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THE ENERGY DIMENSION IN RUSSIAN GLOBAL STRATEGY

RUSSIAN NATURAL GAS SUPPLY: SOME IMPLICATIONS FOR JAPAN

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Abstract

The paper presents a spatial and intertemporal equilibrium model of the world market for natural gas over the next three decades. Specifically, the model calculates a pattern of production, transportation routes and prices to equate demands and supplies while maximizing the present value of producer rents within a competitive framework. Data incorporated into the specifications of supplies and demands in each location were taken from a variety of sources including the *United States Geological Survey*, the *Energy Information Administration*, the *OECD*, the *International Energy Agency* and various industry sources. We illustrate how the model can be used to examine the implications for Japan of increased exploitation of Russian natural gas resources, including the economic consequences of alternative political scenarios.

Introduction

In this paper, we examine the potential future development of a world market for natural gas, with a particular focus on Russia as a supplier and Japan as a major consumer. An important context for the analysis is that the demand for natural gas is expanding throughout the world while much of current production is coming from mature basins in the United States and the North Sea.[1] Russia, on the other hand, has substantial proved reserves and great potential for further discoveries. Within this context, we consider the potential market share for Russian gas in Asia, taking into account global and regional trends in natural gas demand and supply and the development of transportation between regions. We also consider scenarios under which political factors drive a different level of usage of Russian gas in Asia than might otherwise have been promoted by strictly commercial forces.

Natural gas is an important fuel in Japan. The share of natural gas in Japanese primary energy consumption has steadily increased over the last two decades from 6.4% in 1980 to 12.7% in 2002. An increasing reliance upon natural gas as a source of energy in Japan has been motivated

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[1] Reported reserves in the U.S. have actually increased in each of the past few years. However, much of the increase has been in deposits that typically produce at lower rates of production, such as coal bed methane in the Rocky Mountains. Lower production rates, *ceteris paribus*, will generally distribute cash flows more evenly over the life of the well and raise per unit costs, thus lowering the NPV of such deposits. This is one reason firms opt for conventional plays over non-conventional plays… their returns are greater in the first few years of production due to higher production rates and, accordingly, their NPV's are higher. As such, as unconventional deposits are increasingly tapped, the long run market price must be higher to justify the capital outlay.

in part by government policy to diversify sources of energy supply. Still, Japan's natural gas use is considerably lower than the world average at 23.0% of total primary energy.

For the world as a whole, natural gas has increased from slightly below 19% of primary energy demand in 1980, to slightly above 23% in 2002.[2] Natural gas is now produced and consumed in 43 countries around the world. The *International Energy Agency* (IEA, 2004) predicts that world natural gas demand will be about 90% higher by 2030. They also project the share of gas in world primary energy demand to increase from 23% in 2002 to 25% in 2030, with gas potentially overtaking coal as the world's second largest energy source. Moreover, the IEA predicts that the power sector will account for 60% of the increase in gas demand.

On the supply side of the natural gas market, Russia currently accounts for almost one quarter of world production of natural gas, second only to the United States. This proportion is expected to increase in coming decades. Russia and the countries of the former Soviet Union[3] rank first globally in undiscovered natural gas potential.[4] These countries already export considerable quantities of natural gas to Europe, and they are expected to become important suppliers to the growing needs in Asia. Strategically, Russian natural gas supplies could become an important source of diversification, particularly for Japan, China and South Korea, from dependence on energy supplies from the Persian Gulf. More generally, increased volumes of Russian gas to Asia could have considerable ramifications for liquefied natural gas (LNG) pricing to Asia.

European demand for natural gas currently totals more than 18 trillion cubic feet (tcf) per year. As natural gas production in the U.K. North Sea declines, Russian market share could rise from around 28% in 2005 to 40% in 2015, according to some analyst projections.[5] The Russian state-monopoly Gazprom supplied European countries with 4.8 tcf of gas in 2003, and contractual obligations portend an increase to 6.6 tcf by 2010. To meet rising European demand for gas, Russia will need to expand development of natural gas fields and associated export routes on the Yamal peninsula and Shtokmanovskoye region.

[2] Figures are based on Energy Information Administration (EIA, 2004).
[3] Hereafter, these countries will be referred to collectively as the FSU.
[4] United States Geologic Survey, *World Resource Assessment, 2000.*
[5] U.S.-Russia Commercial Energy Summit Executive Seminar "The Strategic and Geopolitical Implications Of Russian Energy Supply, Security and Pricing", June 2003, available at www.bakerinstitute.org.

It has also been proposed that Russia build natural gas pipelines to China and South Korea from producing areas in East Siberia and to Japan and South Korea from the Sakhalin Islands. Gazprom estimates that the Russian Republic of Sakha/Yakutia and East Siberian gas reserves total about 230 tcf and has a production potential of at least 2 tcf per year. Other estimates put probable reserves for the Russian Far East at 50 to 65 tcf for the Sakhalin Islands, 35 tcf for Yakutia and 50 to 105 tcf for East Siberia.[6]

In October 2004, the Russian government officially announced the merger of Gazprom and state oil concern Rosneft in the creation of a major state-controlled oil and gas giant, Gazpromneft. Gazprom and Rosneft had already established alliances at a number of fields in northern Russia and East Siberia, including the development, together with Surgutneftegas, of the Talakanskoye field, which is thought to hold up to 800 bcf of natural gas. In addition to the Russian government-led project, TNK-BP, through its major shareholding in Rusia Petroleum, has been striving to develop the Kovykta gas field, which is estimated to hold 70 tcf of gas. TNK-BP has been lobbying for an $18 billion development plan for the field but has met resistance from Gazprom, which has criticized the project as "economically unrealistic," adding "domestic markets could be more attractive because of uncertainty about Asian gas prices." [7] Some analysts believe Gazprom's ongoing talks with Rusia Petroleum, initiated after the Russian government announced that Gazprom should be involved in coordinating all gas exports from East Siberia to Asia, are designed to gain a large stake in the project at more preferential terms. Gazprom and Rusia agreed in 2003 to cooperate in East Siberian gas development.

TNK-BP has expressed a willingness to work jointly with Gazprom at Kovykta, and Gazprom is seeking a controlling interest in the project, which calls for 420 bcf per year to be shipped by pipeline to China beginning in 2008, increasing to 700 bcf by 2013.[8] The pipeline could also potentially supply South Korea with 350 bcf per year. Project development, however, remains clouded by a series of negative reports about TNK-BP, including review of compliance with the

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[6] Troner, Alan, "Japan and The Russian Far East: The Economics and Competitive Impact of Least Cost Gas Imports", Baker Institute working paper, available at www.bakerinstitute.org.
[7] Reported in *Energy Compass* in "Russia: TNK-BP come under pressure", July 11, 2004. The article also reports that TNK-BP has decided to use Kovytka gas to first supply the Irkutsk region. It may be significant that Gazprom also has a South Kovytka gas field with 10 tcf of reserves. The Natural Resources Ministry has given Gazprom a 5 year license to explore for more reserves in this area.
[8] "Gazprom in Showdown over Kovykta Sales" Petroleum Intelligence Weekly, June 21, 2004

terms of the license and an investigation by the FSB into divulging reserve data, which is considered a state secret.[9]

Most recently, following its merger with Rosneft, Gazprom has indicated that it intends to give priority to Sakhalin over Kovytka in developing resources to export to China and South Korea. The newly merged Russian firm has also signed a cooperation agreement with Statoil of Norway to participate in development of the Snohvit field in the Norwegian sector of the Barents Sea in exchange for Statoil receiving a larger share in the Shtokman field on the Russian side.[10] Both fields are to be developed for LNG exports, potentially to the Cove Point LNG regasification terminal in the U.S., where Statoil currently has capacity rights for 250 mmcf per day and has indicated a desire to expand the facility. Gazprom also has signed a memorandum of understanding with PetroCanada to bring natural gas to North America as LNG.

A consortium led by Royal Dutch Shell has announced that it will be building a major LNG liquefaction facility on the Sakhalin Islands. The expected primary consuming markets for Sakhalin LNG are in Japan and South Korea, with potential delivery to China and the U.S. West Coast. Royal Dutch Shell's $10 billion Sakhalin energy project is expected to export 234 bcf per year of LNG by 2007, increasing to 468 bcf in the next decade. The Shell consortium Sakhalin-2 block is said to contain up to 16 tcf of natural gas. Another consortium, led by ExxonMobil and including Gazpromneft, is developing the Sakhalin-1 project. This project could supply Japan, via pipeline, with up to 300 bcf of natural gas per year, and recently, there have been indications that China could also become a destination market. The Sakhalin-1 area is said to contain as much as 14 tcf of natural gas.[11] Several other consortiums also have plans to develop other Sakhalin projects in the future. For example, in return for bringing Gazprom into Sakhalin-2, Shell may receive acreage in Sakhalin-3 when it is re-tendered next year.[12] Gazpromneft also has a 51% stake in a joint venture with BP to develop Sakhalin-5 acreage.

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[9] "Gazprom Lays On Pressure in Talks to Join Kovykta Gas Project", *International Oil Daily*, January 30, 2004.
[10] Gorst, Isabel, "Putin Supports Plan to Merge Gazprom, Rosneft" Platt's Oil Gram News, Vol. 82, No. 177, p. 2 September 15, 2004
[11] Troner, op cit and Hartley and Brito, "Using Sakhalin Natural Gas in Japan", Baker Institute working paper available at www.bakerinstitute.org.
[12] "Sakhalin-2 to Expand –With Gazprom Aboard" World Gas Intelligence, October 13, 2004

With such a large number of potential Russia gas export projects, it is useful to examine the place of Russian natural gas in a future global market. Until recently, natural gas markets around the world have been for the most part isolated from each other. Limited availability of regasification, shipping, and liquefaction capacity, as well as prohibitive costs, have limited the exploitation of remote gas deposits and inhibited the flow of liquefied natural gas (LNG) from one region of the globe to another. In the last few years, however, many of the costs associated with the movement of LNG to distant markets have fallen just as the global demand for natural gas has expanded considerably. Both of these developments have encouraged expansion of LNG trade and the diversion of LNG cargoes from one market to another based on price arbitrage opportunities.

Japan is currently the largest importer of LNG, consuming close to two-thirds of all LNG traded worldwide. South Korea is the second largest importer. Although LNG represented roughly 5% of world natural gas consumption in the 1990s, this is expected to change as supplies from mature producing basins in the industrialized West begin to dwindle. Increasingly, Western markets will pull on supplies from around the globe, encouraging growth in the trade of LNG. Such growth will increasingly connect previously isolated markets, which in turn will allow market disturbances in one region to be transmitted to other regions by altering natural gas flows.

LNG imports are likely to be stimulated by expanding demand, particularly in the electricity sector. High growth in the demand for primary energy in China and India is also expected to stimulate the demand for greater LNG trade. As geographic natural gas markets become more tightly linked by the expanding trade in LNG, Japanese and Asian gas prices will be increasingly influenced by global, rather than regional, trends. To examine the complex dynamics of rising gas imports in Asia and the U.S. and increased Russian supply, we rely on the construction of a world gas trade model.

The Baker Institute World Gas Trade Model

The Baker Institute World Gas Trade Model (BIWGTM) provides a framework for examining the effects of critical economic and political influences on the global natural gas market within a framework grounded in geologic data and economic theory. The resource data underlying the model is based on an assessment produced by the United States Geological Survey (USGS). That supply data is combined with economic models of the demand for natural gas, which include important determinants of natural gas use such as the level of economic development, the price of natural gas, the price of competing fuels, and population growth. The costs of constructing new pipelines and LNG facilities have been estimated using data on previously completed projects available from the U.S. Energy Information Administration (EIA).

The extent of regional detail has been chosen on the basis of the questions posed in the study. In addition, the absence of suitable data in some regions has constrained the level of regional detail. For large markets, such as China, the U.S., India and Japan, sub-regional detail has been created to gain more accurate results. In these cases, *intra*-country capacity constraints could have a significant effect on the current or likely future overall pattern of world trade in natural gas.

The BIWGTM is a dynamic spatial general equilibrium model. The solution algorithm is based on the software platform *Market Builder* from *Altos Management Partners*, a flexible modeling system widely used in industry. The software calculates a dynamic spatial equilibrium[13] where supply and demand is balanced at each location in each time period such that all spatial and temporal arbitrage opportunities are eliminated.[14] The model thus seeks equilibrium in which supply, demand, and transportation links are developed over time to maximize the net present value of new supply and transportation projects while simultaneously accounting for the impact of these new developments on current and future prices. Output from the model includes regional natural gas prices, pipeline and LNG capacity additions and flows, growth in natural gas reserves from existing fields and undiscovered deposits, and regional production and demand.

Transportation links connecting markets transmit price signals as well as volumes of physical commodity. Thus, building a new link to take gas to a market with high prices will raise prices to consumers from the exporting region and lower prices in the importing region. More

[13] However, the solution need not be economically efficient. It would be if all capital and other costs represented true "opportunity costs." A monopoly supplier might earn an excess rate of return on natural gas deposits by delaying developing supply for some period. The excess returns on capital invested in gas production would then result in an inefficient allocation of resources.

[14] The absence of intertemporal arbitrage opportunities within the model period is a necessary but not a sufficient condition for maximizing the present value from resource supply. Since future exploitation is always an alternative to current production, a maximizing solution also requires that a value of the resource beyond the model time horizon be specified. In our model, the required additional conditions are obtained by assuming that a "backstop" technology ultimately limits the price at which natural gas can be sold.

generally, it is in this manner that markets become increasingly connected over time as profitable spatial arbitrage opportunities are exploited until they are eliminated. In a *global* natural gas market as predicted by the BIWGTM, events in one region of the world generally influence all other regions. For instance, political factors affecting relations between Russia and China will have ramifications for gas flows and prices throughout the world, not just in northeast Asia. After presenting the model, we use it to investigate the global consequences of "shocks" of this sort.

Market structure in the BIWGTM

Current and projected increases in the demand for natural gas, as well as the desire on the part of producers to monetize stranded natural gas resources, has expanded the depth and geographical extent of both sides of the LNG market. Expanding the market alternatives available to both producers and consumers of natural gas reduces the risk of investing in infrastructure, thereby encouraging further development of the natural gas market. Moreover, with a greater number of available supply alternatives and growth in the size of end-use markets located around the globe, the average distance between neighboring suppliers falls, increasing the opportunities for price arbitrage. The resulting increase in trading opportunities increases market liquidity.

An increase in market liquidity could produce a relatively rapid shift in the market equilibrium away from long-term bilateral contracts to a world of multilateral trading and an increased number of "spot market" transactions. The explanation is that market structure is partly endogenous. Expectations about the future evolution of the market influence investment and trading decisions today, and these, in turn, further influence market developments tomorrow. Once market participants begin to expect a change in market structure, their investment decisions accelerate the change.[15]

The model examined in this paper assumes that such a change in market structure has already occurred by treating LNG as a commodity that is traded somewhat analogously to the way oil is traded today. Thus, while the near term evolution of the market will most likely be dictated by contract rigidities, we have assumed that the market will evolve according to a long term solution

[15] Brito and Hartley (2001) present a formal model of the evolution of the LNG market from a world of long-term bilateral contracts to one where LNG will be traded more like the way that oil is traded today.

characterized by more flexibility. Long-term contracts are allowed to affect the risks borne by different parties, but not physical flows of gas. Evidence of emerging corporate behavior in the gas world, and in particular the increasing prominence of swap agreements and spot sales, supports this approach. In essence, we assume that the LNG as well as the pipeline gas market behaves as if contracted trades can be swapped with alternative cargoes whenever such arrangements are cost effective. Even today, this is generally true in the longer term, where any contracted flow that is not least cost can be, and usually is, replaced by swap arrangements that allow the financial terms of contracts to be satisfied regardless of where physical delivery actually occurs.[16] The financial arrangements in the contracts, however, will affect risks and the ability to swap deliveries significantly.[17]

Demand for Natural Gas

Economic growth, expanding power generation requirements, and environmental considerations are the primary explanations for projected rapid increases in natural gas demand. According to the EIA (International Energy Outlook 2004), natural gas consumption in Europe is projected to rise by about 2.0% per annum in the next 2 decades, as governments encourage natural gas as an alternative to more carbon intensive fuels such as oil and coal. In North America, natural gas use is expected to rise about 1.4% per year, with growth in the power generation sector expected rise even faster. Mexican demand is expected to rise by about 3.9% per year through 2025 as the Mexican government pursues policies to replace oil as a fuel for electricity generation. Rapid economic growth in developing Asian countries is expected to result in increases in natural gas demand of about 3.5% per annum through 2025, with Chinese demand forecast to grow at an astounding 6.9% per year and Indian demand at 4.8% per year over the same time horizon. This growth will occur primarily in electricity generation, but residential and commercial cooking and heating, and industrial demand, will also grow.

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[16] During industry review of this effort, it was generally agreed that this approach best captures the current transition of global LNG markets. Increasingly, deliveries are being made through swaps that allow producers to deliver to the lowest cost destinations relative to the location of their production facilities.

[17] The model allows different discount rates to be used for producers in different regions, reflective of varying degrees of political risk or likelihood of supply disruption.

Demand for natural gas in developed economies has been spurred by increasingly stringent environmental controls. Natural gas is less polluting than coal or oil and does not present some of the problems, such as waste disposal, that are associated with nuclear power. Deregulation of wholesale electricity markets also has increased the demand for generating plants with smaller economies of scale, which has been met by the simultaneous development of combined cycle gas turbines (CCGT).[18] Prior to the development of CCGT, gas turbines had much lower capacities than coal or nuclear plants and were only used as peaking plants. CCGT technology raised both the economically efficient scale of operation and the thermal efficiency of gas plants. The greater thermal efficiency of CCGT plants also allows them to have similar operating costs to coal plants even though natural gas feedstock is more expensive than coal on a per BTU basis. In consequence, CCGT plants operate for longer hours in the year than did the older style gas turbines, which, in turn, raises the demand for natural gas.

Developments in the transportation sector could accelerate projected trends as technologies that convert natural gas into transportation fuel could further increase the demand for natural gas. Already, compressed natural gas is used as fuel for mass transit bus systems, taxicabs and commercial vehicles in many large cities in the U.S., Canada, and elsewhere. In addition, innovations in the development of hydrogen fuel cells target natural gas as the primary fuel source. The demand for transport fuels may also indirectly increase the demand for natural gas as an input into the production of unconventional oil resources such as the Athabasca Tar Sands in Western Canada.[19]

Conversely, further development of coal gasification, nuclear or renewable energy technologies may slow the increase in demand for natural gas as a fuel for generating electricity. Since combined cycle gas turbines for electricity generation have played a prominent role in expanding

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[18] Deregulation has increased competition in the provision of new electricity generation plants. As shown for example by Hartley and Kyle (1989), more competitive electricity markets favor more frequent construction of generating plants, with each new plant having a smaller capacity.

[19] The tar sands in Alberta have oil potential estimated at about 1.7 trillion barrels of oil, of which approximately 300 billion barrels are thought to be recoverable at reasonable cost. Natural gas is used to produce the power, steam, and hydrogen needed to mine and process tar sands. The huge shovels that scoop up the sand operate on electricity, although the electricity plants also supply excess power to the grid, while co-generated steam is used to separate the bitumen from the sand. Hydrogen separately produced from gas is used to process the bitumen into synthetic crude. Existing oil sands operations use about 900 mcf of natural gas per day, but this is expected to increase to about 2 bcf per day by 2010.

the demand for natural gas over the last two decades, any development that disadvantages natural gas as a means of generating electricity could substantially slow projected growth in natural gas demand.

Figure 1 illustrates per capita annual natural gas consumption (in mcf) for a sample of countries over the period 1980–2002.[20] Countries have been grouped into sets with similar levels of per capita consumption. As one moves from the top left panel to the bottom right, the level of per capita gas consumption rises. Generally, per capita consumption tends to increase with the level of economic development both from one set of countries to another and within a given country over time. Resource endowments also play a large role. The largest per capita consumption is found in countries that are major producers, while some countries with smaller per capita consumption, like Sweden, France, and Japan, generate a substantial proportion of their electricity from nuclear power plants.

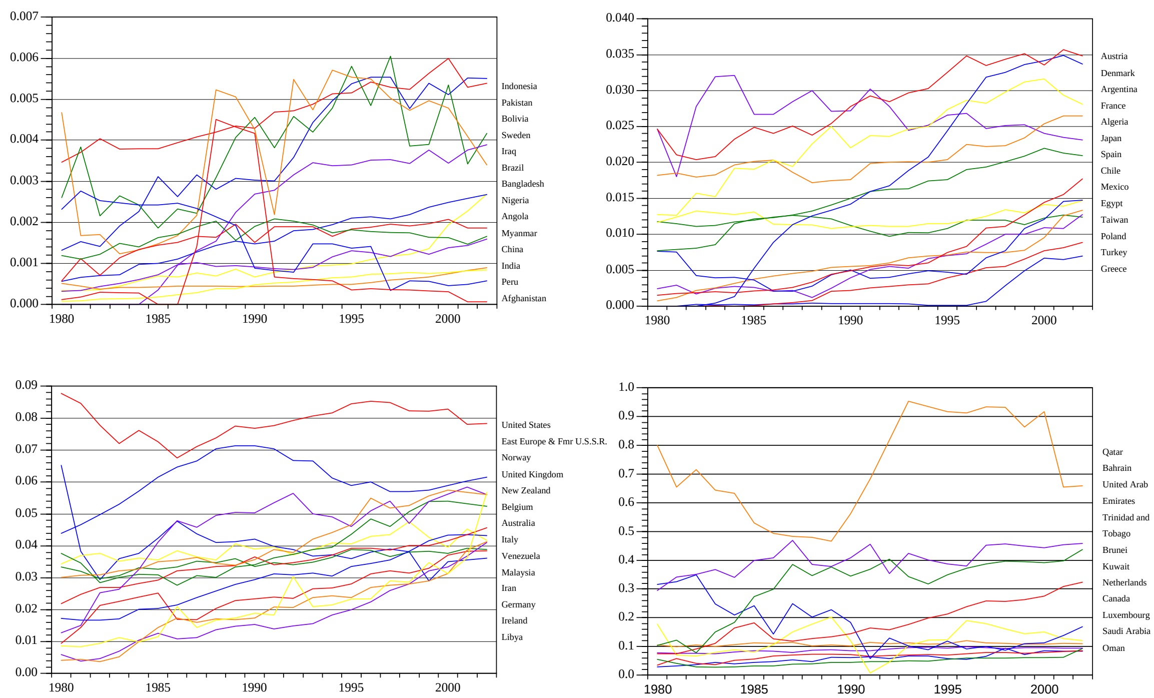

Figure 1: Historical demand for natural gas (annual mcf/person), selected countries

[20] The data comes from the EIA web site.

The demand forecasts in the BIWGTM are based on the assumption that there are five major determinants for natural gas demand: population, economic development, resource endowments and other country specific attributes, the relative price of different primary fuels and new technological developments. In constructing the demand relationship, we first estimated models to extrapolate patterns of economic and population growth into the future.[21] We then, following Medlock and Soligo (2001), estimated total primary energy demand per capita as a function of the level of economic development. Finally, we estimated a function relating the *share* of natural gas in total primary energy to real energy prices and the level of economic development.[22]

An advantage of this multi-step approach is that theory can guide the choice of functional form at each stage. For example, by choosing a suitable functional form, we can constrain the share of natural gas in primary energy to lie between zero and one. This helps to ensure that demand forecasts that extend substantially beyond the sample period neither expand uncontrollably nor decline precipitously in the face of large out-of-sample changes in the exogenous variables. Although the focus of our analysis extends only through 2040, it is necessary to forecast demand over a much longer period. The reason is that investments depend on expected future prices. As we explain in more detail below, we assume that new technologies will compete with natural gas and ultimately establish a competitive ceiling for natural gas prices. The model time horizon needs to be large enough for this assumption to be realistic.

We use E_{it} to denote the consumption of primary energy in quadrillion (10^{15}) BTU per thousand of population in country i and year t. We use the level of GDP per capita measured in purchasing power parity terms in 1995 real international dollars (denoted y_{it}) to proxy the level of economic development in country i and year t. We then estimated the following equation (estimated standard errors are indicated below each coefficient):[23]

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[21] The estimation used data on population and economic growth from the World Bank supplemented by the well known Summers and Heston data set. The latter data has been used for a large number of studies on international economic growth and development. It is available at the Center for International Comparisons, the University of Pennsylvania, http://pwt.econ.upenn.edu/.

[22] Primary energy demand and natural gas demand data were obtained from the EIA web site. The IEA web site provided international energy price data. The World Bank and IEA data banks are accessible only to subscribers.

