THE OUTLOOK FOR GLOBAL TRADE IN LIQUEFIED NATURAL GAS PROJECTIONS TO THE YEAR 2020

CONSULTANT REPORT

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ABSTRACT

This report provides projections of world trade in liquefied natural gas (LNG) to the year 2020. Because of substantial uncertainties in the current markets for LNG, the study utilizes three illustrative scenarios — a base case, a high case that captures the optimistic view of world LNG trade that was common several years ago and a low case that reflects concern for geopolitical constraints on supply. The base case estimate for the year 2020 is 48.3 billions of cubic fee per day (Bcf/d), up from 2005's trade of 18.3 Bcfd. By 2020, the high case will be 29 percent higher than the base case. The low case will be 15 percent lower.

In the illustrative base case, Northeast Asia remains the largest market, but North America and Organization for Economic Co-operation and Development (OECD) Europe are growing more rapidly. The study does not foresee any difficulty in meeting the three projected levels of LNG trade from proven natural gas reserves in potential exporting countries. While Pacific Basin supply dominated world trade until recently, the base case projects that Atlantic Basin supply will exceed the Pacific Basin by 2020 and the Middle East will be almost as large.

KEYWORDS

Liquefied natural gas, LNG, liquefaction, LNG tankers, regasification, LNG receipt terminals, natural gas geopolitics, LNG forecast, LNG trade, LNG exports, LNG imports, LNG costs

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EXECUTIVE SUMMARY

Purpose and Scope

The California Energy Commission is interested in understanding the way in which international trade in liquefied natural gas (LNG) is likely to develop. The Commission hired Jensen Associates as a consultant to provide an analysis of future world LNG trade with forecasts out to the year 2020. Among the tasks Jensen Associates was asked to perform were: 1) Identify potential supplies of LNG by region; 2) match potential supplies to anticipated regional demands for LNG in three illustrative cases; and 3) calculate LNG transportation costs.

Major Findings

The global trade in LNG, which has increased at a rate of 7.4 percent per year over the decade from 1995 to 2005, should continue to grow substantially under all three scenarios that we have analyzed in this study. The projected growth in LNG in the base case is expected to increase at 6.7 percent per year from 2005 to 2020. Until the mid-1990s, LNG demand was heavily concentrated in Northeast Asia — Japan, Korea and Taiwan. At the same time, Pacific Basin supplies dominated world LNG trade.

The world-wide interest in using natural gas-fired combined cycle generating units for electric power generation, coupled with the inability of North American and North Sea natural gas supplies to meet the growing demand, substantially broadened the regional markets for LNG. It also brought new Atlantic Basin and Middle East suppliers into the trade. At the same time, deregulation of the natural gas industry in many parts of the world led to more destination-flexible contracting and trading. LNG is now a global fuel.

There are very great uncertainties about how LNG markets will develop. To deal with these uncertainties, this study utilized three illustrative scenarios. The base case reflects, in the views of Jensen Associates, the current conservative thinking of the international government forecasting organizations — the International Energy Agency and the U.S. Energy Information Administration. The high case attempts to capture some of the common optimism about LNG that was prevalent several years ago. The low case reflects the concerns that geopolitical issues will limit LNG supply in the period beyond 2010, when current projects that are under construction are finally completed.

By 2020 in the Jensen Associates illustrative base case scenario, Northeast Asia remains the largest market, but North America and Europe are growing more rapidly. China and India, though important markets, remain small.

By 2020, the high case demand will be 29 percent higher than the base case. The low case will be 15 percent lower.

The earlier dominance of Pacific Basin supplies is being eroded, as well. By 2020 in the base case, the Atlantic Basin will have substantially passed the Pacific Basin and the Middle East will be almost as large as the Atlantic Basin. By 2020 in the high case, the Atlantic Basin far exceeds, by similar amounts, both the Pacific Basin and the Middle East. By 2020 in the low case, the Pacific Basin and Middle East are again roughly even and both are again exceeded by the Atlantic Basin.

Worldwide uncommitted natural gas reserves are sufficient to support anticipated increases in LNG trade.

The illustrative base case demonstrates that uncommitted reserves could support an increase in LNG trade from about 18 billion cubic feet per day (Bcfd) in 2005 to about 48 Bcfd in 2020. LNG imports to North America could rise from 1.8 Bcfd in 2005 to 12.7 Bcfd in 2020.

The illustrative high case demonstrates that, but for geopolitical issues and lack of demand, uncommitted reserves could support an increase in LNG trade to 62 Bcfd in 2020. LNG imports to North America in the high case could increase by 5.6 Bcfd over the base case by 2020.

