Austria	0.061	0.064	0.041	0.031	0.031	0.018	0.011	0.007	-3.85%	-2.79%	-9.42%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.011	0.018	0.012	0.028	-14.42%	-1.74%	6.28%
Germany	0.689	0.526	0.329	0.174	0.229	0.435	0.590	0.452	-7.12%	-3.55%	4.63%
Italy	0.426	0.297	0.239	0.151	0.239	0.232	0.146	0.096	-5.63%	0.03%	-5.89%
Netherlands	2.773	3.131	3.128	2.905	2.378	1.577	0.912	0.568	1.21%	-2.71%	-9.11%
Norway	3.196	3.849	3.743	4.156	4.404	4.272	4.017	3.771	1.59%	1.64%	-1.03%
Poland	0.214	0.215	0.181	0.152	0.091	0.053	0.081	0.118	-1.68%	-6.65%	1.74%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.359	0.469	0.458	0.372	0.359	0.293	-1.39%	2.44%	-2.93%
Spain	0.006	0.002	0.001	0.001	0.006	0.012	0.043	0.184	-13.54%	15.68%	25.75%
Turkey	0.032	0.024	0.056	0.155	0.159	0.148	0.067	0.022	5.86%	11.01%	-12.26%
United Kingdom	3.275	2.124	1.307	1.467	1.742	1.815	1.894	1.626	-8.78%	2.91%	-0.46%
Other Europe	0.574	0.502	0.378	0.398	0.403	0.405	0.346	0.261	-4.10%	0.66%	-2.85%
Eurasia	**27.386**	**27.903**	**28.444**	**30.514**	**33.562**	**35.528**	**36.715**	**37.641**	**0.38%**	**1.67%**	**0.77%**
Kazakhstan	0.428	0.441	0.630	1.068	1.421	1.519	1.579	1.695	3.94%	8.48%	1.18%
Russia	21.698	22.372	21.628	22.389	24.189	25.457	26.300	26.835	-0.03%	1.13%	0.69%
Turkmenistan	2.225	1.600	2.573	3.200	3.851	4.550	5.419	6.288	1.46%	4.11%	3.32%
Ukraine	0.685	0.684	0.604	0.296	0.407	0.749	0.960	0.994	-1.25%	-3.88%	6.14%
Uzbekistan	2.119	2.130	2.454	3.152	3.152	2.517	1.660	1.064	1.48%	2.54%	-6.98%
Other Eurasia	0.232	0.677	0.556	0.409	0.542	0.736	0.798	0.765	9.12%	-0.26%	2.33%
Middle East	**12.334**	**18.699**	**21.349**	**22.504**	**24.172**	**25.810**	**27.289**	**28.631**	**5.64%**	**1.25%**	**1.13%**
Iran	3.818	6.031	6.405	6.725	7.113	7.477	7.746	8.040	5.31%	1.05%	0.82%
Qatar	1.826	4.359	5.705	5.931	6.347	6.718	6.754	6.777	12.07%	1.07%	0.44%
Oman	0.748	1.035	1.134	1.227	1.311	1.383	1.422	1.454	4.24%	1.46%	0.69%
Saudi Arabia	2.860	3.424	3.916	4.304	4.847	5.327	5.752	6.216	3.19%	2.16%	1.67%
United Arab Emirates	1.828	1.992	2.007	1.892	1.862	1.927	2.084	2.192	0.94%	-0.75%	1.10%
Other Middle East	1.255	1.858	2.184	2.424	2.692	2.979	3.531	3.951	5.70%	2.12%	2.59%
Africa	**6.877**	**8.553**	**7.415**	**8.301**	**9.972**	**11.234**	**13.054**	**14.880**	**0.76%**	**3.01%**	**2.70%**
Algeria	3.613	3.465	3.429	3.480	3.825	4.076	4.232	3.868	-0.52%	1.10%	0.07%
Egypt	1.610	2.284	1.748	1.931	2.088	2.093	2.556	3.117	0.83%	1.79%	2.71%
Nigeria	0.862	1.317	1.202	1.172	1.744	1.981	2.553	3.544	3.39%	3.79%	4.84%
Other Africa	0.792	1.486	1.036	1.719	2.314	3.084	3.713	4.352	2.72%	8.37%	4.30%
Asia & Oceania	**12.907**	**17.527**	**19.468**	**23.923**	**26.543**	**29.869**	**32.052**	**32.072**	**4.20%**	**3.15%**	**1.27%**
Australia	1.266	1.708	3.527	5.914	6.141	6.249	6.652	7.571	10.79%	5.70%	1.41%
China	1.763	3.334	3.799	2.913	3.532	4.650	5.517	6.083	7.98%	-0.73%	3.69%
India	1.153	1.848	1.204	1.453	1.648	2.063	2.200	1.719	0.43%	3.19%	0.28%
Indonesia	2.406	3.047	2.552	3.184	3.773	4.938	6.265	7.163	0.59%	3.99%	4.37%
Japan	0.191	0.171	0.076	0.028	0.025	0.016	0.008	0.005	-8.79%	-10.49%	-10.62%
Malaysia	2.147	2.347	2.643	3.579	4.007	4.252	3.772	3.167	2.10%	4.25%	-1.56%
Myanmar	0.479	0.437	0.415	0.541	0.616	0.933	1.468	1.399	-1.41%	4.02%	5.63%
Pakistan	1.194	1.484	1.430	1.777	2.122	2.295	1.899	1.255	1.83%	4.02%	-3.44%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.005	0.005	0.002	0.001	0.000	-1.91%	-9.86%	-15.00%
Thailand	0.925	1.378	1.521	1.367	1.190	0.829	1.015	0.871	5.09%	-2.42%	-2.06%
Other Asia & Oceania	1.366	1.739	2.286	3.161	3.485	3.641	3.255	2.839	5.29%	4.30%	-1.36%
World	**104.006**	**120.194**	**127.727**	**140.981**	**153.608**	**162.052**	**169.610**	**174.425**	**2.08%**	**1.86%**	**0.85%**

LNG12_Hi-D Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.045**	**40.313**	**43.665**	**45.369**	**47.514**	**48.845**	**2.47%**	**2.22%**	**0.75%**
Canada	7.185	5.909	5.929	7.715	8.687	8.893	9.284	9.340	-1.90%	3.89%	0.48%
Mexico	1.349	1.799	1.251	0.718	1.021	2.240	3.628	5.419	-0.74%	-2.01%	11.77%
United States	18.927	22.382	27.864	31.880	33.957	34.236	34.602	34.086	3.94%	2.00%	0.03%
Central & South America	**5.318**	**6.267**	**6.529**	**6.828**	**7.726**	**8.336**	**8.795**	**9.116**	**2.07%**	**1.70%**	**1.11%**
Argentina	1.753	1.585	1.386	2.485	3.114	3.558	3.856	4.114	-2.32%	8.43%	1.87%
Brazil	0.432	0.570	0.762	0.338	0.157	0.096	0.048	0.024	5.84%	-14.61%	-11.89%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.80%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.199	0.300	7.08%	-4.56%	-0.31%
Peru	0.073	0.291	0.442	0.454	0.490	0.516	0.573	0.591	19.65%	1.05%	1.25%
Trinidad and Tobago	1.094	1.512	1.464	1.373	1.568	1.561	1.549	1.518	2.96%	0.69%	-0.22%
Venezuela	1.172	1.201	1.253	1.225	1.547	1.809	1.908	1.880	0.66%	2.13%	1.31%
Other Central & South America	0.472	0.589	0.695	0.514	0.530	0.571	0.610	0.614	3.94%	-2.68%	0.99%
Europe	**11.723**	**11.155**	**9.777**	**10.029**	**10.150**	**9.358**	**8.511**	**7.413**	**-1.80%**	**0.37%**	**-2.07%**
Austria	0.061	0.064	0.042	0.031	0.031	0.018	0.011	0.007	-3.72%	-2.90%	-9.37%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.012	0.018	0.012	0.029	-14.42%	-0.89%	5.98%
Germany	0.689	0.526	0.329	0.173	0.233	0.433	0.590	0.458	-7.11%	-3.42%	4.61%
Italy	0.426	0.297	0.239	0.144	0.233	0.235	0.153	0.097	-5.63%	-0.22%	-5.69%
Netherlands	2.773	3.131	3.133	2.909	2.371	1.564	0.920	0.557	1.23%	-2.75%	-9.21%
Norway	3.196	3.849	3.742	4.149	4.428	4.274	3.986	3.786	1.59%	1.70%	-1.04%
Poland	0.214	0.215	0.180	0.152	0.091	0.055	0.088	0.114	-1.73%	-6.55%	1.52%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.357	0.463	0.457	0.376	0.367	0.285	-1.44%	2.48%	-3.09%
Spain	0.006	0.002	0.001	0.001	0.007	0.012	0.041	0.175	-13.55%	17.64%	23.98%
Turkey	0.032	0.024	0.056	0.143	0.157	0.150	0.069	0.025	5.91%	10.78%	-11.53%
United Kingdom	3.275	2.124	1.307	1.461	1.725	1.819	1.927	1.618	-8.78%	2.81%	-0.43%
Other Europe	0.574	0.502	0.378	0.398	0.405	0.404	0.346	0.261	-4.10%	0.69%	-2.88%
Eurasia	**27.386**	**27.903**	**28.439**	**30.505**	**33.515**	**35.486**	**36.595**	**37.519**	**0.38%**	**1.66%**	**0.76%**
Kazakhstan	0.428	0.441	0.631	1.056	1.400	1.534	1.616	1.715	3.95%	8.30%	1.36%
Russia	21.698	22.372	21.634	22.407	24.153	25.446	26.246	26.757	-0.03%	1.11%	0.68%
Turkmenistan	2.225	1.600	2.564	3.183	3.824	4.469	5.367	6.228	1.43%	4.08%	3.31%
Ukraine	0.685	0.684	0.604	0.298	0.428	0.771	0.946	0.991	-1.25%	-3.38%	5.75%
Uzbekistan	2.119	2.130	2.449	3.144	3.149	2.520	1.653	1.065	1.46%	2.55%	-6.98%
Other Eurasia	0.232	0.677	0.557	0.416	0.561	0.746	0.769	0.763	9.13%	0.09%	2.07%
Middle East	**12.334**	**18.699**	**21.354**	**22.502**	**24.166**	**25.815**	**27.278**	**28.652**	**5.64%**	**1.24%**	**1.14%**
Iran	3.818	6.031	6.408	6.726	7.111	7.472	7.744	8.062	5.32%	1.05%	0.84%
Qatar	1.826	4.359	5.704	5.930	6.349	6.717	6.754	6.767	12.07%	1.08%	0.43%
Oman	0.748	1.035	1.134	1.227	1.309	1.383	1.424	1.452	4.25%	1.44%	0.70%
Saudi Arabia	2.860	3.424	3.916	4.303	4.849	5.323	5.745	6.197	3.19%	2.16%	1.65%
United Arab Emirates	1.828	1.992	2.007	1.893	1.860	1.927	2.077	2.218	0.94%	-0.75%	1.18%
Other Middle East	1.255	1.858	2.185	2.422	2.689	2.992	3.533	3.958	5.71%	2.09%	2.61%
Africa	**6.877**	**8.553**	**7.410**	**8.253**	**9.975**	**11.222**	**12.869**	**14.620**	**0.75%**	**3.02%**	**2.58%**
Algeria	3.613	3.465	3.429	3.454	3.827	4.072	4.155	3.837	-0.52%	1.11%	0.02%
Egypt	1.610	2.284	1.750	1.932	2.082	2.085	2.554	3.123	0.84%	1.75%	2.74%
Nigeria	0.862	1.317	1.195	1.149	1.753	1.968	2.493	3.344	3.33%	3.90%	4.40%
Other Africa	0.792	1.486	1.036	1.717	2.312	3.097	3.666	4.315	2.72%	8.36%	4.25%
Asia & Oceania	**12.907**	**17.527**	**19.475**	**23.869**	**26.605**	**29.693**	**31.504**	**31.505**	**4.20%**	**3.17%**	**1.13%**
Australia	1.266	1.708	3.527	5.874	6.167	6.223	6.501	7.380	10.79%	5.75%	1.20%
China	1.763	3.334	3.803	2.902	3.544	4.558	5.282	5.849	7.99%	-0.70%	3.40%
India	1.153	1.848	1.208	1.453	1.655	2.049	2.170	1.695	0.47%	3.20%	0.16%
Indonesia	2.406	3.047	2.549	3.185	3.775	4.910	6.241	7.137	0.58%	4.01%	4.34%
Japan	0.191	0.171	0.078	0.027	0.025	0.016	0.008	0.005	-8.60%	-10.54%	-10.86%
Malaysia	2.147	2.347	2.644	3.583	4.012	4.266	3.767	3.128	2.10%	4.26%	-1.65%
Myanmar	0.479	0.437	0.415	0.541	0.617	0.925	1.452	1.410	-1.41%	4.05%	5.66%
Pakistan	1.194	1.484	1.430	1.778	2.136	2.302	1.867	1.248	1.83%	4.09%	-3.52%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.005	0.005	0.002	0.001	0.000	-1.89%	-9.87%	-15.00%
Thailand	0.925	1.378	1.521	1.362	1.189	0.836	1.011	0.870	5.10%	-2.43%	-2.06%
Other Asia & Oceania	1.366	1.739	2.287	3.160	3.479	3.606	3.204	2.782	5.29%	4.28%	-1.48%
World	**104.006**	**120.194**	**128.030**	**142.299**	**155.802**	**165.280**	**173.066**	**177.670**	**2.10%**	**1.98%**	**0.88%**

LNG20_Ref Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.905**	**39.796**	**42.056**	**45.244**	**48.634**	**50.802**	**2.43%**	**1.88%**	**1.27%**
Canada	7.185	5.909	5.902	7.642	8.632	8.778	8.852	8.901	-1.95%	3.87%	0.20%
Mexico	1.349	1.799	1.251	0.715	1.028	2.471	3.989	5.064	-0.74%	-1.95%	11.22%
United States	18.927	22.382	27.751	31.440	32.396	33.994	35.793	36.837	3.90%	1.56%	0.86%
Central & South America	**5.318**	**6.267**	**6.548**	**6.937**	**7.748**	**8.347**	**8.849**	**9.081**	**2.10%**	**1.70%**	**1.06%**
Argentina	1.753	1.585	1.386	2.485	3.115	3.557	3.856	4.098	-2.32%	8.43%	1.85%
Brazil	0.432	0.570	0.762	0.338	0.158	0.097	0.048	0.023	5.84%	-14.59%	-12.01%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.76%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.199	0.296	7.08%	-4.55%	-0.42%
Peru	0.073	0.291	0.442	0.454	0.485	0.537	0.575	0.584	19.66%	0.93%	1.24%
Trinidad and Tobago	1.094	1.512	1.481	1.474	1.570	1.560	1.586	1.566	3.08%	0.58%	-0.02%
Venezuela	1.172	1.201	1.253	1.220	1.551	1.808	1.908	1.823	0.66%	2.16%	1.08%
Other Central & South America	0.472	0.589	0.696	0.527	0.549	0.563	0.626	0.617	3.95%	-2.34%	0.78%
Europe	**11.723**	**11.155**	**9.768**	**10.014**	**10.025**	**9.129**	**8.340**	**7.346**	**-1.81%**	**0.26%**	**-2.05%**
Austria	0.061	0.064	0.041	0.032	0.030	0.017	0.011	0.007	-3.88%	-3.19%	-9.42%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.013	0.017	0.011	0.032	-14.43%	-0.02%	6.12%
Germany	0.689	0.526	0.329	0.176	0.228	0.428	0.579	0.452	-7.12%	-3.62%	4.68%
Italy	0.426	0.297	0.239	0.159	0.247	0.226	0.144	0.123	-5.63%	0.35%	-4.53%
Netherlands	2.773	3.131	3.133	2.934	2.377	1.550	0.900	0.556	1.23%	-2.72%	-9.23%
Norway	3.196	3.849	3.735	4.150	4.430	4.253	3.979	3.723	1.57%	1.72%	-1.15%
Poland	0.214	0.215	0.183	0.149	0.090	0.050	0.070	0.116	-1.56%	-6.83%	1.69%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.362	0.477	0.451	0.360	0.355	0.298	-1.32%	2.24%	-2.73%
Spain	0.006	0.002	0.001	0.001	0.006	0.012	0.043	0.189	-13.56%	16.60%	25.35%
Turkey	0.032	0.024	0.049	0.047	0.029	0.018	0.011	0.008	4.36%	-4.96%	-8.62%
United Kingdom	3.275	2.124	1.311	1.482	1.723	1.797	1.887	1.581	-8.75%	2.78%	-0.57%
Other Europe	0.574	0.502	0.372	0.403	0.399	0.400	0.349	0.261	-4.25%	0.71%	-2.78%
Eurasia	**27.386**	**27.903**	**28.483**	**29.336**	**31.965**	**33.572**	**34.578**	**35.391**	**0.39%**	**1.16%**	**0.68%**
Kazakhstan	0.428	0.441	0.629	1.012	1.363	1.470	1.534	1.654	3.94%	8.03%	1.30%
Russia	21.698	22.372	21.665	21.336	22.714	23.747	24.396	24.720	-0.01%	0.47%	0.57%
Turkmenistan	2.225	1.600	2.571	3.148	3.760	4.358	5.283	6.152	1.46%	3.87%	3.34%
Ukraine	0.685	0.684	0.604	0.300	0.418	0.746	0.937	1.023	-1.25%	-3.63%	6.16%
Uzbekistan	2.119	2.130	2.454	3.121	3.121	2.520	1.668	1.083	1.48%	2.43%	-6.82%
Other Eurasia	0.232	0.677	0.558	0.419	0.589	0.732	0.760	0.759	9.16%	0.54%	1.70%
Middle East	**12.334**	**18.699**	**21.347**	**22.516**	**24.347**	**25.802**	**27.199**	**28.714**	**5.64%**	**1.32%**	**1.11%**
Iran	3.818	6.031	6.406	6.725	7.114	7.468	7.744	8.062	5.31%	1.05%	0.84%
Qatar	1.826	4.359	5.706	5.935	6.458	6.719	6.753	6.783	12.07%	1.25%	0.33%
Oman	0.748	1.035	1.134	1.228	1.333	1.384	1.422	1.455	4.25%	1.63%	0.59%
Saudi Arabia	2.860	3.424	3.916	4.304	4.848	5.326	5.745	6.193	3.19%	2.16%	1.65%
United Arab Emirates	1.828	1.992	2.005	1.889	1.885	1.923	2.089	2.215	0.93%	-0.62%	1.08%
Other Middle East	1.255	1.858	2.181	2.436	2.709	2.983	3.447	4.006	5.68%	2.19%	2.64%
Africa	**6.877**	**8.553**	**7.435**	**8.501**	**10.013**	**11.321**	**13.067**	**14.403**	**0.78%**	**3.02%**	**2.45%**
Algeria	3.613	3.465	3.429	3.527	3.841	4.123	4.296	3.924	-0.52%	1.14%	0.14%
Egypt	1.610	2.284	1.748	1.932	2.101	2.070	2.443	2.953	0.82%	1.86%	2.29%
Nigeria	0.862	1.317	1.225	1.308	1.757	2.015	2.677	3.644	3.58%	3.67%	4.99%
Other Africa	0.792	1.486	1.034	1.734	2.315	3.114	3.651	3.882	2.70%	8.40%	3.51%
Asia & Oceania	**12.907**	**17.527**	**19.384**	**24.767**	**28.242**	**30.475**	**31.606**	**30.980**	**4.15%**	**3.84%**	**0.62%**
Australia	1.266	1.708	3.520	6.008	6.158	6.254	6.545	6.688	10.77%	5.75%	0.55%
China	1.763	3.334	3.746	3.363	4.553	5.062	5.724	6.018	7.83%	1.97%	1.88%
India	1.153	1.848	1.185	1.493	1.827	1.886	1.658	1.275	0.28%	4.42%	-2.37%
Indonesia	2.406	3.047	2.547	3.245	3.887	5.063	6.683	7.927	0.57%	4.32%	4.87%
Japan	0.191	0.171	0.076	0.028	0.032	0.015	0.008	0.005	-8.73%	-8.35%	-11.66%
Malaysia	2.147	2.347	2.643	3.600	4.094	4.356	3.957	3.281	2.10%	4.47%	-1.46%
Myanmar	0.479	0.437	0.413	0.541	0.649	1.078	1.523	1.367	-1.45%	4.60%	5.10%
Pakistan	1.194	1.484	1.430	1.777	2.126	2.319	1.917	1.303	1.83%	4.04%	-3.21%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.015	0.006	0.005	0.002	0.001	0.000	-1.72%	-10.02%	-15.00%
Thailand	0.925	1.378	1.518	1.402	1.225	0.813	0.586	0.466	5.08%	-2.12%	-6.23%
Other Asia & Oceania	1.366	1.739	2.289	3.304	3.687	3.627	3.004	2.649	5.30%	4.88%	-2.18%
World	**104.006**	**120.194**	**127.870**	**141.867**	**154.396**	**163.890**	**172.272**	**176.718**	**2.09%**	**1.90%**	**0.90%**