[23] The cross-section time series model was estimated on 172 countries with an average of 18.7 years per country (resulting in 3218 total observations). The shortest time series for any country was 7 years while the longest was 21 years (1980-2001). Since the error term was autocorrelated, the lagged dependent variable was instrumented with E_{it-2}, y_{it-1}, and y^2_{it-1}. Autocorrelation in total energy services demand per capita could reflect dynamic interactions

$$E_{it} = a_i + \underset{(0.0110)}{0.8228}\ E_{it-1} + \underset{(0.0852)}{0.4040}\ y_{it} - \underset{(0.0051)}{0.0145}\ y_{it}^2 + \varepsilon_{it} \qquad (1)$$

where the coefficients a_i are country-specific effects. The positive coefficient on y_{it} implies that per capita energy demand rises as the economy develops, but the negative coefficient on the quadratic term implies that the increase occurs at a declining rate.[24] This result is consistent with the notion that both the income elasticity of energy demand and the energy intensity of a country decline with the level of economic development.[25]

To estimate the own- and cross-price elasticities of demand, we used 23 years of data on 29 OECD economies from the IEA *Energy Statistics and Balances for OECD Countries* that included prices of natural gas, oil and coal. The econometric analysis did not reveal a significant effect of coal prices on the demand for natural gas once oil and gas prices had been included. As a result, coal prices were omitted from the analysis.[26] The estimated equation then related the share of natural gas in primary energy demand in country i and year t (θ_{it}^{NG}) to the real prices of natural gas and crude oil and the level of economic development measured by real GDP per capita (measured in purchasing power parity terms). The latter variable captures the idea that natural gas is a "premium fuel." Increased environmental regulation in wealthier economies encourages the use of cleaner burning natural gas, while higher wealth facilitates the large investments required to deliver gas supplies to customers. The functional form we estimated guarantees that the share, θ_{it}^{NG}, remains bounded between zero and one:[27]

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between energy supply and the overall level of economic activity. The within country R^2 = 0.8063, while the between country R^2 = 0.9961. The F-statistic for the test of joint statistical significance of the country-specific fixed effects was $F_{171,3043}$ = 2.77, indicating that there are systematic country-specific differences that are not explained by the level of economic development.

[24] The quadratic only approximates the true relationship, in particular because we would not expect energy per capita to decline. Nevertheless, the quadratic in equation (1) attains a maximum at a per capita income of more than $1.136 million 1995 U.S. dollars, which is more than 10 times any feasible per capita income level for any country in 2100.

[25] See Medlock and Soligo (2001) for more on this issue.

[26] There is more than one plausible explanation for the lack of significance of coal prices. Two such arguments are: (1) since coal varies substantially in quality, coal prices are more difficult to measure and the series we used may therefore contain substantial error, and (2) coal became a close substitute for gas only when CCGT allowed gas to be used for base load power generation, and this occurs only in recent years. Previously, gas turbines competed with fuel oil to generate peak load power.

[27] The combined cross-section time series model was estimated for 29 countries with an average of 18.9 years per country (resulting in 548 total observations). Unlike the energy services demand equation, Hausman tests did not suggest that the lagged dependent variable was endogenous, while allowing for a common first order autoregressive structure across panels produced an estimated coefficient of only 0.0365. Hausman tests also did not suggest that the

$$\ln\left(-\ln\theta_{it}^{NG}\right) = b_i + \underset{(0.0149)}{0.8291}\ \ln\left(-\ln\theta_{it-1}^{NG}\right) + \underset{(0.0059)}{0.0335}\ \ln Png_{it} - \underset{(0.0059)}{0.0302}\ \ln Poil_{it} - \underset{(0.0118)}{0.0677}\ \ln y_{it} + \xi_{it} \tag{2}$$

for country i in year t and where the country specific effect b_i represents resource availabilities or other characteristics, and the variance of the error differs by country.

By differentiating equation (2), we see that the elasticity of per capita natural gas demand with respect to its various arguments is:

$$\begin{aligned}
&\frac{\theta_{t-1}^{NG}}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial\theta_{t-1}^{NG}} = 0.8291\frac{\ln\theta_t^{NG}}{\ln\theta_{t-1}^{NG}},\\
&-\frac{Png_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial Png_t} = -0.0335\ln\theta_t^{NG},\\
&\frac{Poil_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial Poil_t} = -0.0302\ln\theta_t^{NG},\ \text{and}\\
&\frac{y_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial y_t} = -0.0677\ln\theta_t^{NG}
\end{aligned} \tag{3}$$

In particular, the functional form in equation (2) implies that the elasticity of demand for natural gas with respect to prices and per capita GDP declines toward zero as θ^{NG} rises (recall that $\theta^{NG} < 1$, so $\ln \theta^{NG} < 0$). The lagged dependent variable on the right hand side of equation (2) implies that the long run elasticity of demand with respect to the prices and per capita income will be approximately 5.85 times larger than the short run elasticity.

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real prices were endogenous to the natural gas share in any one country. Instead of using instrumental variables, we therefore focused on modeling heteroskedasticity using generalized least squares. Heterogeneity may be more important for the share equation because country specific differences in resource endowments are likely to explain a substantial fraction of the variation in the data. The log likelihood of the cross-sectional time series model was 1054.247, while the chi-square statistic for testing whether the estimated coefficients are jointly significantly different from zero was 106629.16 with 32 degrees of freedom.

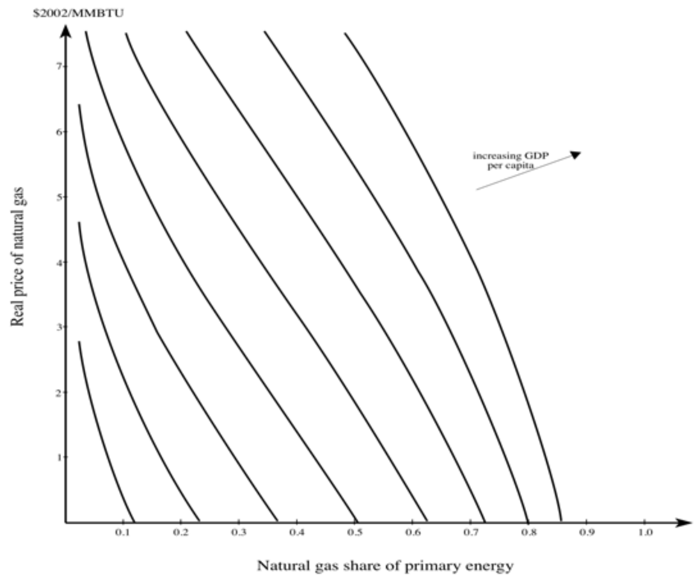

Figure 2: Long-run demand curve for different per capita GDP levels

Figure 2 illustrates the resulting long run demand curves for various levels of per capita real GDP, *y*. These curves become more inelastic as the share approaches zero or one. If the gas share were close to one, further declines in prices could not greatly stimulate gas demand. Similarly, if the share is already close to zero, price increases will do little to further decrease gas demand.

In order to use equations (1) and (2) to forecast natural gas demand, we need to forecast energy prices, population and real GDP (in purchasing power parity terms) for each country. While the price of natural gas will be calculated endogenously in the model to equate supplies to demands at each demand location, we include an exogenous forecast of the price of oil. In the base case, we assumed oil prices will follow the Reference Case forecast from the EIA's *International Energy Outlook* (IEO), which carries through 2025. Beyond 2025, we linked the oil price projection to a gas price that asymptotes to $5/mmbtu (the backstop price, see discussion below) by 2100. In doing so, we take the ratio of the IEO world oil price and U.S. wellhead price (both in $/mmbtu) in 2025, and hold it constant. This results in a world oil price that rises from $27/bbl, or about $4.66/mmbtu, in 2025 to $31.20, or approximately $5.38/mmbtu, by 2100.

The model of economic growth we develop is based on the notion of economic convergence. In particular, capital and labor mobility, as well as the flow of trade in goods and services, should tend to increase economic growth rates in less developed regions relative to more developed regions. Holding things such as legal institutions and technologies fixed, returns to investment ought to be higher in locations where capital is relatively scarce. Therefore, firms have an incentive to increase investment in those locations rather than locations where capital is relatively abundant. Similarly, if workers can migrate, they also have an incentive to seek employment where their skills earn the highest real wage. Both capital and labor mobility, therefore, ought to raise per capita income growth rates in locations where per capita income is currently below average and reduce it in locations with per capita incomes above the current average. Furthermore, even in the absence of international flows of capital and labor, trade in goods and services will tend to reduce differences in income. This result is commonly referred to as factor price equalization. Regions with high payments to a particular factor of production will tend to import goods intensive in the use of that factor. This, in turn, will tend to raise factor payments in the exporting country while simultaneously reducing them in the importing one.

Yet another vehicle for convergence involves the diffusion of technology. Wealthier nations have a higher standard of living in part because they use more productive technologies. As those technologies spread into less developed nations, differences in productivity decline. As a result, the spread of technological innovations will also tend to produce convergence of living standards over time.

In our statistical analysis, we use real GDP per capita adjusted for purchasing power parity differences as the basic measure of living standards. We also assume the U.S. as the leading country. In other words, we assume that the living standards in other countries will tend to converge toward those of the United States over the next century. Our empirical specification also assumes that living standards in the United States (and by extension in other countries too, as they approach the U.S. level) will tend to increase over time but at a diminishing rate. The main motivation for this assumption is that, as the economy matures, economic activity shifts toward the service sector where past technological progress has been low, and foreseeable opportunities for future technological progress appear limited, relative to the manufacturing and agricultural sectors of the economy. Specifically, we estimated the following equation for real per capita GDP growth, defined as $\dot{y}_{it} = \ln y_{it} - \ln y_{it-1}$ in country i in year t (estimated standard errors are in parentheses):[28]

$$\begin{aligned}\dot{y}_{it} = c_i + \underset{(0.0886)}{0.9362}\ \dot{y}_{it-1} + \underset{(0.1178)}{0.9431}\ (1/\ln y_{it-1}) - \underset{(0.7009)}{6.1930}\ (\dot{y}_{it-1}/\ln y_{it-1}) \\ - \underset{(0.0030)}{0.0152}\ (\ln y_{it-1} - \ln y_{USt-1}) + \zeta_{it}\end{aligned} \tag{4}$$

where c_i is a country specific constant effect (reflecting, for example, persistent differences in legal or political institutions), y_{it} is the level of real per capita GDP in purchasing power parity terms and y_{USt} is the corresponding U.S. real per capita GDP in year t. The variance of the error term, ζ_{it}, was allowed to vary across countries. The negative coefficient on the difference between country i GDP per capita and U.S. GDP per capita implies that per capita growth rates of other countries will tend to converge toward those of the U.S. over time. The positive coefficient on the inverse log level of per capita GDP (1/ln y_{it}) implies that growth rates will tend to diminish as per capita GDP increases. Furthermore, the negative coefficient on the interaction term implies that growth rates will tend to become more persistent as the economy matures.[29]

Before we used equation (4) to forecast future economic growth, we adjusted the country-specific constant terms c_i. The reason for doing so is that the constants reflect the average experience of a country over the sample period while the recent experience might be more salient for projecting future developments. We therefore calculated a value of c_i for each year from 1996 to 2002 by using the estimated coefficients from the regression and the actual data for each country. We then averaged these values with the estimated constant term, thereby giving increased weight to recent experience.

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[28] The equation was estimated for 173 countries with an average sample of 37.6 years for each country and a maximum sample size of 52 years for any one country. The log likelihood of the cross-sectional time series model was 10513.88, while the chi-square statistic for testing whether the estimated coefficients together are significantly different from zero was 1311.39 with 176 degrees of freedom.

[29] Since 1/ln y ranges from a maximum of 0.18 in the sample to a minimum of 0.085 out of sample, the *net* coefficient on the lagged dependent variable ranges from -0.186 to 0.4057, implying that the model is dynamically stable.

We also estimated a simple model where economic development reduces population growth rates.[30] Specifically, defining the approximate population growth rate in country i in year t as $\dot{P}_{it} = \ln P_{it} - \ln P_{it-1}$, we estimated the following model (estimated standard errors of the coefficients are again in parentheses):[31]

$$\dot{P}_{it} = d_i + \underset{(0.0080)}{0.7882}\ \dot{P}_{it-1} + \underset{(0.1922)}{1.5769}\ 1/y_{it-1} + \upsilon_{it} \tag{5}$$

where, y_{it} is again the per capita real GDP, d_i is a country specific constant effect and the error terms for each country are again allowed to have different variances.

In using the model to make forecasts, we modified the country-specific constants so that the implied average population growth from 2000 to 2015 matched the World Bank forecast average population growth over the same period. The motivation is that the World Bank forecast may be based on demographic considerations (particularly the current age profile of the population) that are not accounted for in equation (5).

Finally, the demand curves included in the model were modified from curves like those graphed in Figure 1 in order to accommodate likely future technological change, where the modification is phased in over time to reflect the potential adoption of "backstop" technologies. There are many substitutes for natural gas in generating electricity, ranging from hydroelectricity, diesel and fuel oil for supplying peak power, to coal, nuclear and newer renewable technologies like wind or solar power for supplying base load power. There also are substitutes for the other uses of natural gas. Indeed, prior to the widespread use of natural gas, many cities had plants to gasify

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[30]There are multiple reasons given to explain the phenomenon that birth rates decline as per capita incomes rise. In particular, as income rises, the opportunity cost of having children rises as more women enter the labor force and their wages rise. Moreover, the cost of educating and caring for children tends to increase. Initially, we examined a model where economic development at first raises population growth rates by bringing improved health care, water supplies and other living standard advances that raise survival rates for children and increase life spans. We found, however, that the terms needed to allow for a rising initial population growth rate as a function of y added little to the within sample explanatory value of the model once we also allowed for country specific effects. In addition, these terms were irrelevant for projected out of sample population growth rates.

[31] The equation was estimated for 173 countries with an average sample of 38.1 years for each country and a maximum sample size of 52 years for any one country. The log likelihood of the cross-sectional time series model was 27864.99, while the chi-square statistic for testing whether the estimated coefficients together are significantly different from zero was 114349.55 with 174 degrees of freedom.

coal and distribute it to industrial and household consumers.[32] Until the 1940s, almost all fuel gas distributed for residential or commercial use in the United States was produced by the gasification of coal or coke.

The estimated elasticity of demand incorporated into the model reflects the substitution possibilities between gas and other fuels that are available within the estimation period. However, this estimated elasticity does not reflect new technologies that may increase substitutability, particularly at higher prices for natural gas. For example, the gas produced from coal using newer technologies is a closer substitute for natural gas than was the case in the 1940s while production costs also are lower in real terms. As another example, experimental Integrated Gasification Combined Cycle (IGCC) electricity generating plants are already in operation in the U.S. (at West Terra Haute, Indiana, and Tampa, Florida) and overseas (Spain, Netherlands, Germany, Japan and India). In August 2004, the American Electric Power Company announced plans to build at least one commercial-scale IGCC plant. Current IGCC plants are dramatically cleaner than conventional coal-fired generating plants, producing only 3% of the sulfur, 18% of the nitrogen oxide, 50% of the mercury and 80% of the CO_2 of an equivalent capacity conventional coal-fired plant without scrubbers. Using current technologies, generating electricity using IGCC is said to be competitive with natural gas CCGT in the U.S. at a natural gas price of \$3.50-\$4.00 per mcf (see, for example, documents available at http://www.netl.doe.gov, the National Energy Technology Laboratory, U.S. Department of Energy).

[32] Commercial gasification of coal began in 1792, while the first coal gasification company in the United States, the Baltimore Gas Company, was established 1816.

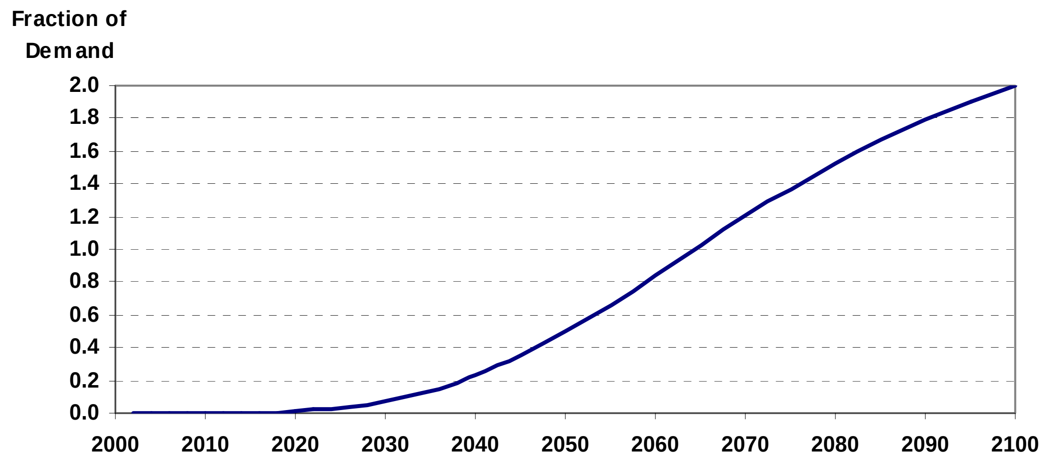

Figure 3: Availability of Backstop Technology

We allow for the possibility that new technologies could begin to substantially displace natural gas late in the model time horizon. The backstop technology is first made available in 2020 but can only meet a small portion of demand. It becomes increasingly available in subsequent years, where availability is dictated by a Gompertz curve ($y = ab^{q^t}$) as drawn in Figure 3.[33]

In order to define the available backstop quantity, we must first define a reference demand level that the backstop is assumed to satisfy. Note that the reference demand is *not* the demand forecast by the model, which is calculated endogenously. Rather, the reference demand provides a benchmark to establish a predetermined quantity of backstop assumed to be available at a given price in a given year. If the total demand calculated by the model is less (more) than the reference demand, the backstop will supply a larger (smaller) proportion of demand than illustrated in Figure 3. To calculate the reference demand, we estimated natural gas demand using the method described above for reference oil and natural gas prices. Then, the parameters of the curve depicted in Figure 3 are chosen so that the backstop can supply all of the reference demand by 2100 at a price of $5.50/mmbtu.[34]

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[33] The parameters of the Gompertz function determine the minimum (b) and maximum (a) values of y and the rate of ascent (q) through time (t). For the function used here, a=2.5, b=0.005, and q=0.9612.
[34] The quantities are somewhat arbitrary. They are chosen so that the backstop does not penetrate the market too rapidly, but is sufficient in later years to ensure all demand can be satisfied between $5.00 and $5.50. We allow the backstop to displace natural gas in this manner because the type of energy consumed is related to installed capital. Allowing capital stocks to be replaced at a reasonable rate would slow the growth of the backstop initially, as the

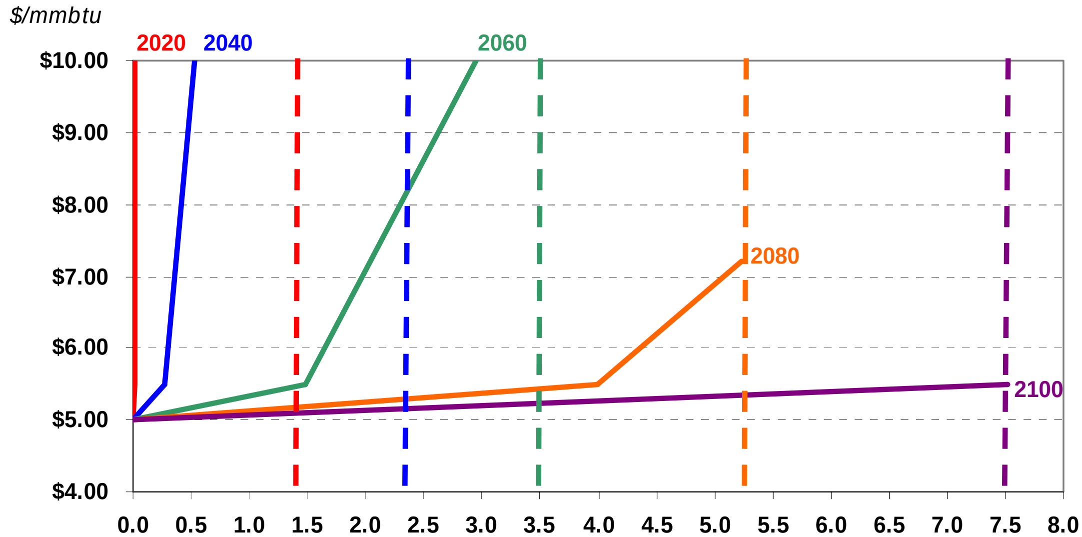

Figure 4: The hypothetical supply of a gas substitute, 2020-2100

To be more specific, beginning in 2020, we subtracted an upward sloping supply curve of a close substitute for gas from the constant elasticity demand curve. In 2020, this curve has an intercept of $5/mmbtu, rising to satisfy 0.625% of the reference demand for natural gas (half the corresponding percentage number for 2020 in Figure 3) at a price of $5.50/mmbtu and a maximum of 1.25% of the reference demand for a natural gas price of $10/mmbtu or above. The substitute technology is then assumed to become increasingly available, as illustrated in Figure 4 for a location where the reference demand is 1.41 tcf in 2020 (red curves), 2.34 tcf in 2040 (blue curves), 3.50 tcf in 2060 (green curves), 5.25 tcf in 2080 (orange curves) and 7.5 tcf in 2100. The vertical dashed lines in each case represent the reference case demands at this location in each year.

While the initial price at which the backstop technology can be supplied remains at $5/mmbtu (in 2002 prices), the percentages of reference demand assumed to be satisfied at a price of $5.50/mmbtu or $10/mmbtu increase each year according to the curve in Figure 3. In 2040, for example, the substitute technology is assumed to be capable of satisfying about 11.4% of the reference demand at a price of $5.50/mmbtu and about 22.8% at a price of $10/mmbtu. By 2100,

cost of capital equipment that consumes natural gas as an input is sunk. However, a competitive backstop would also slow, if not stop, the installation of natural gas capital equipment, so that the use of the backstop would begin to accelerate as older capital is continually replaced.

the percentage of demand that can be satisfied by the backstop at a price of $5.50/mmbtu increases to 100%.[35]

Current and Potential Supply Sources

To model the evolution of the world natural gas market, we must determine where new sources of supply are likely to be developed to meet the rising demand. We use, as the primary data source for this exercise, regional resource potential as given in the P-50 resource estimates from the *World Resource Assessment* of the United States Geological Survey (USGS, 2000).[36] Resources are divided into three categories: proved reserves, growth in known reserves, and undiscovered resource.

[35] This does not imply that natural gas is no longer consumed. Rather, all resources that can still be extracted and competitively supplied at a price of $5.50/mmbtu (in 2002 prices) will be used. Moreover, not all regions reach the backstop simultaneously. Areas with large deposits of natural gas tend to see exports fall but continue to consume natural gas domestically.

[36] We supplemented the USGS data with data from the Australian Bureau of Agricultural and Resource Economics (Dickson and Noble, 2003) and Geosciences Australia (2001). In particular, Geosciences Australia used a methodology similar to that used by the USGS to assess the resource potential of Australian basins that were not assessed quantitatively by the USGS.