The illustrative low case demonstrates that if new project development difficulties and geopolitical constraints slow development of LNG trade, then LNG trade could increase to no more than 41 Bcfd in 2020. This low case would reduce LNG imports to North America by about 0.6 Bcfd in 2020, as compared to the base case.

Transportation costs (the sum of liquefaction, shipping and regasification) have increased as economies of scale are not enough to offset higher construction costs. The Jensen Associates estimate of transportation costs (assumes traditional land-based regasification terminals) from Australia to the North American Pacific Coast has increased from approximately $2.75 per million British thermal unit (Btu) in 2003 to about $3.50 per million Btu in 2007.

Background

The first demonstration tanker shipment of liquefied natural gas was made from Lake Charles**,** LA to Canvey Island in the U.K. in 1958. It enabled the natural gas industry to break free of the transportation constraints imposed by land based pipeline systems and presented the first opportunity to move natural gas over long ocean distances.

An LNG project has been described as a “chain” of investments whose ultimate success depends on the integration of four (possibly five) elements. They are field development, a possible pipeline to deliver the natural gas to a coastal location, a liquefaction plant, cryogenic tankers, and a receipt and regasification terminal in the market country.

Liquefaction plants come in processing modules that are called “trains.” Their size tends to be determined by compressor technology. Until recently, train sizes were limited to about 2 million tons (about 270 millions of cubic feet per day (MMcf/d)), but in the late 1990s, new designs significantly increased train sizes, providing substantial economies of scale. Current trains are typically in the 4 to 5 million ton range, but Qatar, which is located in the Middle East, has a number of “super trains” under construction that are designed for 7.8 million tons (approximately 1 Bcfd).

Tanker capacities are commonly quoted in cubic meters of liquid capacity. Current typical tanker sizes are in the 135,000 to 145,000 cubic meter size range. A 138,000 cubic meter vessel (a common size) has the capability to deliver about 2.9 Bcf of natural gas equivalent. Tanker sizes have also been increasing, but somewhat less rapidly than liquefaction train sizes. Qatar, again has taken the lead in super sizing tankers and its “Q flex” design is 216,000 cubic meters. Its “Q max” class will be even larger.

Receipt and regasification terminals are also needed to receive the tanker deliveries, store the liquid until needed and regasify it for sendout. There is greater variation in receipt terminal sizing based on the market characteristics of the consuming country. The Costa Azul terminal is being built in Baja California for both Mexican and United States consumption and its initial design calls for 1 Bcfd of sendout. The world’s largest receipt terminal is Inchon in Korea, which has a design sendout of about 1.4 Bcfd.

The strong popular resistance to terminal siting has led to the development of offshore terminal designs. There are two approaches. One utilizes floating vessels moored offshore that have the capability to receive liquid LNG and to regasify it for pipeline delivery onshore. The proposed Cabrillo Port and Crystal Clearwater Port projects for offshore California are of this type.

A somewhat newer approach that utilizes the “Energy Bridge” concept of regasification on specially designed tankers and delivery onshore from a special mooring buoy is that taken by Excelerate Energy. The company has two operating terminals, Gulf Gateway offshore Louisiana, and the Gasport Terminal at Teeside in the United Kingdom. The Oceanway LNG Terminal proposed for offshore California is based on this design. For nearly thirty years, world trade in LNG was largely a Pacific Basin phenomenon. Although the tanker transportation of liquefied natural gas made its first commercial appearance with shipments of LNG to France and the U.K. from Algeria in 1964, the Atlantic Basin trade initially failed to live up to expectations, and in the 1970s interest shifted to the Pacific. As recently as 1994, Japan, Korea and Taiwan accounted for 77 percent of world LNG demand and Pacific Basin suppliers accounted for 73 percent of world LNG supply.

But that began to change in the late 1990s. Worldwide natural gas demand accelerated as countries increasingly looked to natural gas-fired combined cycle power generation to provide a larger share of their electricity supply. However, limitations on traditional sources of natural gas forced many of them to look to imports to support this growth. For LNG, substantial reductions in costs made LNG an attractive option for many markets to meet this growing demand.

Interest in LNG came not only from natural gas-poor countries, such as China, India, Spain and Turkey, but from natural gas-rich countries such as the U.S. and the U.K. where traditional supply sources no longer appeared adequate to support the expected increases in demand. For the twenty-five years between 1980 and 2005, world LNG trade grew at a rate of 7.4 percent per year.

Where once LNG supply was largely confined to Pacific Basin sources, new sources in the Atlantic Basin and in the Middle East emerged to meet the growing demand. No new Atlantic Basin LNG liquefaction plants had gone on line between 1982 and 1999, but new greenfield plants in both Nigeria and Trinidad started operation in that year. Now, Egypt, Equatorial Guinea and Norway will join the list of exporters with new projects either on line or currently under construction and Angola is likely to follow shortly as well.