LNG20_HRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.081**	**40.285**	**42.830**	**46.809**	**51.418**	**54.257**	**2.48%**	**2.02%**	**1.59%**
Canada	7.185	5.909	5.710	6.752	8.096	8.650	8.841	8.899	-2.27%	3.55%	0.63%
Mexico	1.349	1.799	1.251	0.668	0.864	1.511	2.959	4.296	-0.75%	-3.63%	11.28%
United States	18.927	22.382	28.119	32.865	33.869	36.648	39.619	41.062	4.04%	1.88%	1.29%
Central & South America	**5.318**	**6.267**	**6.532**	**6.913**	**7.749**	**8.327**	**8.774**	**9.138**	**2.08%**	**1.72%**	**1.11%**
Argentina	1.753	1.585	1.386	2.484	3.114	3.551	3.854	4.118	-2.32%	8.43%	1.88%
Brazil	0.432	0.570	0.762	0.338	0.155	0.096	0.047	0.023	5.84%	-14.74%	-11.83%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.79%
Colombia	0.253	0.454	0.502	0.427	0.315	0.224	0.197	0.292	7.08%	-4.55%	-0.50%
Peru	0.073	0.291	0.442	0.456	0.488	0.521	0.575	0.592	19.65%	1.01%	1.30%
Trinidad and Tobago	1.094	1.512	1.465	1.447	1.569	1.559	1.547	1.521	2.96%	0.69%	-0.21%
Venezuela	1.172	1.201	1.253	1.223	1.547	1.799	1.901	1.902	0.66%	2.13%	1.39%
Other Central & South America	0.472	0.589	0.696	0.526	0.555	0.574	0.604	0.614	3.96%	-2.23%	0.67%
Europe	**11.723**	**11.155**	**9.769**	**10.026**	**10.025**	**9.138**	**8.319**	**7.381**	**-1.81%**	**0.26%**	**-2.02%**
Austria	0.061	0.064	0.041	0.031	0.030	0.018	0.011	0.007	-3.86%	-3.06%	-9.33%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.012	0.018	0.012	0.026	-14.43%	-1.16%	5.44%
Germany	0.689	0.526	0.329	0.174	0.230	0.419	0.581	0.454	-7.12%	-3.54%	4.65%
Italy	0.426	0.297	0.239	0.159	0.246	0.226	0.144	0.120	-5.63%	0.30%	-4.69%
Netherlands	2.773	3.131	3.127	2.918	2.373	1.566	0.902	0.558	1.21%	-2.72%	-9.20%
Norway	3.196	3.849	3.743	4.193	4.419	4.264	3.954	3.764	1.59%	1.68%	-1.06%
Poland	0.214	0.215	0.182	0.150	0.091	0.050	0.072	0.117	-1.58%	-6.77%	1.71%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.362	0.474	0.453	0.361	0.358	0.291	-1.32%	2.26%	-2.89%
Spain	0.006	0.002	0.001	0.001	0.006	0.012	0.040	0.179	-13.55%	16.02%	25.28%
Turkey	0.032	0.024	0.048	0.048	0.029	0.018	0.011	0.007	4.32%	-4.95%	-9.03%
United Kingdom	3.275	2.124	1.308	1.463	1.734	1.791	1.891	1.599	-8.77%	2.86%	-0.54%
Other Europe	0.574	0.502	0.375	0.409	0.403	0.396	0.342	0.259	-4.18%	0.72%	-2.91%
Eurasia	**27.386**	**27.903**	**28.487**	**29.318**	**31.955**	**33.579**	**34.539**	**35.284**	**0.39%**	**1.16%**	**0.66%**
Kazakhstan	0.428	0.441	0.632	1.012	1.360	1.473	1.524	1.611	3.98%	7.96%	1.13%
Russia	21.698	22.372	21.661	21.321	22.688	23.710	24.413	24.712	-0.02%	0.46%	0.57%
Turkmenistan	2.225	1.600	2.572	3.157	3.803	4.412	5.239	6.089	1.46%	3.99%	3.19%
Ukraine	0.685	0.684	0.604	0.301	0.425	0.742	0.927	1.003	-1.25%	-3.46%	5.89%
Uzbekistan	2.119	2.130	2.459	3.117	3.117	2.509	1.666	1.090	1.50%	2.40%	-6.77%
Other Eurasia	0.232	0.677	0.558	0.410	0.562	0.732	0.769	0.781	9.16%	0.08%	2.21%
Middle East	**12.334**	**18.699**	**21.348**	**22.513**	**24.328**	**25.792**	**27.223**	**28.598**	**5.64%**	**1.32%**	**1.08%**
Iran	3.818	6.031	6.405	6.721	7.109	7.469	7.748	8.055	5.31%	1.05%	0.84%
Qatar	1.826	4.359	5.706	5.936	6.454	6.719	6.754	6.771	12.07%	1.24%	0.32%
Oman	0.748	1.035	1.134	1.227	1.333	1.383	1.427	1.454	4.24%	1.63%	0.58%
Saudi Arabia	2.860	3.424	3.917	4.303	4.846	5.323	5.748	6.200	3.19%	2.15%	1.66%
United Arab Emirates	1.828	1.992	2.006	1.888	1.878	1.926	2.083	2.204	0.93%	-0.65%	1.07%
Other Middle East	1.255	1.858	2.181	2.438	2.707	2.974	3.465	3.913	5.69%	2.18%	2.49%
Africa	**6.877**	**8.553**	**7.426**	**8.494**	**10.031**	**11.180**	**12.763**	**14.198**	**0.77%**	**3.05%**	**2.34%**
Algeria	3.613	3.465	3.429	3.527	3.833	4.088	4.198	3.907	-0.52%	1.12%	0.13%
Egypt	1.610	2.284	1.748	1.945	2.134	2.053	2.392	2.919	0.83%	2.02%	2.11%
Nigeria	0.862	1.317	1.216	1.298	1.759	1.979	2.544	3.534	3.50%	3.76%	4.76%
Other Africa	0.792	1.486	1.034	1.724	2.305	3.059	3.629	3.838	2.70%	8.35%	3.46%
Asia & Oceania	**12.907**	**17.527**	**19.398**	**24.812**	**28.085**	**30.049**	**30.665**	**29.934**	**4.16%**	**3.77%**	**0.43%**
Australia	1.266	1.708	3.524	6.002	6.167	6.253	6.495	6.746	10.78%	5.76%	0.60%
China	1.763	3.334	3.743	3.401	4.460	4.744	5.171	5.581	7.82%	1.77%	1.51%
India	1.153	1.848	1.192	1.501	1.842	1.868	1.635	1.214	0.33%	4.45%	-2.74%
Indonesia	2.406	3.047	2.548	3.244	3.873	4.978	6.477	7.502	0.57%	4.27%	4.51%
Japan	0.191	0.171	0.078	0.030	0.031	0.015	0.007	0.005	-8.59%	-8.65%	-12.01%
Malaysia	2.147	2.347	2.644	3.603	4.077	4.372	3.909	3.230	2.10%	4.43%	-1.54%
Myanmar	0.479	0.437	0.414	0.543	0.639	1.074	1.483	1.348	-1.43%	4.43%	5.11%
Pakistan	1.194	1.484	1.430	1.778	2.132	2.311	1.870	1.256	1.83%	4.07%	-3.47%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.015	0.007	0.005	0.002	0.001	0.000	-1.52%	-10.21%	-15.00%
Thailand	0.925	1.378	1.518	1.401	1.230	0.811	0.593	0.460	5.08%	-2.08%	-6.35%
Other Asia & Oceania	1.366	1.739	2.291	3.303	3.628	3.621	3.025	2.592	5.31%	4.70%	-2.22%
World	**104.006**	**120.194**	**128.042**	**142.361**	**155.003**	**164.873**	**173.702**	**178.790**	**2.10%**	**1.93%**	**0.96%**

LNG20_LRR Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.678**	**39.266**	**41.430**	**43.593**	**46.194**	**48.019**	**2.36%**	**1.79%**	**0.99%**
Canada	7.185	5.909	6.132	8.136	8.730	8.784	8.864	8.962	-1.57%	3.60%	0.17%
Mexico	1.349	1.799	1.251	0.833	1.633	3.170	4.866	5.053	-0.74%	2.70%	7.82%
United States	18.927	22.382	27.295	30.297	31.067	31.639	32.464	34.004	3.73%	1.30%	0.60%
Central & South America	**5.318**	**6.267**	**6.548**	**6.957**	**7.740**	**8.382**	**8.844**	**9.259**	**2.10%**	**1.69%**	**1.20%**
Argentina	1.753	1.585	1.386	2.486	3.116	3.559	3.855	4.103	-2.32%	8.44%	1.85%
Brazil	0.432	0.570	0.762	0.338	0.157	0.094	0.050	0.023	5.84%	-14.61%	-12.00%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.82%
Colombia	0.253	0.454	0.502	0.427	0.315	0.224	0.200	0.313	7.08%	-4.55%	-0.04%
Peru	0.073	0.291	0.441	0.453	0.487	0.547	0.577	0.588	19.63%	0.99%	1.26%
Trinidad and Tobago	1.094	1.512	1.483	1.495	1.568	1.574	1.582	1.561	3.09%	0.56%	-0.03%
Venezuela	1.172	1.201	1.253	1.223	1.548	1.799	1.913	1.866	0.66%	2.14%	1.26%
Other Central & South America	0.472	0.589	0.695	0.523	0.545	0.583	0.617	0.730	3.94%	-2.40%	1.96%
Europe	**11.723**	**11.155**	**9.766**	**10.052**	**10.022**	**9.115**	**8.373**	**7.362**	**-1.81%**	**0.26%**	**-2.04%**
Austria	0.061	0.064	0.041	0.031	0.030	0.017	0.011	0.007	-3.83%	-3.16%	-9.46%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.012	0.017	0.012	0.031	-14.43%	-0.83%	6.42%
Germany	0.689	0.526	0.329	0.176	0.229	0.425	0.582	0.446	-7.13%	-3.55%	4.55%
Italy	0.426	0.297	0.239	0.162	0.246	0.224	0.145	0.129	-5.63%	0.28%	-4.20%
Netherlands	2.773	3.131	3.130	2.920	2.371	1.554	0.905	0.553	1.22%	-2.74%	-9.25%
Norway	3.196	3.849	3.744	4.203	4.434	4.255	3.983	3.759	1.59%	1.71%	-1.09%
Poland	0.214	0.215	0.182	0.150	0.090	0.050	0.072	0.115	-1.58%	-6.85%	1.66%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.359	0.470	0.454	0.356	0.356	0.289	-1.40%	2.39%	-2.97%
Spain	0.006	0.002	0.001	0.001	0.007	0.012	0.046	0.185	-13.56%	17.34%	24.65%
Turkey	0.032	0.024	0.048	0.047	0.029	0.017	0.011	0.007	4.27%	-4.88%	-9.23%
United Kingdom	3.275	2.124	1.304	1.473	1.723	1.792	1.907	1.582	-8.80%	2.83%	-0.57%
Other Europe	0.574	0.502	0.375	0.412	0.397	0.395	0.343	0.258	-4.18%	0.58%	-2.84%
Eurasia	**27.386**	**27.903**	**28.484**	**29.338**	**31.942**	**33.605**	**34.585**	**35.424**	**0.39%**	**1.15%**	**0.69%**
Kazakhstan	0.428	0.441	0.632	1.014	1.364	1.476	1.502	1.653	3.97%	8.00%	1.29%
Russia	21.698	22.372	21.659	21.327	22.706	23.777	24.453	24.821	-0.02%	0.47%	0.60%
Turkmenistan	2.225	1.600	2.572	3.166	3.771	4.362	5.276	6.122	1.46%	3.90%	3.28%
Ukraine	0.685	0.684	0.604	0.299	0.412	0.744	0.938	1.004	-1.25%	-3.75%	6.12%
Uzbekistan	2.119	2.130	2.459	3.117	3.117	2.516	1.671	1.085	1.50%	2.40%	-6.79%
Other Eurasia	0.232	0.677	0.558	0.416	0.573	0.731	0.745	0.737	9.16%	0.26%	1.69%
Middle East	**12.334**	**18.699**	**21.352**	**22.511**	**24.340**	**25.812**	**27.320**	**28.805**	**5.64%**	**1.32%**	**1.13%**
Iran	3.818	6.031	6.406	6.723	7.110	7.476	7.746	8.075	5.31%	1.05%	0.85%
Qatar	1.826	4.359	5.706	5.934	6.468	6.720	6.752	6.790	12.07%	1.26%	0.32%
Oman	0.748	1.035	1.133	1.228	1.331	1.385	1.422	1.450	4.24%	1.62%	0.57%
Saudi Arabia	2.860	3.424	3.916	4.303	4.850	5.330	5.752	6.197	3.19%	2.16%	1.65%
United Arab Emirates	1.828	1.992	2.005	1.890	1.886	1.927	2.092	2.222	0.93%	-0.61%	1.10%
Other Middle East	1.255	1.858	2.185	2.432	2.695	2.974	3.557	4.072	5.70%	2.12%	2.79%
Africa	**6.877**	**8.553**	**7.440**	**8.589**	**10.034**	**11.480**	**13.203**	**14.365**	**0.79%**	**3.04%**	**2.42%**
Algeria	3.613	3.465	3.429	3.570	3.839	4.218	4.392	3.915	-0.52%	1.14%	0.13%
Egypt	1.610	2.284	1.747	1.945	2.138	2.063	2.422	2.940	0.82%	2.04%	2.15%
Nigeria	0.862	1.317	1.230	1.341	1.761	2.027	2.716	3.641	3.62%	3.66%	4.96%
Other Africa	0.792	1.486	1.034	1.733	2.295	3.171	3.672	3.870	2.70%	8.30%	3.54%
Asia & Oceania	**12.907**	**17.527**	**19.381**	**24.799**	**28.334**	**30.965**	**32.457**	**31.775**	**4.15%**	**3.87%**	**0.77%**
Australia	1.266	1.708	3.519	6.043	6.167	6.317	6.576	6.630	10.77%	5.77%	0.48%
China	1.763	3.334	3.747	3.359	4.631	5.403	6.224	6.298	7.83%	2.14%	2.07%
India	1.153	1.848	1.183	1.481	1.797	1.902	1.684	1.318	0.26%	4.27%	-2.05%
Indonesia	2.406	3.047	2.547	3.248	3.890	5.124	6.885	8.304	0.57%	4.33%	5.19%
Japan	0.191	0.171	0.075	0.031	0.032	0.016	0.008	0.005	-8.88%	-8.21%	-11.34%
Malaysia	2.147	2.347	2.643	3.593	4.101	4.366	3.971	3.295	2.10%	4.49%	-1.45%
Myanmar	0.479	0.437	0.413	0.541	0.657	1.090	1.551	1.373	-1.46%	4.75%	5.04%
Pakistan	1.194	1.484	1.430	1.775	2.114	2.311	1.957	1.337	1.82%	3.99%	-3.01%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.007	0.005	0.002	0.001	0.000	-1.89%	-9.87%	-15.00%
Thailand	0.925	1.378	1.519	1.405	1.227	0.809	0.578	0.479	5.09%	-2.11%	-6.08%
Other Asia & Oceania	1.366	1.739	2.290	3.316	3.713	3.625	3.022	2.736	5.30%	4.95%	-2.02%
World	**104.006**	**120.194**	**127.648**	**141.512**	**153.842**	**162.952**	**170.976**	**175.008**	**2.07%**	**1.88%**	**0.86%**