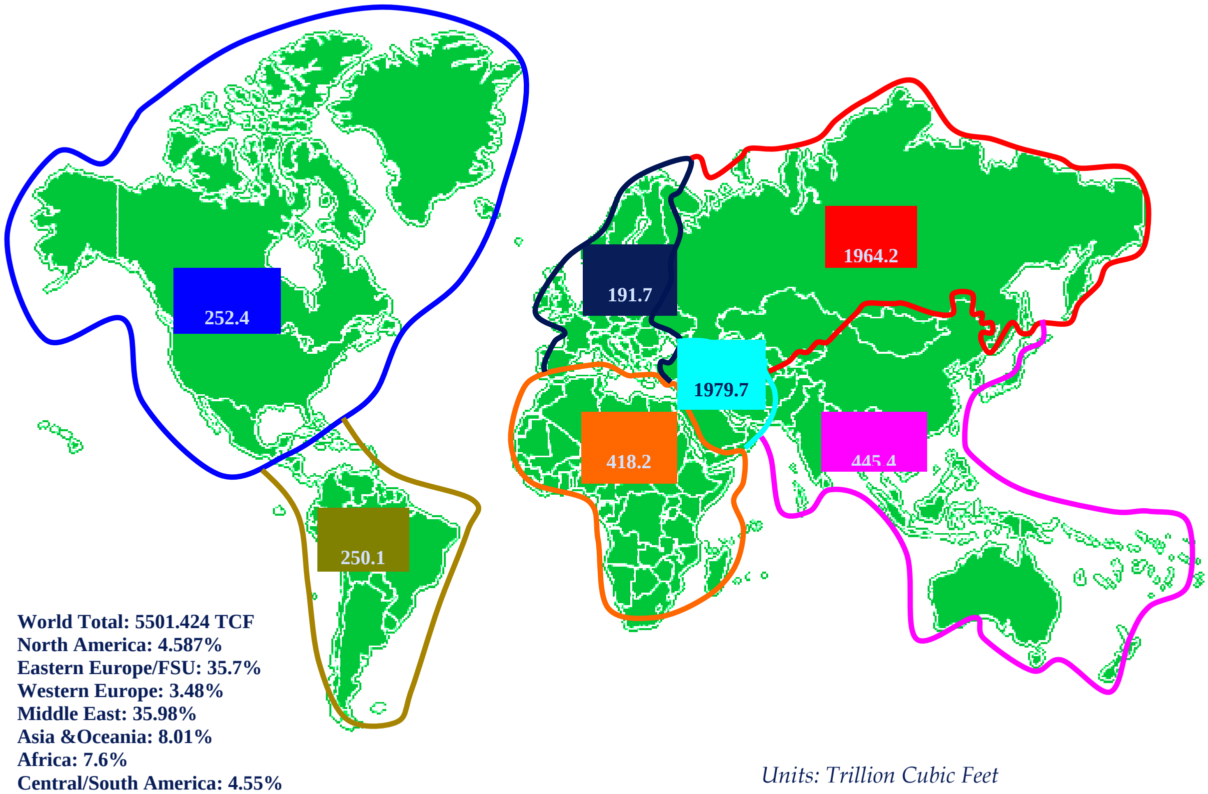

Figure 5: Proved Natural Gas Reserves by Region, 2003

The USGS data includes both associated and unassociated natural gas resources, estimates for both conventional and unconventional gas deposits in North America, and conventional gas deposits in the rest of the world.[37] The USGS estimates of reserve growth in existing fields and undiscovered resources uses a stochastic simulation of the success of past exploration and development in particular types of deposits in different regions.[38] Figures 5 and 6 are constructed using the USGS database, and indicate, in particular, the significant role that Russia

[37] The lack of unconventional resource estimates outside of North America is a function of the lack of exploration and development of commercial unconventional natural gas deposits in other regions of the world. Australia also already has some coal bed methane (CBM) production, while several companies have announced plans to examine further CBM production. The Australian data sources referenced above provided estimates of economically viable CBM resources in the coalfields of eastern Australia. While the lack of such data for other regions underestimates the global resource potential, it is unlikely to have a substantial impact in the time horizon considered in this exercise. We would expect the massive quantities of economically accessible reserves of conventional natural gas outside North America and Australia to be exploited before the industry moves on to exploit substantial deposits of unconventional reserves.

[38] See website of USGS for more details on their data.

and the Middle East may play in supplying natural gas to the rest of the world in coming decades.

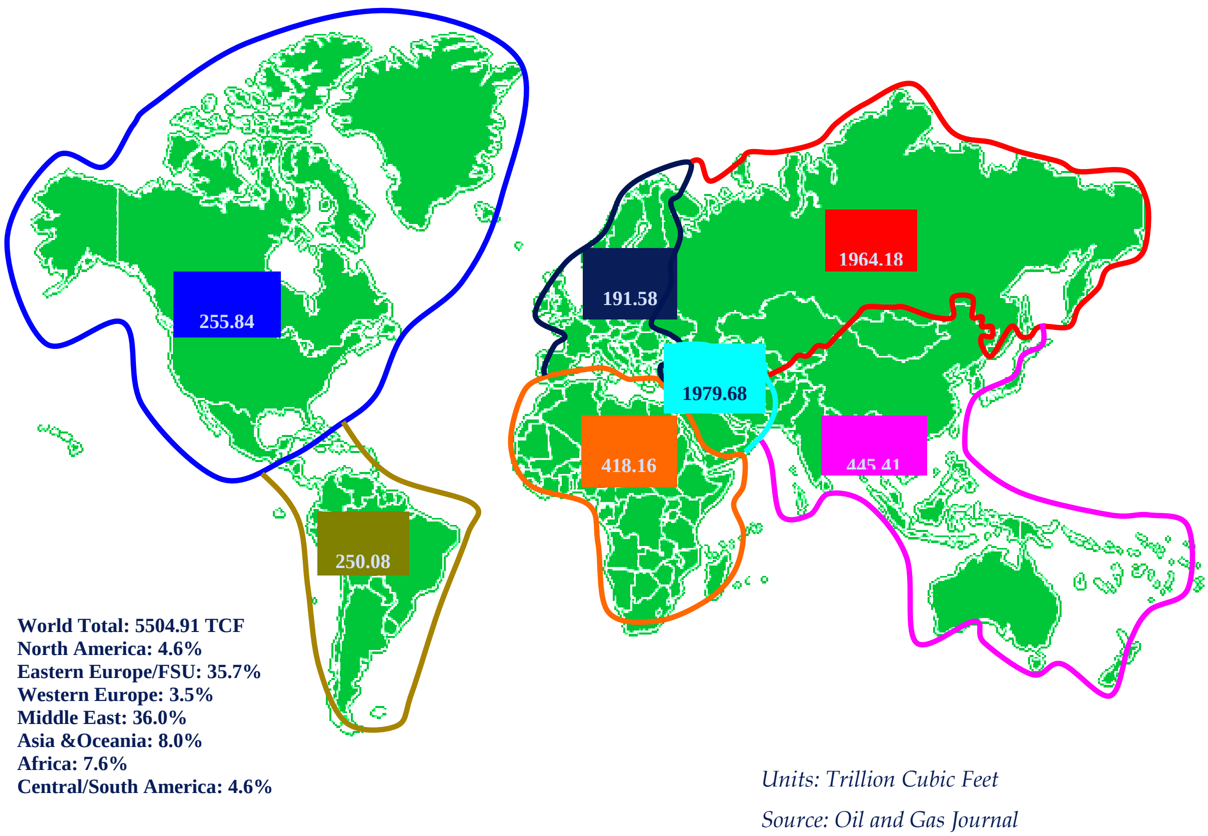

Figure 6: Undiscovered Natural Gas by Region, 2001 estimates

Capital cost of resource development

The resource data include estimates not only of field size but also of minimum, median and maximum depth for each field. Using data for the U.S., Canada and Mexico, we estimated equations relating the capital cost of development and operating and maintenance costs to the median estimate of recoverable reserves and the three depth measures.

The Modeling Subgroup of the National Petroleum Council (NPC) study (National Petroleum Council, 2003) of the North American natural gas market developed data for long run marginal cost curves to be used in the *Market Builder* platform. These curves are characterized by three cost levels $\{c_1, c_2, c_3\}$ where c_1 is capital cost of developing the first incremental unit of gas, c_2 is the capital cost of the 75th-percentile of the estimated median reserves, and c_3 is the capital cost of the median resource estimate. The approximate curves for the United States, Canada, and Mexico were based on proprietary industry information supplied by firms participating in the NPC study. While the NPC used many other variables in a fairly sophisticated discovery-process model to develop the cost estimates for basins in North America, we found that the three cost measures could be reasonably explained by the median estimate of recoverable reserves and the three depth measures – the minimum, maximum and median depth of resources in the field. Total resource enters the equation as an inverse, implying there are economies of scale in developing resources. Specifically, we estimated the following three equations:[39]

$$\begin{array}{l}
c_2 = -0.0207 + 0.00066 \cdot (MedD) + .000014 \cdot (MedD/\mathrm{Re}\,s) \\
\quad (0.1998)\ (0.000075) \qquad\qquad (0.000002) \\
\quad N = 316, \quad R^2 = 0.427 \\[1em]
c_1 = -0.0619 + 0.3838 \cdot c_2 - 0.00009 \cdot (MinD) + .000009 \cdot (MinD/\mathrm{Re}\,s) \\
\quad (0.1998)\ (0.0155) \qquad (0.000027) \qquad\qquad (0.000001) \\
\quad N = 221, \quad R^2 = 0.855 \\[1em]
c_3 = -4.4073 + 6.4009 \cdot c_2 - 0.00161 \cdot (MaxD) + .000024 \cdot (MaxD/\mathrm{Re}\,s) \\
\quad (0.9912)\ (0.2516) \qquad (0.000229) \qquad\qquad (0.000006) \\
\quad N = 221, \quad R^2 = 0.859
\end{array} \tag{6}$$

where *MedD*, *MinD* and *MaxD* are, respectively, the median, minimum and maximum well depth and *Res* is the median estimate of the ultimately recoverable reserves from the field.

The estimated equations were then used to construct long run marginal capital costs curves for all resources outside of North America. Field depth and resource size were obtained from the

[39] Each equation also included a set of regional indicator variables. Since most of these coefficients are of little interest for applying the estimated equations internationally, they have not been reported. The complete equations with fixed regional effects are available from the authors. One regional effect that is of interest would be the higher costs associated with exploiting Alaskan deposits, since the costs due to harsh weather are also likely to apply to other resources located above the Arctic circle. Unfortunately, however, Alaska was not included in the original data. Nevertheless, we added a premium for exploiting fields in the Barents Sea and Sakhalin in Russia, and in Greenland, to make them comparable to the Alaskan costs. The constant terms as reported are chosen so that the equations fit the means of the reported variables ignoring regional effects. Estimated standard errors are placed in parentheses below each coefficient. The equation for c_2 includes additional observations since only the median field depth was available for Canada, Mexico and offshore fields in the U.S..

USGS *World Resource Assessment*, which is available online. The resulting long run marginal capital cost curve for the undiscovered resources in selected regions is depicted in Figure 7.

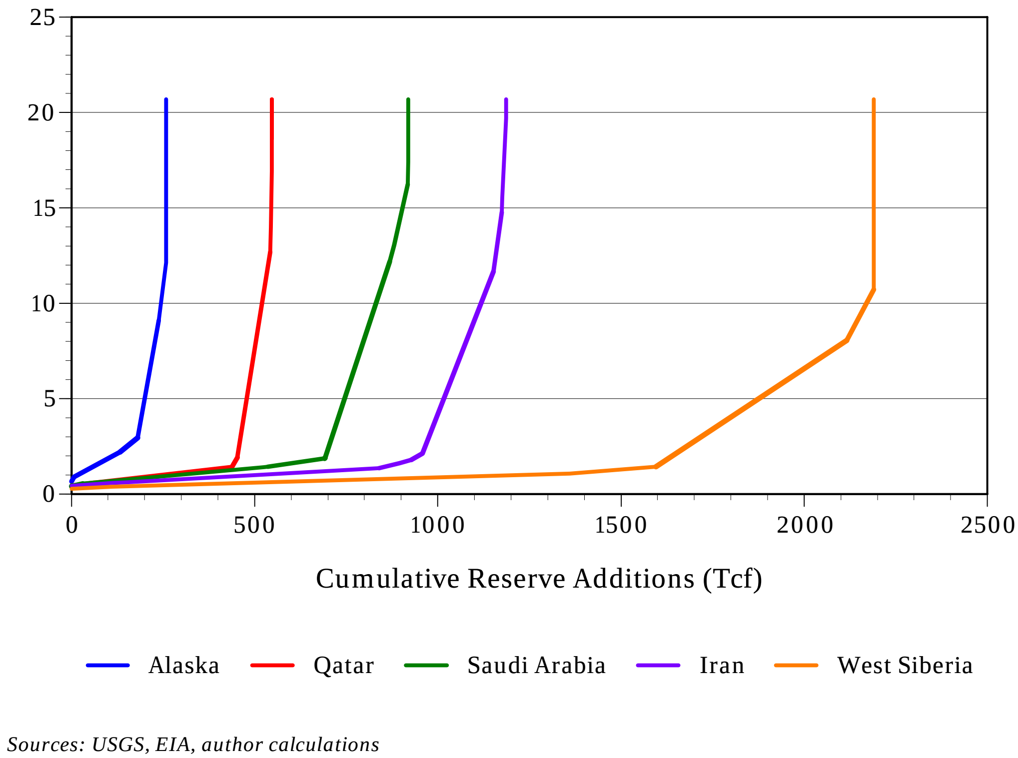

Figure 7: Estimated Long Run Cost of Supply Curves for Selected Regions

Recent years have seen substantial declines in the costs of exploiting a given hydrocarbon resource. Advances in computer hardware, signal processing software and remote sensing technology have all played a role. To allow for further technological change in the mining industry, the future costs of reserve additions are assumed to decline according to the rates used in the NPC study "Balancing Natural Gas Policy." Thus, the curves illustrated in Figure 7 are only valid for the year 2002, which is the initial year of the model. Beyond 2002, all such curves will shift down by the assumed rate of technological innovation in finding and development costs.

Operating and maintenance costs

The NPC study also produced estimates of the operating and maintenance costs (*OM*) associated with exploiting different fields in the United States, Canada, and Mexico. We also found that these costs were predictably related to the resource size and depth measures. In contrast to the capital costs, however, there also was a systematic relationship in the regional effects. In the operating costs regression, only the offshore regions of the United States and Mexico displayed higher costs. Hence, we included an indicator variable (*Off)* to capture the distinction between operating costs for onshore and offshore fields. The estimated regression equation was:

$$\begin{array}{l} OM = \underset{(0.01786)}{0.00972} + \underset{(0.01875)}{0.32952} \cdot Off + \underset{(0.000004)}{0.000027} \cdot MedD + \underset{(14.2720)}{67.3652} \cdot (1/MedD) + \underset{(0.00028)}{0.00356} \cdot (1/Res) \\ N = 316, \quad R^2 = 0.6436 \end{array} \tag{7}$$

As with capital costs, the inverse term in total resources implies that there are some economies of scale in exploiting resources.[40] As with the capital costs, we assumed that operating costs also will decline at the rates contained in the recently released National Petroleum Council "Balancing Natural Gas Policy."

Transport Links and the World Natural Gas Market

About 73% of the world's proven gas reserves are located in the former Soviet Union and the Middle East, and moving those supplies to distant consuming markets will present new technical, logistic and economic challenges. Indeed, construction of transportation infrastructure is currently the major barrier to increased world natural gas consumption. [41]

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[40] The terms in median depth imply that costs decline up to a depth of around 1600 meters. Since the minimum median depth in our North American data set is 400 meters, while the average median depth is slightly over 2500 meters, only about 26% of the fields show declining costs with increasing depth. Most of these are located in Western Canada, the Rockies and northeast Mexico. Perhaps shallow deposits are correlated with other geological features, such as highly folded rock layers, that raise extraction costs.

[41] According to the IEA (2003), cumulative investments in the global natural gas industry of $3.1 trillion, or $105 billion per year, will be needed to meet rising demand for gas between 2001 and 2030. Exploration and development of gas fields are projected to require over half of this investment, with more than two thirds of the new capacity replacing declining production in existing fields. Investment in LNG facilities is expected to double after 2020. Investment in Russia will be a critical factor to world gas supply. The IEA projects that investment in Russian infrastructure will need to exceed $330 billion over the next thirty years in order to meet domestic demands and for export to other industrialized countries. The average of $11 billion per year compares with Russian investment of $9 billion in gas fields and infrastructure in 2000.

In order to connect supply to demand, the model constructs transportation links between supply and demand nodes based on current investment cost, current and future prices, and, therefore, anticipated net benefits from the future flows. Supply sources compete for end-use markets via a specified range of transportation options thought to be feasible.[42] In particular, the model chooses the manner in which natural gas flows to consumers, either as LNG or via pipeline, in order to maximize the rents to the wellhead. Equivalently, the model seeks a solution that minimizes the discounted capital costs of expansion and the operating and maintenance costs of utilizing new and existing capacity. Hence, supplies earning the greatest rents (or with the highest "netbacks"), once all relevant costs of getting the resource to market have been taken into account, are extracted first. Supplies that are isolated from end-use markets or located in areas lacking prior infrastructure development are, therefore, disadvantaged due to the comparatively high cost of transportation.

Currently, most natural gas is transported by the well-developed pipeline infrastructures in North America and Europe that connect major consuming and producing regions. In Asia, liquefied natural gas (LNG) is the primary means of connecting end-users to supply, most of which originates in remote locations and must be transported in refrigerated vessels. International trade in LNG, though currently small relative to pipeline flows, has been occurring for over 30 years and involves shipments from close to a dozen countries.

A complicating factor in modeling investment in transportation links is that they are inherently discrete, linking a supply source with a particular demand sink. In order to accurately forecast the development of transportation links, one needs to consider a wide range of current and future potential options. It is very easy to bias the results by inadvertently precluding viable options. One way to minimize this problem is to model the transportation system using a "hub and spoke" framework. This breaks particular links down into notional transportation from a supply source to a regional hub and then from the regional hub to the demand sinks. Such an arrangement is less sensitive to the presence of any one link in the network. Swap agreements would be the physical analog of the "hub and spoke" arrangement in the model. Although one particular

[42] The model allows only for a limited number of transportation options to be specified in advance. However, once we have a solution for an assumed potential network, a new transportation option can be introduced when the price difference between two nodes suggests that it would be profitable to construct such a link.

supplier linked in the model to a notional hub may have a contract with one particular demander linked to the same hub, the model solution will not be affected if any supplier to the hub in question fulfills the contract with the demander. In fact, such a “hub and spoke” representation ensures least cost flows and higher netbacks in an equilibrium solution. Figure 8 illustrates the “hub and spoke” framework for LNG proposed in the model.

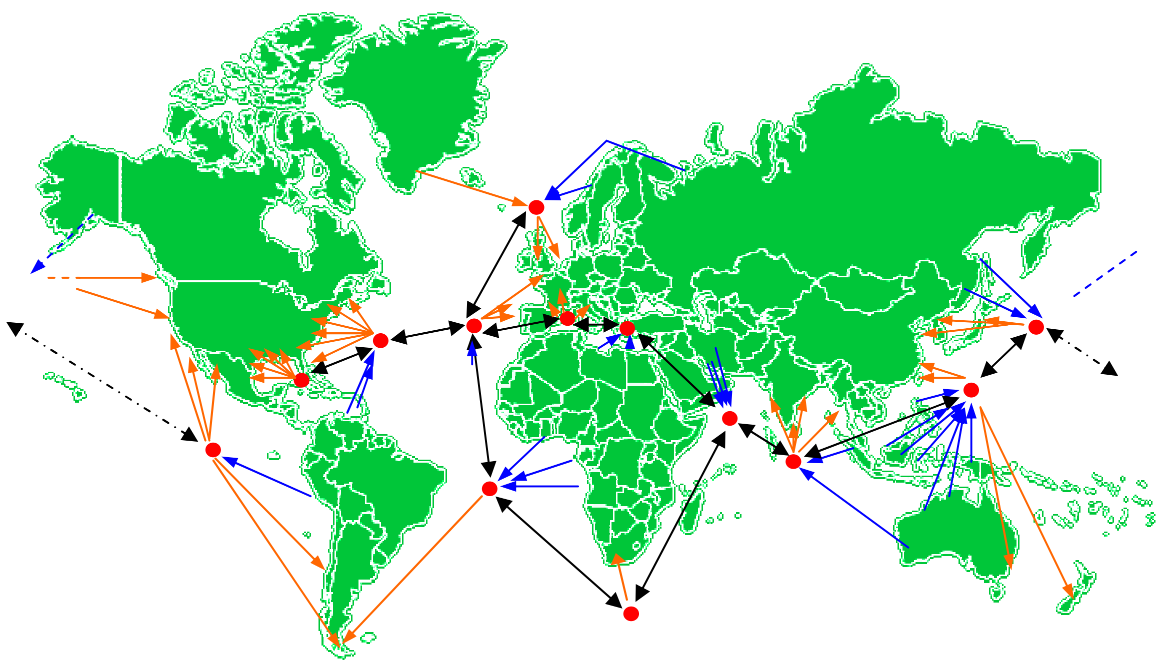


Figure 8: LNG transportation network

Cost variables for development, construction, and operation and maintenance of transportation links, are of critical importance to the model outcome. For example, the development of a liquid market in natural gas will be greatly affected by anticipated further reductions in costs in liquefaction, shipping and regasification, as well as changes in costs of developing reserves and expanding pipeline capacity. Thus, in order to model market evolution, estimates of liquefaction, shipping, and regasification costs are required.

As with all capacity investment in the model (pipelines, liquefaction, regasification, resources, etc.), liquefaction projects already under construction are exogenously input into the model, and the associated capacity is made available at the expected start-up date of the projects. The average capital costs for liquefaction for any potential project, as given in the IEA's *World Energy Investment Outlook* (WEIO) 2003, are $4.11 per mcf of annual throughput capacity. These costs, however, have been adjusted using various industry sources to reflect regional deviations about the average. The actual costs assumed in the model are given in Figure 9. It should be noted that these costs are not the sole determinant of the decision to develop LNG liquefaction. In particular, differences in the feed gas costs, which are determined by the costs of developing reserves and which change through the model time horizon, serve to either offset or exacerbate the differences in liquefaction costs across regions. Therefore, the full cost to the tailgate of the liquefaction facility can differ substantially from project to project.

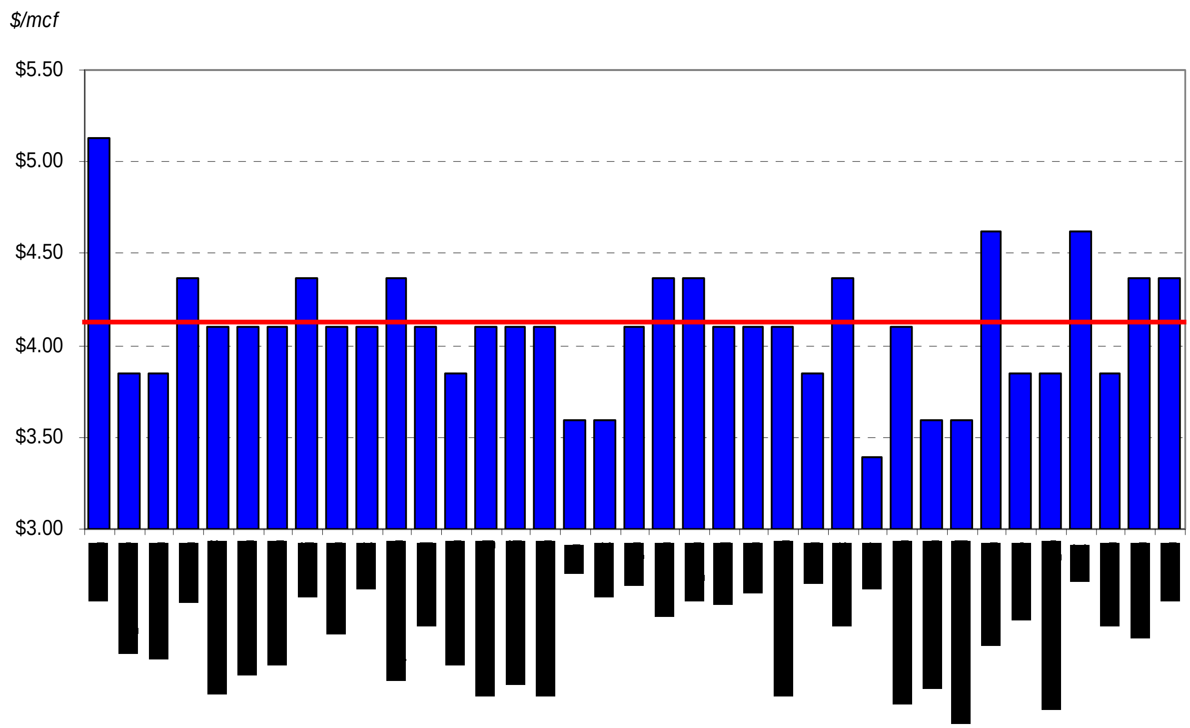


Figure 9: LNG Liquefaction Costs

To estimate the shipping costs, we modified point-to-point data from an industry source on 2002 lease rates (in $/mcf). The lease rates implicitly include a return to capital and operating and maintenance expenses. They were available from various existing and proposed liquefaction locations to various existing and proposed regasification terminals. Since the shipping costs were estimated as point-to-point deliveries, it is necessary to fit them to the hub-and-spoke representation given in Figure 7. To do this, we regressed total point-to-point shipping costs on a set of indicator variables for each of the hub flows implicitly included in each point-to-point route. Specifically, note that for each liquefaction node *i*, there is just one hub where LNG is presumed to go initially, while each regasification terminal *j* also is assumed to obtain its LNG from just one hub. Let the associated shipping costs be β_i^L and β_j^R respectively. In addition, let the total number of inter-hub routes be H and number them $h = 1, \ldots, H$, with associated shipping costs β_h . The cost on a particular route between *i* and *j* can then be written as:

$$C_{ij} = \beta_i^L + \sum_{h=1}^{H} \beta_h D_h^{ij} + \beta_j^R \tag{8}$$

where D_h^{ij} is an indicator variable taking the value of 1 if the inter-hub route *h* is part of the shortest route between *i* and *j* and 0 otherwise.

The original data set contained 26 different points of origination and multiple destinations, but not all origination and destination pairs are included. For example, data from Peru was available to only four delivery locales, whereas data from Qatar was available to 32 different delivery locales. We, nevertheless, were able to estimate the cost of shipping on each of the routes drawn in Figure 8, except for the routes involving Argentina.[43] The results are given in Table 2 in the appendix.