In 1997, Qatar became the second Middle East LNG exporter after Abu Dhabi. Qatar’s export policies are extremely aggressive and current plans call for 77 million tons (10.3 Bcfd) of LNG capacity to be in place by 2011. That level of capacity would have satisfied the entire world trade in LNG as recently as 1996. Since Qatar’s startup, Oman has also joined the group of Middle East exporters and both Iran and Yemen are discussing new projects.

The traditional LNG structure was based on comparatively rigid long term contracts that linked specific suppliers with specific customers. LNG now confronts not only geographic diversification, but a much more flexible market environment in which restructured natural gas industries in North America, the U.K. and, increasingly the European Continent, make it difficult to operate under the historic and rigid contract structure.

While some form of long term contracting will remain, the LNG industry is now much more destination-flexible with a small, but thriving spot market and pricing arbitrage among previously-isolated regional markets. LNG is truly a global business.

THE CURRENT LNG MARKET OUTLOOK – A REVOLUTION IN PERSPECTIVE – AND IN UNCERTAINTY

The outlook for LNG is probably more uncertain at this time than it has been for many years. This is the result of a number of factors. Among them are:

- The speed with which LNG demand, particularly in North America and the United Kingdom, developed.

- The inherently slow response time of supply to the sharply increased demand signals, since the normal LNG investment cycle is four years or more. The supply lags have created a shortage of LNG supply relative to expectations.

- The burst in demand for new plant capacity, which has taxed the capabilities of experienced design-construction contractors and sophisticated machinery suppliers. As a result, it has become extremely difficult to acquire the supplies and services needed for plant construction. This has led to "demand pull" inflation that has reversed the long period of declining costs for LNG facilities. Costs are not only much higher than expectations, but the potential for cost overruns and construction delays has increased. It is not clear how severely this has affected the plans of the many projects that are under active consideration.

- The sharp increase in world oil prices, which has affected natural gas and other energy prices, as well. The response of demand and the effect on interfuel competition of these higher prices is not well understood.

- The uncertainties raised by global warming. Pressures to limit coal utilization may tend to favor natural gas-fired power generation despite higher natural gas price levels. This is a particularly important issue in China, where absent government policy intervention; high priced natural gas would find it very difficult to compete with low cost coal.

- The persistence of difficult geopolitical issues surrounding the natural gas export policies of a number of countries, such as Bolivia, Nigeria, Iran, Russia or Venezuela. It is difficult to foresee the roles that they will play in LNG supply between now and 2020.

- And last, but not least, LNG demand is inherently sensitive to small changes in world natural gas supply/demand balances. This is as a result of the "leverage" effect on LNG demand as a result of its position as a supplemental source of natural gas.

Because of these uncertainties, it is probably unrealistic to expect that any forecast — no matter how well done — can accurately predict specific LNG trade flows out to the year 2020. But the fact of uncertainty does not eliminate the need for intelligent decision-making in LNG policies and investment commitments. The best way to cope with this uncertain environment is to lay out the possible ways in which LNG markets might develop in a series of internally consistent scenarios.

That has been the approach that this analysis has taken. It provides three scenarios:

- A "base" case, representing — in the view of Jensen Associates — the most likely course of LNG trade development.
- A "high" case embodying some of the recent more optimistic views of LNG demand growth.
- A "low" case, assuming that supply problems will continue to plague future LNG availability.

The three cases have differing impacts on the relative regional patterns of LNG trade. Thus they provide a better understanding of the risks and uncertainties of LNG supply to California.

The Study Approach

The study's approach has been to start with public forecast sources, such as the International Energy Agency's (IEA) *World Energy Outlook 2006* (WEO) and the U.S. Energy Information Administration's (EIA) *International Energy Outlook 2006* (IEO) and *Annual Energy Outlook 2007* (AEO). These have been supplemented by individual country and private sector analyses (the latter commonly from financial institutions). But importantly, the study has relied on an extensive database that Jensen Associates maintains on worldwide LNG projects, including judgments about the likelihood and the timing of their commercial development. The result is a set of projections — unique to Jensen Associates — that may well differ from other estimates.

The Forecasting Organizations Do Not Completely Agree With One Another and Have Grown More Conservative Over Time

The two major governmental organizations that publish world energy forecasts — the IEA and the EIA — both publish projections of future world natural gas supply and demand. But historically they have been reluctant to provide significant detail about their estimates, in part because of the sensitivity of providing geopolitical judgments about specific country ambitions. This has been particularly true of cross-border natural gas trade projections.