LNG20_Hi-D Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.054**	**40.733**	**43.705**	**47.405**	**50.535**	**52.525**	**2.47%**	**2.23%**	**1.23%**
Canada	7.185	5.909	5.976	7.866	8.709	8.781	8.864	8.943	-1.83%	3.84%	0.18%
Mexico	1.349	1.799	1.251	0.735	1.180	2.722	4.416	5.060	-0.74%	-0.58%	10.19%
United States	18.927	22.382	27.826	32.131	33.816	35.902	37.255	38.523	3.93%	1.97%	0.87%
Central & South America	**5.318**	**6.267**	**6.543**	**6.922**	**7.739**	**8.380**	**8.843**	**9.212**	**2.09%**	**1.69%**	**1.17%**
Argentina	1.753	1.585	1.386	2.484	3.116	3.558	3.857	4.114	-2.32%	8.44%	1.87%
Brazil	0.432	0.570	0.762	0.338	0.157	0.097	0.048	0.024	5.84%	-14.61%	-11.85%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.78%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.197	0.293	7.08%	-4.56%	-0.49%
Peru	0.073	0.291	0.442	0.453	0.485	0.551	0.575	0.590	19.66%	0.93%	1.31%
Trinidad and Tobago	1.094	1.512	1.477	1.465	1.568	1.560	1.585	1.559	3.04%	0.60%	-0.04%
Venezuela	1.172	1.201	1.253	1.224	1.547	1.811	1.914	1.899	0.66%	2.13%	1.38%
Other Central & South America	0.472	0.589	0.695	0.521	0.546	0.579	0.615	0.658	3.94%	-2.38%	1.25%
Europe	**11.723**	**11.155**	**9.771**	**10.024**	**10.059**	**9.156**	**8.405**	**7.386**	**-1.80%**	**0.29%**	**-2.04%**
Austria	0.061	0.064	0.042	0.033	0.030	0.017	0.011	0.007	-3.77%	-3.21%	-9.49%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.014	0.017	0.011	0.032	-14.44%	0.22%	5.95%
Germany	0.689	0.526	0.329	0.177	0.231	0.425	0.585	0.456	-7.11%	-3.50%	4.64%
Italy	0.426	0.297	0.239	0.160	0.247	0.227	0.147	0.121	-5.63%	0.35%	-4.64%
Netherlands	2.773	3.131	3.133	2.930	2.382	1.556	0.912	0.559	1.23%	-2.70%	-9.21%
Norway	3.196	3.849	3.740	4.169	4.437	4.257	3.997	3.744	1.58%	1.72%	-1.13%
Poland	0.214	0.215	0.182	0.151	0.090	0.051	0.074	0.116	-1.58%	-6.80%	1.72%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.360	0.473	0.455	0.364	0.365	0.294	-1.36%	2.35%	-2.87%
Spain	0.006	0.002	0.001	0.001	0.006	0.012	0.041	0.182	-13.56%	16.23%	25.29%
Turkey	0.032	0.024	0.049	0.048	0.029	0.018	0.011	0.007	4.52%	-5.12%	-9.03%
United Kingdom	3.275	2.124	1.305	1.473	1.740	1.812	1.903	1.609	-8.79%	2.92%	-0.52%
Other Europe	0.574	0.502	0.377	0.404	0.400	0.401	0.348	0.260	-4.11%	0.59%	-2.84%
Eurasia	**27.386**	**27.903**	**28.485**	**29.347**	**31.950**	**33.550**	**34.530**	**35.445**	**0.39%**	**1.15%**	**0.69%**
Kazakhstan	0.428	0.441	0.631	1.014	1.351	1.459	1.518	1.631	3.96%	7.91%	1.26%
Russia	21.698	22.372	21.663	21.326	22.711	23.729	24.403	24.886	-0.02%	0.47%	0.61%
Turkmenistan	2.225	1.600	2.570	3.175	3.780	4.364	5.263	6.118	1.45%	3.93%	3.26%
Ukraine	0.685	0.684	0.604	0.302	0.417	0.747	0.927	0.963	-1.25%	-3.64%	5.74%
Uzbekistan	2.119	2.130	2.458	3.118	3.118	2.520	1.669	1.080	1.50%	2.41%	-6.82%
Other Eurasia	0.232	0.677	0.558	0.412	0.573	0.731	0.750	0.767	9.16%	0.26%	1.96%
Middle East	**12.334**	**18.699**	**21.348**	**22.511**	**24.349**	**25.807**	**27.242**	**28.733**	**5.64%**	**1.32%**	**1.11%**
Iran	3.818	6.031	6.406	6.726	7.113	7.479	7.751	8.048	5.31%	1.05%	0.83%
Qatar	1.826	4.359	5.704	5.931	6.471	6.719	6.752	6.771	12.07%	1.27%	0.30%
Oman	0.748	1.035	1.134	1.228	1.330	1.385	1.424	1.459	4.24%	1.62%	0.62%
Saudi Arabia	2.860	3.424	3.916	4.304	4.847	5.322	5.755	6.213	3.19%	2.16%	1.67%
United Arab Emirates	1.828	1.992	2.007	1.894	1.879	1.926	2.077	2.218	0.94%	-0.66%	1.11%
Other Middle East	1.255	1.858	2.182	2.429	2.707	2.976	3.483	4.023	5.69%	2.18%	2.68%
Africa	**6.877**	**8.553**	**7.438**	**8.519**	**10.005**	**11.370**	**13.125**	**14.417**	**0.79%**	**3.01%**	**2.47%**
Algeria	3.613	3.465	3.428	3.530	3.838	4.151	4.345	3.927	-0.52%	1.14%	0.15%
Egypt	1.610	2.284	1.748	1.938	2.088	2.064	2.443	2.969	0.83%	1.79%	2.37%
Nigeria	0.862	1.317	1.228	1.318	1.761	2.023	2.675	3.635	3.60%	3.67%	4.95%
Other Africa	0.792	1.486	1.034	1.733	2.318	3.132	3.662	3.886	2.70%	8.41%	3.50%
Asia & Oceania	**12.907**	**17.527**	**19.390**	**24.768**	**28.262**	**30.626**	**31.814**	**31.271**	**4.15%**	**3.84%**	**0.68%**
Australia	1.266	1.708	3.526	6.000	6.157	6.282	6.535	6.660	10.79%	5.73%	0.53%
China	1.763	3.334	3.740	3.365	4.576	5.151	5.813	6.086	7.81%	2.04%	1.92%
India	1.153	1.848	1.187	1.491	1.824	1.894	1.668	1.280	0.29%	4.39%	-2.33%
Indonesia	2.406	3.047	2.550	3.249	3.893	5.095	6.758	8.101	0.58%	4.32%	5.01%
Japan	0.191	0.171	0.077	0.029	0.032	0.015	0.008	0.005	-8.71%	-8.38%	-11.51%
Malaysia	2.147	2.347	2.644	3.596	4.079	4.375	3.957	3.271	2.10%	4.43%	-1.46%
Myanmar	0.479	0.437	0.414	0.541	0.647	1.075	1.543	1.369	-1.45%	4.58%	5.12%
Pakistan	1.194	1.484	1.430	1.776	2.115	2.312	1.931	1.323	1.82%	3.99%	-3.08%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.015	0.006	0.005	0.002	0.001	0.000	-1.73%	-10.02%	-15.00%
Thailand	0.925	1.378	1.517	1.402	1.228	0.812	0.583	0.470	5.07%	-2.09%	-6.20%
Other Asia & Oceania	1.366	1.739	2.291	3.314	3.706	3.612	3.017	2.705	5.31%	4.93%	-2.08%
World	**104.006**	**120.194**	**128.028**	**142.825**	**156.071**	**166.293**	**174.495**	**178.989**	**2.10%**	**2.00%**	**0.92%**

LNG20_Ref12 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.926**	**39.808**	**42.166**	**44.608**	**45.533**	**46.498**	**2.43%**	**1.90%**	**0.65%**
Canada	7.185	5.909	5.884	7.562	8.596	8.775	8.858	8.919	-1.98%	3.86%	0.25%
Mexico	1.349	1.799	1.251	0.711	0.958	2.251	3.467	4.873	-0.74%	-2.63%	11.45%
United States	18.927	22.382	27.791	31.535	32.612	33.582	33.208	32.707	3.92%	1.61%	0.02%
Central & South America	**5.318**	**6.267**	**6.544**	**6.940**	**7.749**	**8.382**	**8.843**	**9.300**	**2.10%**	**1.70%**	**1.22%**
Argentina	1.753	1.585	1.386	2.483	3.114	3.559	3.856	4.106	-2.32%	8.43%	1.86%
Brazil	0.432	0.570	0.762	0.338	0.158	0.095	0.048	0.023	5.84%	-14.55%	-11.97%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.076	-9.34%	-15.00%	19.85%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.203	0.315	7.08%	-4.55%	0.00%
Peru	0.073	0.291	0.440	0.455	0.486	0.546	0.575	0.594	19.62%	0.98%	1.35%
Trinidad and Tobago	1.094	1.512	1.480	1.470	1.571	1.570	1.588	1.557	3.07%	0.60%	-0.06%
Venezuela	1.172	1.201	1.253	1.223	1.548	1.808	1.896	1.859	0.66%	2.14%	1.23%
Other Central & South America	0.472	0.589	0.695	0.532	0.551	0.578	0.626	0.770	3.94%	-2.29%	2.26%
Europe	**11.723**	**11.155**	**9.767**	**10.024**	**10.050**	**9.165**	**8.366**	**7.399**	**-1.81%**	**0.29%**	**-2.02%**
Austria	0.061	0.064	0.041	0.032	0.030	0.017	0.011	0.007	-3.82%	-3.29%	-9.40%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.012	0.018	0.012	0.031	-14.43%	-0.79%	6.38%
Germany	0.689	0.526	0.330	0.182	0.229	0.427	0.585	0.448	-7.10%	-3.56%	4.56%
Italy	0.426	0.297	0.239	0.160	0.246	0.226	0.146	0.123	-5.63%	0.31%	-4.52%
Netherlands	2.773	3.131	3.129	2.913	2.378	1.566	0.911	0.554	1.21%	-2.71%	-9.25%
Norway	3.196	3.849	3.742	4.182	4.423	4.268	3.965	3.786	1.59%	1.68%	-1.03%
Poland	0.214	0.215	0.183	0.149	0.090	0.051	0.071	0.118	-1.55%	-6.89%	1.83%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.362	0.475	0.452	0.361	0.363	0.293	-1.32%	2.26%	-2.86%
Spain	0.006	0.002	0.001	0.001	0.008	0.012	0.040	0.176	-13.55%	19.45%	22.77%
Turkey	0.032	0.024	0.048	0.047	0.029	0.018	0.011	0.007	4.19%	-4.80%	-9.02%
United Kingdom	3.275	2.124	1.306	1.472	1.752	1.801	1.902	1.599	-8.78%	2.98%	-0.61%
Other Europe	0.574	0.502	0.373	0.406	0.401	0.402	0.348	0.258	-4.24%	0.74%	-2.90%
Eurasia	**27.386**	**27.903**	**28.486**	**29.334**	**31.995**	**33.543**	**34.616**	**35.451**	**0.39%**	**1.17%**	**0.69%**
Kazakhstan	0.428	0.441	0.632	1.007	1.348	1.470	1.547	1.635	3.98%	7.87%	1.29%
Russia	21.698	22.372	21.659	21.322	22.713	23.722	24.451	24.843	-0.02%	0.48%	0.60%
Turkmenistan	2.225	1.600	2.572	3.162	3.790	4.351	5.264	6.146	1.46%	3.95%	3.28%
Ukraine	0.685	0.684	0.604	0.301	0.439	0.761	0.945	0.978	-1.25%	-3.14%	5.49%
Uzbekistan	2.119	2.130	2.461	3.130	3.130	2.510	1.656	1.080	1.51%	2.43%	-6.85%
Other Eurasia	0.232	0.677	0.558	0.412	0.575	0.731	0.754	0.769	9.16%	0.30%	1.96%
Middle East	**12.334**	**18.699**	**21.346**	**22.521**	**24.345**	**25.793**	**27.399**	**28.716**	**5.64%**	**1.32%**	**1.11%**
Iran	3.818	6.031	6.405	6.727	7.114	7.473	7.756	8.036	5.31%	1.06%	0.82%
Qatar	1.826	4.359	5.704	5.934	6.469	6.719	6.758	6.779	12.07%	1.27%	0.31%
Oman	0.748	1.035	1.133	1.227	1.331	1.384	1.423	1.454	4.23%	1.62%	0.59%
Saudi Arabia	2.860	3.424	3.916	4.303	4.846	5.325	5.762	6.230	3.19%	2.15%	1.69%
United Arab Emirates	1.828	1.992	2.008	1.891	1.880	1.929	2.081	2.240	0.94%	-0.65%	1.17%
Other Middle East	1.255	1.858	2.181	2.439	2.705	2.963	3.620	3.977	5.68%	2.18%	2.60%
Africa	**6.877**	**8.553**	**7.425**	**8.504**	**10.019**	**11.440**	**13.234**	**14.404**	**0.77%**	**3.04%**	**2.45%**
Algeria	3.613	3.465	3.429	3.545	3.832	4.193	4.384	3.924	-0.52%	1.12%	0.16%
Egypt	1.610	2.284	1.748	1.941	2.128	2.071	2.436	2.972	0.83%	1.99%	2.25%
Nigeria	0.862	1.317	1.214	1.292	1.757	2.045	2.747	3.636	3.49%	3.76%	4.97%
Other Africa	0.792	1.486	1.034	1.726	2.302	3.132	3.667	3.871	2.70%	8.34%	3.53%
Asia & Oceania	**12.907**	**17.527**	**19.398**	**24.714**	**28.180**	**30.908**	**33.413**	**32.441**	**4.16%**	**3.80%**	**0.94%**
Australia	1.266	1.708	3.527	6.005	6.167	6.282	6.603	6.603	10.79%	5.75%	0.46%
China	1.763	3.334	3.748	3.320	4.536	5.404	6.748	6.725	7.83%	1.93%	2.66%
India	1.153	1.848	1.186	1.476	1.765	1.870	1.737	1.350	0.28%	4.06%	-1.77%
Indonesia	2.406	3.047	2.553	3.249	3.889	5.114	7.149	8.433	0.59%	4.30%	5.30%
Japan	0.191	0.171	0.076	0.029	0.032	0.015	0.009	0.006	-8.84%	-8.31%	-10.77%
Malaysia	2.147	2.347	2.644	3.592	4.077	4.360	3.977	3.316	2.10%	4.43%	-1.37%
Myanmar	0.479	0.437	0.413	0.541	0.664	1.119	1.559	1.348	-1.46%	4.87%	4.83%
Pakistan	1.194	1.484	1.430	1.773	2.109	2.312	2.022	1.412	1.82%	3.96%	-2.64%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.007	0.005	0.002	0.001	0.000	-1.86%	-9.89%	-15.00%
Thailand	0.925	1.378	1.519	1.403	1.234	0.810	0.578	0.481	5.08%	-2.06%	-6.09%
Other Asia & Oceania	1.366	1.739	2.289	3.320	3.702	3.620	3.031	2.767	5.30%	4.93%	-1.92%
World	**104.006**	**120.194**	**127.893**	**141.845**	**154.503**	**163.840**	**171.403**	**174.208**	**2.09%**	**1.91%**	**0.80%**