The capital costs of regasification included in the model vary by location, ranging from $1.02 to $3.69 per mcf of annual throughput capacity. The variation in costs results from a variety of factors, one being variation in the cost of land. We used industry cost data and data published in a number of reports (CERA 2002, IEA 2003, and the trigger prices for regasification terminals reported in EIA AEO 2004) to generate cost estimates for regasification facilities. For all terminals outside the U.S., except Japan, Taiwan, and Hong Kong, we used the cost for regasification reported in the WEIO (IEA, 2003). For the U.S., CERA reports a range of regasification costs by capacity in areas characterized as “Low Cost” and “High Cost”, but they do not identify specific high and low cost areas. However, the EIA reports trigger prices for

[43] In the latter case we pro-rated the shipping costs involving (respectively) Peru and Brazil on the basis of distances covered.

investment in regasification capacity in different regions of the United States. Using industry estimates, we fit a regression describing cost as a function of capacity. The EIA data was then used to identify where in the low-to-high cost range different regions fall. In the United States, this ranks, in descending order of cost, the West Coast, the Northeast, South Atlantic, and the Gulf Coast region. "High cost" industry estimates were also used for Japan, Taiwan, and Hong Kong.

Table 1: Indicative LNG costs (excluding cost of feed gas) 2002

Note: Price differential required for expansion… Cost of Capital included

	Liquefaction	Shipping	Regas	Total
Trinidad to Boston	$ 0.82	$ 0.25	$ 0.69	$ 1.75
Trinidad to Lake Charles	$ 0.82	$ 0.32	$ 0.21	$ 1.35
Algeria to Boston	$ 0.82	$ 0.45	$ 0.69	$ 1.96
Algeria to Lake Charles	$ 0.82	$ 0.63	$ 0.22	$ 1.66
Nigeria to Lake Charles	$ 0.82	$ 0.77	$ 0.22	$ 1.81
Qatar to Lake Charles	$ 0.82	$ 1.17	$ 0.23	$ 2.22
Qatar to Baja	$ 0.82	$ 1.32	$ 0.28	$ 2.41
NW Shelf to Baja	$ 0.82	$ 0.99	$ 0.27	$ 2.07
Norway to Cove Point	$ 0.82	$ 0.57	$ 0.36	$ 1.74

Sources:

1. "The Global Liquefied Natural Gas Market: Status and Outlook" (Dec 2003), U.S. EIA
2. Various Industry Consultant Reports
3. Author's estimates (see text)

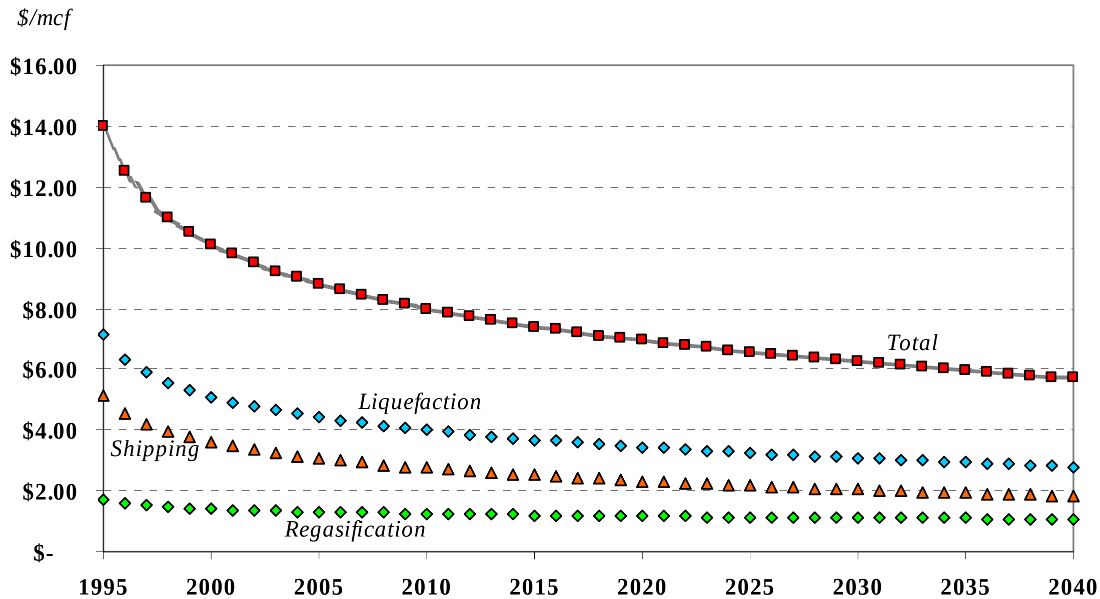
Taken together, the required differential from liquefaction intake to regasification tailgate falls between $2.54 and $3.09 per mcf of annual throughput capacity. Note, however, the actual number will vary by shipping distance and regasification location and will change over time as feed gas costs change and technological innovations occur in the LNG chain. Table 1 gives indicative costs for shipping LNG between a number of origination and destination pairs. Note the costs reported in Table 1 do not include feed gas costs for liquefaction.

The costs in Table 1 are indicative costs for 2002. We allowed these costs to change over time as a result of technological change because there have been substantial declines in LNG costs and further declines are anticipated. To accommodate this, we used the projected rate of cost declines in liquefaction, shipping and regasification as given in the WEIO (IEA, 2003). According to the WEIO, total costs for liquefaction, shipping and regasification have fallen from about

\$14.00/mcf in 1995 to about \$10.12/mcf in 2000, and will continue to fall to about \$7.99/mcf by 2010. In order to extrapolate this progress, we fit a regression equation of the form:

$$Cost_t = \alpha + \beta \cdot \ln(Time) \tag{9}$$

to the point estimates of past, current and future costs for each piece of the LNG "value chain" (liquefaction, shipping and regasification). Figure 10 depicts the resulting cost estimates through 2040.



Source: *World Energy Investment Outlook, 2003*, International Energy Agency

Figure 10: Technological progress in transporting LNG

We also used historical data to estimate the costs associated with building pipelines. The EIA has published project specific data for 52 pipeline projects in the report "Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002". We used this data to estimate a regression equation (with an R^2 of 0.690) that expresses the up-front cost per unit of capacity (also known as the specific capital cost, SCC) as a function of miles, capacity, and geography. OLS regression on the cross-section data yields the following estimates:

$$\ln(SCC_i) = \underset{(0.514)}{-0.152} + \underset{(0.072)}{0.290} \cdot \ln(miles_i) - \underset{(0.108)}{0.384} \cdot \ln(capacity_i) + \underset{(0.260)}{0.776} \cdot D_{Mountain,i} + \underset{(0.323)}{1.072} \cdot D_{Water,i} + \underset{(0.252)}{1.243} \cdot D_{Population,i} \tag{10}$$

where the variables $D_{n,i}$ are indicator variables that take the value of 1 or 0. For example, if the project is in a mountainous region, is offshore, or crosses densely populated areas, then $D_{Mountain,i}$, $D_{Water,i}$, and $D_{Population,i}$, respectively, take the value of 1. The positive coefficients indicate that an increase in length, crossing mountains, moving offshore, and/or developing in populous areas will raise the cost of a project. The negative coefficient on ln(*capacity*) indicates that larger capacity results in *per unit* cost reductions, which implies that there are economies of scale associated with pipeline construction.

Equation (10) was then used to estimate the cost of any generic pipeline project based on miles, capacity, and geographical location. For example, the Gulfstream project, extending from Mobile Bay, Alabama to Tampa Bay, Florida, is calculated according to the EIA data to have a SCC of $3.05 per mcf. The estimated value using the methodology applied herein is $3.20 per mcf. Likewise, the estimated SCC of the Kern River Pipeline is $2.63 per mcf.

A rate-of-return calculation generated the tariffs on pipelines. Specifically, the tariff rate was calculated such that the present value of the tariff revenue at 50% capacity utilization, using the required return on investment (see next section) as a discount rate, just recovers the up-front capital cost in twenty years. As an example, suppose the weighted average cost of capital (WACC) is 8.4%. To recover an upfront outlay of $3.20 per mcf (such as the Gulfstream pipeline) over a period of twenty years, the tariff would need to be about $0.46 per mcf. However, pipeline capacity is not always fully utilized. In practice, the tariff typically allows some costs (for example maintenance and fuel) always to be recovered, while another proportion is dependent upon capacity utilization. For example, any molecule of gas transported on a pipeline (such as the Gulfstream) may incur a charge of, say, $0.06 plus a 1.5% fuel charge. As capacity utilization rises from 0% to 100%, the tariff on the pipeline grows. This occurs because as capacity becomes scarce, shippers bid up the price of using the pipeline. We set the parameters describing this scarcity premium such that at any load factor above 50%, the pipeline owner earns rents. In the case of the Gulfstream pipeline, the tariff rises to $0.46 per mcf at 50% utilization, and $0.75 per mcf at 92% utilization, which would be akin to a fully loaded rate. The tariff can then rise as high as $15 per mcf at a load factor of 100%, although this will not occur in an unconstrained long run equilibrium. Such rents would more than compensate for capacity expansion, or alternative supply options will develop.

Required returns on investments

The BIWGTM solves not only for a spatial equilibrium of supply and demand in each year, but also for new investments in resource development, transportation, liquefaction, and/or regasification capacity. The investments are assumed to yield a competitive rate of return, such that the NPV of the marginal unit of capacity is non-negative. The project life of all new investments is assumed to be 100 years, and the tax life is assumed to be 20 years. The tax levied on income earned from projects is assumed to be 40%, and property tax and insurance is assumed to be 2.5%.

The model uses a weighted average cost of capital to determine the net present value of each increment of new capital. The debt-equity ratio is allowed to differ across different categories of investment. Pipeline investments are taken to be the most highly levered (with 90% debt) reflecting the likelihood that pipeline transportation rates will be regulated, and hence, the income stream will be very predictable. LNG investments are assumed to have a higher equity level (30% equity). Most of these will only be undertaken if a substantial fraction of the anticipated output is contracted in advance using bankable contracts. Mining investments are taken to be the most risky category with an assumed debt ratio of only 40%. In addition to differing levels of leverage, the different categories of investments are assumed to have differing required rates of return on equity again as a reflection of differing risks. Specifically, the required return on equity (ROE) for pipeline capacity is 12% (real), and the ROE on upstream investments is 15% (real). The real interest rate on debt is set at 8% for all projects. The assumptions regarding required returns are based on numerous meetings with industry sources.

The Reference Case Solution

Figure 11 presents the supply projections in the Reference Case. In many cases, these have been aggregated at the regional level to make the graph easier to read. Table 3 in the appendix presents the numerical results for a larger number of individual countries and a selection of years. Table 4 presents similarly disaggregated results for demand. It is important to note that the Reference Case represents the outcomes of a world in which there are no political constraints.

Thus, by corollary, one could think of these results as occurring if the countries throughout the world shared relationships similar to those shared by Canada and the U.S.

The model suggests, absent potential policy constraints, that Russia will play a pivotal role in price formation in a more flexible and integrated global natural gas market. Russia is projected to be the single largest producer of natural gas until 2040, although beyond 2038 the Middle East as a region (which, of course, is an aggregation of countries) becomes the largest global supplier. Russia is also strategically positioned to move large amounts of gas to consuming markets in both the Atlantic and Pacific, giving it the potential to play an important role in linking prices between the two regions. In the Reference Case, Eastern Siberian gas begins flowing into Northern China at the beginning of the next decade, and eventually flows into the Korean peninsula. Toward the end of the model time horizon, specifically 2035-2040, northeast Asian demand grows sufficiently to make the construction of a pipeline from Western Siberia to Eastern Siberia economic, and gas begins to flow into China from Western Siberia. Throughout the model period, Russia is also a very large supplier to Europe via pipeline. Once Russian pipeline gas is simultaneously flowing both east and west, production in the Western Siberian basin becomes the arbitrage point between Europe and Asia, thus linking gas prices in the two regions.

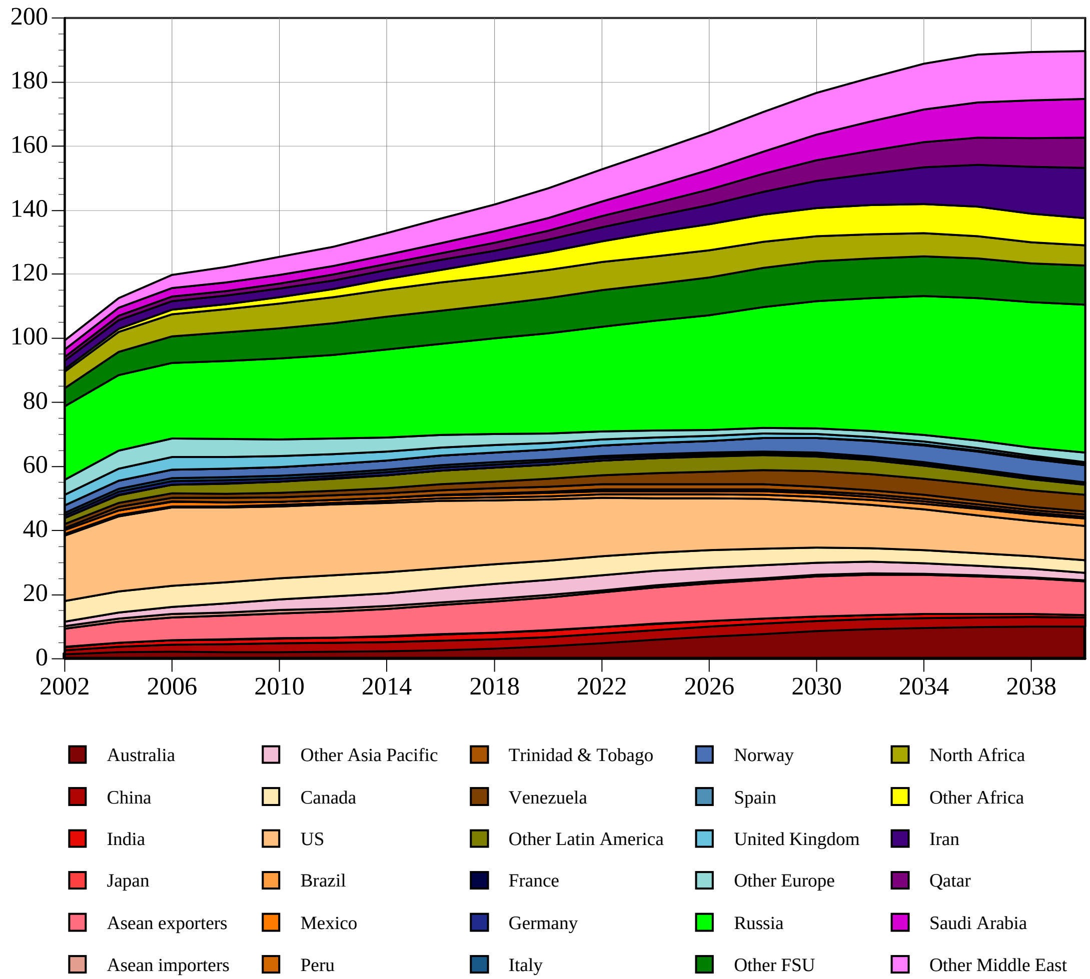


Figure 11: Supply projections – major countries or regions

The model also indicates that Russia will enter the LNG export market in both the Pacific and Atlantic basins. In the Pacific basin, production in the Sakhalin region is exported as LNG but also flows to Japan via pipeline beginning in 2010. In the Atlantic basin, production in the Barents Sea eventually provides gas exports in the form of LNG beginning in the mid-2020's.[44] This ultimately provides another link between gas prices in North America, Europe and Asia. Specifically, when gas is simultaneously flowing in all three directions out of Russia, the "netback" price from sending the gas in any of the three directions has to be the same. Russia benefits not only from its location and size of resources but also because it was one of the first major gas exporters and has access to a sophisticated network of infrastructure already in place.

[44] Production from the Barents Sea also moves to Europe via a pipeline through St Petersburg from 2008.

Figure 11 also indicates that, in aggregate, the Middle East will become an important future supplier of natural gas, with production surpassing that of the U.S. in 2022 and North America as a whole in 2026. The largest exporters of the Middle Eastern region are Qatar, Iran, UAE, and late in the time horizon, Saudi Arabia. The majority of these exports occur as LNG. However, barring from consideration any prohibitive political factors, pipeline infrastructure is developed to move Iranian gas through Pakistan to India. In addition, existing infrastructure is expanded to move gas from Iran to Europe though Turkey and Armenia.

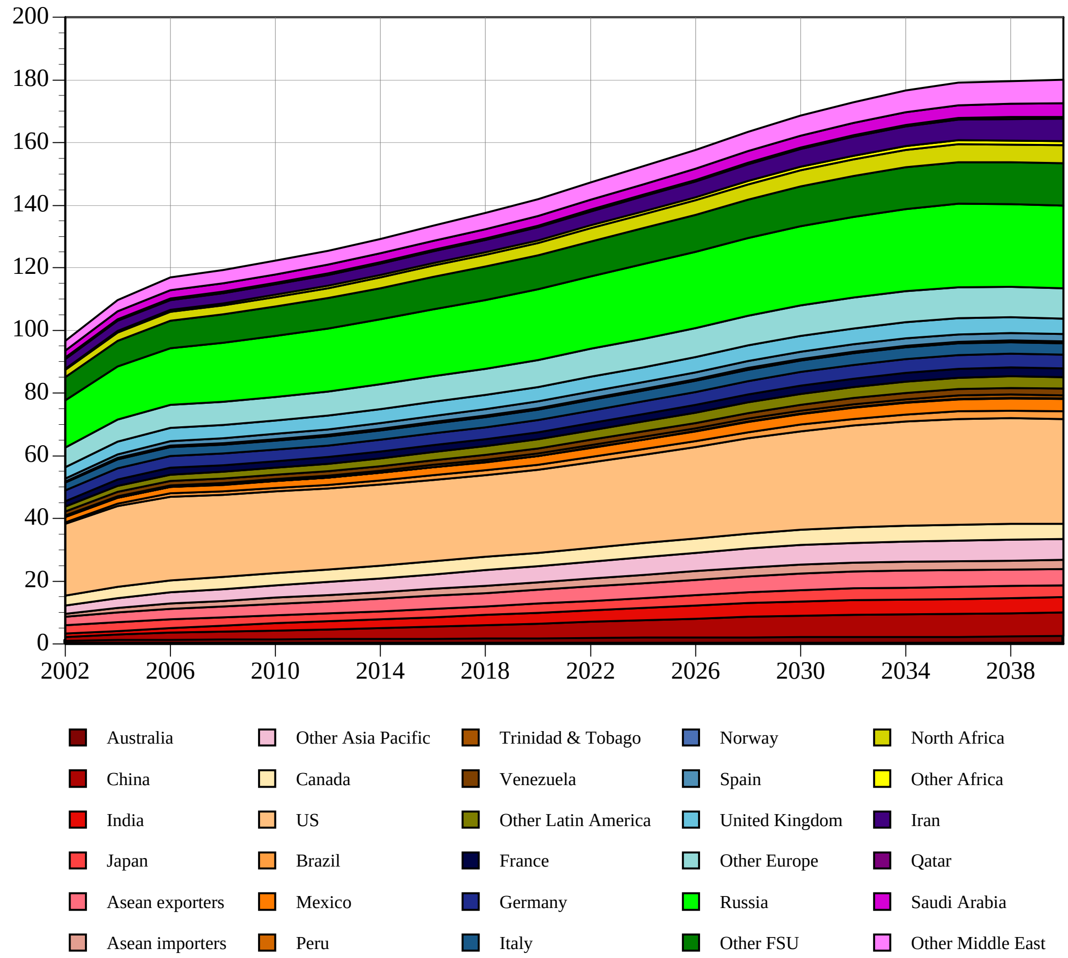


Figure 12: Demand net of backstop supply – major countries or regions

Figure 12 gives the demand projections for the Reference Case. (Note that quantity differences between Figures 11 and 12 are due to natural gas used as fuel in the transportation process.) Interestingly, although Russia is the largest single national source for natural gas throughout most of the model period, Figure 12 shows that Russia is simultaneously a large consumer. Demand growth in Iran and Saudi Arabia also limits exports from the Middle East. Thus, despite these countries' prominence in the future of global natural gas supply, their export capacity is limited by domestic requirements.

The largest consuming regions are North America and Europe. North American demand, in particular, is large prior to the introduction of the backstop technology beginning in 2020. Japan, which is primarily dependent upon LNG supplies, also adopts the backstop technology relatively early. The model also projects that strong European demand growth will eventually lead to fairly aggressive adoption of the backstop technology, but not before it draws on Nigerian supplies via the Trans-Saharan pipeline (from Nigeria to Algeria), which is constructed in the beginning of the next decade.

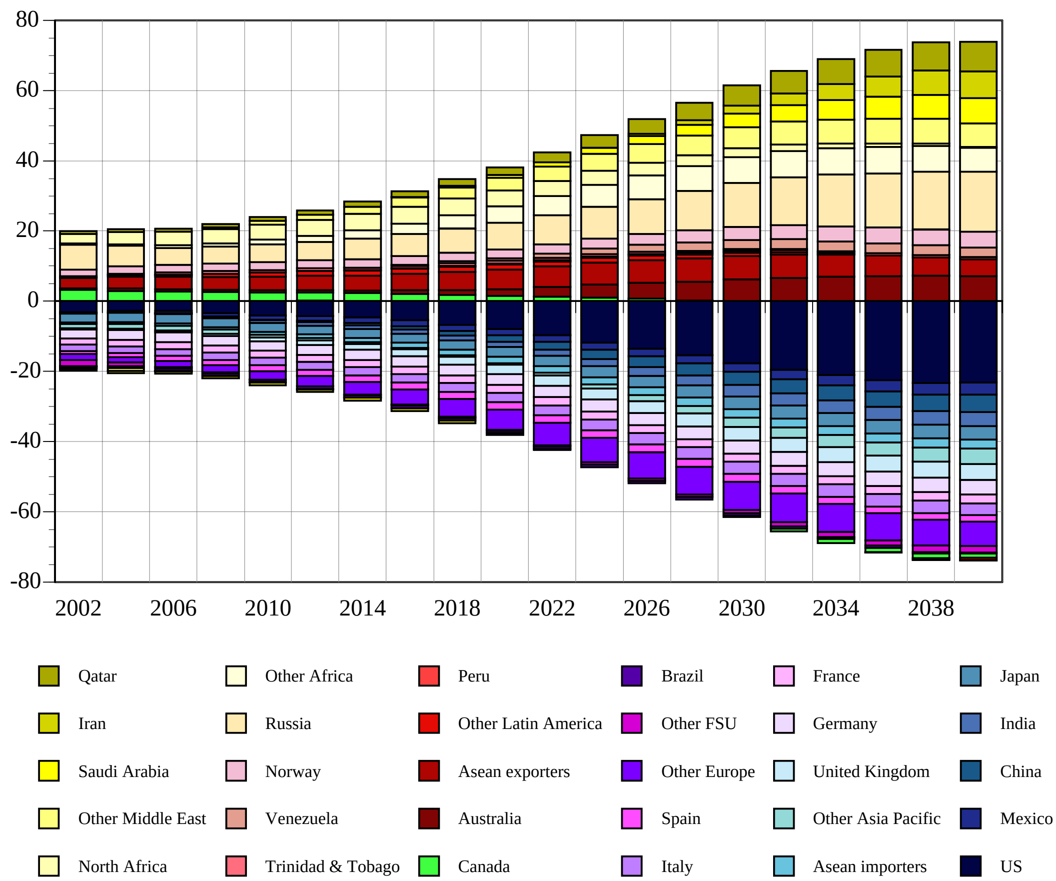


Figure 13: Major natural gas trades between regions

Figure 13 summarizes the implications of the above changes in supply and demand for international trade in natural gas via both pipeline and LNG. Note that this figure consolidates trade within each of the identified regions. Figure 14 focuses on LNG imports alone, while Figure 15 graphs model projections for LNG exports.