The reluctance to provide detail has been changing and the most recent projections (annual for the EIA, biennial for the IEA) provide more information than they did previously. The EIA has become dissatisfied with the natural gas trade estimates implied by its two major models — the National Energy Modeling System (NEMS) model used for U.S. forecasts and the System for the Analysis of Global Energy Markets (SAGE) model used for the international estimates. As a result, the EIA has embarked on a major effort to construct a specific world natural gas model, which will be used in the future for international natural gas projections.

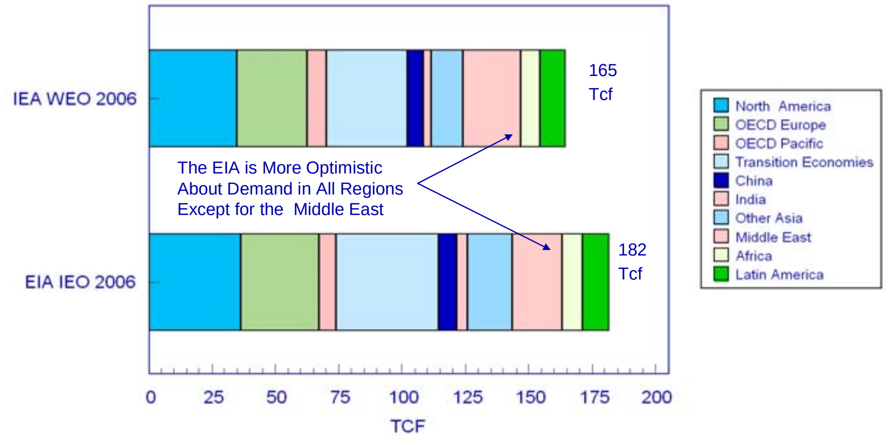
If one can generalize about most published world and regional natural gas forecasts, they tended to become more optimistic in the 1990s about natural gas demand as the enthusiasm for natural gas-fired combined cycle power generation took hold. Then, the North American "gas shock" of the winter of 2000/2001 and subsequent North Sea supply problems injected a note of supply concern into many estimates.

Initially, the tendency of most forecasts was to retain much of the demand optimism while transferring some of the responsibility for natural gas supply to imported LNG. In the early period following the natural gas shock, proposals for import terminals in North America proliferated, and it was not uncommon to find analysts assuming that the rate at which such terminals were approved would determine how much LNG would be imported. For many, there was little concern for potential limitations on supply. During this period, demand estimates tended to remain high and LNG tended to substitute for some of the projected loss of indigenous natural gas. (This demand/supply view is the logic behind the "high case" assessed in this study.)

But there was a gradual recognition that supply was the major determinant of the rate of growth of world LNG trade. The major capital investments in LNG supply are upstream of the importing country (perhaps only 15 percent of the capital expenditures in an LNG chain are in the importing country). And there was an increasing recognition that supply response would be slowed by the very long lead times between project initiation and project completion. Now a more common forecast pattern is for estimates to reduce the amount of natural gas for future power generation and be more conservative about LNG trade.

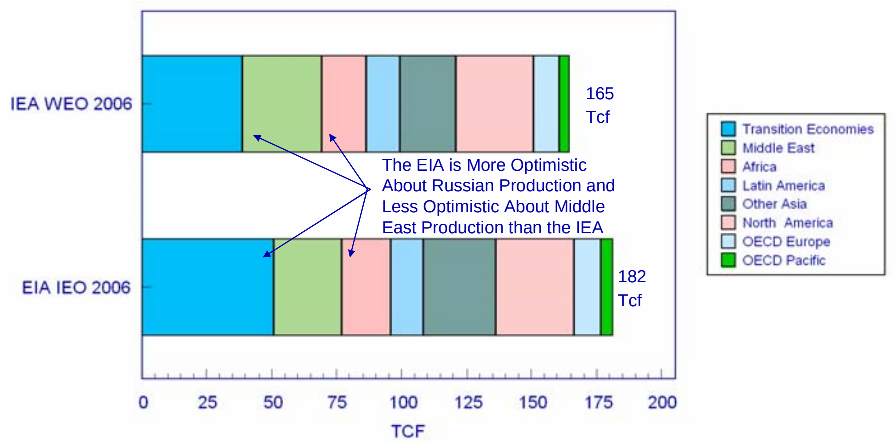
The most recent projections of world natural gas supply and demand for the EIA and the IEA show some differences in total levels and in regional patterns. **Figures 1** and **2** compare the base case estimates of both organizations for the year 2030. The EIA expects higher overall natural gas supply and demand. It is more optimistic than the IEA about demand in all regions except for the Middle East. The IEA has concluded that the Middle East intends to use more of its natural gas locally and has been raising its estimates of Middle East demand, suggesting that less would be available for export. For production, the EIA is more optimistic about Russian production and less optimistic about the Middle East than is the IEA.