LNG20_HRR12 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.098**	**40.270**	**42.813**	**45.448**	**46.475**	**47.460**	**2.48%**	**2.01%**	**0.69%**
Canada	7.185	5.909	5.694	6.644	7.966	8.556	8.820	8.892	-2.30%	3.41%	0.74%
Mexico	1.349	1.799	1.251	0.661	0.873	1.283	2.426	3.213	-0.75%	-3.53%	9.07%
United States	18.927	22.382	28.152	32.965	33.974	35.609	35.229	35.355	4.05%	1.90%	0.27%
Central & South America	**5.318**	**6.267**	**6.545**	**6.934**	**7.742**	**8.384**	**8.844**	**9.295**	**2.10%**	**1.69%**	**1.23%**
Argentina	1.753	1.585	1.386	2.483	3.117	3.560	3.853	4.101	-2.32%	8.44%	1.84%
Brazil	0.432	0.570	0.762	0.338	0.156	0.094	0.048	0.023	5.84%	-14.68%	-11.89%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.80%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.205	0.318	7.08%	-4.55%	0.05%
Peru	0.073	0.291	0.442	0.454	0.486	0.545	0.572	0.596	19.66%	0.96%	1.36%
Trinidad and Tobago	1.094	1.512	1.476	1.470	1.567	1.572	1.588	1.561	3.04%	0.59%	-0.02%
Venezuela	1.172	1.201	1.253	1.224	1.548	1.805	1.894	1.861	0.66%	2.14%	1.24%
Other Central & South America	0.472	0.589	0.698	0.526	0.549	0.583	0.635	0.760	3.99%	-2.38%	2.20%
Europe	**11.723**	**11.155**	**9.771**	**10.021**	**10.027**	**9.144**	**8.363**	**7.376**	**-1.81%**	**0.26%**	**-2.03%**
Austria	0.061	0.064	0.041	0.032	0.029	0.017	0.011	0.007	-3.80%	-3.39%	-9.30%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.011	0.018	0.012	0.025	-14.43%	-2.05%	5.88%
Germany	0.689	0.526	0.329	0.181	0.230	0.423	0.588	0.445	-7.12%	-3.54%	4.52%
Italy	0.426	0.297	0.239	0.160	0.245	0.226	0.147	0.121	-5.63%	0.26%	-4.58%
Netherlands	2.773	3.131	3.129	2.917	2.378	1.563	0.915	0.539	1.21%	-2.71%	-9.42%
Norway	3.196	3.849	3.740	4.174	4.425	4.267	3.957	3.792	1.58%	1.70%	-1.02%
Poland	0.214	0.215	0.184	0.150	0.089	0.050	0.072	0.112	-1.51%	-6.95%	1.49%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.360	0.470	0.455	0.366	0.367	0.288	-1.38%	2.37%	-2.99%
Spain	0.006	0.002	0.001	0.001	0.009	0.012	0.046	0.192	-13.56%	20.25%	22.93%
Turkey	0.032	0.024	0.049	0.047	0.029	0.018	0.011	0.007	4.56%	-5.22%	-9.10%
United Kingdom	3.275	2.124	1.310	1.479	1.731	1.787	1.891	1.589	-8.76%	2.83%	-0.57%
Other Europe	0.574	0.502	0.376	0.405	0.398	0.398	0.345	0.258	-4.16%	0.57%	-2.83%
Eurasia	**27.386**	**27.903**	**28.478**	**29.343**	**32.002**	**33.585**	**34.591**	**35.508**	**0.39%**	**1.17%**	**0.70%**
Kazakhstan	0.428	0.441	0.630	1.012	1.356	1.477	1.523	1.596	3.95%	7.96%	1.09%
Russia	21.698	22.372	21.662	21.327	22.718	23.696	24.447	25.030	-0.02%	0.48%	0.65%
Turkmenistan	2.225	1.600	2.569	3.158	3.790	4.406	5.282	6.096	1.45%	3.97%	3.22%
Ukraine	0.685	0.684	0.604	0.310	0.439	0.764	0.922	0.955	-1.25%	-3.14%	5.32%
Uzbekistan	2.119	2.130	2.455	3.119	3.122	2.517	1.666	1.075	1.49%	2.43%	-6.86%
Other Eurasia	0.232	0.677	0.558	0.417	0.578	0.725	0.752	0.755	9.16%	0.35%	1.80%
Middle East	**12.334**	**18.699**	**21.351**	**22.506**	**24.330**	**25.805**	**27.330**	**28.810**	**5.64%**	**1.31%**	**1.13%**
Iran	3.818	6.031	6.406	6.720	7.108	7.467	7.718	8.083	5.31%	1.04%	0.86%
Qatar	1.826	4.359	5.705	5.932	6.456	6.720	6.753	6.786	12.07%	1.24%	0.33%
Oman	0.748	1.035	1.133	1.227	1.333	1.383	1.420	1.454	4.24%	1.64%	0.58%
Saudi Arabia	2.860	3.424	3.916	4.303	4.854	5.330	5.743	6.201	3.19%	2.17%	1.65%
United Arab Emirates	1.828	1.992	2.007	1.893	1.880	1.928	2.090	2.213	0.94%	-0.65%	1.09%
Other Middle East	1.255	1.858	2.183	2.431	2.699	2.976	3.605	4.073	5.70%	2.14%	2.78%
Africa	**6.877**	**8.553**	**7.429**	**8.510**	**10.022**	**11.426**	**13.348**	**14.538**	**0.78%**	**3.04%**	**2.51%**
Algeria	3.613	3.465	3.429	3.537	3.833	4.179	4.398	3.937	-0.52%	1.12%	0.18%
Egypt	1.610	2.284	1.749	1.943	2.137	2.062	2.420	2.952	0.83%	2.03%	2.18%
Nigeria	0.862	1.317	1.218	1.306	1.756	2.035	2.749	3.630	3.52%	3.73%	4.96%
Other Africa	0.792	1.486	1.034	1.725	2.296	3.150	3.782	4.019	2.70%	8.30%	3.80%
Asia & Oceania	**12.907**	**17.527**	**19.390**	**24.704**	**28.041**	**30.848**	**33.412**	**32.438**	**4.15%**	**3.76%**	**0.98%**
Australia	1.266	1.708	3.519	6.002	6.162	6.303	6.601	6.579	10.77%	5.76%	0.44%
China	1.763	3.334	3.746	3.314	4.445	5.336	6.704	6.724	7.83%	1.73%	2.80%
India	1.153	1.848	1.188	1.479	1.765	1.867	1.743	1.349	0.30%	4.04%	-1.78%
Indonesia	2.406	3.047	2.552	3.249	3.886	5.115	7.169	8.427	0.59%	4.29%	5.30%
Japan	0.191	0.171	0.076	0.029	0.031	0.015	0.009	0.006	-8.76%	-8.53%	-10.81%
Malaysia	2.147	2.347	2.643	3.591	4.064	4.358	3.982	3.323	2.10%	4.40%	-1.33%
Myanmar	0.479	0.437	0.414	0.541	0.659	1.115	1.558	1.349	-1.45%	4.76%	4.90%
Pakistan	1.194	1.484	1.430	1.772	2.107	2.307	2.030	1.416	1.82%	3.95%	-2.62%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.007	0.005	0.002	0.001	0.000	-1.79%	-9.96%	-15.00%
Thailand	0.925	1.378	1.519	1.404	1.232	0.807	0.581	0.483	5.08%	-2.08%	-6.04%
Other Asia & Oceania	1.366	1.739	2.290	3.316	3.685	3.624	3.036	2.782	5.30%	4.87%	-1.86%
World	**104.006**	**120.194**	**128.062**	**142.289**	**154.977**	**164.640**	**172.364**	**175.426**	**2.10%**	**1.93%**	**0.83%**

LNG20_LRR12 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.714**	**39.293**	**41.498**	**43.416**	**44.862**	**45.568**	**2.37%**	**1.80%**	**0.63%**
Canada	7.185	5.909	6.097	8.098	8.740	8.807	8.882	8.933	-1.63%	3.67%	0.15%
Mexico	1.349	1.799	1.251	0.823	1.586	3.068	4.765	5.062	-0.74%	2.40%	8.04%
United States	18.927	22.382	27.365	30.371	31.172	31.541	31.215	31.574	3.76%	1.31%	0.09%
Central & South America	**5.318**	**6.267**	**6.546**	**6.945**	**7.743**	**8.394**	**8.835**	**9.282**	**2.10%**	**1.69%**	**1.22%**
Argentina	1.753	1.585	1.386	2.483	3.116	3.559	3.856	4.107	-2.32%	8.44%	1.86%
Brazil	0.432	0.570	0.762	0.338	0.158	0.097	0.048	0.023	5.84%	-14.58%	-11.98%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.78%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.201	0.284	7.08%	-4.56%	-0.67%
Peru	0.073	0.291	0.442	0.452	0.488	0.550	0.568	0.596	19.67%	0.99%	1.33%
Trinidad and Tobago	1.094	1.512	1.480	1.482	1.567	1.583	1.587	1.558	3.07%	0.57%	-0.04%
Venezuela	1.172	1.201	1.253	1.225	1.546	1.791	1.895	1.892	0.66%	2.13%	1.36%
Other Central & South America	0.472	0.589	0.695	0.527	0.549	0.589	0.630	0.746	3.95%	-2.34%	2.07%
Europe	**11.723**	**11.155**	**9.766**	**10.044**	**10.034**	**9.125**	**8.396**	**7.349**	**-1.81%**	**0.27%**	**-2.05%**
Austria	0.061	0.064	0.041	0.032	0.030	0.017	0.011	0.007	-3.86%	-3.10%	-9.54%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.013	0.017	0.011	0.029	-14.44%	0.01%	5.23%
Germany	0.689	0.526	0.329	0.179	0.232	0.436	0.579	0.444	-7.12%	-3.42%	4.42%
Italy	0.426	0.297	0.239	0.163	0.245	0.226	0.145	0.127	-5.63%	0.27%	-4.27%
Netherlands	2.773	3.131	3.133	2.934	2.376	1.547	0.901	0.560	1.23%	-2.73%	-9.18%
Norway	3.196	3.849	3.734	4.163	4.419	4.236	4.018	3.758	1.57%	1.70%	-1.07%
Poland	0.214	0.215	0.183	0.150	0.090	0.050	0.059	0.108	-1.56%	-6.81%	1.19%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.361	0.474	0.454	0.364	0.362	0.292	-1.34%	2.32%	-2.91%
Spain	0.006	0.002	0.001	0.001	0.008	0.012	0.043	0.191	-13.56%	18.89%	23.81%
Turkey	0.032	0.024	0.047	0.048	0.029	0.018	0.011	0.007	4.12%	-4.72%	-8.85%
United Kingdom	3.275	2.124	1.310	1.487	1.736	1.804	1.909	1.565	-8.75%	2.86%	-0.69%
Other Europe	0.574	0.502	0.374	0.408	0.401	0.397	0.346	0.260	-4.20%	0.69%	-2.84%
Eurasia	**27.386**	**27.903**	**28.488**	**29.355**	**31.986**	**33.590**	**34.534**	**35.416**	**0.40%**	**1.16%**	**0.68%**
Kazakhstan	0.428	0.441	0.632	1.014	1.355	1.473	1.529	1.640	3.98%	7.93%	1.28%
Russia	21.698	22.372	21.653	21.329	22.670	23.748	24.423	24.852	-0.02%	0.46%	0.61%
Turkmenistan	2.225	1.600	2.580	3.172	3.823	4.371	5.225	6.120	1.49%	4.01%	3.19%
Ukraine	0.685	0.684	0.604	0.301	0.433	0.748	0.939	0.962	-1.25%	-3.27%	5.47%
Uzbekistan	2.119	2.130	2.461	3.112	3.112	2.519	1.674	1.084	1.51%	2.37%	-6.79%
Other Eurasia	0.232	0.677	0.558	0.426	0.592	0.731	0.745	0.757	9.15%	0.59%	1.66%
Middle East	**12.334**	**18.699**	**21.349**	**22.515**	**24.354**	**25.826**	**27.423**	**28.838**	**5.64%**	**1.33%**	**1.13%**
Iran	3.818	6.031	6.406	6.726	7.109	7.475	7.719	8.065	5.31%	1.05%	0.84%
Qatar	1.826	4.359	5.703	5.929	6.478	6.722	6.759	6.782	12.06%	1.28%	0.31%
Oman	0.748	1.035	1.134	1.228	1.334	1.384	1.422	1.453	4.24%	1.64%	0.57%
Saudi Arabia	2.860	3.424	3.915	4.304	4.847	5.325	5.764	6.231	3.19%	2.16%	1.69%
United Arab Emirates	1.828	1.992	2.008	1.897	1.878	1.926	2.087	2.228	0.94%	-0.66%	1.14%
Other Middle East	1.255	1.858	2.183	2.432	2.708	2.994	3.672	4.080	5.69%	2.18%	2.77%
Africa	**6.877**	**8.553**	**7.441**	**8.586**	**10.015**	**11.534**	**13.250**	**14.381**	**0.79%**	**3.02%**	**2.44%**
Algeria	3.613	3.465	3.429	3.577	3.839	4.251	4.396	3.921	-0.52%	1.14%	0.14%
Egypt	1.610	2.284	1.749	1.938	2.107	2.058	2.443	2.958	0.83%	1.88%	2.29%
Nigeria	0.862	1.317	1.229	1.338	1.757	2.027	2.747	3.645	3.61%	3.64%	4.98%
Other Africa	0.792	1.486	1.034	1.734	2.311	3.198	3.665	3.858	2.70%	8.38%	3.47%
Asia & Oceania	**12.907**	**17.527**	**19.383**	**24.753**	**28.276**	**31.061**	**33.312**	**32.447**	**4.15%**	**3.85%**	**0.92%**
Australia	1.266	1.708	3.520	6.028	6.155	6.282	6.631	6.712	10.77%	5.75%	0.58%
China	1.763	3.334	3.741	3.332	4.589	5.493	6.628	6.636	7.82%	2.06%	2.49%
India	1.153	1.848	1.184	1.475	1.761	1.888	1.733	1.350	0.27%	4.05%	-1.76%
Indonesia	2.406	3.047	2.554	3.249	3.895	5.152	7.128	8.401	0.60%	4.31%	5.26%
Japan	0.191	0.171	0.075	0.030	0.032	0.016	0.009	0.006	-8.94%	-8.07%	-10.95%
Malaysia	2.147	2.347	2.643	3.592	4.094	4.353	3.977	3.330	2.10%	4.47%	-1.37%
Myanmar	0.479	0.437	0.413	0.541	0.663	1.126	1.559	1.336	-1.46%	4.84%	4.79%
Pakistan	1.194	1.484	1.430	1.773	2.108	2.310	2.026	1.419	1.82%	3.96%	-2.60%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.007	0.005	0.002	0.001	0.000	-1.90%	-9.86%	-15.00%
Thailand	0.925	1.378	1.519	1.404	1.231	0.810	0.578	0.481	5.08%	-2.08%	-6.07%
Other Asia & Oceania	1.366	1.739	2.290	3.322	3.744	3.629	3.043	2.776	5.30%	5.04%	-1.97%
World	**104.006**	**120.194**	**127.688**	**141.491**	**153.907**	**162.946**	**170.611**	**173.282**	**2.07%**	**1.89%**	**0.79%**

LNG20_Hi-D12 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.077**	**40.793**	**43.757**	**46.889**	**48.100**	**49.000**	**2.48%**	**2.24%**	**0.76%**
Canada	7.185	5.909	5.959	7.794	8.705	8.792	8.858	8.923	-1.85%	3.86%	0.16%
Mexico	1.349	1.799	1.251	0.733	1.100	2.573	3.996	5.090	-0.74%	-1.28%	10.75%
United States	18.927	22.382	27.867	32.266	33.951	35.525	35.246	34.988	3.94%	1.99%	0.20%
Central & South America	**5.318**	**6.267**	**6.540**	**6.923**	**7.748**	**8.392**	**8.824**	**9.327**	**2.09%**	**1.71%**	**1.24%**
Argentina	1.753	1.585	1.386	2.484	3.117	3.559	3.847	4.086	-2.32%	8.44%	1.82%
Brazil	0.432	0.570	0.762	0.338	0.156	0.097	0.048	0.023	5.84%	-14.67%	-11.93%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.050	0.075	-9.34%	-15.00%	19.79%
Colombia	0.253	0.454	0.502	0.427	0.315	0.223	0.203	0.280	7.08%	-4.54%	-0.79%
Peru	0.073	0.291	0.442	0.455	0.486	0.548	0.573	0.590	19.65%	0.97%	1.29%
Trinidad and Tobago	1.094	1.512	1.475	1.466	1.567	1.574	1.586	1.565	3.03%	0.61%	-0.01%
Venezuela	1.172	1.201	1.253	1.222	1.549	1.804	1.881	1.916	0.66%	2.14%	1.43%
Other Central & South America	0.472	0.589	0.695	0.519	0.552	0.585	0.637	0.792	3.94%	-2.28%	2.43%
Europe	**11.723**	**11.155**	**9.768**	**10.039**	**10.021**	**9.120**	**8.354**	**7.386**	**-1.81%**	**0.26%**	**-2.01%**
Austria	0.061	0.064	0.041	0.032	0.029	0.017	0.011	0.007	-3.82%	-3.37%	-9.23%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.013	0.017	0.011	0.023	-14.44%	-0.49%	4.16%
Germany	0.689	0.526	0.329	0.177	0.231	0.416	0.585	0.452	-7.13%	-3.48%	4.58%
Italy	0.426	0.297	0.239	0.164	0.246	0.222	0.144	0.124	-5.63%	0.31%	-4.45%
Netherlands	2.773	3.131	3.135	2.937	2.373	1.543	0.899	0.560	1.23%	-2.75%	-9.17%
Norway	3.196	3.849	3.740	4.172	4.429	4.272	3.963	3.769	1.58%	1.71%	-1.07%
Poland	0.214	0.215	0.182	0.149	0.090	0.050	0.061	0.110	-1.59%	-6.77%	1.33%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.361	0.474	0.453	0.362	0.364	0.295	-1.34%	2.29%	-2.80%
Spain	0.006	0.002	0.001	0.001	0.007	0.012	0.044	0.182	-13.56%	17.08%	24.71%
Turkey	0.032	0.024	0.048	0.048	0.029	0.018	0.011	0.007	4.18%	-4.84%	-8.88%
United Kingdom	3.275	2.124	1.305	1.473	1.724	1.793	1.914	1.593	-8.79%	2.83%	-0.53%
Other Europe	0.574	0.502	0.374	0.405	0.397	0.397	0.346	0.262	-4.20%	0.60%	-2.73%
Eurasia	**27.386**	**27.903**	**28.476**	**29.330**	**31.974**	**33.578**	**34.583**	**35.467**	**0.39%**	**1.17%**	**0.69%**
Kazakhstan	0.428	0.441	0.632	1.019	1.363	1.478	1.527	1.624	3.98%	7.99%	1.17%
Russia	21.698	22.372	21.659	21.312	22.683	23.693	24.430	24.870	-0.02%	0.46%	0.62%
Turkmenistan	2.225	1.600	2.568	3.149	3.786	4.394	5.288	6.149	1.44%	3.96%	3.29%
Ukraine	0.685	0.684	0.604	0.302	0.432	0.768	0.922	0.979	-1.25%	-3.29%	5.60%
Uzbekistan	2.119	2.130	2.455	3.123	3.122	2.519	1.670	1.083	1.48%	2.43%	-6.81%
Other Eurasia	0.232	0.677	0.558	0.426	0.587	0.726	0.746	0.762	9.16%	0.51%	1.75%
Middle East	**12.334**	**18.699**	**21.350**	**22.515**	**24.363**	**25.821**	**27.413**	**28.748**	**5.64%**	**1.33%**	**1.11%**
Iran	3.818	6.031	6.406	6.726	7.114	7.470	7.738	8.054	5.31%	1.05%	0.83%
Qatar	1.826	4.359	5.703	5.926	6.477	6.721	6.759	6.783	12.06%	1.28%	0.31%
Oman	0.748	1.035	1.134	1.228	1.331	1.386	1.424	1.451	4.24%	1.62%	0.58%
Saudi Arabia	2.860	3.424	3.917	4.303	4.852	5.333	5.759	6.208	3.19%	2.16%	1.66%
United Arab Emirates	1.828	1.992	2.009	1.899	1.877	1.927	2.085	2.222	0.95%	-0.68%	1.13%
Other Middle East	1.255	1.858	2.182	2.433	2.712	2.985	3.649	4.029	5.69%	2.20%	2.68%
Africa	**6.877**	**8.553**	**7.439**	**8.535**	**10.013**	**11.477**	**13.256**	**14.395**	**0.79%**	**3.02%**	**2.45%**
Algeria	3.613	3.465	3.429	3.540	3.838	4.205	4.381	3.917	-0.52%	1.13%	0.14%
Egypt	1.610	2.284	1.748	1.936	2.104	2.071	2.441	2.952	0.83%	1.87%	2.28%
Nigeria	0.862	1.317	1.229	1.331	1.761	2.040	2.756	3.657	3.61%	3.66%	4.99%
Other Africa	0.792	1.486	1.034	1.729	2.312	3.162	3.678	3.870	2.70%	8.38%	3.50%
Asia & Oceania	**12.907**	**17.527**	**19.392**	**24.711**	**28.208**	**30.910**	**33.315**	**32.493**	**4.16%**	**3.82%**	**0.95%**
Australia	1.266	1.708	3.525	5.998	6.151	6.282	6.614	6.709	10.79%	5.73%	0.58%
China	1.763	3.334	3.747	3.320	4.539	5.388	6.645	6.687	7.83%	1.94%	2.62%
India	1.153	1.848	1.187	1.475	1.762	1.875	1.733	1.346	0.29%	4.03%	-1.78%
Indonesia	2.406	3.047	2.546	3.246	3.888	5.126	7.136	8.419	0.57%	4.32%	5.29%
Japan	0.191	0.171	0.076	0.029	0.032	0.015	0.009	0.006	-8.84%	-8.27%	-10.86%
Malaysia	2.147	2.347	2.644	3.598	4.098	4.361	3.977	3.306	2.10%	4.48%	-1.42%
Myanmar	0.479	0.437	0.413	0.541	0.661	1.120	1.555	1.347	-1.45%	4.81%	4.85%
Pakistan	1.194	1.484	1.430	1.773	2.109	2.313	2.017	1.413	1.82%	3.96%	-2.63%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.006	0.005	0.002	0.001	0.000	-1.87%	-9.89%	-15.00%
Thailand	0.925	1.378	1.520	1.403	1.229	0.810	0.579	0.480	5.09%	-2.10%	-6.08%
Other Asia & Oceania	1.366	1.739	2.290	3.321	3.731	3.617	3.049	2.780	5.30%	5.00%	-1.94%
World	**104.006**	**120.194**	**128.042**	**142.845**	**156.082**	**166.188**	**173.846**	**176.816**	**2.10%**	**2.00%**	**0.83%**