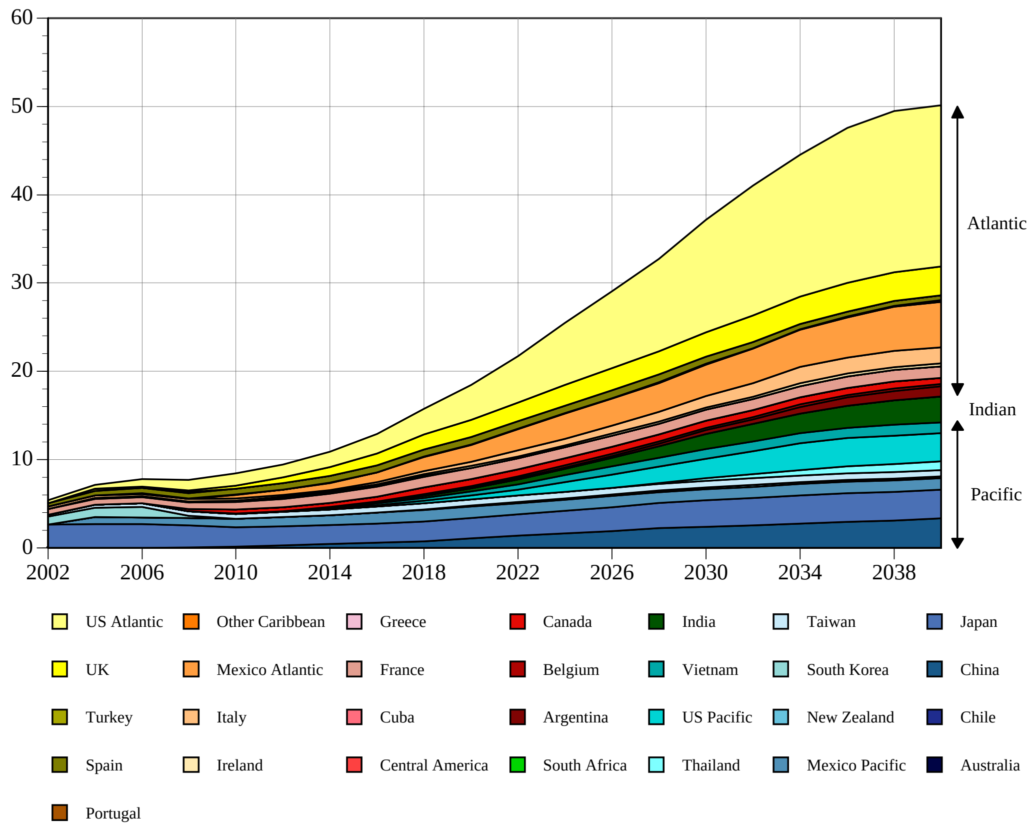


Figure 14: LNG Importers

The change in importation of LNG is particularly striking. While Japan is currently the largest importer of LNG, the U.S. assumes that role by the end of next decade. To some extent, this reflects a slight switch in Japan to pipeline imports with the development of a Sakhalin pipeline, but it also reflects the increasing inability of North American production to keep pace with North American demand. Price increases brought about by the depletion of low cost resources in North America allow LNG to take an increasing share of the North American market and serve to limit growth in demand. In addition, aggressive adoption of the backstop technology, particularly beyond 2040, abates demand somewhat. Nevertheless, the U.S. grows as an importer of natural gas throughout the modeling period. In fact, the United States market is projected to become a premium region drawing on gas supplies from around the world. Alaskan resources are an important source of future supply, as the model constructs capacity into Alberta beginning in 2014, but it neither collapses the North American price, nor eliminates the need for imported LNG.[45]

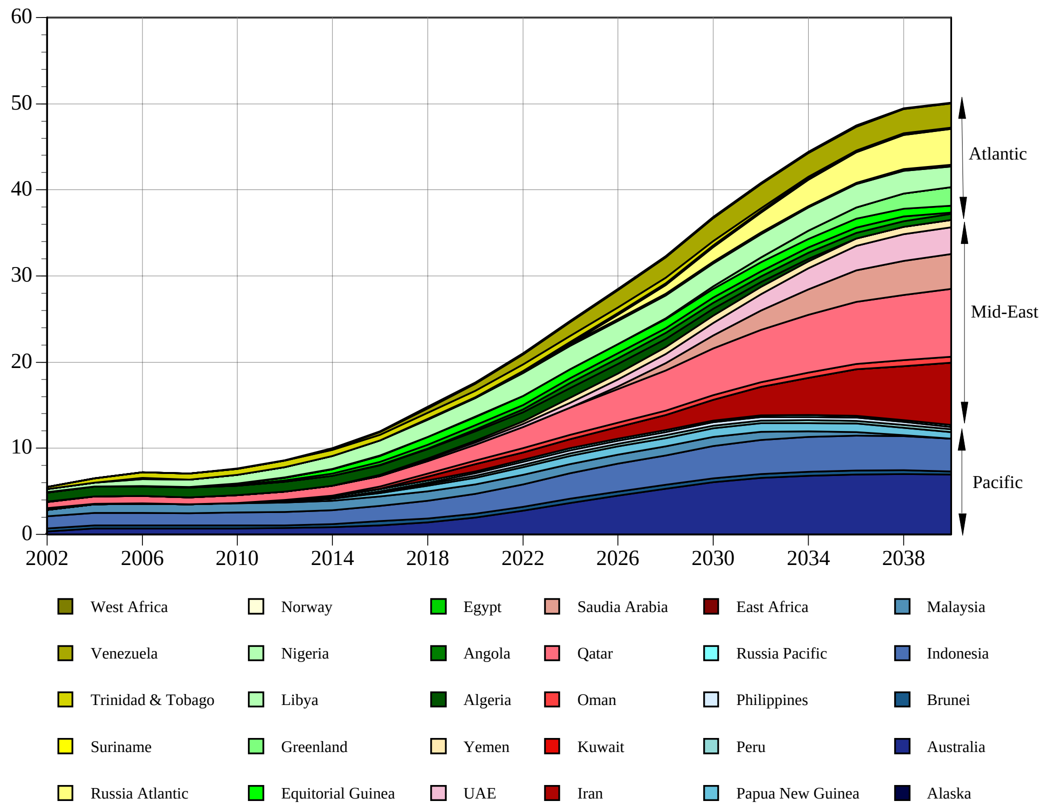


Figure 15: LNG Exporters

Mexico and Canada add to North American LNG imports by the end of the modeling horizon. Mexico (Pacific plus Atlantic imports) overtakes Japan as an importer of LNG at about the same

[45] Rather, Alaskan pipeline gas replaces declining Western Canadian Sedimentary Basin production, delaying further exploitation of marginal Canadian resources. This is not to say Alaskan gas is not beneficial. Rather, it serves to stabilize prices in the medium term. While many analysts have predicted a substantial price impact of Alaskan supplies, the model results suggest otherwise. With a lead time approaching 10 years, producers will have adequate time to adjust their behavior once an Alaskan project is announced. Thus, intertemporal arbitrage in complete forward markets will eliminate the impact that Alaskan gas has on the North American market.

time as the United States although some of that gas is actually destined for the U.S. market.[46] Mexican domestic demand growth is stimulated by Mexican government policy favoring conversion of existing fuel oil facilities as well as targeting gas as the fuel for new plants. Early in the period, demand for natural gas in Canada is stimulated by the production of oil from tar sands, while later in the model time horizon LNG imports into northeast Canada are stimulated by demand in the New England region of the United States.

Demand growth in Europe also outpaces indigenous production, making Europe the second largest importing region as a whole.[47] Increasing availability of the backstop also causes European imports to level off by the end of the model horizon. Europe imports via pipeline from Africa, the Middle East, and Russia as well as via LNG. The UK more or less matches Japan as an importer of LNG by 2020, while total European demand for LNG overtakes Japanese demand in the middle of the next decade.

High demand growth in India and China also affects world trade. In particular, the model implies that India and China also rival Japan as importers of LNG by 2030 even though LNG imports to China are limited to the southeast. In the early part of the model period, both India and China obtain supplies from domestic sources, while both countries also become large importers via pipeline.

Another notable feature of Figure 13 is the very small impact of South America in global natural gas markets. The continent as a whole is neither a large importer nor a large exporter of natural gas at any time in the model horizon. There is, however, substantial trade in gas between countries within the continent. In particular, Brazil and Argentina are large consumers and eventually become large importers as their domestic resources become relatively expensive.

Toward the end of the modeling period, the Middle East becomes the largest gas exporting region, with Qatar being the leading exporter from that region. Russia is a dominant exporter

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[46] A substantial portion of the Mexican imports into Baja California, which accelerate in the 2020's and 2030's, are also destined for the U.S. West Coast. The model assumes that LNG regasification terminals are cheaper to build in Mexico than in southern California. The cost differential is more than enough to compensate for the additional costs of piping gas to California.

[47] Note that trade between two countries in "other Europe," for example, is not counted as inter-regional trade for the purposes of Figure 13.

throughout the model period. In early years, Canada is a relatively large exporter to the U.S., but its exports fade by the early 2020s, with its balance largely offset by the import of Alaskan gas in transit to the lower 48 states. The ASEAN exporting countries remain significant suppliers throughout the model period although some ASEAN countries also become significant importers beginning in 2025. Australia also becomes a substantial exporter from 2025. The Australian share is particularly evident in the graph of LNG exporters (Figure 15).

Qatar, Iran, and to a lesser extent Saudi Arabia and the UAE also become large exporters of LNG. Although Iraq also develops into a large exporter, it utilizes pipeline routes (both new and existing) to Syria and Turkey and on to Europe. For the period up to 2015, Indonesia, North Africa, Malaysia, Australia, Qatar, Nigeria, and Trinidad and Tobago all have significant shares in LNG supply. By 2040, Qatar and Australia are the two largest LNG suppliers, followed in order by Iran, Russia, Indonesia, Saudi Arabia, the UAE, Venezuela, and Nigeria. The flow of LNG from the four largest suppliers makes up over half of all LNG supply in 2040. It is important, however, to note the scale of LNG exports. While these countries dominate LNG trade, they are not necessarily the largest suppliers of natural gas in the world. Russian exports by pipeline roughly equal the sum of the five largest LNG export volumes combined.

Qatar is an early leader in supplying LNG from the Middle East. Other resource-rich players lacking existing infrastructure needed to bear substantial fixed costs to enter the LNG market. Early entry would drive down prices and lead to inadequate returns on investment. Therefore, entry must be delayed until world demand in excess of alternative sources of supply is large enough to accommodate these incremental supplies. Thus, the principle of “first mover advantage” plays a crucial role in the development of the LNG market. Consequently, Iranian LNG supplies do not enter the world market until 2016. Saudi Arabia does not begin to supply LNG until 2022, and Russian Barents Sea LNG exports begin only in 2024. However, all three of these countries are also better placed than Qatar to supply large consumers via pipeline. Iran eventually supplies India and Turkey while Saudi Arabia supplies Egypt, Syria and Jordan, via pipeline.

Figure 16 provides price projections for six locations. Henry Hub and Zeebrugge already are reference pricing nodes. The exercise predicts that possibly Tokyo, Beijing or Delhi could evolve as representative pricing nodes in Asia and Buenos Aires in South America. The most prominent feature of Figure 15 is the convergence of prices over time as other countries, like Japan today, become dependent upon LNG as their marginal source of natural gas.

Increasing use of the backstop technologies leads to a reduction in prices beyond the model horizon. As end users substitute away from natural gas in the locations where gas becomes more expensive, the cost of gas for the remaining users actually declines, curtailing the demand for the backstop technologies. As a result of the backstop technology, natural gas is eventually (late in the century) only consumed in regions where it is in relative abundance, such as the Middle East, Russia and Australia.

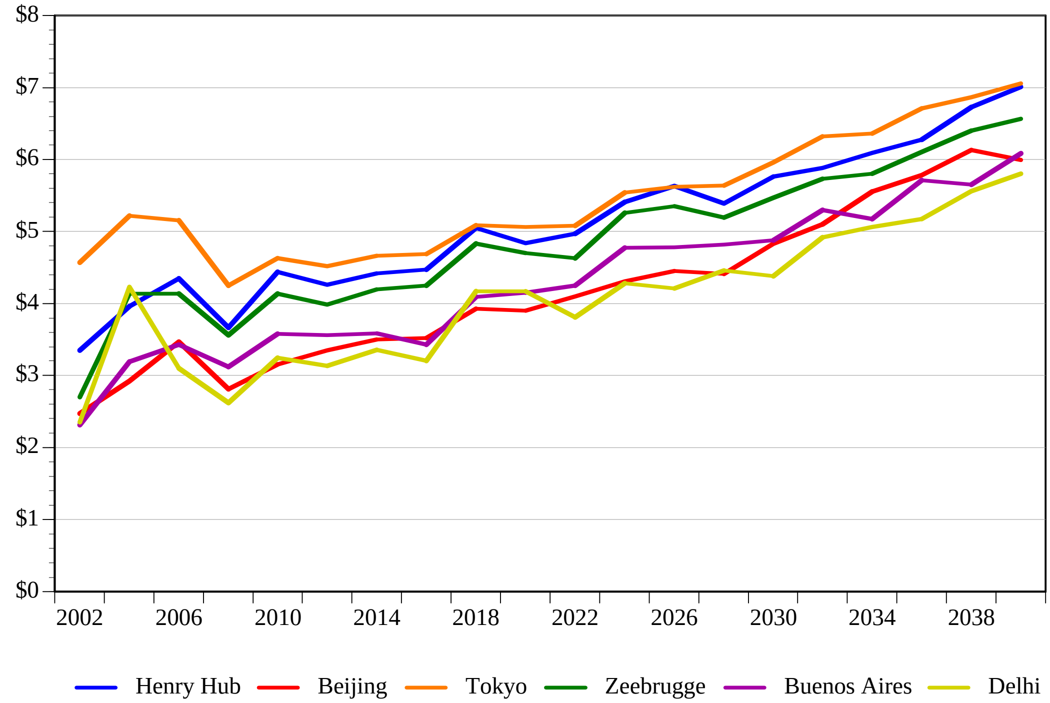

Figure 16: Representative price projections

Sensitivity studies

We conducted several sensitivity studies to assess the possible effects of various changes to the base case. Our choice of studies is motivated by factors that we expect to be of particular relevance to Japan and the potential role of Russia in meeting northeast Asian gas demand. The sensitivity cases examined herein are:

1. Russian resource and infrastructure development is delayed.
2. Pipelines connecting Eastern Siberia to China and South Korea, and Sakhalin to Japan are not allowed.
3. Japanese demand growth is accelerated.

The Reference Case results suggest that Russia is destined to play a pivotal role in a global gas market. Russia's importance as a global supplier may allow it to earn additional rents on gas resources by restricting the development of new sources of supply and driving up gas prices around the world. Government control of Russian gas production and transportation, effectively making it a monopoly, would be one mechanism for achieving such a goal, but the investment decisions of Russian producers could be coordinated without combining them into a single firm. Another means to achieving a similar end would be to impose a tax on natural gas exports. In the scenario discussed herein, we restrict the development of Russian resources by raising the required rate of return on Russian investments in the natural gas industry.

The discussion in the introduction of the various recent intrigues involving the Russian government and domestic and foreign gas producing companies suggests another motivation for the same experiment. Although it may not be the intent of the Russian government to slow development by raising questions about the nature or control of resource development lease agreements, or by reducing the commitment of new capital investment during ownership reorganizations or tax disputes, such a delay might be the unintended consequence.

The Reference Case solution involves the development of a pipeline network in northeast Asia. By the end of the model horizon, pipelines stretch across Russia delivering Western Siberian gas to China. Although Korean demand is met initially using LNG imports, ultimately Korea imports pipeline gas originating in Russia. The model suggests that pipelines directly from China to South Korea and from Siberia through North Korea could be profitable. Finally, the model also suggests that it will be profitable to pipe gas from Sakhalin to northern Japan. If one draws an analogy with North America, where gas already is piped thousands of miles, such projects sound reasonable from an economic perspective. The political relationships between Russia, China, Japan, and North and South Korea are, however, quite different from the relationships between the states in the United States, or between the United States, Canada, and Mexico. In particular, a project to build a pipeline through North Korea to supply Russian gas to South Korea does not seem politically feasible in today's world. Russia may also be reluctant to rely too heavily upon Chinese end-use markets, and China may become more wary of relying upon Russia as a major energy supplier. While we would, in principle, like to consider these different "political overrides" as separate variations on the base case, for ease of exposition, we combined them into a single case. The reason is that each of the changes causes a similar substitution of LNG for pipeline gas in northeast Asia so the changes in combination magnify the effects.

The final case increases the annual growth rate in reference demand for natural gas through 2025 to match historical growth from 1990-2000.[48] This results in an average annual increase in reference demand of about 1.5 percentage points although the realized increase will be lower as prices are higher in the higher demand case. The Reference Case assumes a rather low rate of growth in demand for natural gas in Japan (again holding prices fixed). A more optimistic view of future Japanese economic growth, or perhaps a less favorable attitude toward the development of nuclear power in Japan, would lead to a higher growth in demand for gas.

Scenario 1: Russian development is delayed

We delay development of gas resources in Russia by assuming that all equity investments in Russia need to earn a rate of return of 25% (real) instead of the default of 12% on pipeline investments and 15% on upstream investments. Figure 17 illustrates the resulting changes in natural gas supply. Figure 18 shows changes in liquefaction capacity alone.

From Figure 17, it is evident that the reduction in Russian supply stimulates increased output from a wide range of countries. The biggest aggregate production increases come from the Middle East (Saudi Arabia, Iran, Qatar, UAE and Iraq), Australia, Turkmenistan, and Norway. Other countries surrounding Russia (Kazakhstan, Uzbekistan, Azerbaijan, and Ukraine) increase

[48] Reference demand is demand at some constant price. Note also that the growth was calibrated through 2025 in order compare the results to the EIA IEO 2004. The calibration was done by adjusting the constant term from the regression. Beyond 2025, the growth rate declines as development progresses.

supply substantially in some years, but a considerable proportion of this supply increase comes at the expense of supply in other years, and thus the aggregate supply change is muted. Other countries showing a similar intertemporal shift in the pattern of production include Nigeria, Oman, and Papua New Guinea. Another prominent feature of Figure 17 is that the supply increases from other countries are not sufficient to offset the supply reduction from Russia so total world output of natural gas declines.

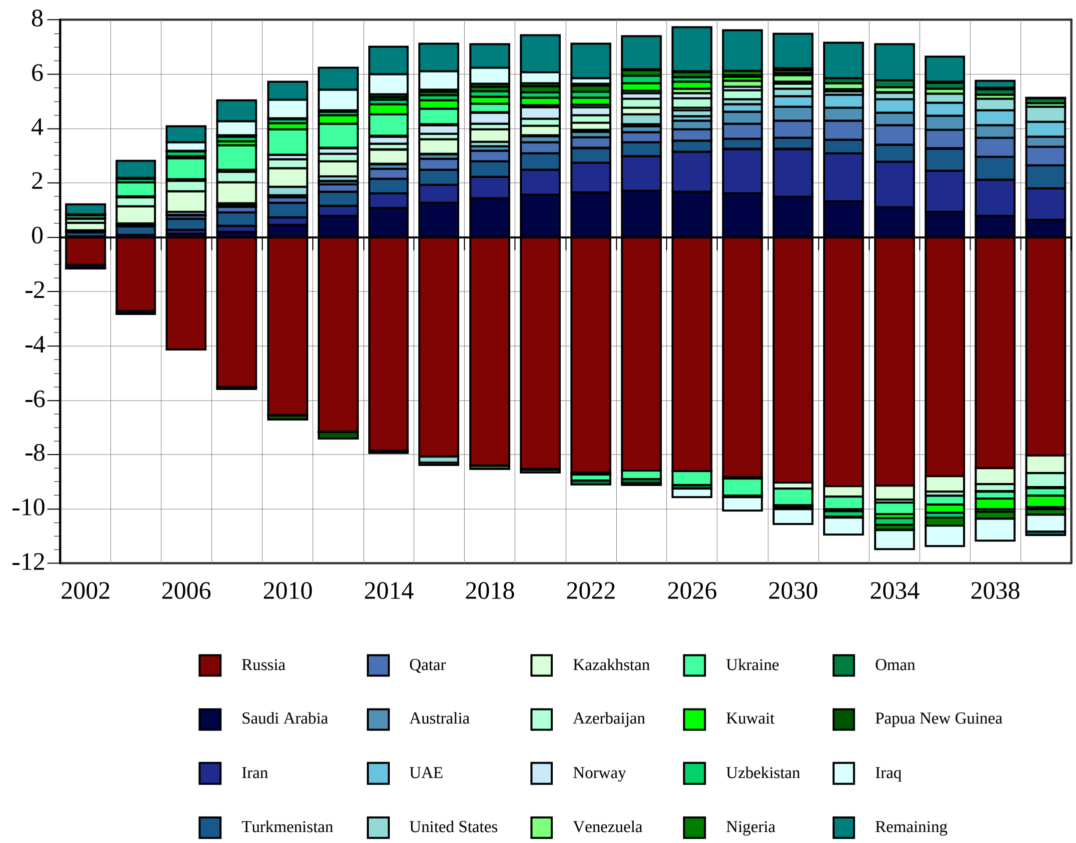

Figure 17: Supply changes following delayed Russian development

Figure 18 shows that delayed Russian development reduces the supply of LNG from both the Pacific and Atlantic coasts of Russia. In addition, although production of natural gas increases in both Saudi Arabia and Iran, the supply of LNG from these countries falls. This occurs because both countries increase exports of gas to Europe via pipeline to compensate for reductions in supply from Russia. Similarly, Algerian exports of LNG fall, albeit by a smaller amount, allowing an increase in pipeline exports of natural gas to Europe from North Africa.

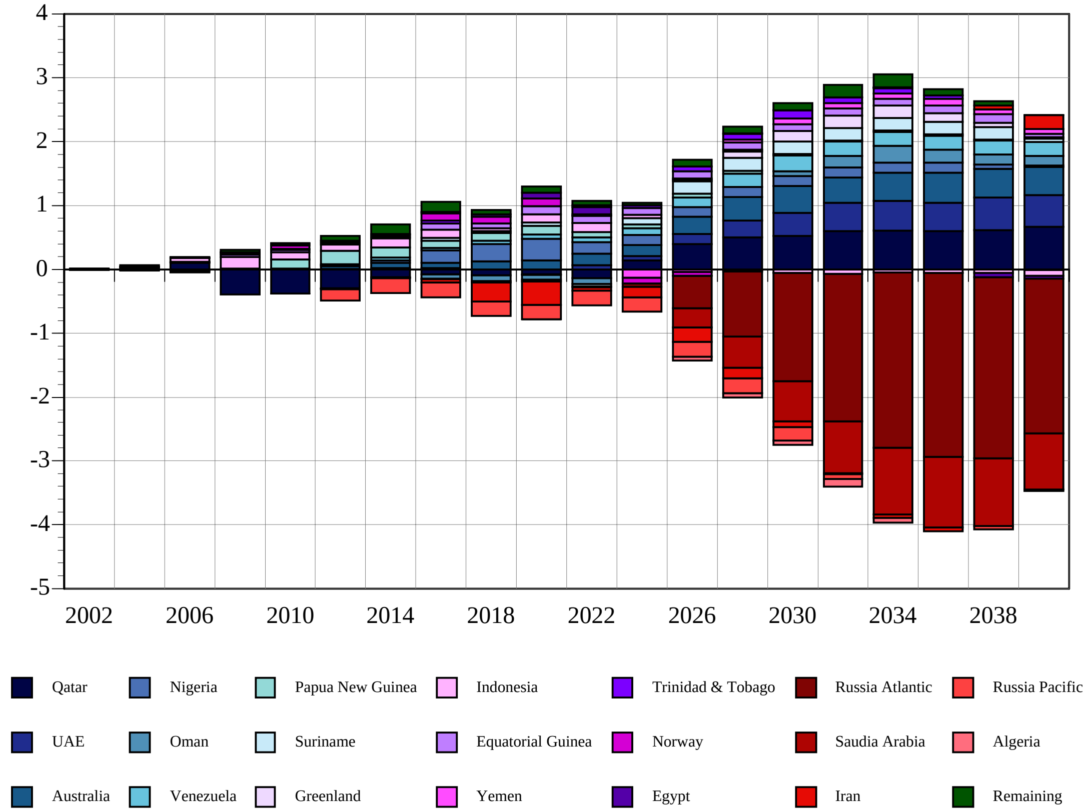

Figure 18: Changes in LNG supply following delayed Russian development

A range of other countries, including Qatar, the UAE and Oman in the Middle East, Australia, Papua New Guinea, and Indonesia in Southeast Asia, Egypt, Nigeria, and Equatorial Guinea in Africa, Norway and Greenland in the North Atlantic and Trinidad and Tobago, Venezuela, and Suriname in South America, expand LNG supply. This expansion more than offsets the reduction in LNG supply from Russia and other sources up to 2030. Under this scenario, increased supply of LNG partially compensates for the net reduction in pipeline supplies in Europe and Northeast Asia.

Figure 19 shows that because the supply from other sources is insufficient to fully compensate for reduced Russian supply and prices are generally higher, aggregate world demand for natural gas declines for all years beyond 2002. Russian consumers, followed by consumers in the U.S., China, India, South Korea, and Germany, suffer the largest decline in overall demand as a result of delayed Russian development.