Figure 1.
Comparison of Projected World Natural Gas Demand in 2030:
IEA's WEO 2006 with EIA's IEO 2006



Source: Jensen Associates

Figure 2.
Comparison of Projected World Natural Gas Production in 2030:
IEA's WEO 2006 with EIA's IEO 2006

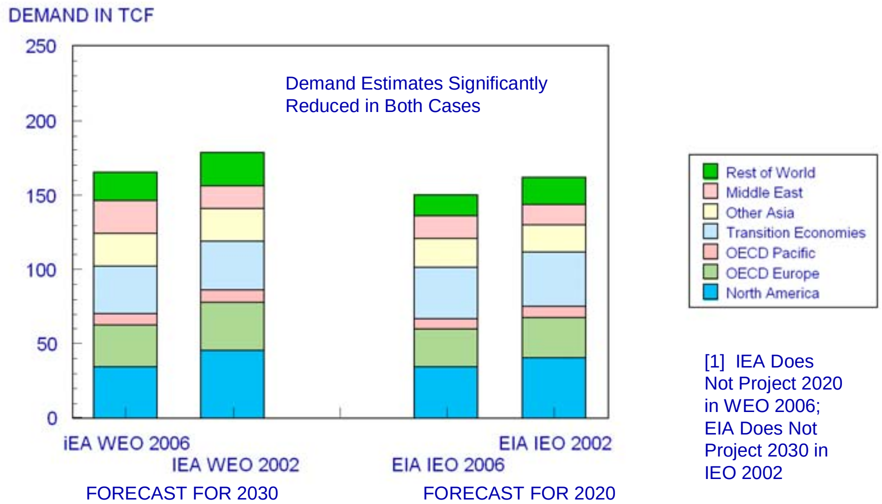


Source: Jensen Associates

A confirmation that the forecasting organizations have been reducing their world natural gas demand estimates can be shown by comparing the projections of both the IEA and the EIA made in 2002 with those that were made four years later. These are shown in **Figure 3**. Unfortunately, the EIA did not provide projections for 2030 in its IEO 2002 document (it did provide 2020 estimates throughout) and the IEA did not provide 2020 estimates in its WEO 2006. Thus, the two year comparisons in **Figure 3** are for 2030 for the IEA and 2020 for the EIA. While the absolute changes are difficult to compare, the sharp reduction in LNG demand over time for both organizations is quite apparent.

This pattern of declining LNG trade estimates over time is significant. It suggests that some of the LNG demand estimates that were made during the early 2000s might now be regarded as too optimistic and therefore unsuitable for a base or reference case. It is this view that has led this study to start with the most recent governmental projections to form the base case and utilize some of the earlier, more optimistic estimates, to develop the “high” scenario.

Figure 3.
Changes in Forecast Demand Expectations with Later Projections: IEA WEO 2006 Forecast for 2030 [1] Compared with WEO 2002; EIA IEO 2006 Forecast for 2020 [1] Compared with IEO 2002



Source: Jensen Associates

LNG – A Supply Focus on Projects, Rather Than Drilling Activity and Reserve Additions

In contrast to the supply of North American natural gas, which might be described as “commodity supply,” LNG is better characterized as “project supply.” In North America, the existence of an extensive Continental natural gas grid provides a ready market outlet for most discoveries, even those that are relatively small or short-lived. Supply analysts can focus on drilling activity and resource base estimates, with only limited concern for the size and location of discoveries.

LNG is much different. A typical 4.8 million ton LNG liquefaction plant requires at least 700 million cubic feet per day (MMcfd) of feedstock. If the underlying natural gas fields supporting the plant must guarantee deliverability over the life of a twenty year contract (recognizing problems with field decline late in field life), it requires about 7 trillion cubic feet (Tcf) to support the project. Thus the discovery of a large block of quality natural gas reserves tends to define an LNG export project, which often takes the name of the “anchor” field that supports it. In LNG exporting countries, small discoveries remote from an existing or proposed LNG project may become a part of local natural gas consumption, but they are rarely considered a factor in LNG export potential.

Like many LNG analysts, Jensen Associates maintains a database of potential LNG projects and this database provides a significant resource for the estimates included in this study. Since the number of projects reported in the trade press substantially exceed the number of projects that are likely to be commercialized in the near future, it is necessary to utilize judgments as to which projects are likely to go forward and when. We do that by classifying LNG projects as "operating", "firm", "probable", "possible" and "remote" and placing a startup date on them where there is enough information to do so. Firm projects are those that are either under construction or have received a final investment decision. Probable projects are typically those which are well defined and contract negotiations are far enough along to provide grounds for optimism that they will ultimately go forward.