LNG20_Ref20 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**34.915**	**39.790**	**42.144**	**45.257**	**48.256**	**49.364**	**2.43%**	**1.90%**	**1.06%**
Canada	7.185	5.909	5.904	7.628	8.640	8.774	8.849	8.938	-1.94%	3.88%	0.23%
Mexico	1.349	1.799	1.251	0.716	1.015	2.464	4.027	5.045	-0.74%	-2.07%	11.28%
United States	18.927	22.382	27.759	31.446	32.489	34.019	35.381	35.381	3.90%	1.59%	0.57%
Central & South America	**5.318**	**6.267**	**6.547**	**6.925**	**7.745**	**8.335**	**8.775**	**9.250**	**2.10%**	**1.69%**	**1.19%**
Argentina	1.753	1.585	1.386	2.485	3.114	3.556	3.849	4.109	-2.32%	8.43%	1.87%
Brazil	0.432	0.570	0.762	0.338	0.157	0.095	0.048	0.023	5.84%	-14.60%	-12.00%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.78%
Colombia	0.253	0.454	0.502	0.427	0.315	0.224	0.204	0.311	7.08%	-4.55%	-0.08%
Peru	0.073	0.291	0.441	0.455	0.486	0.537	0.576	0.587	19.64%	0.97%	1.27%
Trinidad and Tobago	1.094	1.512	1.481	1.470	1.572	1.559	1.587	1.560	3.07%	0.60%	-0.05%
Venezuela	1.172	1.201	1.253	1.223	1.547	1.800	1.896	1.878	0.66%	2.13%	1.30%
Other Central & South America	0.472	0.589	0.696	0.516	0.548	0.561	0.565	0.706	3.96%	-2.36%	1.70%
Europe	**11.723**	**11.155**	**9.770**	**10.031**	**10.032**	**9.142**	**8.351**	**7.399**	**-1.81%**	**0.26%**	**-2.01%**
Austria	0.061	0.064	0.041	0.031	0.030	0.018	0.011	0.007	-3.83%	-3.31%	-9.16%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.012	0.018	0.012	0.029	-14.44%	-1.37%	6.32%
Germany	0.689	0.526	0.329	0.179	0.230	0.424	0.586	0.452	-7.12%	-3.51%	4.60%
Italy	0.426	0.297	0.239	0.157	0.245	0.228	0.146	0.128	-5.63%	0.27%	-4.25%
Netherlands	2.773	3.131	3.133	2.930	2.375	1.556	0.902	0.566	1.23%	-2.73%	-9.12%
Norway	3.196	3.849	3.734	4.169	4.423	4.264	3.964	3.726	1.57%	1.71%	-1.14%
Poland	0.214	0.215	0.184	0.150	0.089	0.050	0.069	0.116	-1.47%	-7.03%	1.76%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.360	0.470	0.454	0.366	0.364	0.293	-1.38%	2.37%	-2.88%
Spain	0.006	0.002	0.001	0.001	0.007	0.012	0.045	0.186	-13.56%	17.47%	24.61%
Turkey	0.032	0.024	0.049	0.048	0.029	0.018	0.011	0.007	4.49%	-5.14%	-8.83%
United Kingdom	3.275	2.124	1.310	1.480	1.739	1.791	1.900	1.626	-8.75%	2.87%	-0.45%
Other Europe	0.574	0.502	0.375	0.410	0.400	0.398	0.343	0.263	-4.16%	0.62%	-2.75%
Eurasia	**27.386**	**27.903**	**28.491**	**29.334**	**31.967**	**33.552**	**34.537**	**35.399**	**0.40%**	**1.16%**	**0.68%**
Kazakhstan	0.428	0.441	0.632	1.012	1.347	1.474	1.530	1.638	3.98%	7.86%	1.32%
Russia	21.698	22.372	21.653	21.324	22.693	23.715	24.402	24.833	-0.02%	0.47%	0.60%
Turkmenistan	2.225	1.600	2.581	3.178	3.816	4.369	5.199	6.091	1.50%	3.98%	3.17%
Ukraine	0.685	0.684	0.604	0.302	0.432	0.747	0.954	0.989	-1.25%	-3.30%	5.68%
Uzbekistan	2.119	2.130	2.464	3.106	3.111	2.517	1.673	1.086	1.52%	2.36%	-6.78%
Other Eurasia	0.232	0.677	0.558	0.411	0.569	0.731	0.779	0.762	9.15%	0.20%	1.97%
Middle East	**12.334**	**18.699**	**21.347**	**22.511**	**24.333**	**25.806**	**27.257**	**28.824**	**5.64%**	**1.32%**	**1.14%**
Iran	3.818	6.031	6.405	6.723	7.106	7.468	7.729	8.069	5.31%	1.04%	0.85%
Qatar	1.826	4.359	5.707	5.940	6.459	6.720	6.752	6.779	12.07%	1.25%	0.32%
Oman	0.748	1.035	1.133	1.227	1.333	1.383	1.417	1.467	4.24%	1.64%	0.64%
Saudi Arabia	2.860	3.424	3.916	4.304	4.847	5.323	5.738	6.188	3.19%	2.16%	1.64%
United Arab Emirates	1.828	1.992	2.005	1.884	1.886	1.923	2.075	2.239	0.93%	-0.61%	1.15%
Other Middle East	1.255	1.858	2.181	2.433	2.701	2.989	3.546	4.082	5.68%	2.16%	2.79%
Africa	**6.877**	**8.553**	**7.426**	**8.491**	**10.023**	**11.339**	**13.097**	**14.393**	**0.77%**	**3.04%**	**2.44%**
Algeria	3.613	3.465	3.428	3.530	3.832	4.153	4.349	3.930	-0.52%	1.12%	0.17%
Egypt	1.610	2.284	1.749	1.945	2.138	2.073	2.435	2.955	0.83%	2.03%	2.18%
Nigeria	0.862	1.317	1.214	1.288	1.765	1.999	2.664	3.620	3.49%	3.81%	4.91%
Other Africa	0.792	1.486	1.035	1.728	2.287	3.114	3.650	3.887	2.71%	8.26%	3.60%
Asia & Oceania	**12.907**	**17.527**	**19.399**	**24.761**	**28.223**	**30.472**	**31.902**	**31.739**	**4.16%**	**3.82%**	**0.79%**
Australia	1.266	1.708	3.529	6.004	6.154	6.288	6.617	6.701	10.80%	5.72%	0.57%
China	1.763	3.334	3.747	3.359	4.544	5.041	5.809	6.269	7.83%	1.95%	2.17%
India	1.153	1.848	1.187	1.492	1.824	1.878	1.663	1.305	0.29%	4.39%	-2.21%
Indonesia	2.406	3.047	2.551	3.250	3.886	5.066	6.759	8.218	0.59%	4.30%	5.12%
Japan	0.191	0.171	0.076	0.029	0.032	0.015	0.008	0.005	-8.75%	-8.41%	-11.14%
Malaysia	2.147	2.347	2.643	3.596	4.092	4.369	3.964	3.298	2.10%	4.47%	-1.43%
Myanmar	0.479	0.437	0.413	0.541	0.648	1.064	1.529	1.393	-1.45%	4.59%	5.24%
Pakistan	1.194	1.484	1.430	1.775	2.123	2.307	1.937	1.345	1.82%	4.03%	-3.00%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.014	0.006	0.005	0.002	0.001	0.000	-1.83%	-9.93%	-15.00%
Thailand	0.925	1.378	1.519	1.402	1.227	0.813	0.581	0.479	5.08%	-2.11%	-6.08%
Other Asia & Oceania	1.366	1.739	2.289	3.308	3.687	3.628	3.034	2.724	5.30%	4.89%	-2.00%
World	**104.006**	**120.194**	**127.896**	**141.842**	**154.466**	**163.902**	**172.176**	**176.367**	**2.09%**	**1.91%**	**0.89%**

LNG20_HRR20 Case (Supply)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040	cagr 2005-15	cagr 2015-25	cagr 2025-40
North America	**27.461**	**30.089**	**35.083**	**40.321**	**42.841**	**46.683**	**49.606**	**50.767**	**2.48%**	**2.02%**	**1.14%**
Canada	7.185	5.909	5.716	6.731	8.051	8.617	8.832	8.921	-2.26%	3.49%	0.69%
Mexico	1.349	1.799	1.251	0.670	0.870	1.506	2.848	3.800	-0.75%	-3.57%	10.33%
United States	18.927	22.382	28.116	32.920	33.920	36.560	37.927	38.047	4.04%	1.89%	0.77%
Central & South America	**5.318**	**6.267**	**6.542**	**6.932**	**7.772**	**8.346**	**8.786**	**9.232**	**2.09%**	**1.74%**	**1.15%**
Argentina	1.753	1.585	1.386	2.484	3.117	3.558	3.854	4.105	-2.32%	8.44%	1.85%
Brazil	0.432	0.570	0.762	0.338	0.156	0.095	0.048	0.023	5.84%	-14.65%	-11.91%
Chile	0.068	0.065	0.025	0.011	0.005	0.002	0.051	0.075	-9.34%	-15.00%	19.74%
Colombia	0.253	0.454	0.502	0.427	0.314	0.223	0.200	0.291	7.08%	-4.57%	-0.51%
Peru	0.073	0.291	0.440	0.454	0.488	0.522	0.577	0.597	19.61%	1.03%	1.35%
Trinidad and Tobago	1.094	1.512	1.479	1.468	1.570	1.559	1.585	1.560	3.06%	0.60%	-0.04%
Venezuela	1.172	1.201	1.253	1.225	1.553	1.804	1.908	1.921	0.66%	2.17%	1.43%
Other Central & South America	0.472	0.589	0.694	0.524	0.569	0.583	0.564	0.661	3.94%	-1.98%	1.01%
Europe	**11.723**	**11.155**	**9.771**	**10.017**	**10.051**	**9.116**	**8.377**	**7.324**	**-1.80%**	**0.28%**	**-2.09%**
Austria	0.061	0.064	0.042	0.033	0.030	0.017	0.011	0.007	-3.75%	-3.36%	-9.43%
Belgium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
France	0.063	0.048	0.013	0.006	0.013	0.018	0.012	0.024	-14.43%	-0.44%	4.32%
Germany	0.689	0.526	0.329	0.183	0.232	0.427	0.582	0.449	-7.11%	-3.43%	4.49%
Italy	0.426	0.297	0.239	0.158	0.248	0.225	0.146	0.121	-5.63%	0.38%	-4.67%
Netherlands	2.773	3.131	3.131	2.917	2.379	1.559	0.912	0.543	1.22%	-2.71%	-9.38%
Norway	3.196	3.849	3.736	4.160	4.431	4.237	4.007	3.739	1.57%	1.72%	-1.13%
Poland	0.214	0.215	0.184	0.150	0.089	0.050	0.066	0.114	-1.47%	-7.02%	1.65%
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
Romania	0.413	0.374	0.361	0.473	0.454	0.361	0.363	0.288	-1.33%	2.30%	-2.98%
Spain	0.006	0.002	0.001	0.001	0.008	0.012	0.038	0.183	-13.56%	19.27%	23.22%
Turkey	0.032	0.024	0.048	0.049	0.029	0.018	0.011	0.007	4.32%	-4.86%	-9.33%
United Kingdom	3.275	2.124	1.310	1.480	1.736	1.792	1.885	1.594	-8.76%	2.85%	-0.57%
Other Europe	0.574	0.502	0.376	0.408	0.403	0.399	0.345	0.256	-4.15%	0.69%	-2.98%
Eurasia	**27.386**	**27.903**	**28.482**	**29.334**	**31.976**	**33.581**	**34.590**	**35.454**	**0.39%**	**1.16%**	**0.69%**
Kazakhstan	0.428	0.441	0.630	1.008	1.355	1.482	1.549	1.656	3.95%	7.95%	1.35%
Russia	21.698	22.372	21.655	21.320	22.720	23.757	24.441	24.863	-0.02%	0.48%	0.60%
Turkmenistan	2.225	1.600	2.575	3.165	3.782	4.334	5.244	6.129	1.47%	3.92%	3.27%
Ukraine	0.685	0.684	0.604	0.298	0.433	0.757	0.913	0.965	-1.25%	-3.29%	5.49%
Uzbekistan	2.119	2.130	2.460	3.113	3.113	2.520	1.676	1.091	1.50%	2.39%	-6.75%
Other Eurasia	0.232	0.677	0.558	0.430	0.574	0.730	0.767	0.751	9.15%	0.28%	1.81%
Middle East	**12.334**	**18.699**	**21.348**	**22.509**	**24.307**	**25.826**	**27.258**	**28.819**	**5.64%**	**1.31%**	**1.14%**
Iran	3.818	6.031	6.405	6.720	7.103	7.477	7.740	8.091	5.31%	1.04%	0.87%
Qatar	1.826	4.359	5.704	5.933	6.455	6.718	6.756	6.774	12.07%	1.24%	0.32%
Oman	0.748	1.035	1.133	1.227	1.332	1.384	1.421	1.457	4.24%	1.63%	0.60%
Saudi Arabia	2.860	3.424	3.916	4.304	4.845	5.320	5.744	6.199	3.19%	2.15%	1.66%
United Arab Emirates	1.828	1.992	2.007	1.892	1.875	1.923	2.088	2.237	0.94%	-0.68%	1.18%
Other Middle East	1.255	1.858	2.182	2.433	2.697	3.003	3.508	4.060	5.69%	2.14%	2.77%
Africa	**6.877**	**8.553**	**7.420**	**8.484**	**10.018**	**11.225**	**13.007**	**14.415**	**0.76%**	**3.05%**	**2.46%**
Algeria	3.613	3.465	3.428	3.539	3.828	4.103	4.302	3.938	-0.52%	1.11%	0.19%
Egypt	1.610	2.284	1.749	1.943	2.131	2.068	2.410	2.939	0.83%	2.00%	2.16%
Nigeria	0.862	1.317	1.209	1.283	1.756	2.000	2.644	3.623	3.44%	3.81%	4.95%
Other Africa	0.792	1.486	1.034	1.720	2.302	3.054	3.651	3.914	2.70%	8.33%	3.60%
Asia & Oceania	**12.907**	**17.527**	**19.413**	**24.786**	**28.060**	**30.061**	**31.571**	**31.483**	**4.17%**	**3.75%**	**0.77%**
Australia	1.266	1.708	3.525	5.998	6.156	6.239	6.551	6.621	10.78%	5.74%	0.49%
China	1.763	3.334	3.764	3.386	4.459	4.801	5.610	6.245	7.88%	1.71%	2.27%
India	1.153	1.848	1.190	1.498	1.831	1.844	1.659	1.306	0.31%	4.40%	-2.23%
Indonesia	2.406	3.047	2.545	3.246	3.880	5.021	6.721	8.112	0.56%	4.31%	5.04%
Japan	0.191	0.171	0.077	0.029	0.031	0.015	0.008	0.005	-8.65%	-8.57%	-11.27%
Malaysia	2.147	2.347	2.645	3.601	4.067	4.353	3.967	3.284	2.11%	4.40%	-1.42%
Myanmar	0.479	0.437	0.414	0.541	0.638	1.054	1.524	1.397	-1.44%	4.43%	5.36%
Pakistan	1.194	1.484	1.430	1.776	2.117	2.301	1.919	1.338	1.83%	4.00%	-3.01%
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	---	---	---
South Korea	0.017	0.033	0.015	0.007	0.005	0.002	0.001	0.000	-1.75%	-10.00%	-15.00%
Thailand	0.925	1.378	1.521	1.400	1.231	0.808	0.584	0.471	5.09%	-2.09%	-6.20%
Other Asia & Oceania	1.366	1.739	2.288	3.303	3.644	3.624	3.028	2.703	5.30%	4.76%	-1.97%
World	**104.006**	**120.194**	**128.059**	**142.383**	**155.025**	**164.839**	**173.195**	**177.494**	**2.10%**	**1.93%**	**0.91%**

D4. Net LNG Exports (tcf)[48]