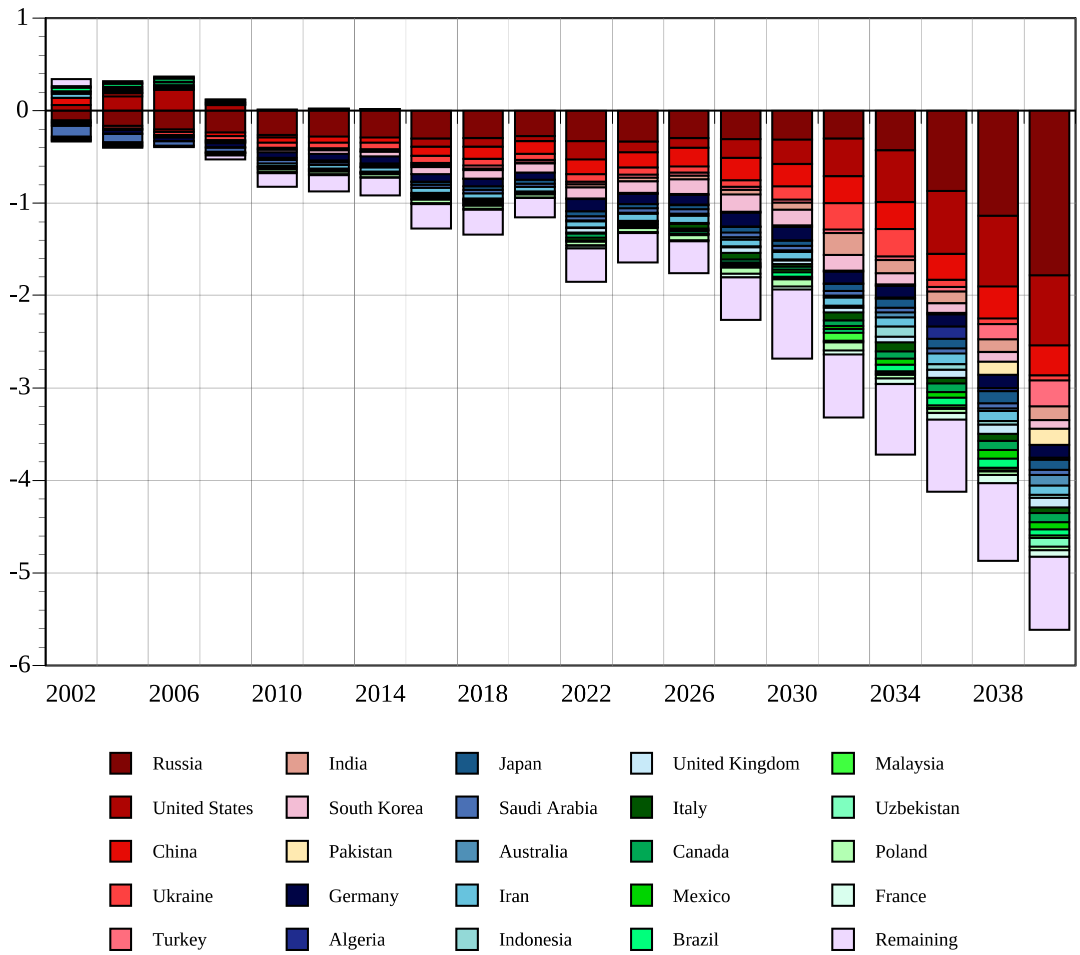

Figure 19: Demand changes following delayed Russian development

In the near term (through 2008), a redistribution of supply limits the decline in aggregate demand. In the long run, however, the overall decline in demand is substantial and spreads across the globe. In particular, the large "remaining countries" category in Figure 19 shows that the sum of small demand changes is substantial when aggregated over a large number of countries.

Figure 20 illustrates the change in LNG demand only. Figure 17 shows that the largest decline in LNG supply is from the Russian Atlantic coast while the biggest expansions occur in the Middle East and Southeast Asia. This trend would by itself tend to favor expansion of LNG trade in the Pacific basin. Thus, it is not surprising to see LNG imports expand into Japan, South Korea, and the Mexican and U.S. Pacific coasts. However, the reduction in demand in China that results from higher prices due to a lack of pipeline supply from Eastern Siberia is sufficient to allow Chinese imports of LNG to decline. Expansion of LNG imports into the west coast of North

America also displaces some imports into the Atlantic coasts of Mexico and the United States. This, in turn, frees up some Atlantic Basin supply to move to countries in Western Europe (France, U.K., Belgium. and Portugal) to offset declining supplies of pipeline gas from Russia. An increase of pipeline imports from North Africa, however, allows Spain to actually decrease LNG imports.

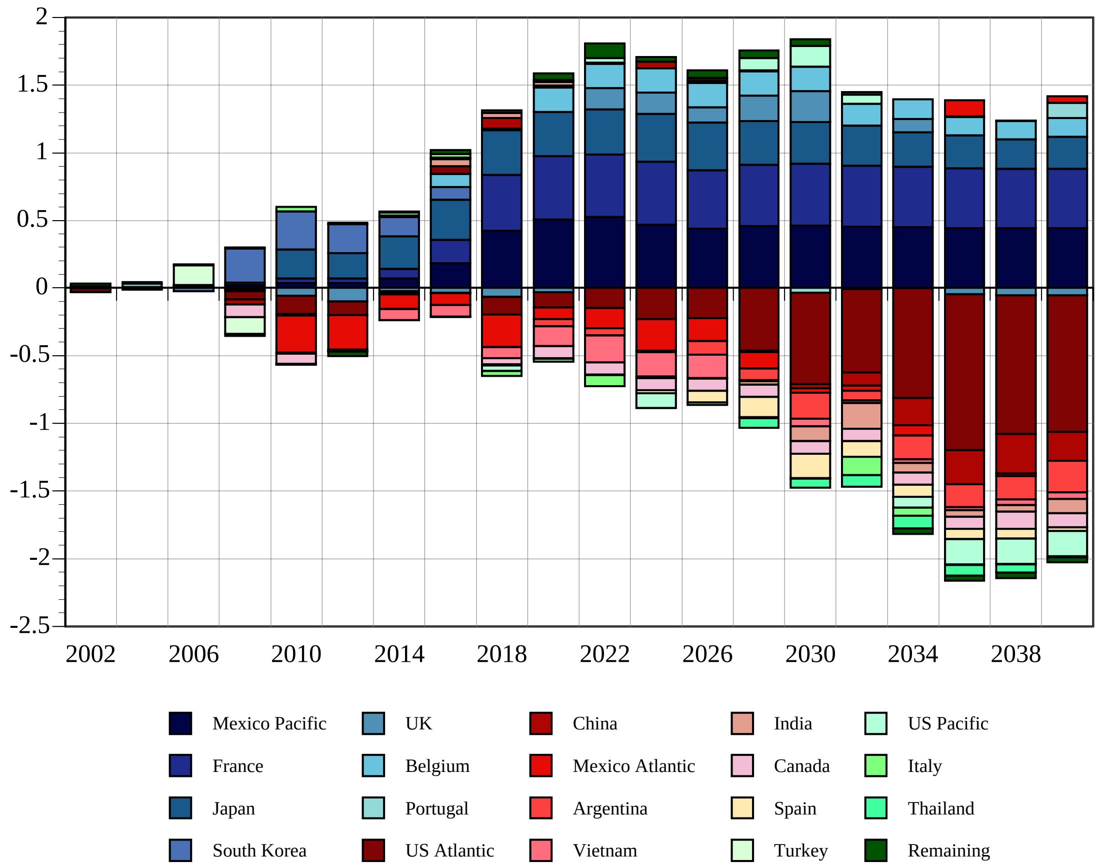

Figure 20: Changes in LNG demand following delayed Russian development

If the percentage change in prices and elasticities of demand were constant across countries, the declines in demand would be proportional to initial levels of consumption. The declines graphed in Figure 19 differ from this "benchmark" case partly because the elasticity of demand depends on the level of demand. However, as Figure 21 illustrates, the changes in prices also differ across countries.

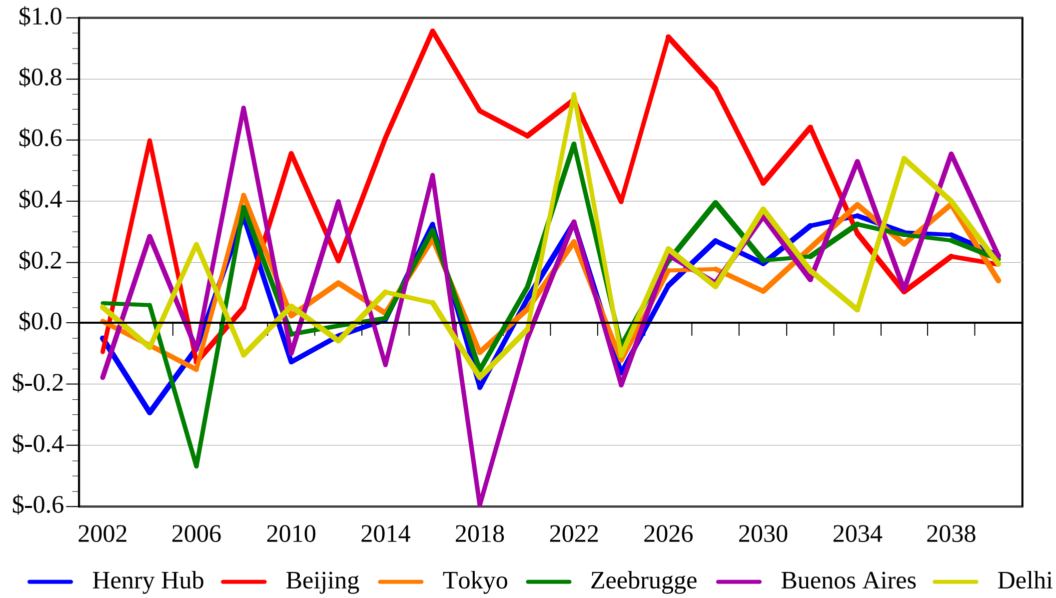

Figure 21: Changes in prices following delayed Russian development

The price changes graphed in Figure 21 are much more volatile than the original price paths graphed in Figure 16. The explanation is that the timing of many large investments changes between the two scenarios. When a large investment is delayed, prices increase in the year of the delay but subsequently decrease when the investment eventually comes on line. These fluctuations make the changes difficult to interpret. Delayed Russian development raises prices on average in all locations, but the increase is substantially larger in Beijing than elsewhere. The impact in China is largely due to the fact that a lack of pipeline supplies to China will result in increased dependence on LNG. This, in turn, pushes Chinese gas prices closer to those in South Korea and Japan. Henry Hub, Tokyo, Zeebrugge, and, to a lesser extent, Delhi, all display a positive trend in the price differential.[49] While there is no significant overall trend in the Beijing price change, the average price change is higher. From 2002–2012 and again from 2034–2040, the price change in Beijing is similar to the other cities, with the higher prices being restricted to 2012-2034. The convergence in the price changes toward the end of the period is due to the increasing use of the backstop technology (at the same price) in all locations.

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[49] The average price change (in real terms) over the entire period of analysis (2002-2040) was $0.110 in Henry Hub, $0.440 in Beijing, $0.132 in Tokyo, $0.145 in Zeebrugge, $0.156 in Buenos Aires and $0.142 in Delhi. The price changes in Henry Hub, Tokyo, Zeebrugge and Delhi also had a positive trend of around $0.01 per year that was significantly different from zero.

Scenario 2: No Russian Pipes to China, South Korea or Japan

Figure 22 illustrates the supply consequences of preventing the construction of pipelines to China, South Korea, and Japan from Russia. The motivation for considering this change is that actual or potential policy impediments might override the economic incentives to engage in such mutually beneficial trade.

Prohibiting pipeline transport into Northeast Asia raises the cost of transport to market for Eastern Siberian gas, as the nearest market becomes LNG through Nahodkha or Western Russia. Thus, the rents to the wellhead, once accounting for transport costs, are significantly reduced making Eastern Siberian gas much less attractive relative to other supply options in the global market. Hence, total Russian production declines. Production does, however, increase in a number of other locations, particularly in Australia, Norway, and Turkmenistan. These countries benefit the most from constraints on pipeline infrastructure development in Northeast Asia. Indeed, the graph of demand changes (Figure 23) shows that overall world demand is affected by less than 1 tcf in most years, indicating that these marginal supplies are capturing market share without having a significant impact on price.

Of the Northeast Asian countries directly affected, China is the only one with substantial domestic resources. It expands domestic production, but there are insufficient resources to replace the lost Russian imports. The acceleration of domestic production in China actually stimulates domestic demand over the rest of this decade, and is a major reason total world demand increases slightly.

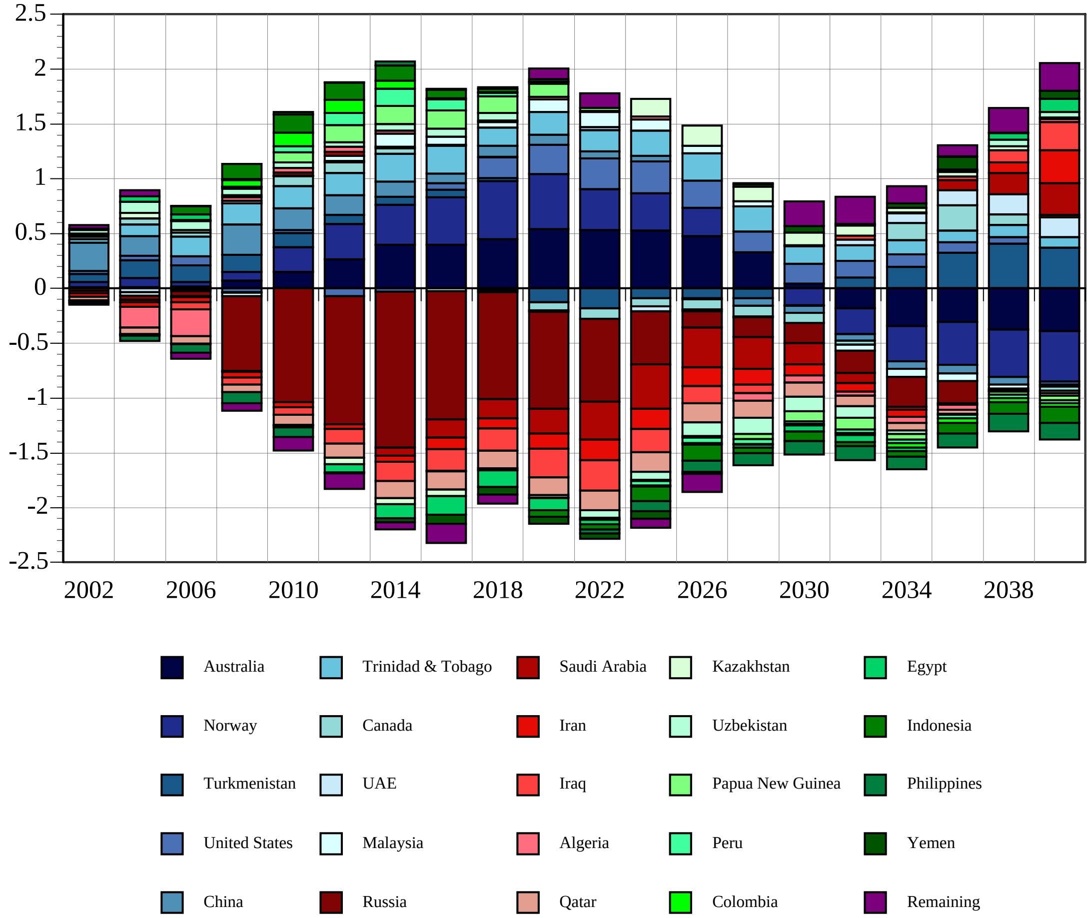

Figure 22: Supply changes with restricted Northeast Asia pipelines

Another reason that overall world demand increases on net in the short term is that restricting Russian gas exports by pipeline to the east lowers prices within Russia. This occurs despite the fact that Eastern Siberian gas does not flow west until 2008. In an intertemporal rational expectations equilibrium, the knowledge that infrastructure will be developed to move Eastern Siberian supplies to Western Siberia encourages earlier development of Western Siberian deposits. This lowers prices in the near term and increases consumption within Russia, as well as in Ukraine, Belarus, Germany, and other European countries that import gas from Russia.

An interesting feature of Figure 22 is that the acceleration of production in Australia and Norway results in reduced output from these countries beyond 2030. A similar acceleration of production can be seen in Kazakhstan, Uzbekistan, Indonesia, Papua New Guinea, Malaysia, the Philippines, Egypt, Yemen, Columbia. and Peru. Figure 24, which focuses solely on changes in the production of LNG, provides one explanation for this pattern. A major alternative use of Russian gas is to export it as LNG. Given that the pipeline exports are restricted only in Northeast Asia, increased exports are strongest from the Russian Pacific coast. The increase, however, occurs later in the time horizon. Thus, production from Australia and Indonesia serves to bridge the supply void left by a reduction in the immediate supply of Russian gas in the Pacific basin.

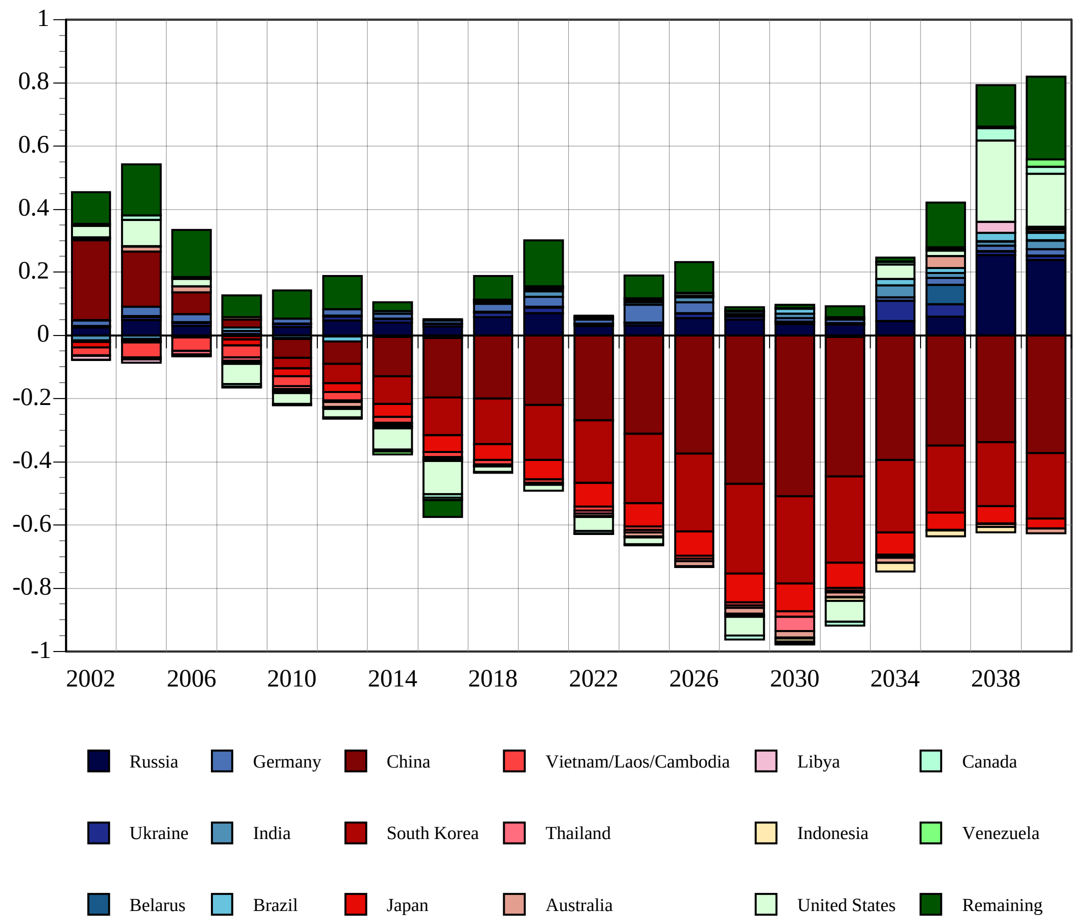

Figure 23: Demand changes with restricted Northeast Asia pipelines

The increased export of LNG from Russia might appear inconsistent with the notion underlying the original experiment. If China, Japan, and South Korea decline to import gas via pipeline from Russia, why would they import Russian gas as LNG instead? The answer lies in the fact that a pipeline would connect Russia and these countries as supplier and customer much more firmly than would increased LNG trade. In the latter case, the importing countries always have the capability to turn to the developing world market for LNG in the event of a disturbance in their political relationship with Russia.

Figure 25, graphing the changes in re-gasification capacity, shows that South Korea, China and Japan all substantially increase their LNG import capacity in response to the policy shock under consideration. Figure 24, however, also shows that it takes some time for Russia to expand its LNG export capability. This explains why other LNG exporters who can expand their capacity much more readily, such as Australia, Papua New Guinea, Brunei, and Indonesia, substitute for the lost Russian sales to Northeast Asia in the short term.

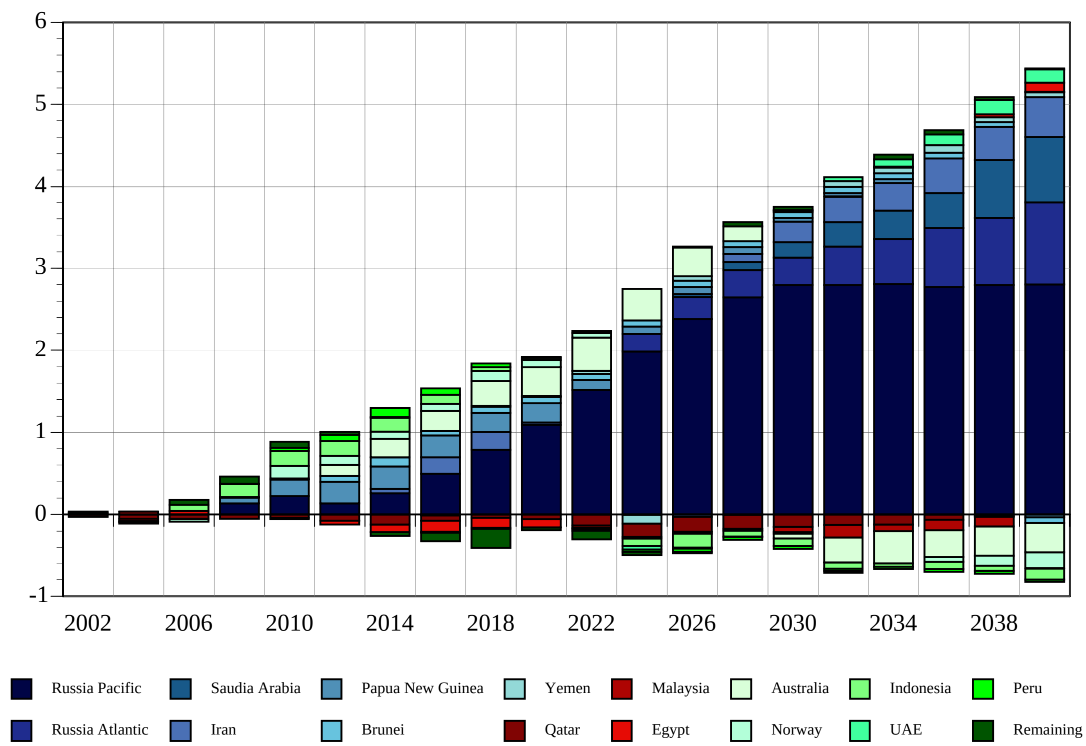

Figure 24: Changes in LNG supply with restricted Northeast Asia pipelines

There are some other interesting consequences of preventing Russian pipeline exports to Northeast Asia. We have already noted the increase in gas demand in central Europe as Russian exports to the west increase. Another consequence of this increased westward export of Russian gas is that it increases the competition that Middle Eastern supplies face in Europe. This explains the production declines in Saudi Arabia, Iran, Iraq, Qatar, and Algeria evident in Figure 22.

Figure 24 also shows that the reduced opportunities for pipeline exports of Middle Eastern gas encourage the expansion of LNG exports from Saudi Arabia, Iran, and Yemen. On the other hand, this provides increased direct competition for Qatar and hence Qatari LNG exports marginally decline.