Most possible projects face problems, either of a technical, economic or geopolitical nature, that make it much less certain whether and when they will become commercial. In the long run, these problems may well be resolved, but their near term commercialization remains in doubt. For example, seven different LNG export projects have been proposed in Iran. However, in the current geopolitical environment, where Iran is subject to international sanctions, access to international technology and markets is extremely difficult. And there are political groups in Iran that oppose LNG export altogether. Hence the outlook for these plants must be regarded as highly uncertain.

Another example would be Russia's proposed LNG export project based on the Shtokman field in the offshore Barents Sea. This has been discussed as a possible source of LNG for U.S. markets. While the field is a super giant natural gas field with nearly 60 percent of the natural gas reserves of the entire U.S., it is located 300 miles offshore under shifting ice. In addition to the technological challenges posed by its high arctic offshore location, Russian policy has been ambivalent about whether to consider LNG at all or just dedicate the field to European pipeline supply.

The possible category is divided into "Scheduled" and "Unscheduled." The public information about projects in the latter group is as yet so ill-defined that it is too early to even attempt an estimate of a likely startup date.

The potential capacity from LNG supply projects that have been publicly described (and warrant classification as firm, probable or possible, excluding remote) is very large. It exceeds the projected capacity requirements for all three cases in this study. (See **Table 1**)

Table 1.
Jensen Database Liquefaction Capacities
by Project Classification

Project Classification		BCFD
Operating YE 2006		24.1
Firm		10.0
Probable		9.5
Possible (Stated Schedule)		16.5
Possible (Unscheduled)		14.1
Total Potentially Available in 2020		74.2
Total Requirements in 2020	Base	48.3
	High	62.4
	Low	40.9

Source: Jensen Associates

In addition to the projects in the database, there are very large remaining reserves backing up some projects (such as in Qatar or Russia's Shtokman field) that could at some time provide for major expansion of the original capacity. In light of all the existing gas reserves potentially available, it may seem curious to even contemplate limitations natural on future supply, but the magnitude of potential projects can be very deceiving.

The industry has a long history of projects that have been around for many years before finally being developed. Some seemingly attractive projects have never made it to commercialization. The trade press began discussing a potential Nigerian LNG project in the early 1970s, but it was not until 1999 that the Bonny project – Nigeria's first – actually went on stream. In Western Australia, the fields that formed the basis for the Northwest Shelf LNG project were discovered in 1971, but the project itself did not go on stream until 1999. Also in Australia, Gorgon was discovered in 1980, and although it is a prime candidate for early development, it is not yet commercial. Venezuela began discussing potential LNG projects in the 1960s and has yet to develop its first. Long experience suggests substantial caution is in order in the scheduling of proposed projects as a part of future LNG supply.

The Three Scenarios

In all three cases, the approach was first to develop a forecast of LNG trade as a "control" and then to match sources and markets to the projection. The Appendix summarizes the matching of sources and markets in the base case.

For the base case, it was important to capture the current caution reflecting concern about the effect of high energy prices on demand and the constraints on LNG liquefaction capacity. The starting point for the base case was the natural gas projections contained in the IEA's WEO 2006. The IEA projections are conservative and thus meet the objectives of the base case. In addition to regional supply and demand projections for selected years, the WEO 2006 provides “interregional gas trade flow” estimates for the year 2030 as well as less detailed flow estimates for 2015 and limited estimates about potential LNG trade.

The IEA uses the convention of “interregional trade” to distinguish it from the more common description of international trade, which includes many relatively short, cross-border pipeline movements between neighbors. Thus pipeline trade between Canada and the U.S. or Norway and Germany are excluded from the IEA’s estimates as “intraregional trade”. While this study has adopted the same “interregional trade” convention, it has made one important change. LNG trade within regions, such as Indonesian shipments to Taiwan, is not included in the IEA figures since it occurs within the IEA’s “Other Developing Asia” category — a net exporter. This study includes all LNG, whether interregional or intraregional, but limits its pipeline trade to the interregional definition.