Ref_Ref Case (Net LNG Exports)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.100**	**1.425**	**1.978**	**1.983**	**2.387**
Canada	0.000	-0.072	-0.096	-0.090	-0.089	-0.089	-0.088	0.311
Mexico	0.000	-0.198	-0.253	-0.256	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	1.446	1.766	2.319	2.325	2.329
Central & South America	**0.463**	**0.464**	**0.404**	**0.097**	**0.152**	**0.151**	**0.291**	**0.298**
Argentina	0.000	-0.062	-0.091	-0.092	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.125	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.202	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.181	0.182	0.182	0.182	0.182
Trinidad and Tobago	0.495	0.719	0.671	0.471	0.538	0.560	0.722	0.730
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.137	-0.164	-0.188	-0.210	-0.211
Europe	**-1.640**	**-2.856**	**-2.170**	**-3.138**	**-3.078**	**-2.827**	**-2.381**	**-2.141**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.094	-0.096	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.389	-0.498	-0.606	-0.666	-0.541	-0.423
Germany	0.000	0.000	-0.062	-0.063	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.126	-0.434	-0.403	-0.403	-0.279	-0.186
Netherlands	0.000	0.000	-0.145	-0.146	-0.144	-0.151	-0.144	-0.144
Norway	0.000	0.166	0.184	0.107	0.181	0.184	0.184	0.185
Poland	0.000	0.000	0.000	-0.148	-0.145	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.120	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.674	-0.682	-0.673	-0.705	-0.701	-0.673
Turkey	-0.168	-0.275	-0.130	-0.284	-0.279	-0.158	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.436	-0.430	-0.441	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.336	-0.303	-0.212	-0.179	-0.179
Eurasia	**0.000**	**0.473**	**0.454**	**0.346**	**0.250**	**0.333**	**0.460**	**0.596**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.560	0.461	0.460	0.460	0.596
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	-0.005	-0.215	-0.211	-0.127	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.569**	**4.588**	**4.807**	**5.013**	**5.018**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.654	3.871	4.038	4.042
Oman	0.325	0.406	0.413	0.413	0.414	0.414	0.440	0.441
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.226	0.222	0.227	0.227	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.282	0.294	0.294	0.294	0.295
Africa	**1.607**	**2.062**	**1.677**	**1.430**	**1.825**	**2.171**	**2.177**	**2.193**
Algeria	0.907	0.682	0.807	0.607	0.790	0.816	0.817	0.818
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.685	0.471	0.650	0.913	0.918	0.920
Other Africa	0.031	0.194	0.185	0.351	0.385	0.442	0.442	0.454
Asia & Oceania	**-1.413**	**-2.957**	**-4.511**	**-4.404**	**-5.163**	**-6.612**	**-7.544**	**-8.349**
Australia	0.524	0.895	2.506	3.962	4.589	4.595	4.603	4.610
China	0.000	-0.444	-1.559	-2.677	-3.571	-3.791	-3.240	-3.096
India	-0.208	-0.421	-0.872	-0.966	-1.176	-1.707	-2.716	-3.786
Indonesia	1.111	1.107	0.827	1.232	1.285	1.285	1.288	1.410
Japan	-2.789	-3.426	-3.974	-4.119	-4.010	-3.906	-3.958	-3.918
Malaysia	1.007	1.078	1.080	1.257	1.258	1.258	1.259	1.260
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	-0.190	-0.532	-0.945	-1.421
Singapore	0.000	0.000	-0.100	-0.101	-0.100	-0.100	-0.100	-0.100
South Korea	-1.049	-1.541	-2.256	-2.744	-2.941	-3.089	-3.125	-3.077
Thailand	0.000	0.000	-0.083	-0.084	-0.083	-0.083	-0.083	-0.140
Other Asia & Oceania	-0.008	-0.205	-0.081	-0.163	-0.225	-0.543	-0.528	-0.091
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

48 A negative number denotes the country is a net *importer*.

Ref_HRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.366**	**1.962**	**1.984**	**1.989**	**2.599**
Canada	0.000	-0.072	-0.096	-0.090	-0.089	-0.089	-0.089	0.389
Mexico	0.000	-0.198	-0.253	-0.257	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	1.713	2.304	2.325	2.331	2.463
Central & South America	**0.463**	**0.464**	**0.402**	**0.071**	**0.129**	**0.188**	**0.300**	**0.298**
Argentina	0.000	-0.062	-0.091	-0.092	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.149	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.202	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.181	0.181	0.182	0.182	0.183
Trinidad and Tobago	0.495	0.719	0.669	0.471	0.514	0.597	0.729	0.731
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.138	-0.164	-0.188	-0.208	-0.212
Europe	**-1.640**	**-2.856**	**-2.170**	**-3.260**	**-3.256**	**-2.788**	**-2.337**	**-2.146**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.094	-0.096	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.389	-0.537	-0.651	-0.664	-0.523	-0.425
Germany	0.000	0.000	-0.062	-0.063	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.127	-0.494	-0.454	-0.403	-0.258	-0.191
Netherlands	0.000	0.000	-0.145	-0.147	-0.144	-0.151	-0.144	-0.144
Norway	0.000	0.166	0.184	0.107	0.181	0.184	0.185	0.185
Poland	0.000	0.000	0.000	-0.148	-0.145	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.121	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.674	-0.684	-0.680	-0.701	-0.700	-0.673
Turkey	-0.168	-0.275	-0.129	-0.285	-0.279	-0.145	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.437	-0.473	-0.431	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.355	-0.336	-0.201	-0.176	-0.176
Eurasia	**0.000**	**0.473**	**0.456**	**0.362**	**0.248**	**0.368**	**0.483**	**0.595**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.578	0.460	0.460	0.483	0.595
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	-0.004	-0.216	-0.211	-0.091	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.570**	**4.588**	**4.832**	**5.013**	**5.019**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.653	3.896	4.039	4.042
Oman	0.325	0.406	0.413	0.413	0.414	0.414	0.440	0.441
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
United Arab Emirates	0.252	0.273	0.226	0.222	0.227	0.227	0.240	0.240
Other Middle East	0.000	0.097	0.256	0.283	0.294	0.294	0.295	0.295
Africa	**1.607**	**2.062**	**1.681**	**1.427**	**1.743**	**2.172**	**2.179**	**2.193**
Algeria	0.907	0.682	0.807	0.607	0.748	0.815	0.817	0.818
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.688	0.472	0.608	0.914	0.918	0.921
Other Africa	0.031	0.194	0.185	0.347	0.386	0.443	0.443	0.455
Asia & Oceania	**-1.413**	**-2.957**	**-4.514**	**-4.535**	**-5.414**	**-6.757**	**-7.627**	**-8.560**
Australia	0.524	0.895	2.506	3.937	4.587	4.595	4.603	4.610
China	0.000	-0.444	-1.561	-2.725	-3.684	-3.900	-3.332	-3.193
India	-0.208	-0.421	-0.873	-0.975	-1.212	-1.684	-2.679	-3.802
Indonesia	1.111	1.107	0.826	1.208	1.284	1.286	1.288	1.415
Japan	-2.789	-3.426	-3.974	-4.127	-4.025	-3.900	-3.955	-3.914
Malaysia	1.007	1.078	1.083	1.256	1.258	1.258	1.259	1.260
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	-0.218	-0.543	-0.937	-1.420
Singapore	0.000	0.000	-0.100	-0.101	-0.100	-0.099	-0.100	-0.100
South Korea	-1.049	-1.541	-2.256	-2.749	-2.950	-3.085	-3.121	-3.071
Thailand	0.000	0.000	-0.083	-0.084	-0.083	-0.083	-0.083	-0.203
Other Asia & Oceania	-0.008	-0.205	-0.082	-0.175	-0.271	-0.603	-0.573	-0.143
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

Ref_LRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**0.893**	**0.898**	**1.072**	**1.482**	**2.024**
Canada	0.000	-0.072	-0.096	-0.090	-0.089	-0.089	-0.089	0.378
Mexico	0.000	-0.198	-0.253	-0.256	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	1.238	1.240	1.413	1.823	1.899
Central & South America	**0.463**	**0.464**	**0.407**	**0.106**	**0.202**	**0.230**	**0.300**	**0.295**
Argentina	0.000	-0.062	-0.091	-0.092	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.114	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.202	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.181	0.182	0.182	0.182	0.183
Trinidad and Tobago	0.495	0.719	0.674	0.471	0.585	0.636	0.728	0.730
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.138	-0.161	-0.185	-0.208	-0.214
Europe	**-1.640**	**-2.856**	**-2.175**	**-3.066**	**-2.989**	**-2.620**	**-2.346**	**-2.134**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.094	-0.096	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.389	-0.472	-0.562	-0.597	-0.530	-0.419
Germany	0.000	0.000	-0.062	-0.063	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.130	-0.407	-0.403	-0.389	-0.255	-0.180
Netherlands	0.000	0.000	-0.144	-0.146	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.113	0.181	0.184	0.184	0.185
Poland	0.000	0.000	0.000	-0.147	-0.144	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.120	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.673	-0.681	-0.673	-0.693	-0.700	-0.673
Turkey	-0.168	-0.275	-0.131	-0.283	-0.261	-0.091	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.436	-0.431	-0.430	-0.430	-0.431
Other Europe	-0.016	-0.041	-0.184	-0.327	-0.278	-0.184	-0.181	-0.181
Eurasia	**0.000**	**0.473**	**0.445**	**0.335**	**0.248**	**0.402**	**0.483**	**0.596**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.549	0.458	0.461	0.483	0.596
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	-0.014	-0.214	-0.210	-0.059	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.574**	**4.589**	**4.867**	**5.013**	**5.023**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.654	3.931	4.039	4.043
Oman	0.325	0.406	0.413	0.413	0.414	0.414	0.440	0.445
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
United Arab Emirates	0.252	0.273	0.226	0.222	0.227	0.227	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.287	0.294	0.294	0.295	0.295
Africa	**1.607**	**2.062**	**1.685**	**1.447**	**1.935**	**2.172**	**2.178**	**2.221**
Algeria	0.907	0.682	0.807	0.607	0.807	0.816	0.817	0.818
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.693	0.470	0.742	0.914	0.918	0.920
Other Africa	0.031	0.194	0.185	0.369	0.385	0.442	0.442	0.483
Asia & Oceania	**-1.413**	**-2.957**	**-4.509**	**-4.288**	**-4.882**	**-6.123**	**-7.110**	**-8.026**
Australia	0.524	0.895	2.506	3.978	4.590	4.596	4.604	4.610
China	0.000	-0.444	-1.561	-2.641	-3.437	-3.554	-2.998	-2.914
India	-0.208	-0.421	-0.870	-0.950	-1.156	-1.638	-2.698	-3.785
Indonesia	1.111	1.107	0.828	1.248	1.285	1.286	1.288	1.422
Japan	-2.789	-3.426	-3.974	-4.112	-4.004	-3.893	-3.953	-3.920
Malaysia	1.007	1.078	1.082	1.257	1.258	1.259	1.259	1.260
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	-0.152	-0.484	-0.941	-1.422
Singapore	0.000	0.000	-0.100	-0.101	-0.100	-0.100	-0.100	-0.100
South Korea	-1.049	-1.541	-2.256	-2.739	-2.937	-3.078	-3.116	-3.071
Thailand	0.000	0.000	-0.083	-0.084	-0.083	-0.083	-0.083	-0.113
Other Asia & Oceania	-0.008	-0.205	-0.080	-0.144	-0.145	-0.433	-0.373	0.007
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