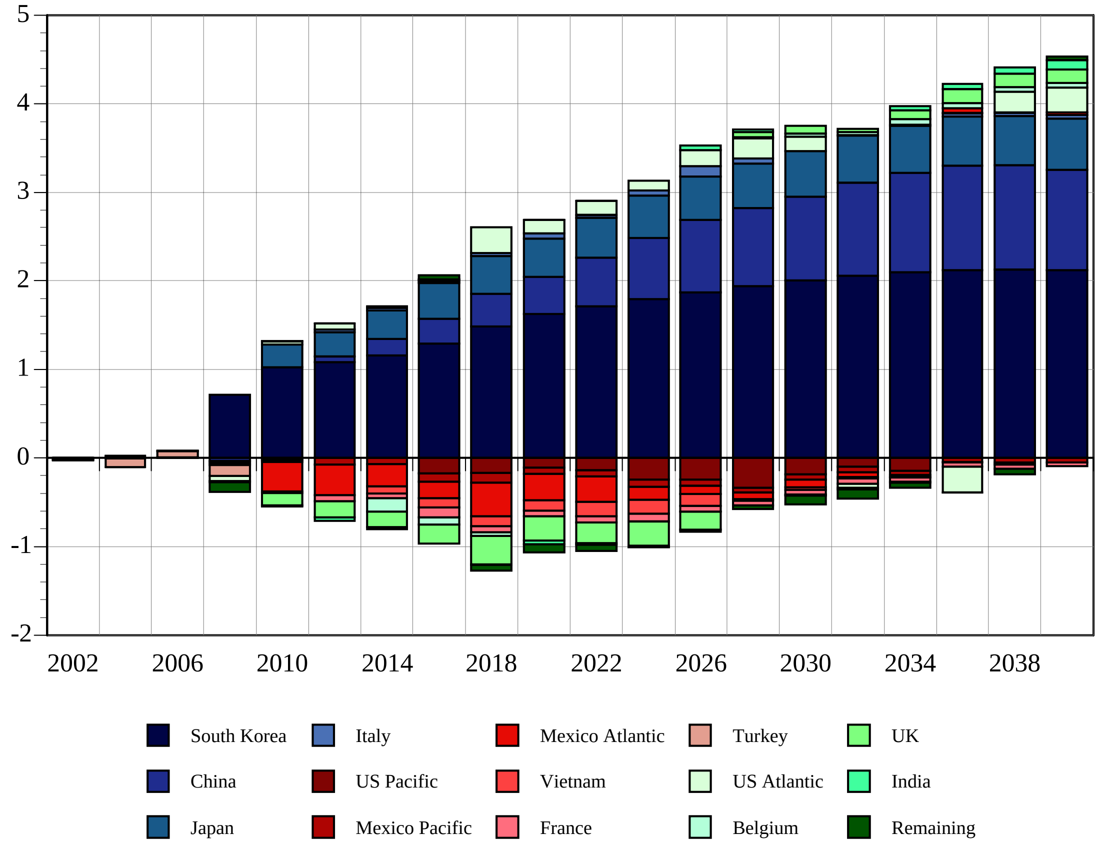

Figure 25: Changes in LNG demand with restricted Northeast Asia pipelines

Restricted pipeline construction in Northeast Asia also has repercussions in North America. Figure 25 shows that increased competition for Pacific basin LNG supplies reduces LNG imports into both the U.S. and Mexican Pacific coasts. These are partly compensated by increased LNG imports into the U.S. Atlantic coast. Figure 22 indicates that LNG supplies from Trinidad and Tobago allow for some of this increase. In contrast to the situation in the United States, imports into Mexico from the Atlantic as well as the Pacific basin decline. Increased production in Peru and Columbia, which also is evident in Figure 22, allow more aggressive development of pipeline import infrastructure into Mexico from South America through Central America, even though Figure 24 shows that Peru also supplies slightly more LNG to the expanded Pacific basin LNG market from 2010-2018.

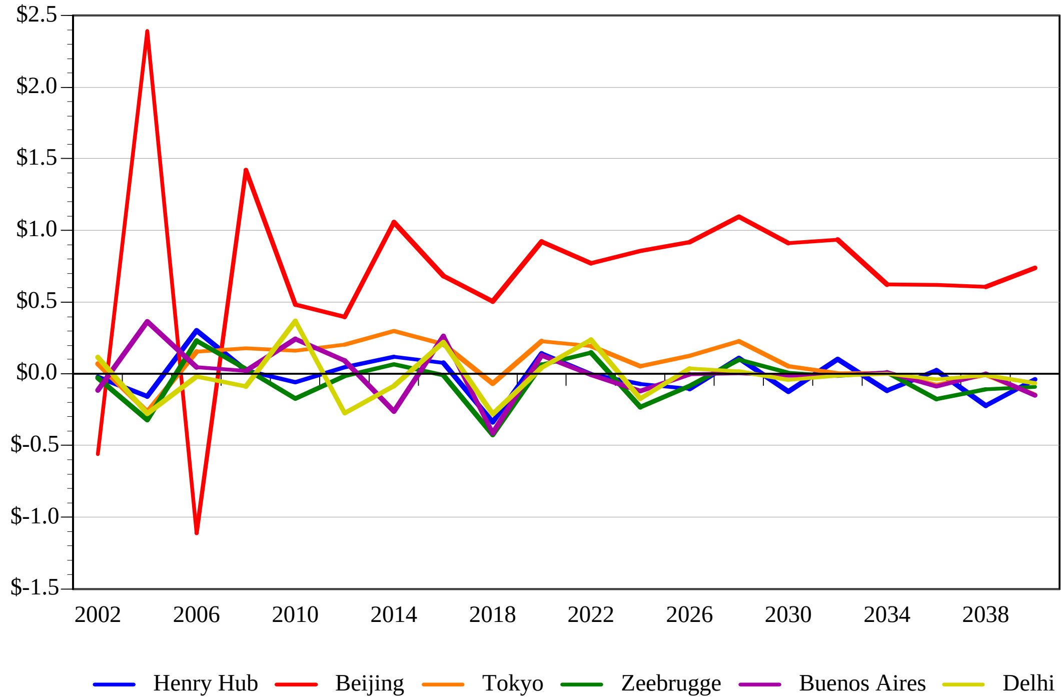

Figure 26: Changes in prices with restricted Northeast Asia pipelines

Figure 26 illustrates the effect of the policy experiment on natural gas prices. Reduced pipeline imports of natural gas to China raise gas prices in Beijing as China must rely on LNG to meet demand.[50] Tokyo also sees slightly higher prices on average, but in the remaining locations, average prices over the whole period (in real terms) decline slightly.[51] Another point worth noting is that expanded LNG trade more closely links prices in a greater number of markets to arbitrage points which lie offshore, thereby causing more rapid convergence of prices.

[50] The large swings in Beijing prices in the initial years again result from shifts in the timing of large infrastructure investments.

[51] The mean price changes over 2002-2040 were -$0.016 in Henry Hub, $0.713 in Beijing, $0.080 in Tokyo, -$0.052 in Zeebrugge, -$0.001 in Buenos Aires and -$0.017 in Delhi.

Scenario 3: Higher demand growth in Japan

Higher natural gas demand growth in Japan raises total world demand, but, in the long term, it also encourages more rapid adoption of the backstop technology. Increased Japanese demand, which raises price everywhere, tends to reduce demand in other regions. The largest such reduction occurs in the United States although China and, beyond 2034, Russia, also show significant demand reductions.

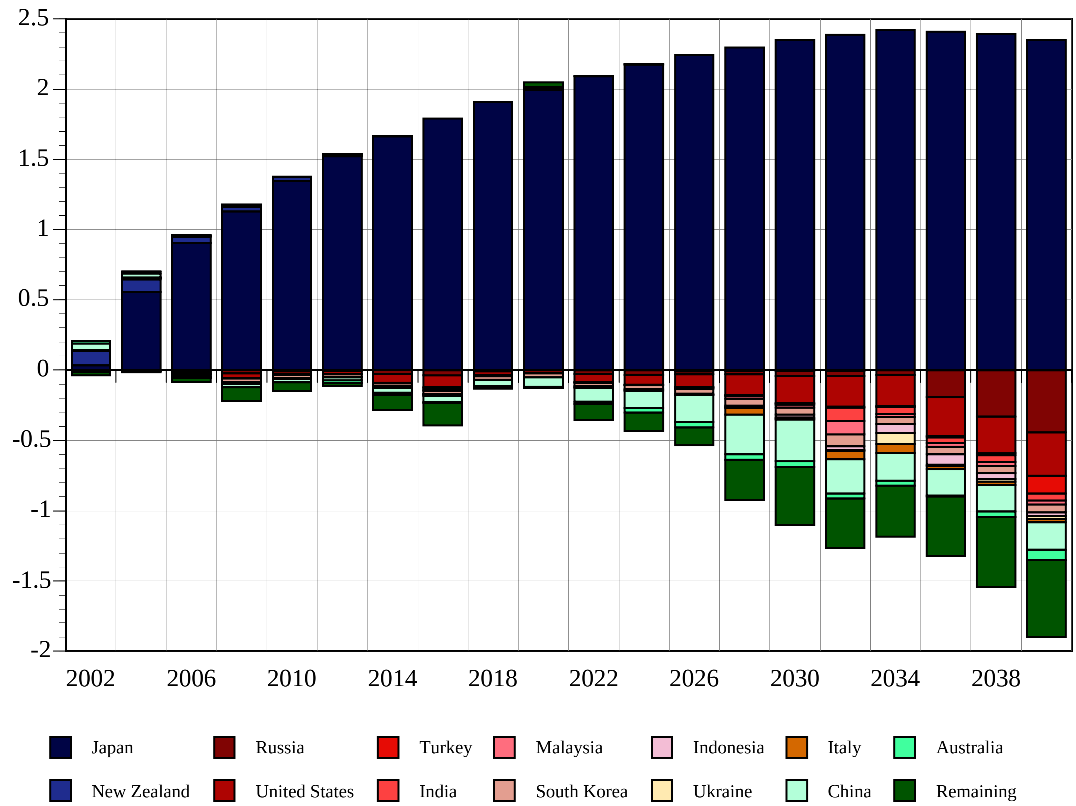

Figure 27: Net demand changes under higher Japanese demand growth

The graph of supply changes, Figure 28, shows that New Zealand production is shifted forward, and Australian production is increased substantially in response to the higher Japanese growth. Increased LNG trade in the Pacific basin pushes New Zealand producers to exploit domestic resources at a faster rate in anticipation of increased availability of LNG imports, particularly from Southeast Asia and Australia. Higher Japanese demand stimulates increased production from Australia and producers in Southeast Asia, including Indonesia, Malaysia, Brunei, Papua New Guinea, the Philippines, and Myanmar, although in most of these cases increased earlier production is offset by reduced production at a later date. Iraq, Iran, Turkmenistan, and, to a lesser extent, Saudi Arabia, show the opposite response of initially lower production followed by expanded production beyond 2030.

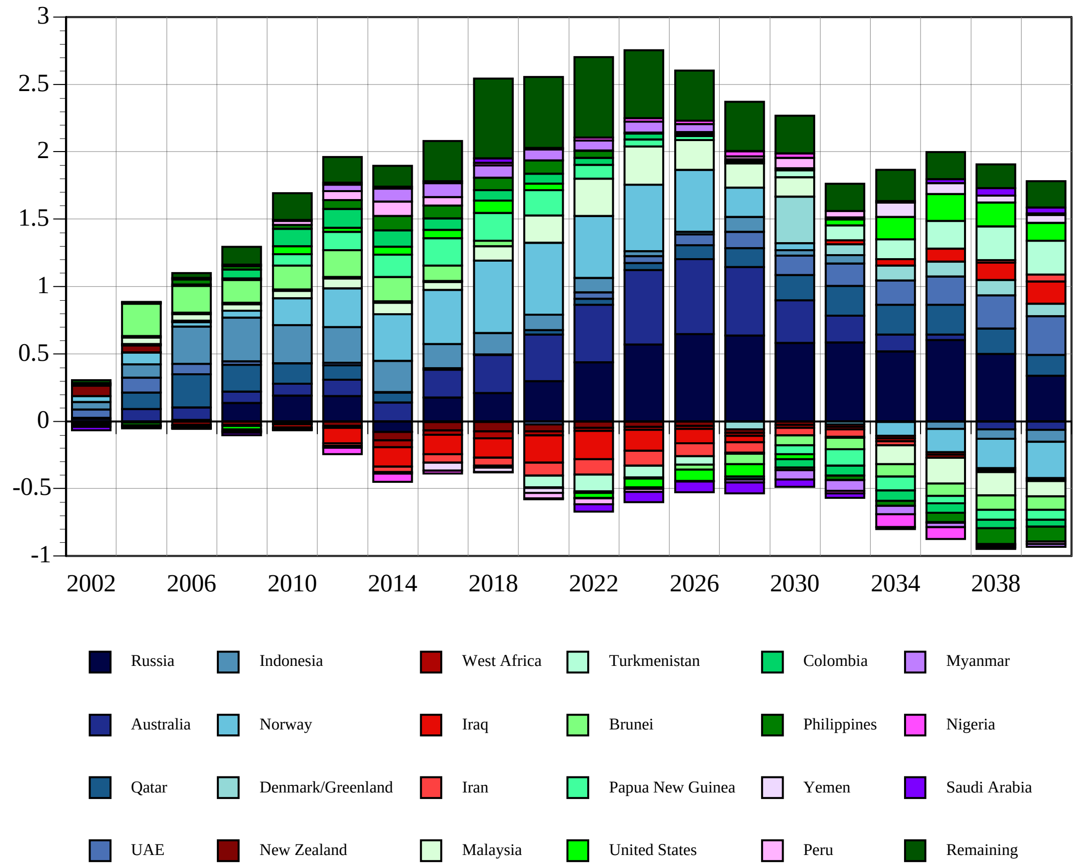

Figure 28: Supply changes with higher Japanese demand growth

Beyond 2020, Russia shows the single biggest increased supply response to the Japanese demand stimulus. Figure 29 shows, however, that a substantial part of this increase, particularly beyond 2030, is responding to indirect effects of the Japanese demand expansion. In particular, expanding Russian exports of LNG after 2030 come almost entirely from Atlantic basin ports. This occurs as a result of geography. In particular, Middle Eastern LNG holds a transportation advantage over moving additional Western Siberian supplies east via pipeline. Increased eastward movement of Middle Eastern gas facilitates an increased Russian presence in the Atlantic basin. It should be noted, however, that Russian pipeline flows to Japan do increase as well.

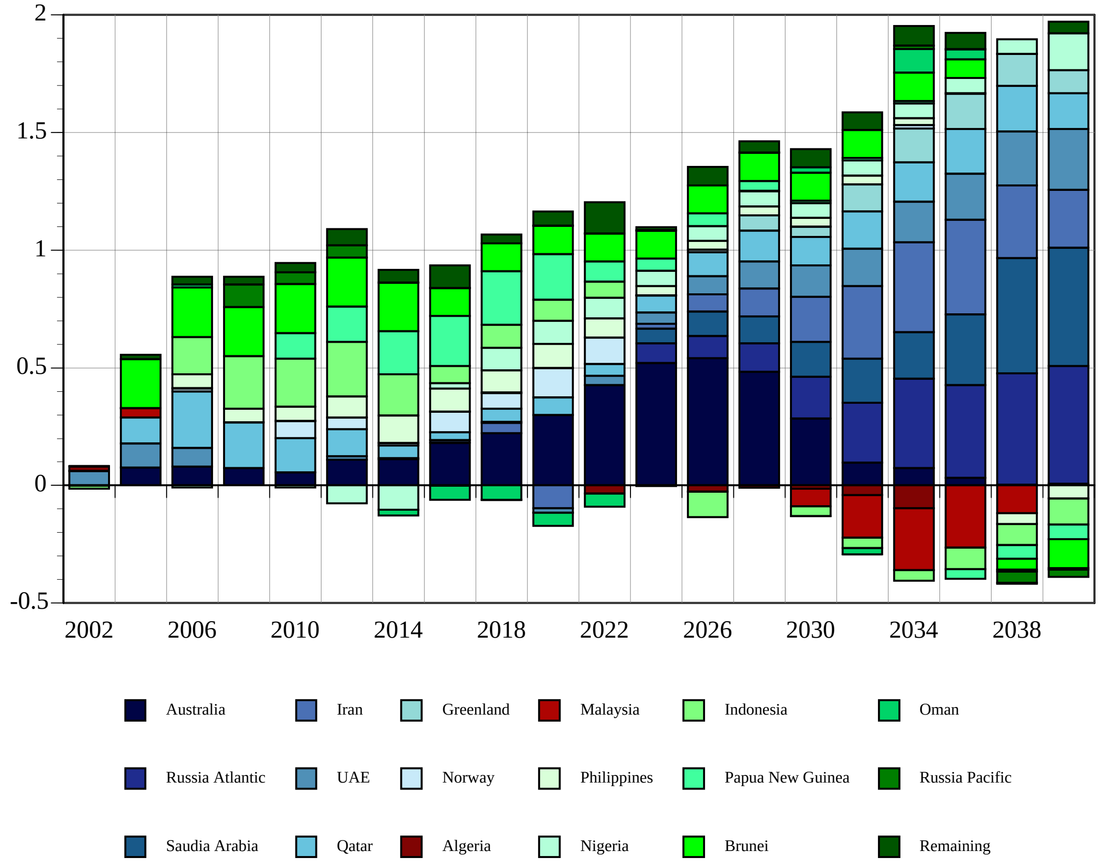

Figure 29: Changes in LNG supply with higher Japanese demand growth

The considerable expansion in supply from Norway is another notable feature in Figure 28. Figure 29 shows that a significant part of the Norwegian supply increase, particularly from 2016-2022, is exported as LNG. Again, the increased flow of Middle Eastern gas to the east allows Norwegian LNG (as well as Russian LNG) to fill the void in the Atlantic basin.

Figure 29 also shows that Australia has the biggest single LNG supply response to increased Japanese demand. The substantial acceleration of supply in Southeast Asia, noted from Figure 28, also is evident in Figure 29. Indeed through most of the 2010's increased Japanese demand for LNG imports stimulates supply in Brunei, Indonesia, the Philippines, and Papua New Guinea much more than Australia.

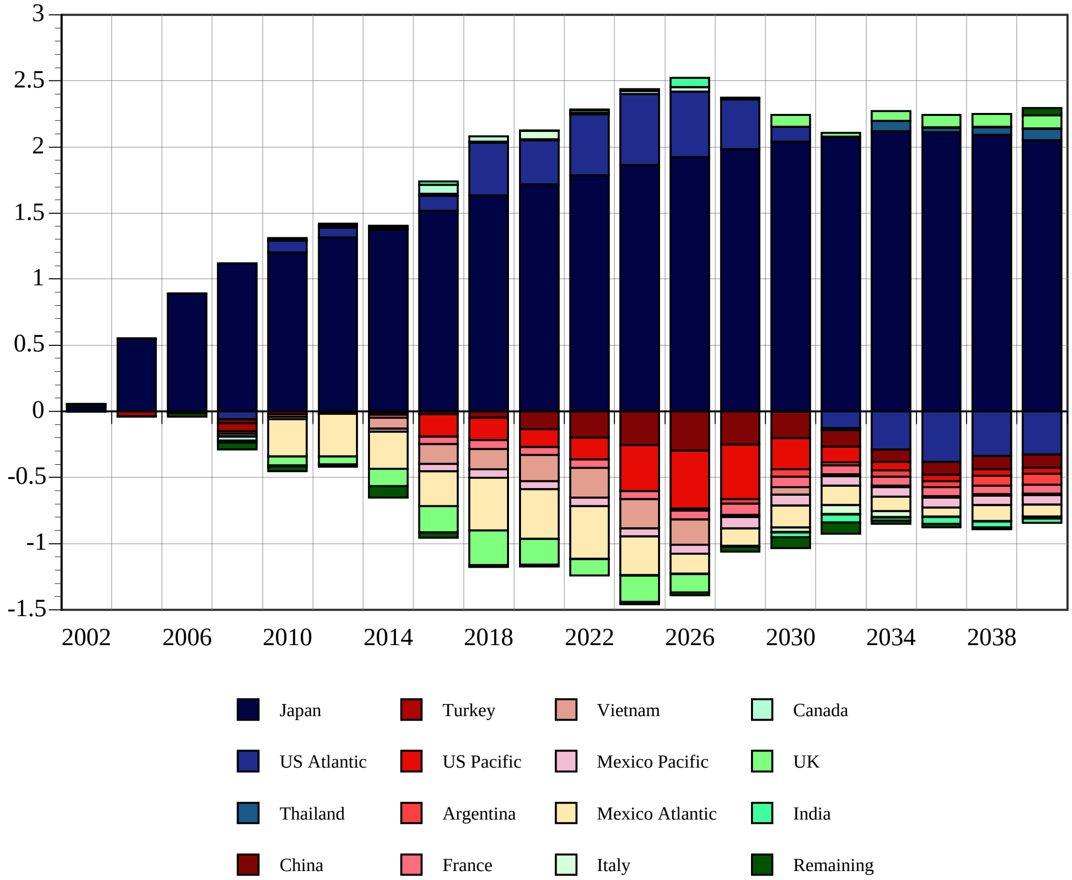

Figure 30: Changes in LNG demand with higher Japanese demand growth

Once again, Mexico imports less LNG into both its Atlantic and Pacific ports facilitated by an expansion of supply in both Columbia and Peru, as shown in Figure 28. In this instance, however, increased exports of LNG from Peru are less evident, and more of the increased supply flows north to meet Mexican demand via pipeline. Reduced imports of LNG into Argentina beyond 2030 suggest that some increase in South American production is shipped south as well as north.

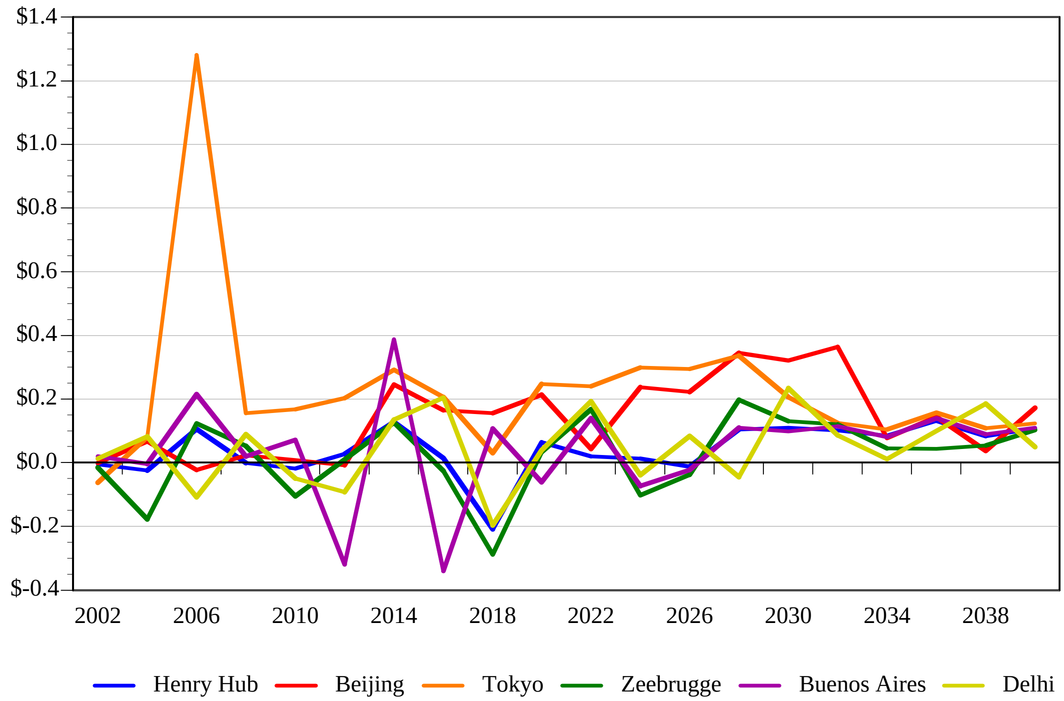

Figure 31: Changes in prices with higher Japanese demand growth

Figure 31 graphs the price changes resulting from higher Japanese demand growth, again for just six representative locations. The large price increase in Tokyo in 2006 results because the additional demand growth exacerbates an existing infrastructure constraint (Tokyo prices in 2006 were already quite high in the base case). Not surprisingly, Tokyo prices tend to increase the most as a result of the demand shock, with Beijing prices not far behind. Henry Hub, Buenos Aires, and Delhi prices increase by a noticeably smaller amount while Zeebrugge prices increase the least on average.[52]

Concluding Remarks

We have presented an equilibrium model of the evolution of the world market for natural gas over the next four decades. The model was constructed on geologic and economic fundamentals,

[52] In this case, average price changes were $0.041 in Henry Hub, $0.140 in Beijing, $0.229 in Tokyo, $0.022 in Zeebrugge, $0.044 in Buenos Aires and $0.048 in Delhi. All cities other than Tokyo displayed a positive trend in the price change of about $0.0025 per year, statistically significantly different from zero. Even if we focus on the period after 2008, Tokyo price changes do not have a trend significantly different from zero.

and respects well-known economic principles that resource extraction and trade should eliminate profitable spatial and intertemporal arbitrage opportunities.

The widespread use of LNG predicted by the model, and also the extension of major pipeline systems to span continents, will link markets for natural gas around the world. A consequence is that wholesale prices will tend to converge over time while regional shocks will have global consequences.

Another central finding is that Russia is destined to play a central role in linking the European and Asian markets for natural gas. Eventually, it is likely that Russia also will enter the LNG market in both the Atlantic and Pacific basins. As a result, Russia is likely to play a pivotal role in price arbitrage. Nevertheless, we also found that Russia's ability to exploit its dominant position is limited over time. Any restriction on Russian supply is likely to stimulate alternative sources of supply around the world, including the Middle East, Southeast Asia, Australia, and Norway. In addition, higher natural gas prices would not be welcome in Russia, which is one of the largest gas consumers in the world. Finally, natural gas differs from oil in that a reasonably good substitute for gas is available at a cost that is not dramatically higher than prices normally expected to prevail over the model horizon. Any long-term increase in gas prices above the $5/mcf range is likely to stimulate demand for these backstop technologies over time.