We also provided somewhat more detailed regional breakdowns. The following list compares the regional definitions of the two studies:

IEA IMPORTERS	JENSEN ASSOCIATES IMPORTERS
OECD North America	OECD North America (Atlantic)
	OECD North America (Pacific)
OECD Europe	OECD Europe
OECD Asia (Excludes Taiwan)	Northeast Asia (Includes Taiwan)
China	China
India	India
IEA EXPORTERS	**JENSEN ASSOCIATES EXPORTERS**
Transition Economies	Former Soviet Union
Middle East	Middle East
Africa	North Africa
	West Africa
Other Developing Asia	Southeast Asia
OECD Oceania	Australia
Latin America	Latin America (Atlantic)
	Latin America (Pacific)

Since the IEA does not attempt to differentiate between pipeline and LNG trade, this study has made its own estimates of the breakdown between the two for the various cases. This study also made a number of adjustments to the base IEA estimates, both to update the base case starting years to reflect recent developments and to substitute other estimates where in our judgment they seemed warranted. We found the IEA North American estimates to be too conservative and utilized information from the Energy Information Administration for the U.S.

There were other developments as well. We found ourselves more optimistic about Australian supply and less optimistic about both Southeast Asian and Latin American supply than the IEA. The net result is an analysis that has its roots in the IEA projections but departs from them in significant ways. For the 26 year period between 2004 and 2030, the IEA's LNG growth rate is 4.5 percent per year. The base case in this study shows a growth rate over a shorter period from 2005 to 2020 of 6.7 percent per year, although a significant part of that growth in the early years is the result of a surge of new capacity that is already under construction.

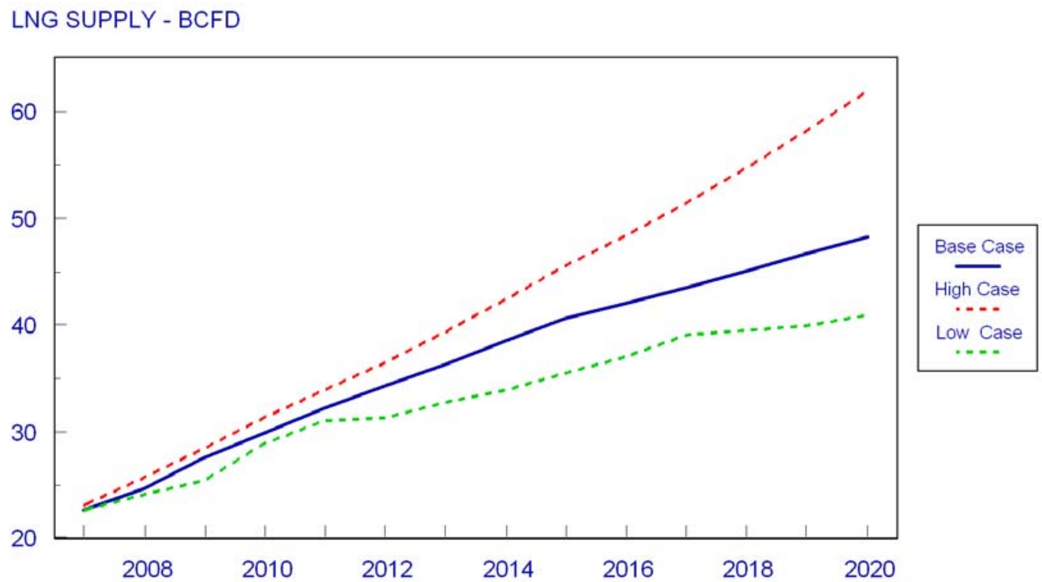
The high case was designed to capture some of the ebullience about future LNG trade that was common in the early 2000s. Forecasts during that period commonly projected growth rates of 7 to 8 percent for extended periods into the future.

For the high case, this study selected a growth rate of 7.5 percent to take effect after the current group of construction projects is completed. Because of the early surge in plant construction, the effective growth rate between 2005 and 2020 is somewhat higher at 8.5 percent.

The logic behind the low case was that the difficulties of new project development — high construction costs and geopolitical constraints — would slow the process of adding new capacity. The study simply slipped the construction completion dates for most of the projects in the base case by a year. It also made the assumption that new capacity scheduled for most countries after 2009 would only be available at 75 percent of base case levels. For countries where geopolitical issues are a concern, such as Iran or Venezuela for example, the limitation was more severe, at one third of the base case scheduled capacity. It was also assumed that Russia would choose to emphasize pipeline, rather than LNG exports, for all future exports after completion of the project in Sakhalin already under way.

The resulting three scenarios are shown in **Figure 4**. The range from high to low in the year 2020 is 21.6 Bcfd.