Ref_Hi-D Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.021**	**1.239**	**1.878**	**1.978**	**2.392**
Canada	0.000	-0.072	-0.096	-0.090	-0.089	-0.089	-0.089	0.323
Mexico	0.000	-0.198	-0.253	-0.256	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	1.367	1.581	2.220	2.319	2.322
Central & South America	**0.463**	**0.464**	**0.403**	**0.102**	**0.173**	**0.166**	**0.291**	**0.299**
Argentina	0.000	-0.062	-0.091	-0.092	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.119	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.202	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.181	0.182	0.182	0.182	0.183
Trinidad and Tobago	0.495	0.719	0.671	0.471	0.557	0.574	0.720	0.730
Venezuela	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001
Other Central & South America	-0.032	-0.055	-0.084	-0.137	-0.163	-0.187	-0.209	-0.212
Europe	**-1.640**	**-2.856**	**-2.174**	**-3.112**	**-3.043**	**-2.787**	**-2.349**	**-2.156**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.094	-0.096	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.389	-0.490	-0.581	-0.657	-0.525	-0.427
Germany	0.000	0.000	-0.062	-0.063	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.129	-0.420	-0.403	-0.403	-0.261	-0.192
Netherlands	0.000	0.000	-0.144	-0.146	-0.144	-0.146	-0.144	-0.144
Norway	0.000	0.166	0.184	0.106	0.181	0.184	0.184	0.185
Poland	0.000	0.000	0.000	-0.147	-0.144	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.120	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.674	-0.682	-0.673	-0.702	-0.699	-0.673
Turkey	-0.168	-0.275	-0.131	-0.284	-0.279	-0.149	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.436	-0.430	-0.434	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.333	-0.295	-0.204	-0.184	-0.184
Eurasia	**0.000**	**0.473**	**0.451**	**0.345**	**0.245**	**0.351**	**0.460**	**0.595**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.559	0.456	0.460	0.460	0.595
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	-0.009	-0.215	-0.210	-0.108	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.572**	**4.589**	**4.820**	**5.013**	**5.020**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.654	3.884	4.039	4.042
Oman	0.325	0.406	0.413	0.413	0.414	0.414	0.440	0.441
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
United Arab Emirates	0.252	0.273	0.226	0.222	0.227	0.227	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.285	0.294	0.294	0.295	0.295
Africa	**1.607**	**2.062**	**1.682**	**1.438**	**1.891**	**2.171**	**2.177**	**2.206**
Algeria	0.907	0.682	0.807	0.607	0.807	0.816	0.817	0.818
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.690	0.471	0.698	0.914	0.918	0.921
Other Africa	0.031	0.194	0.185	0.360	0.386	0.442	0.442	0.467
Asia & Oceania	**-1.413**	**-2.957**	**-4.508**	**-4.366**	**-5.095**	**-6.601**	**-7.570**	**-8.357**
Australia	0.524	0.895	2.506	3.969	4.590	4.595	4.603	4.610
China	0.000	-0.444	-1.561	-2.666	-3.544	-3.801	-3.321	-3.094
India	-0.208	-0.421	-0.871	-0.967	-1.169	-1.702	-2.696	-3.788
Indonesia	1.111	1.107	0.828	1.243	1.287	1.287	1.290	1.420
Japan	-2.789	-3.426	-3.974	-4.117	-4.004	-3.902	-3.953	-3.913
Malaysia	1.007	1.078	1.085	1.257	1.258	1.258	1.259	1.260
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	-0.190	-0.532	-0.941	-1.420
Singapore	0.000	0.000	-0.100	-0.101	-0.100	-0.099	-0.100	-0.100
South Korea	-1.049	-1.541	-2.256	-2.742	-2.937	-3.085	-3.120	-3.070
Thailand	0.000	0.000	-0.083	-0.084	-0.083	-0.083	-0.083	-0.176
Other Asia & Oceania	-0.008	-0.205	-0.081	-0.157	-0.205	-0.537	-0.509	-0.086
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG12_Ref Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.398**	**1.628**	**1.989**	**2.607**	**4.259**	**4.644**
Canada	0.000	-0.072	-0.095	-0.089	-0.088	-0.012	0.266	0.270
Mexico	0.000	-0.198	-0.250	-0.253	-0.250	-0.255	-0.083	0.288
United States	-0.551	-0.366	-0.053	1.969	2.326	2.874	4.075	4.086
Central & South America	**0.463**	**0.464**	**0.403**	**0.148**	**0.358**	**0.351**	**0.356**	**0.356**
Argentina	0.000	-0.062	-0.090	-0.091	-0.090	-0.092	-0.094	-0.094
Brazil	0.000	-0.096	-0.112	-0.113	-0.111	-0.114	-0.116	-0.117
Chile	0.000	-0.106	-0.160	-0.199	-0.197	-0.201	-0.205	-0.206
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.182	0.183	0.204	0.207
Trinidad and Tobago	0.495	0.719	0.664	0.499	0.724	0.731	0.733	0.734
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.130	-0.149	-0.157	-0.166	-0.168
Europe	**-1.640**	**-2.856**	**-2.159**	**-2.887**	**-2.401**	**-2.060**	**-2.111**	**-2.122**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.093	-0.094	-0.093	-0.095	-0.098	-0.099
France	-0.442	-0.483	-0.384	-0.438	-0.431	-0.390	-0.399	-0.401
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.063	-0.064	-0.064
Italy	-0.086	-0.315	-0.132	-0.402	-0.275	-0.124	-0.127	-0.127
Netherlands	0.000	0.000	-0.143	-0.144	-0.143	-0.145	-0.149	-0.149
Norway	0.000	0.166	0.184	0.165	0.184	0.185	0.185	0.185
Poland	0.000	0.000	0.000	-0.145	-0.142	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.117	-0.119	-0.117	-0.120	-0.122	-0.123
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.661	-0.668	-0.660	-0.674	-0.689	-0.693
Turkey	-0.168	-0.275	-0.144	-0.279	-0.058	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.425	-0.430	-0.425	-0.433	-0.443	-0.445
Other Europe	-0.016	-0.041	-0.182	-0.272	-0.181	-0.185	-0.189	-0.190
Eurasia	**0.000**	**0.473**	**0.460**	**0.276**	**0.444**	**0.602**	**0.602**	**0.603**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.487	0.565	0.602	0.602	0.603
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.211	-0.121	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.551**	**4.585**	**4.715**	**5.015**	**5.018**	**5.022**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.776	4.040	4.044	4.048
Oman	0.325	0.406	0.413	0.413	0.415	0.441	0.441	0.442
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.226	0.228	0.239	0.238	0.238
Other Middle East	0.000	0.097	0.258	0.294	0.295	0.295	0.294	0.294
Africa	**1.607**	**2.062**	**1.702**	**1.569**	**2.168**	**2.180**	**2.441**	**2.959**
Algeria	0.907	0.682	0.815	0.678	0.816	0.819	0.957	1.064
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.702	0.502	0.910	0.917	0.921	0.946
Other Africa	0.031	0.194	0.185	0.389	0.442	0.443	0.562	0.949
Asia & Oceania	**-1.413**	**-2.957**	**-4.558**	**-5.319**	**-7.273**	**-8.695**	**-10.564**	**-11.464**
Australia	0.524	0.895	2.506	4.299	4.594	4.609	4.718	5.520
China	0.000	-0.444	-1.554	-3.653	-5.407	-6.754	-7.748	-8.004
India	-0.208	-0.421	-0.866	-0.993	-1.404	-1.723	-2.265	-3.328
Indonesia	1.111	1.107	0.896	1.282	1.289	1.316	1.454	1.470
Japan	-2.789	-3.426	-4.145	-4.475	-4.319	-4.221	-4.253	-4.033
Malaysia	1.007	1.078	1.087	1.257	1.259	1.481	1.505	1.505
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	-0.083	-0.685	-1.391
Singapore	0.000	0.000	-0.098	-0.099	-0.098	-0.100	-0.103	-0.103
South Korea	-1.049	-1.541	-2.226	-2.681	-2.870	-2.997	-3.073	-2.992
Thailand	0.000	0.000	-0.082	-0.083	-0.082	-0.084	-0.085	-0.086
Other Asia & Oceania	-0.008	-0.205	-0.075	-0.174	-0.235	-0.140	-0.029	-0.022
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG12_HRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.952**	**1.987**	**3.309**	**5.746**	**6.470**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.068	0.233	0.273
Mexico	0.000	-0.198	-0.253	-0.254	-0.253	-0.253	-0.164	0.246
United States	-0.551	-0.366	-0.054	2.295	2.328	3.629	5.677	5.951
Central & South America	**0.463**	**0.464**	**0.422**	**0.202**	**0.359**	**0.361**	**0.360**	**0.369**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.200	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.182	0.183	0.200	0.205
Trinidad and Tobago	0.495	0.719	0.689	0.553	0.729	0.731	0.732	0.734
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.129	-0.149	-0.151	-0.168	-0.167
Europe	**-1.640**	**-2.856**	**-2.155**	**-2.918**	**-2.247**	**-2.040**	**-2.041**	**-2.040**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.095	-0.094
France	-0.442	-0.483	-0.388	-0.440	-0.402	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.063	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.403	-0.241	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.145	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.141	0.184	0.185	0.185	0.185
Poland	0.000	0.000	0.000	-0.146	-0.072	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.670	-0.668	-0.667	-0.668	-0.667
Turkey	-0.168	-0.275	-0.125	-0.280	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.431	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.268	-0.184	-0.184	-0.184	-0.184
Eurasia	**0.000**	**0.473**	**0.460**	**0.271**	**0.512**	**0.596**	**0.597**	**0.598**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.483	0.562	0.596	0.597	0.598
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.212	-0.051	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.584**	**4.710**	**5.015**	**5.020**	**5.025**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.774	4.039	4.043	4.047
Oman	0.325	0.406	0.413	0.413	0.415	0.441	0.441	0.442
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.226	0.227	0.240	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.295	0.296	0.296
Africa	**1.607**	**2.062**	**1.702**	**1.512**	**2.168**	**2.179**	**2.268**	**2.650**
Algeria	0.907	0.682	0.815	0.639	0.816	0.819	0.836	0.922
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.702	0.490	0.910	0.917	0.919	0.922
Other Africa	0.031	0.194	0.185	0.383	0.442	0.443	0.513	0.806
Asia & Oceania	**-1.413**	**-2.957**	**-4.573**	**-5.603**	**-7.489**	**-9.420**	**-11.950**	**-13.072**
Australia	0.524	0.895	2.506	4.308	4.596	4.609	4.652	5.241
China	0.000	-0.444	-1.520	-3.892	-5.637	-7.409	-8.917	-9.262
India	-0.208	-0.421	-0.831	-0.995	-1.300	-1.649	-2.316	-3.355
Indonesia	1.111	1.107	0.889	1.280	1.287	1.292	1.459	1.460
Japan	-2.789	-3.426	-4.194	-4.505	-4.375	-4.200	-4.201	-3.907
Malaysia	1.007	1.078	1.087	1.257	1.259	1.282	1.282	1.283
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	-0.070	-0.699	-1.358
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.100	-0.100	-0.099
South Korea	-1.049	-1.541	-2.246	-2.695	-2.895	-2.973	-2.988	-2.895
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.082	-0.178	-0.244	-0.120	-0.040	-0.097
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG12_LRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.339**	**1.981**	**2.165**	**2.708**	**3.137**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	0.017	0.273	0.274
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.005	0.407
United States	-0.551	-0.366	-0.054	1.681	2.322	2.401	2.439	2.456
Central & South America	**0.463**	**0.464**	**0.420**	**0.239**	**0.360**	**0.364**	**0.397**	**0.396**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.182	0.183	0.219	0.220
Trinidad and Tobago	0.495	0.719	0.687	0.587	0.729	0.732	0.734	0.735
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.126	-0.147	-0.148	-0.154	-0.156
Europe	**-1.640**	**-2.856**	**-2.155**	**-2.791**	**-2.239**	**-2.041**	**-2.040**	**-2.039**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.095	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.413	-0.400	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.382	-0.237	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.174	0.184	0.185	0.186	0.186
Poland	0.000	0.000	0.000	-0.145	-0.070	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.668	-0.668	-0.667	-0.667
Turkey	-0.168	-0.275	-0.125	-0.276	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.230	-0.184	-0.184	-0.184	-0.184
Eurasia	**0.000**	**0.473**	**0.460**	**0.249**	**0.514**	**0.598**	**0.599**	**0.600**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.562	0.598	0.599	0.600
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.211	-0.049	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.585**	**4.715**	**5.017**	**5.024**	**5.044**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.777	4.040	4.046	4.049
Oman	0.325	0.406	0.413	0.413	0.416	0.441	0.442	0.442
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.226	0.227	0.240	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.296	0.313
Africa	**1.607**	**2.062**	**1.703**	**1.633**	**2.168**	**2.181**	**2.741**	**3.360**
Algeria	0.907	0.682	0.815	0.720	0.816	0.820	1.173	1.267
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.703	0.524	0.909	0.918	0.923	1.001
Other Africa	0.031	0.194	0.185	0.389	0.442	0.444	0.646	1.092
Asia & Oceania	**-1.413**	**-2.957**	**-4.573**	**-5.256**	**-7.499**	**-8.284**	**-9.429**	**-10.497**
Australia	0.524	0.895	2.506	4.488	4.597	4.612	4.911	5.687
China	0.000	-0.444	-1.522	-3.798	-5.653	-6.811	-7.700	-8.134
India	-0.208	-0.421	-0.834	-0.992	-1.298	-1.513	-1.995	-3.080
Indonesia	1.111	1.107	0.898	1.282	1.287	1.348	1.523	1.620
Japan	-2.789	-3.426	-4.197	-4.474	-4.373	-4.179	-4.085	-3.879
Malaysia	1.007	1.078	1.087	1.258	1.259	1.497	1.505	1.506
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	-0.017	-0.564	-1.315
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.100	-0.100	-0.099
South Korea	-1.049	-1.541	-2.246	-2.675	-2.894	-2.952	-2.958	-2.870
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.162	-0.241	-0.087	0.115	0.150
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG12_Hi-D Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.525**	**1.983**	**2.394**	**3.528**	**3.940**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	0.003	0.273	0.274
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.033	0.373
United States	-0.551	-0.366	-0.054	1.867	2.324	2.645	3.287	3.294
Central & South America	**0.463**	**0.464**	**0.420**	**0.219**	**0.361**	**0.360**	**0.393**	**0.392**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.182	0.183	0.219	0.219
Trinidad and Tobago	0.495	0.719	0.688	0.567	0.729	0.732	0.734	0.734
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.127	-0.148	-0.152	-0.157	-0.159
Europe	**-1.640**	**-2.856**	**-2.154**	**-2.825**	**-2.253**	**-2.041**	**-2.039**	**-2.039**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.415	-0.398	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.402	-0.239	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.173	0.184	0.185	0.186	0.186
Poland	0.000	0.000	0.000	-0.145	-0.083	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.668	-0.668	-0.667	-0.667
Turkey	-0.168	-0.275	-0.124	-0.279	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.239	-0.184	-0.184	-0.184	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.249**	**0.509**	**0.597**	**0.598**	**0.599**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.562	0.597	0.598	0.599
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.211	-0.053	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.585**	**4.713**	**5.017**	**5.023**	**5.032**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.777	4.040	4.045	4.048
Oman	0.325	0.406	0.413	0.413	0.415	0.441	0.442	0.442
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.226	0.227	0.240	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.296	0.301
Africa	**1.607**	**2.062**	**1.698**	**1.584**	**2.169**	**2.180**	**2.557**	**3.096**
Algeria	0.907	0.682	0.815	0.693	0.816	0.819	1.046	1.123
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.697	0.502	0.910	0.917	0.921	1.000
Other Africa	0.031	0.194	0.185	0.389	0.442	0.443	0.590	0.973
Asia & Oceania	**-1.413**	**-2.957**	**-4.569**	**-5.337**	**-7.482**	**-8.507**	**-10.059**	**-11.020**
Australia	0.524	0.895	2.506	4.446	4.597	4.612	4.812	5.594
China	0.000	-0.444	-1.521	-3.830	-5.640	-6.964	-8.020	-8.402
India	-0.208	-0.421	-0.830	-0.992	-1.296	-1.539	-2.070	-3.121
Indonesia	1.111	1.107	0.895	1.282	1.288	1.332	1.505	1.570
Japan	-2.789	-3.426	-4.195	-4.479	-4.371	-4.184	-4.096	-3.884
Malaysia	1.007	1.078	1.087	1.258	1.259	1.489	1.505	1.505
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	-0.020	-0.609	-1.327
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.100	-0.099	-0.099
South Korea	-1.049	-1.541	-2.246	-2.678	-2.894	-2.957	-2.965	-2.874
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.162	-0.241	-0.094	0.061	0.101
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_Ref Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.974**	**2.172**	**4.510**	**6.722**	**7.812**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.252
United States	-0.551	-0.366	-0.054	2.315	2.513	4.852	7.063	8.153
Central & South America	**0.463**	**0.464**	**0.435**	**0.324**	**0.386**	**0.398**	**0.442**	**0.455**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.209	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.704	0.661	0.732	0.733	0.772	0.773
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.086	-0.115	-0.126	-0.142	-0.147	-0.136
Europe	**-1.640**	**-2.856**	**-2.124**	**-2.602**	**-2.041**	**-2.039**	**-2.037**	**-2.037**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.414	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.284	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.186	0.187
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.667	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.095	-0.214	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.209	-0.184	-0.184	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.598**	**0.600**	**0.601**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.598	0.600	0.601
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.878**	**5.019**	**5.037**	**5.252**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.906	4.042	4.047	4.053
Oman	0.325	0.406	0.413	0.413	0.441	0.441	0.442	0.443
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.235	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.308	0.516
Africa	**1.607**	**2.062**	**1.725**	**1.804**	**2.177**	**2.300**	**2.845**	**3.049**
Algeria	0.907	0.682	0.815	0.757	0.819	0.896	1.305	1.399
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.724	0.653	0.915	0.920	0.938	1.003
Other Africa	0.031	0.194	0.185	0.393	0.443	0.484	0.602	0.647
Asia & Oceania	**-1.413**	**-2.957**	**-4.641**	**-6.336**	**-8.169**	**-10.787**	**-13.608**	**-15.133**
Australia	0.524	0.895	2.506	4.566	4.608	4.625	4.812	4.881
China	0.000	-0.444	-1.576	-4.895	-6.781	-9.170	-10.955	-11.719
India	-0.208	-0.421	-0.848	-0.991	-1.126	-1.697	-2.578	-3.488
Indonesia	1.111	1.107	0.892	1.283	1.293	1.365	1.526	1.906
Japan	-2.789	-3.426	-4.193	-4.459	-4.276	-4.122	-4.070	-3.829
Malaysia	1.007	1.078	1.087	1.258	1.370	1.505	1.506	1.507
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.527	-1.197
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.243	-2.728	-2.900	-3.005	-3.025	-2.910
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.185	-0.175	-0.107	-0.115	-0.102
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_HRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.980**	**2.394**	**5.225**	**8.318**	**9.898**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	2.322	2.735	5.566	8.659	10.239
Central & South America	**0.463**	**0.464**	**0.421**	**0.300**	**0.387**	**0.370**	**0.392**	**0.396**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.191	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.690	0.637	0.732	0.732	0.734	0.735
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.086	-0.115	-0.125	-0.151	-0.158	-0.156
Europe	**-1.640**	**-2.856**	**-2.119**	**-2.610**	**-2.041**	**-2.039**	**-2.039**	**-2.038**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.409	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.291	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.186	0.186
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.668	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.090	-0.218	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.430	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.210	-0.184	-0.184	-0.184	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.598**	**0.599**	**0.599**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.598	0.599	0.599
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.862**	**5.018**	**5.023**	**5.105**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.895	4.041	4.045	4.050
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.442
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.231	0.240	0.240	0.240
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.296	0.373
Africa	**1.607**	**2.062**	**1.715**	**1.796**	**2.177**	**2.186**	**2.564**	**2.863**
Algeria	0.907	0.682	0.815	0.764	0.819	0.824	1.073	1.286
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.714	0.640	0.915	0.918	0.921	1.001
Other Africa	0.031	0.194	0.185	0.393	0.443	0.444	0.570	0.576
Asia & Oceania	**-1.413**	**-2.957**	**-4.622**	**-6.303**	**-8.376**	**-11.358**	**-14.856**	**-16.823**
Australia	0.524	0.895	2.506	4.558	4.607	4.614	4.710	4.875
China	0.000	-0.444	-1.572	-4.861	-6.902	-9.548	-11.631	-12.447
India	-0.208	-0.421	-0.840	-0.991	-1.132	-1.767	-2.797	-3.932
Indonesia	1.111	1.107	0.893	1.282	1.292	1.295	1.400	1.663
Japan	-2.789	-3.426	-4.189	-4.455	-4.283	-4.150	-4.098	-3.871
Malaysia	1.007	1.078	1.087	1.258	1.331	1.505	1.505	1.505
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.606	-1.300
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.242	-2.727	-2.904	-3.018	-3.045	-2.949
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.082	-0.185	-0.201	-0.106	-0.113	-0.186
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_LRR Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.738**	**2.036**	**3.688**	**5.362**	**6.239**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.252	-0.252
United States	-0.551	-0.366	-0.054	2.079	2.377	4.029	5.703	6.580
Central & South America	**0.463**	**0.464**	**0.439**	**0.344**	**0.381**	**0.432**	**0.454**	**0.521**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.218	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.705	0.683	0.732	0.747	0.773	0.774
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.118	-0.131	-0.130	-0.136	-0.071
Europe	**-1.640**	**-2.856**	**-2.128**	**-2.535**	**-2.041**	**-2.039**	**-2.038**	**-2.004**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.395	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.257	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.187	0.219
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.667	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.098	-0.199	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.204	-0.184	-0.184	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.253**	**0.597**	**0.599**	**0.601**	**0.621**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.462	0.597	0.599	0.601	0.621
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.587**	**4.890**	**5.021**	**5.116**	**5.257**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.653	3.917	4.043	4.049	4.056
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.443
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.237	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.384	0.517
Africa	**1.607**	**2.062**	**1.728**	**1.879**	**2.178**	**2.470**	**3.023**	**3.056**
Algeria	0.907	0.682	0.815	0.807	0.819	1.007	1.397	1.401
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.727	0.680	0.915	0.921	0.985	1.004
Other Africa	0.031	0.194	0.185	0.392	0.443	0.542	0.641	0.651
Asia & Oceania	**-1.413**	**-2.957**	**-4.643**	**-6.265**	**-8.040**	**-10.171**	**-12.518**	**-13.689**
Australia	0.524	0.895	2.506	4.588	4.608	4.647	4.862	4.885
China	0.000	-0.444	-1.571	-4.871	-6.690	-8.772	-10.303	-11.180
India	-0.208	-0.421	-0.848	-0.991	-1.125	-1.617	-2.438	-2.879
Indonesia	1.111	1.107	0.892	1.283	1.293	1.426	1.644	2.047
Japan	-2.789	-3.426	-4.196	-4.446	-4.274	-4.087	-4.044	-3.799
Malaysia	1.007	1.078	1.087	1.258	1.385	1.506	1.507	1.509
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.455	-1.123
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.246	-2.720	-2.898	-2.993	-3.007	-2.885
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.084	-0.184	-0.157	-0.099	-0.102	-0.082
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_Hi-D Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.403**	**1.959**	**2.126**	**4.249**	**6.291**	**7.226**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.252
United States	-0.551	-0.366	-0.054	2.300	2.467	4.590	6.633	7.567
Central & South America	**0.463**	**0.464**	**0.434**	**0.311**	**0.382**	**0.406**	**0.443**	**0.468**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.216	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.700	0.653	0.732	0.733	0.772	0.774
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.121	-0.130	-0.140	-0.146	-0.123
Europe	**-1.640**	**-2.856**	**-2.121**	**-2.584**	**-2.042**	**-2.039**	**-2.038**	**-2.036**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.387	-0.410	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.274	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.144	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.186	0.187
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.667	-0.668	-0.668	-0.667	-0.667	-0.666
Turkey	-0.168	-0.275	-0.094	-0.211	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.430	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.208	-0.184	-0.184	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.598**	**0.600**	**0.612**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.598	0.600	0.612
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.883**	**5.020**	**5.064**	**5.254**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.911	4.042	4.047	4.054
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.443
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.236	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.335	0.517
Africa	**1.607**	**2.062**	**1.726**	**1.813**	**2.178**	**2.357**	**2.941**	**3.053**
Algeria	0.907	0.682	0.815	0.766	0.819	0.935	1.367	1.400
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.725	0.658	0.915	0.920	0.944	1.004
Other Africa	0.031	0.194	0.185	0.389	0.443	0.502	0.630	0.649
Asia & Oceania	**-1.413**	**-2.957**	**-4.644**	**-6.335**	**-8.124**	**-10.591**	**-13.302**	**-14.577**
Australia	0.524	0.895	2.506	4.561	4.608	4.632	4.836	4.883
China	0.000	-0.444	-1.575	-4.892	-6.751	-9.057	-10.809	-11.526
India	-0.208	-0.421	-0.845	-0.991	-1.126	-1.670	-2.514	-3.301
Indonesia	1.111	1.107	0.893	1.283	1.293	1.393	1.555	2.001
Japan	-2.789	-3.426	-4.189	-4.457	-4.277	-4.110	-4.063	-3.815
Malaysia	1.007	1.078	1.087	1.258	1.374	1.506	1.506	1.508
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.504	-1.158
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.100	-0.100	-0.099
South Korea	-1.049	-1.541	-2.242	-2.727	-2.900	-3.001	-3.020	-2.898
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.097	-0.186	-0.162	-0.101	-0.105	-0.089
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_Ref12 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.978**	**2.179**	**3.847**	**3.960**	**3.973**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.252
United States	-0.551	-0.366	-0.054	2.319	2.521	4.188	4.301	4.314
Central & South America	**0.463**	**0.464**	**0.436**	**0.319**	**0.381**	**0.420**	**0.464**	**0.566**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.213	0.220	0.221
Trinidad and Tobago	0.495	0.719	0.703	0.659	0.732	0.742	0.774	0.776
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.118	-0.131	-0.132	-0.127	-0.028
Europe	**-1.640**	**-2.856**	**-2.125**	**-2.580**	**-2.041**	**-2.039**	**-2.023**	**-1.992**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.409	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.275	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.201	0.232
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.667	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.096	-0.208	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.429
Other Europe	-0.016	-0.041	-0.184	-0.207	-0.184	-0.184	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.599**	**0.610**	**0.620**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.599	0.610	0.620
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.882**	**5.020**	**5.197**	**5.264**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.910	4.043	4.051	4.061
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.443	0.444
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.235	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.462	0.519
Africa	**1.607**	**2.062**	**1.714**	**1.803**	**2.177**	**2.422**	**3.049**	**3.062**
Algeria	0.907	0.682	0.815	0.778	0.819	0.989	1.399	1.404
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.713	0.634	0.915	0.920	1.001	1.007
Other Africa	0.031	0.194	0.185	0.392	0.443	0.513	0.649	0.651
Asia & Oceania	**-1.413**	**-2.957**	**-4.629**	**-6.356**	**-8.176**	**-10.269**	**-11.257**	**-11.494**
Australia	0.524	0.895	2.506	4.570	4.608	4.637	4.878	4.894
China	0.000	-0.444	-1.566	-4.926	-6.787	-8.785	-9.566	-9.801
India	-0.208	-0.421	-0.846	-0.991	-1.124	-1.648	-2.278	-2.425
Indonesia	1.111	1.107	0.898	1.284	1.294	1.409	1.839	2.071
Japan	-2.789	-3.426	-4.195	-4.455	-4.273	-4.108	-4.014	-3.744
Malaysia	1.007	1.078	1.087	1.258	1.361	1.506	1.508	1.512
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.358	-0.924
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.245	-2.726	-2.899	-2.996	-2.987	-2.837
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.085	-0.186	-0.174	-0.101	-0.098	-0.055
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_HRR12 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.980**	**2.364**	**3.915**	**3.963**	**3.975**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	2.322	2.706	4.257	4.304	4.317
Central & South America	**0.463**	**0.464**	**0.432**	**0.320**	**0.381**	**0.424**	**0.471**	**0.566**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.215	0.220	0.221
Trinidad and Tobago	0.495	0.719	0.699	0.658	0.732	0.744	0.774	0.776
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.117	-0.130	-0.131	-0.121	-0.028
Europe	**-1.640**	**-2.856**	**-2.128**	**-2.584**	**-2.041**	**-2.040**	**-2.021**	**-1.995**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.095
France	-0.442	-0.483	-0.388	-0.407	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.281	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.206	0.232
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.669	-0.668	-0.668	-0.668	-0.668	-0.668
Turkey	-0.168	-0.275	-0.098	-0.207	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.207	-0.184	-0.184	-0.184	-0.184
Eurasia	**0.000**	**0.473**	**0.460**	**0.251**	**0.597**	**0.599**	**0.611**	**0.629**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.461	0.597	0.599	0.611	0.629
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.587**	**4.869**	**5.020**	**5.190**	**5.264**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.898	4.043	4.051	4.061
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.443	0.444
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.236	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.456	0.519
Africa	**1.607**	**2.062**	**1.718**	**1.812**	**2.177**	**2.419**	**3.051**	**3.066**
Algeria	0.907	0.682	0.815	0.774	0.819	0.977	1.399	1.404
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.718	0.648	0.915	0.921	1.002	1.007
Other Africa	0.031	0.194	0.185	0.390	0.443	0.521	0.650	0.655
Asia & Oceania	**-1.413**	**-2.957**	**-4.627**	**-6.366**	**-8.348**	**-10.336**	**-11.265**	**-11.506**
Australia	0.524	0.895	2.506	4.567	4.607	4.640	4.878	4.894
China	0.000	-0.444	-1.567	-4.934	-6.900	-8.845	-9.604	-9.824
India	-0.208	-0.421	-0.844	-0.992	-1.128	-1.651	-2.271	-2.430
Indonesia	1.111	1.107	0.896	1.284	1.294	1.410	1.866	2.101
Japan	-2.789	-3.426	-4.194	-4.454	-4.280	-4.106	-4.016	-3.749
Malaysia	1.007	1.078	1.087	1.258	1.340	1.506	1.509	1.512
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.349	-0.923
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.100
South Korea	-1.049	-1.541	-2.245	-2.726	-2.904	-2.996	-2.988	-2.840
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.084	-0.186	-0.194	-0.111	-0.108	-0.066
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_LRR12 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.758**	**2.040**	**3.440**	**3.958**	**3.970**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.088	-0.088
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.251	-0.251
United States	-0.551	-0.366	-0.054	2.099	2.381	3.781	4.297	4.309
Central & South America	**0.463**	**0.464**	**0.436**	**0.331**	**0.380**	**0.441**	**0.466**	**0.564**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.090	-0.090
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.112	-0.112
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.198	-0.198
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.219	0.221	0.222
Trinidad and Tobago	0.495	0.719	0.702	0.671	0.732	0.756	0.774	0.776
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.118	-0.132	-0.131	-0.128	-0.033
Europe	**-1.640**	**-2.856**	**-2.129**	**-2.524**	**-2.041**	**-2.039**	**-2.013**	**-1.983**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.395	-0.387	-0.387	-0.385	-0.385
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.253	-0.123	-0.123	-0.122	-0.122
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.201	0.232
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.118	-0.118
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.669	-0.668	-0.668	-0.667	-0.664	-0.664
Turkey	-0.168	-0.275	-0.099	-0.199	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.428	-0.428
Other Europe	-0.016	-0.041	-0.184	-0.197	-0.184	-0.183	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.256**	**0.597**	**0.599**	**0.610**	**0.625**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.466	0.597	0.599	0.610	0.625
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.587**	**4.891**	**5.021**	**5.199**	**5.265**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.653	3.919	4.044	4.051	4.061
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.444
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.236	0.240	0.241	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.464	0.519
Africa	**1.607**	**2.062**	**1.727**	**1.878**	**2.178**	**2.530**	**3.050**	**3.062**
Algeria	0.907	0.682	0.815	0.807	0.819	1.054	1.399	1.404
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.727	0.677	0.915	0.921	1.002	1.007
Other Africa	0.031	0.194	0.185	0.394	0.443	0.555	0.649	0.651
Asia & Oceania	**-1.413**	**-2.957**	**-4.639**	**-6.285**	**-8.046**	**-9.992**	**-11.269**	**-11.503**
Australia	0.524	0.895	2.506	4.588	4.608	4.653	4.878	4.895
China	0.000	-0.444	-1.573	-4.894	-6.717	-8.661	-9.628	-9.848
India	-0.208	-0.421	-0.848	-0.990	-1.122	-1.584	-2.277	-2.431
Indonesia	1.111	1.107	0.897	1.283	1.293	1.440	1.854	2.115
Japan	-2.789	-3.426	-4.197	-4.445	-4.271	-4.080	-4.000	-3.730
Malaysia	1.007	1.078	1.087	1.258	1.394	1.507	1.508	1.512
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.356	-0.957
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.246	-2.719	-2.896	-2.988	-2.974	-2.826
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.183	-0.153	-0.097	-0.092	-0.051
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_Hi-D12 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.962**	**2.125**	**3.724**	**3.962**	**3.974**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.088	-0.088	-0.088
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.252	-0.251	-0.251
United States	-0.551	-0.366	-0.054	2.304	2.467	4.065	4.301	4.313
Central & South America	**0.463**	**0.464**	**0.431**	**0.316**	**0.382**	**0.428**	**0.467**	**0.563**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.090	-0.090
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.112	-0.112
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.198	-0.198
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.215	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.698	0.655	0.732	0.746	0.774	0.776
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.083	-0.117	-0.130	-0.132	-0.126	-0.033
Europe	**-1.640**	**-2.856**	**-2.128**	**-2.577**	**-2.041**	**-2.036**	**-2.013**	**-1.978**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.387	-0.409	-0.387	-0.386	-0.384	-0.384
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.274	-0.123	-0.123	-0.122	-0.122
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.143	-0.143
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.197	0.232
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.118	-0.118
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.667	-0.666	-0.663	-0.662
Turkey	-0.168	-0.275	-0.098	-0.207	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.430	-0.430	-0.430	-0.429	-0.427	-0.427
Other Europe	-0.016	-0.041	-0.184	-0.207	-0.184	-0.183	-0.182	-0.182
Eurasia	**0.000**	**0.473**	**0.456**	**0.248**	**0.597**	**0.599**	**0.610**	**0.622**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.456	0.458	0.597	0.599	0.610	0.622
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.887**	**5.021**	**5.203**	**5.265**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.915	4.043	4.051	4.061
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.443	0.444
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.237	0.240	0.241	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.468	0.519
Africa	**1.607**	**2.062**	**1.727**	**1.834**	**2.178**	**2.459**	**3.048**	**3.058**
Algeria	0.907	0.682	0.815	0.773	0.819	1.009	1.399	1.404
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.727	0.668	0.916	0.920	1.002	1.007
Other Africa	0.031	0.194	0.185	0.393	0.443	0.529	0.647	0.647
Asia & Oceania	**-1.413**	**-2.957**	**-4.633**	**-6.369**	**-8.129**	**-10.194**	**-11.276**	**-11.504**
Australia	0.524	0.895	2.506	4.561	4.608	4.644	4.878	4.894
China	0.000	-0.444	-1.567	-4.929	-6.773	-8.773	-9.608	-9.824
India	-0.208	-0.421	-0.845	-0.991	-1.124	-1.625	-2.276	-2.425
Indonesia	1.111	1.107	0.892	1.283	1.293	1.419	1.823	2.076
Japan	-2.789	-3.426	-4.195	-4.456	-4.272	-4.091	-3.991	-3.723
Malaysia	1.007	1.078	1.087	1.258	1.381	1.506	1.508	1.512
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.362	-0.962
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.099	-0.099
South Korea	-1.049	-1.541	-2.245	-2.727	-2.898	-2.989	-2.969	-2.821
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.082	-0.082
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.186	-0.162	-0.102	-0.097	-0.051
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_Ref20 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.977**	**2.188**	**4.475**	**6.364**	**6.530**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.252
United States	-0.551	-0.366	-0.054	2.319	2.529	4.816	6.706	6.871
Central & South America	**0.463**	**0.464**	**0.435**	**0.318**	**0.380**	**0.404**	**0.451**	**0.494**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.206	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.704	0.658	0.732	0.733	0.772	0.774
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.085	-0.119	-0.132	-0.133	-0.138	-0.097
Europe	**-1.640**	**-2.856**	**-2.122**	**-2.584**	**-2.041**	**-2.039**	**-2.039**	**-2.036**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.095	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.408	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.278	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.186	0.187
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.668	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.092	-0.209	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.429
Other Europe	-0.016	-0.041	-0.184	-0.208	-0.184	-0.184	-0.184	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.598**	**0.600**	**0.620**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.598	0.600	0.620
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.878**	**5.020**	**5.063**	**5.256**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.907	4.042	4.047	4.055
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.443
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.235	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.334	0.517
Africa	**1.607**	**2.062**	**1.714**	**1.788**	**2.178**	**2.319**	**2.929**	**3.051**
Algeria	0.907	0.682	0.815	0.766	0.819	0.914	1.359	1.400
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.714	0.631	0.916	0.920	0.938	1.004
Other Africa	0.031	0.194	0.185	0.391	0.443	0.485	0.632	0.647
Asia & Oceania	**-1.413**	**-2.957**	**-4.632**	**-6.334**	**-8.180**	**-10.775**	**-13.368**	**-13.916**
Australia	0.524	0.895	2.506	4.565	4.608	4.629	4.828	4.885
China	0.000	-0.444	-1.568	-4.896	-6.791	-9.178	-10.843	-11.268
India	-0.208	-0.421	-0.845	-0.991	-1.127	-1.699	-2.535	-2.994
Indonesia	1.111	1.107	0.893	1.283	1.293	1.372	1.555	2.029
Japan	-2.789	-3.426	-4.194	-4.457	-4.277	-4.117	-4.069	-3.804
Malaysia	1.007	1.078	1.087	1.258	1.368	1.506	1.506	1.508
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.502	-1.124
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.100	-0.099	-0.099
South Korea	-1.049	-1.541	-2.245	-2.728	-2.901	-3.003	-3.024	-2.889
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.084	-0.185	-0.172	-0.102	-0.102	-0.077
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