This last point emphasizes that natural gas is a "transition fuel." This is true of any depletable resource with an alternative whose cost is, at present, prohibitive. Demand for natural gas has been greatly stimulated in the short term by the expanding use of natural gas in electricity generation. Moreover, most projections indicate that future natural gas demand growth will come primarily from the power generation sector. There are, however, many alternative ways to generate electricity at comparable cost to CCGT while other uses for natural gas can also be satisfied, for example, by "syngas" manufactured from coal or even by hydrogen produced from other sources. Indeed, before the widespread use of natural gas, coal gas was reticulated in many cities in the U.S. and Europe, and provided many similar services to those provided by natural gas today.

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Appendix

Table 2: Estimated shipping costs for the route structure in Figure 6

Routes	Parameter Estimate	Standard Error
Liquefaction to Hub:		
UAE -- Middle East	0.0562	0.0169
Qatar, Iran -- Middle East	0.0619	0.0169
Oman -- Middle East	0.0050	0.0169
Indonesia (Arun) -- Indian Ocean	0.0000	0.0190
Indonesia (Bontang), Brunei, Malaysia -- South Asia Pacific	0.0231	0.0190
Indonesia (Tangguh) -- South Asia Pacific	0.0762	0.0190
Australia (Darwin) -- South Asia Pacific	0.0727	0.0190
Australia (NW Shelf) -- South Asia Pacific	0.0857	0.0190
Sakhalin -- North Pacific	-0.0001	0.0199
Alaska -- North Pacific	0.3451	0.0390
Peru, Bolivia -- American South Pacific	0.1355	0.0423
Angola, Guinea, Nigeria, Brazil -- South Atlantic	0.0554	0.0213
Trinidad, Venezuela -- North Atlantic	0.0620	0.0216
Barents Sea -- North Sea	0.1028	0.0281
Norway -- North Sea	0.0728	0.0281
Libya, Egypt -- East Mediterranean	0.0283	0.0223
Algeria – West Mediterranean	0.0283	0.0223
Hub to Regasification		
Indian Ocean -- India East	0.1655	0.0251
Indian Ocean -- India South	0.1680	0.0251
Indian Ocean -- India West	0.1747	0.0251
South Asia Pacific -- South China	0.2428	0.0248
South Asia Pacific -- Taiwan	0.2034	0.0241
North Pacific -- South Korea, South	0.0688	0.0271
North Pacific -- South Korea, North	0.0841	0.0271
North Pacific -- NE China	0.0903	0.0271
North Pacific -- Japan	0.1134	0.0271
American South Pacific -- Baja, S. California	0.1811	0.0278
American South Pacific -- SW Mexico	0.2589	0.0278
Caribbean -- Lake Charles, Louisiana Gulf	0.0200	0.0294
Caribbean -- Freeport	0.0287	0.0294
Caribbean – Mexico (Altamira)	0.0327	0.0294
Caribbean -- Florida	0.2273	0.0262
U.S. North Atlantic -- New Brunswick	0.1327	0.0262
U.S. North Atlantic -- Everett	0.1840	0.0262
U.S. North Atlantic -- Cove Point	0.2180	0.0262
U.S. North Atlantic -- Elba	0.2293	0.0262
U.S. North Atlantic -- Humboldt	0.4690	0.0251
European North Atlantic -- Portugal	0.1487	0.0210
European North Atlantic -- NW Spain	0.2051	0.0209
European North Atlantic -- France Atlantic	0.2082	0.0210
North Sea -- Zeebrugge (Netherlands)	0.1769	0.0276
North Sea -- UK	0.1774	0.0276
West Mediterranean -- SE Spain	0.1640	0.0204
West Mediterranean -- Italy	0.1656	0.0205
West Mediterranean -- France Mediterranean	0.1665	0.0205
East Mediterranean -- Greece	0.1599	0.0201

Routes	**Parameter Estimate**	**Standard Error**
East Mediterranean -- Turkey	0.1847	0.0201
Hub to Hub		
Middle East -- Indian Ocean	0.1349	0.0132
Indian Ocean -- South Asia Pacific	0.2163	0.0131
South Asia Pacific -- North Pacific	0.2645	0.0164
North Pacific -- American South Pacific	0.4590	0.0230
U.S. North Atlantic -- Caribbean	0.3033	0.0262
U.S. North Atlantic -- European North Atlantic	0.2082	0.0142
European North Atlantic -- South Atlantic	0.2560	0.0155
European North Atlantic -- North Sea	0.0715	0.0225
European North Atlantic -- West Mediterranean	0.1072	0.0109
West Mediterranean -- East Mediterranean	0.0936	0.0135
East Mediterranean -- Middle East	0.4500	0.0167

R^2 = 0.9905

Table 3: Reference case supply projections for selected regions and years (tcf)

	2002	2006	2010	2016	2020	2026	2030	2036	2040
AFRICA	5.870	8.325	8.842	9.675	12.742	14.572	16.742	16.845	16.278
Algeria	3.695	4.357	4.468	4.608	4.808	4.552	3.797	3.117	2.352
Angola	0.026	0.078	0.098	0.115	0.156	0.358	0.852	0.911	0.901
East Africa	0.000	0.002	0.004	0.028	0.106	0.132	0.177	0.213	0.448
Egypt	1.063	1.370	1.467	1.574	2.039	2.306	2.670	2.881	3.157
Libya	0.260	0.936	1.108	1.277	1.634	1.707	1.807	1.760	1.337
Morocco	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nigeria	0.608	1.041	1.090	1.299	2.541	3.677	5.311	5.935	6.246
Southern Africa	0.069	0.102	0.083	0.056	0.065	0.079	0.118	0.093	0.124
Tunisia	0.106	0.178	0.198	0.219	0.242	0.264	0.346	0.293	0.214
West Africa	0.001	0.043	0.072	0.121	0.238	0.320	0.322	0.330	0.318
West Central Coast Africa	0.042	0.217	0.255	0.378	0.913	1.179	1.343	1.311	1.182
ASIA-PACIFIC	11.672	16.129	17.190	18.505	21.890	24.650	28.453	29.997	29.040
Afghanistan	0.004	0.006	0.004	0.183	0.315	0.412	0.565	0.575	0.582
Australia	1.369	2.137	2.084	2.096	2.687	3.852	6.870	8.637	9.864
Bangladesh	0.375	0.709	0.920	1.070	1.227	1.240	1.142	0.960	0.651
Brunei	0.448	0.496	0.517	0.517	0.601	0.718	0.882	0.952	0.793
China	1.288	2.282	2.515	2.700	2.971	2.942	3.100	3.167	3.049
Hong Kong	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
India	1.021	1.317	1.430	1.552	1.934	2.016	1.757	1.391	1.043
Indonesia	2.962	3.325	3.368	3.518	4.080	4.811	5.985	6.724	7.022
Japan	0.088	0.079	0.069	0.061	0.062	0.059	0.034	0.024	0.015
Malaysia	1.985	2.610	2.722	2.836	3.133	3.240	3.274	3.153	2.553
Myanmar	0.246	0.423	0.544	0.701	0.953	1.013	1.016	0.943	0.616
New Zealand	0.180	0.253	0.249	0.241	0.218	0.163	0.101	0.074	0.056
Pakistan	0.854	1.106	1.312	1.526	1.878	1.922	1.305	0.958	0.642
Papua New Guinea	0.006	0.006	0.114	0.203	0.643	1.006	1.186	1.264	1.080
Philippines	0.082	0.150	0.170	0.182	0.290	0.506	0.691	0.738	0.763
Singapore	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
South Korea	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Taiwan	0.091	0.104	0.085	0.069	0.042	0.033	0.030	0.026	0.019
Thailand	0.575	0.770	0.732	0.695	0.580	0.526	0.394	0.316	0.219
Vietnam/Laos/Cambodia	0.100	0.356	0.354	0.356	0.277	0.190	0.121	0.096	0.073
EUROPE	11.986	14.459	13.932	13.222	11.205	9.736	8.329	8.769	9.850
Austria	0.069	0.069	0.056	0.046	0.027	0.020	0.014	0.010	0.007
Balkans	0.193	0.311	0.289	0.262	0.165	0.118	0.069	0.053	0.037
Belgium & Luxembourg	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bulgaria	0.033	0.046	0.038	0.031	0.017	0.012	0.007	0.008	0.009
Czech Republic	0.057	0.072	0.059	0.049	0.027	0.020	0.013	0.010	0.007
Denmark (incl. Greenland)	0.186	0.227	0.229	0.215	0.138	0.099	0.090	0.369	1.493
Finland	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
France	0.065	0.083	0.073	0.060	0.043	0.049	0.190	0.415	0.519
Germany	0.767	1.009	0.970	0.945	0.909	0.831	0.598	0.455	0.275
Greece	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

	2002	2006	2010	2016	2020	2026	2030	2036	2040
Hungary	0.234	0.305	0.260	0.214	0.121	0.084	0.051	0.039	0.027
Ireland	0.033	0.056	0.049	0.041	0.023	0.016	0.010	0.008	0.005
Italy	0.818	1.005	0.882	0.799	0.757	0.669	0.427	0.298	0.182
Netherlands	2.770	3.252	3.242	3.171	2.631	2.072	1.325	0.967	0.577
Norway	2.267	2.667	2.703	2.750	3.007	3.123	3.687	4.561	5.412
Poland	0.333	0.502	0.448	0.377	0.214	0.149	0.089	0.069	0.046
Portugal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Romania	0.732	0.991	0.931	0.853	0.541	0.374	0.228	0.176	0.116
Slovakia	0.037	0.043	0.038	0.035	0.022	0.015	0.009	0.007	0.004
Spain	0.010	0.007	0.005	0.005	0.005	0.009	0.014	0.107	0.405
Sweden	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Switzerland	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
United Kingdom	3.381	3.812	3.659	3.369	2.560	2.078	1.506	1.217	0.730
FSU	28.546	31.876	33.210	34.673	38.710	42.139	47.578	52.063	56.817
Armenia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Azerbaijan	0.338	0.776	0.849	0.926	1.013	1.127	1.623	2.117	2.667
Belarus	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Estonia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Georgia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Kazakhstan	1.206	2.890	3.258	3.511	3.649	3.554	3.168	2.927	2.438
Kyrgyzstan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Latvia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Lithuania	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Moldova	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Russia	22.867	23.462	24.272	25.161	28.428	31.182	35.815	39.691	44.484
Tajikistan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Turkmenistan	1.635	1.648	1.634	1.700	1.946	2.379	3.254	3.868	4.872
Ukraine	0.690	1.252	1.356	1.505	1.795	2.001	1.846	1.627	0.998
Uzbekistan	1.810	1.848	1.842	1.870	1.879	1.897	1.872	1.833	1.358
MIDDLE EAST	8.953	10.810	11.544	12.466	16.062	19.802	28.557	35.818	47.474
Bahrain	0.332	0.318	0.265	0.245	0.167	0.192	0.428	0.524	0.489
Iran	2.683	2.666	2.622	2.640	3.043	3.795	5.931	8.352	13.024
Iraq	0.069	0.762	1.230	1.643	2.920	3.725	4.722	5.134	5.387
Kuwait	0.348	0.379	0.647	0.894	1.495	1.657	1.695	1.696	1.688
Oman	0.427	0.286	0.235	0.220	0.436	0.670	1.016	1.091	1.303
Qatar	1.195	1.394	1.459	1.613	2.120	2.781	4.924	6.482	8.532
Saudi Arabia	2.235	2.605	2.642	2.676	3.225	4.070	6.074	7.946	10.975
Syria/Jordan	0.202	0.600	0.603	0.603	0.427	0.298	0.184	0.145	0.112
Turkey	0.033	0.092	0.076	0.062	0.034	0.024	0.017	0.014	0.011
UAE	1.428	1.645	1.660	1.727	1.925	2.131	2.704	3.469	4.999
Yemen	0.000	0.061	0.105	0.144	0.270	0.459	0.862	0.965	0.955
NORTH AMERICA	28.044	32.480	31.191	29.969	28.330	26.049	22.636	20.140	16.415
Canada	6.443	6.649	6.592	6.565	6.418	5.973	5.420	4.737	3.946
Mexico	1.245	1.410	1.197	0.998	0.888	1.006	1.046	1.011	0.674
United States	20.356	24.421	23.403	22.407	21.024	19.070	16.171	14.393	11.795
CENTRAL/SOUTH AMERICA	4.191	5.659	6.287	6.755	8.405	9.849	11.949	12.945	12.729
Argentina	1.284	1.477	1.467	1.455	1.488	1.449	1.461	1.432	1.051
Bolivia	0.176	0.475	0.502	0.553	0.688	0.740	0.949	0.999	0.917

	2002	**2006**	**2010**	**2016**	**2020**	**2026**	**2030**	**2036**	**2040**
Brazil	0.371	0.376	0.400	0.460	0.721	1.008	1.178	1.414	1.908
Central America	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Chile	0.111	0.239	0.249	0.249	0.229	0.262	0.262	0.232	0.156
Colombia	0.244	0.333	0.682	0.917	1.233	1.256	1.213	1.158	0.880
Cuba	0.023	0.020	0.035	0.035	0.035	0.029	0.018	0.013	0.010
Ecuador	0.002	0.001	0.001	0.001	0.000	0.001	0.008	0.021	0.040
Other Caribbean	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Paraguay	0.000	0.072	0.076	0.086	0.067	0.059	0.047	0.036	0.025
Peru	0.010	0.043	0.050	0.064	0.217	0.423	0.566	0.650	0.786
Suriname/Guyana/Fr. Guiana	0.000	0.072	0.182	0.236	0.476	0.636	0.737	0.745	0.729
Trinidad & Tobago	0.749	1.244	1.293	1.349	1.448	1.558	1.607	1.505	1.050
Uruguay	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Venezuela	1.220	1.308	1.349	1.351	1.803	2.429	3.905	4.739	5.177
WORLD TOTAL	**99.26**	**119.74**	**122.20**	**125.27**	**137.34**	**146.80**	**164.24**	**176.58**	**188.60**

Table 4: Reference case demand projections for selected regions and years (tcf)

	2002	2006	2010	2016	2020	2026	2030	2036	2040
AFRICA	2.671	3.394	3.776	4.425	4.882	5.653	6.194	6.985	7.111
Algeria	0.822	0.896	0.960	1.118	1.243	1.459	1.614	1.834	1.762
Angola	0.026	0.048	0.059	0.075	0.088	0.108	0.123	0.147	0.161
East Africa	0.000	0.002	0.005	0.008	0.010	0.011	0.012	0.013	0.013
Egypt	1.063	1.347	1.491	1.729	1.902	2.194	2.411	2.745	2.955
Libya	0.241	0.307	0.332	0.385	0.424	0.497	0.543	0.610	0.575
Morocco	0.025	0.053	0.062	0.076	0.082	0.090	0.094	0.094	0.089
Nigeria	0.217	0.279	0.308	0.379	0.431	0.523	0.588	0.688	0.745
Southern Africa	0.072	0.150	0.173	0.171	0.169	0.157	0.145	0.125	0.114
Tunisia	0.161	0.211	0.243	0.297	0.334	0.395	0.436	0.498	0.470
West Africa	0.001	0.033	0.071	0.109	0.120	0.132	0.136	0.132	0.126
West Central Coast Africa	0.042	0.069	0.072	0.077	0.080	0.086	0.092	0.098	0.101
ASIA-PACIFIC	12.245	16.411	18.627	22.199	24.769	29.002	31.521	32.970	33.417
Afghanistan	0.006	0.008	0.010	0.012	0.014	0.017	0.020	0.024	0.026
Australia	0.964	1.321	1.440	1.641	1.799	2.036	2.149	2.246	2.456
Bangladesh	0.375	0.490	0.561	0.661	0.726	0.827	0.898	0.922	0.939
Brunei	0.068	0.077	0.081	0.086	0.089	0.095	0.100	0.107	0.112
China	1.241	2.230	2.772	3.834	4.659	6.043	6.796	7.303	7.568
Hong Kong	0.025	0.037	0.032	0.028	0.027	0.027	0.026	0.023	0.021
India	1.012	1.525	2.367	3.063	3.478	4.147	4.592	4.771	4.807
Indonesia	1.298	1.652	1.782	1.961	2.080	2.269	2.391	2.404	2.294
Japan	2.738	2.758	2.538	2.663	2.859	3.312	3.619	3.856	3.844
Malaysia	1.094	1.363	1.493	1.717	1.871	2.115	2.274	2.334	2.343
Myanmar	0.080	0.113	0.130	0.151	0.165	0.183	0.194	0.194	0.194
New Zealand	0.183	0.234	0.240	0.257	0.262	0.276	0.273	0.260	0.245
Pakistan	0.845	1.094	1.212	1.407	1.543	1.795	1.984	2.285	2.361
Papua New Guinea	0.004	0.006	0.007	0.008	0.008	0.009	0.009	0.010	0.010
Philippines	0.073	0.127	0.144	0.182	0.203	0.237	0.266	0.288	0.294
Singapore	0.045	0.096	0.107	0.125	0.134	0.147	0.153	0.140	0.126
South Korea	0.885	1.180	1.283	1.576	1.796	2.116	2.280	2.330	2.327
Taiwan	0.301	0.537	0.613	0.706	0.748	0.784	0.780	0.756	0.730
Thailand	0.906	1.206	1.295	1.393	1.447	1.505	1.525	1.461	1.442
Vietnam/Laos/Cambodia	0.100	0.356	0.520	0.729	0.860	1.061	1.193	1.255	1.279
EUROPE	18.770	22.187	22.589	24.193	25.325	26.946	28.186	28.807	28.342
Austria	0.315	0.370	0.372	0.398	0.418	0.453	0.476	0.476	0.473
Balkans	0.185	0.268	0.278	0.296	0.307	0.326	0.335	0.309	0.289
Belgium & Luxembourg	0.660	0.754	0.743	0.775	0.802	0.832	0.867	0.909	0.905
Bulgaria	0.189	0.175	0.154	0.155	0.164	0.185	0.200	0.213	0.194
Czech Republic	0.352	0.386	0.375	0.392	0.407	0.431	0.461	0.491	0.494
Denmark (incl. Greenland)	0.214	0.270	0.281	0.301	0.313	0.324	0.335	0.344	0.338
Finland	0.180	0.230	0.234	0.259	0.280	0.317	0.341	0.338	0.332
France	1.777	2.103	2.063	2.180	2.275	2.436	2.632	2.834	2.843
Germany	3.340	3.756	3.668	3.797	3.924	4.110	4.289	4.409	4.359
Greece	0.085	0.132	0.145	0.182	0.209	0.258	0.291	0.296	0.294
Hungary	0.489	0.570	0.611	0.695	0.755	0.848	0.907	0.899	0.894

	2002	2006	2010	2016	2020	2026	2030	2036	2040
Ireland	0.166	0.250	0.277	0.300	0.309	0.322	0.337	0.352	0.349
Italy	2.631	2.894	2.942	3.169	3.324	3.570	3.682	3.704	3.622
Netherlands	1.642	1.874	1.924	2.042	2.119	2.186	2.251	2.310	2.263
Norway	0.293	0.403	0.422	0.458	0.481	0.510	0.528	0.548	0.552
Poland	0.493	0.644	0.660	0.728	0.783	0.879	0.940	0.919	0.893
Portugal	0.123	0.247	0.298	0.355	0.380	0.408	0.405	0.410	0.403
Romania	0.680	0.685	0.681	0.750	0.814	0.926	0.999	1.000	0.988
Slovakia	0.283	0.316	0.315	0.325	0.334	0.350	0.359	0.347	0.341
Spain	0.858	1.452	1.676	1.959	2.099	2.267	2.347	2.346	2.304
Sweden	0.040	0.059	0.054	0.053	0.053	0.053	0.056	0.062	0.063
Switzerland	0.119	0.148	0.140	0.143	0.146	0.152	0.163	0.174	0.174
United Kingdom	3.656	4.201	4.275	4.482	4.628	4.804	4.985	5.116	4.974
FSU	22.462	26.881	28.811	31.624	33.434	36.253	38.094	40.056	40.000
Armenia	0.045	0.058	0.059	0.061	0.063	0.067	0.069	0.072	0.073
Azerbaijan	0.348	0.538	0.641	0.771	0.852	0.974	1.056	1.179	1.259
Belarus	0.645	0.747	0.769	0.796	0.814	0.846	0.867	0.834	0.797
Estonia	0.050	0.077	0.091	0.109	0.120	0.138	0.148	0.150	0.149
Georgia	0.055	0.095	0.115	0.136	0.148	0.164	0.174	0.187	0.194
Kazakhstan	0.604	0.773	0.823	0.923	0.994	1.116	1.197	1.301	1.361
Kyrgyzstan	0.078	0.124	0.152	0.191	0.216	0.256	0.283	0.302	0.302
Latvia	0.064	0.078	0.083	0.094	0.103	0.118	0.127	0.128	0.127
Lithuania	0.110	0.135	0.137	0.149	0.158	0.173	0.182	0.176	0.171
Moldova	0.085	0.113	0.123	0.133	0.138	0.144	0.148	0.141	0.136
Russia	15.177	18.149	19.497	21.364	22.524	24.277	25.391	26.825	26.470
Tajikistan	0.049	0.059	0.059	0.064	0.069	0.078	0.084	0.092	0.084
Turkmenistan	0.431	0.557	0.641	0.757	0.833	0.955	1.040	1.172	1.264
Ukraine	3.025	3.545	3.675	3.904	4.059	4.312	4.476	4.311	4.191
Uzbekistan	1.695	1.833	1.947	2.172	2.344	2.638	2.850	3.186	3.421
Middle East	9.040	10.385	10.831	12.062	13.100	15.024	16.395	18.366	19.614
Bahrain	0.332	0.359	0.378	0.424	0.462	0.532	0.582	0.659	0.711
Iran	3.156	3.262	3.308	3.766	4.209	5.067	5.683	6.587	7.172
Iraq	0.069	0.141	0.146	0.210	0.278	0.425	0.537	0.705	0.796
Kuwait	0.347	0.377	0.371	0.392	0.421	0.477	0.518	0.577	0.616
Oman	0.240	0.301	0.339	0.394	0.432	0.495	0.539	0.608	0.658
Qatar	0.413	0.448	0.460	0.474	0.485	0.502	0.513	0.529	0.538
Saudi Arabia	2.235	2.604	2.720	2.957	3.157	3.513	3.770	4.137	4.380
Syria/Jordan	0.202	0.273	0.263	0.290	0.316	0.371	0.412	0.466	0.500
Turkey	0.698	0.981	1.098	1.313	1.461	1.714	1.892	2.134	2.274
UAE	1.346	1.640	1.729	1.805	1.830	1.867	1.880	1.887	1.886
Yemen	0.000	0.000	0.020	0.037	0.048	0.061	0.068	0.076	0.083
North America	27.639	32.606	32.099	32.609	33.485	36.876	39.717	42.609	42.209
Canada	3.069	3.875	3.978	4.169	4.299	4.596	4.850	5.050	4.918
Mexico	1.598	2.038	2.173	2.505	2.742	3.116	3.429	3.848	4.008
United States	22.972	26.693	25.948	25.936	26.443	29.164	31.438	33.712	33.283
Central/South America	3.882	4.984	5.445	6.320	6.935	7.858	8.525	9.306	9.441
Argentina	1.113	1.308	1.418	1.653	1.833	2.121	2.327	2.411	2.456
Bolivia	0.038	0.067	0.080	0.096	0.107	0.123	0.134	0.153	0.145
Brazil	0.525	0.978	1.153	1.441	1.634	1.891	2.091	2.407	2.507

	2002	2006	2010	2016	2020	2026	2030	2036	2040
Central America	0.000	0.004	0.005	0.008	0.009	0.010	0.009	0.008	0.008
Chile	0.245	0.342	0.372	0.407	0.427	0.457	0.471	0.475	0.481
Colombia	0.194	0.284	0.307	0.342	0.367	0.406	0.425	0.440	0.392
Cuba	0.016	0.031	0.031	0.030	0.029	0.026	0.025	0.021	0.018
Ecuador	0.006	0.008	0.007	0.007	0.008	0.010	0.010	0.010	0.010
Other Caribbean	0.021	0.036	0.039	0.045	0.049	0.053	0.063	0.080	0.089
Paraguay	0.000	0.002	0.004	0.007	0.008	0.008	0.008	0.008	0.007
Peru	0.013	0.035	0.046	0.062	0.070	0.083	0.092	0.102	0.109
Suriname/Guyana/Fr. Guiana	0.000	-0.001	0.011	0.019	0.022	0.027	0.029	0.031	0.028
Trinidad & Tobago	0.443	0.532	0.605	0.712	0.784	0.895	0.970	1.086	1.018
Uruguay	0.002	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002
Venezuela	1.266	1.355	1.364	1.488	1.584	1.746	1.868	2.073	2.171
WORLD TOTAL	**96.71**	**116.85**	**122.18**	**133.43**	**141.93**	**157.61**	**168.63**	**179.10**	**180.13**