LNG20_HRR20 Case (Net LNG Exports)(tcf)

	2005	2010	2015	2020	2025	2030	2035	2040
North America	**-0.551**	**-0.637**	**-0.404**	**1.980**	**2.398**	**5.086**	**6.772**	**6.865**
Canada	0.000	-0.072	-0.096	-0.089	-0.089	-0.089	-0.089	-0.089
Mexico	0.000	-0.198	-0.253	-0.253	-0.253	-0.253	-0.253	-0.253
United States	-0.551	-0.366	-0.054	2.322	2.739	5.427	7.113	7.206
Central & South America	**0.463**	**0.464**	**0.435**	**0.314**	**0.378**	**0.383**	**0.446**	**0.498**
Argentina	0.000	-0.062	-0.091	-0.091	-0.091	-0.091	-0.091	-0.091
Brazil	0.000	-0.096	-0.113	-0.113	-0.113	-0.113	-0.113	-0.113
Chile	0.000	-0.106	-0.162	-0.199	-0.199	-0.199	-0.199	-0.199
Colombia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Peru	0.000	0.064	0.183	0.182	0.183	0.192	0.220	0.220
Trinidad and Tobago	0.495	0.719	0.702	0.657	0.732	0.733	0.772	0.774
Venezuela	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Central & South America	-0.032	-0.055	-0.084	-0.121	-0.134	-0.139	-0.143	-0.093
Europe	**-1.640**	**-2.856**	**-2.127**	**-2.599**	**-2.041**	**-2.040**	**-2.038**	**-2.038**
Austria	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Belgium	-0.103	-0.203	-0.095	-0.095	-0.094	-0.094	-0.094	-0.094
France	-0.442	-0.483	-0.388	-0.410	-0.387	-0.387	-0.387	-0.387
Germany	0.000	0.000	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Italy	-0.086	-0.315	-0.123	-0.288	-0.123	-0.123	-0.123	-0.123
Netherlands	0.000	0.000	-0.145	-0.144	-0.144	-0.144	-0.144	-0.144
Norway	0.000	0.166	0.184	0.181	0.185	0.186	0.186	0.187
Poland	0.000	0.000	0.000	-0.144	0.000	0.000	0.000	0.000
Portugal	-0.054	-0.104	-0.119	-0.119	-0.119	-0.119	-0.119	-0.119
Romania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Spain	-0.753	-0.955	-0.668	-0.668	-0.667	-0.667	-0.667	-0.667
Turkey	-0.168	-0.275	-0.097	-0.211	-0.015	-0.015	-0.015	-0.015
United Kingdom	-0.018	-0.647	-0.431	-0.430	-0.430	-0.430	-0.430	-0.430
Other Europe	-0.016	-0.041	-0.184	-0.208	-0.184	-0.184	-0.183	-0.183
Eurasia	**0.000**	**0.473**	**0.460**	**0.250**	**0.597**	**0.598**	**0.599**	**0.619**
Kazakhstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	0.000	0.473	0.460	0.460	0.597	0.598	0.599	0.619
Turkmenistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ukraine	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uzbekistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Eurasia	0.000	0.000	0.000	-0.210	0.000	0.000	0.000	0.000
Middle East	**1.534**	**3.450**	**4.549**	**4.586**	**4.863**	**5.018**	**5.053**	**5.255**
Iran	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Qatar	0.957	2.674	3.653	3.652	3.894	4.041	4.047	4.054
Oman	0.325	0.406	0.413	0.414	0.441	0.441	0.442	0.443
Saudi Arabia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Arab Emirates	0.252	0.273	0.227	0.227	0.233	0.240	0.240	0.241
Other Middle East	0.000	0.097	0.257	0.294	0.295	0.296	0.325	0.517
Africa	**1.607**	**2.062**	**1.709**	**1.786**	**2.177**	**2.217**	**2.853**	**3.057**
Algeria	0.907	0.682	0.815	0.772	0.819	0.845	1.304	1.400
Egypt	0.245	0.343	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.425	0.844	0.709	0.624	0.915	0.919	0.933	1.004
Other Africa	0.031	0.194	0.185	0.390	0.443	0.453	0.616	0.653
Asia & Oceania	**-1.413**	**-2.957**	**-4.621**	**-6.318**	**-8.372**	**-11.263**	**-13.686**	**-14.256**
Australia	0.524	0.895	2.506	4.560	4.607	4.615	4.810	4.884
China	0.000	-0.444	-1.561	-4.877	-6.904	-9.473	-11.053	-11.356
India	-0.208	-0.421	-0.843	-0.992	-1.134	-1.783	-2.564	-3.182
Indonesia	1.111	1.107	0.893	1.284	1.294	1.318	1.532	2.005
Japan	-2.789	-3.426	-4.193	-4.456	-4.282	-4.146	-4.072	-3.812
Malaysia	1.007	1.078	1.087	1.258	1.335	1.505	1.506	1.508
Myanmar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pakistan	0.000	0.000	0.000	0.000	0.000	0.000	-0.526	-1.139
Singapore	0.000	0.000	-0.100	-0.100	-0.100	-0.099	-0.100	-0.099
South Korea	-1.049	-1.541	-2.244	-2.727	-2.905	-3.013	-3.027	-2.896
Thailand	0.000	0.000	-0.083	-0.083	-0.083	-0.083	-0.083	-0.083
Other Asia & Oceania	-0.008	-0.205	-0.083	-0.186	-0.200	-0.104	-0.109	-0.084
World	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**