Figure 4.
Three LNG Growth Scenarios:
BCFD



Source: Jensen Associates

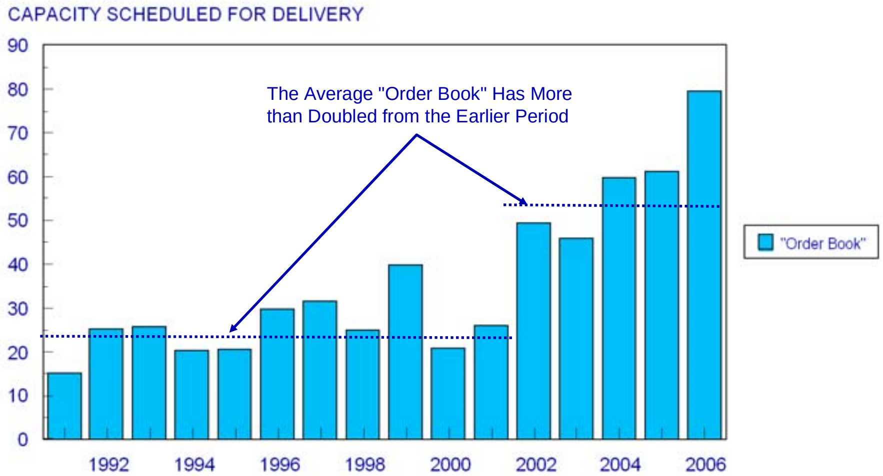
The Changing Perspective on LNG Costs

For an extended period of time, design improvements in liquefaction plants and tankers had the effect of reducing costs. As recently as 2003, it was common to assume that this was a “learning curve” effect and would continue into the future. Given this perception, it was easy to assume that cost reductions would easily offset any tendency of the industry to move increasingly towards more costly and remote fields. But this perception of steadily falling costs for LNG has been dashed in the last several years. The surge in demand for LNG which began in the late 1990s has taxed the capabilities of the experienced design construction contractors and the manufacturing capacities of firms supplying some of the sophisticated materials and machinery required for LNG. The result has been a very large supply bottleneck for construction of new plants.

There are a very few design constructors with the experience to handle the complex construction that LNG requires and they are effectively overloaded. While one might expect over time that new entrants in the field would learn to become reliable suppliers, the risks in the short term are that projects built by the newer contractors will fail to come in on time and on budget. Meanwhile, “demand pull” inflation has hit the industry and reversed the long period of declining costs.

The reason for the “crunch” on the suppliers is evident in looking at the growth in demand for new capacity. With a typical four year design and construction period for most LNG plants, the plants scheduled to come on line over the next four year period might be described as the “order book” for design construction firms. As **Figure 5** indicates, the “order book” has more than doubled since 2002 from the period 1991 to 2001, graphically illustrating the pressures on the suppliers.

Figure 5.
The Capacity that is Scheduled to Come on Line over the Following Four Years — the "Order Book" — has been Steadily Rising, Putting Pressure on the Contractors to Deliver Million Tons of Capacity



Source: Jensen Associates

It is extremely difficult to get reliable estimates of what is happening to costs at the present time. What is apparent is that there is wide dispersion in costs for liquefaction plants that are currently under construction. Unfortunately, “hard” information about the costs of current projects in the trade press is very sparse. It usually comes in the form of reported overall investment costs for a project that is under construction (often to report a cost overrun) and is seldom very specific of just what is included in the estimate. Since contracts may be let for only three or four new trains in a given year, the reports usually represent differing time periods for the letting of the contract.

In addition, the small sample includes a number of “problem trains” which have dramatically higher costs than one might expect from trends in historic cost patterns. It is difficult to separate out the special problems that have escalated the construction costs of these plants from the current pressures on costs that are applicable to construction in general.

Norway’s Snohvit, Russia’s Sakhalin II projects and a new Iranian North Pars construction bid are reported in the trade press to have costs in the range of $1,000 to $1,222 per ton of liquefaction capacity. A reasonable range of costs for these projects in a year 2000 construction environment might have been $250 to $300 and with the 2007 costs utilized in this study $450 to $575. (After completion of this report for the Energy Commission, Jensen Associates updated their cost estimates as part of their ongoing consulting work. The 2007 costs are now $600 to $650 instead of $450 to $575.)

Both Snohvit and Sakhalin II have experienced very large cost overruns, but both are Arctic projects and may be subject to “learning curve” pressures. The Iranian bid is for a project whose government is subject to international sanctions and may have difficulty accessing competitive bids from experienced design construction firms

This analysis has chosen to treat these very high costs as aberrations resulting from a heavily overheated construction industry, and therefore not representative of the costs to be expected over the period of this study. While this judgment may be controversial, it does not seem logical to assume that such radical departure from earlier cost history will persist for an extended period of time. The high cost inflation seems to be limited to plant and upstream projects. There does not seem to be the same upward pressure on tanker costs that there is on liquefaction plants

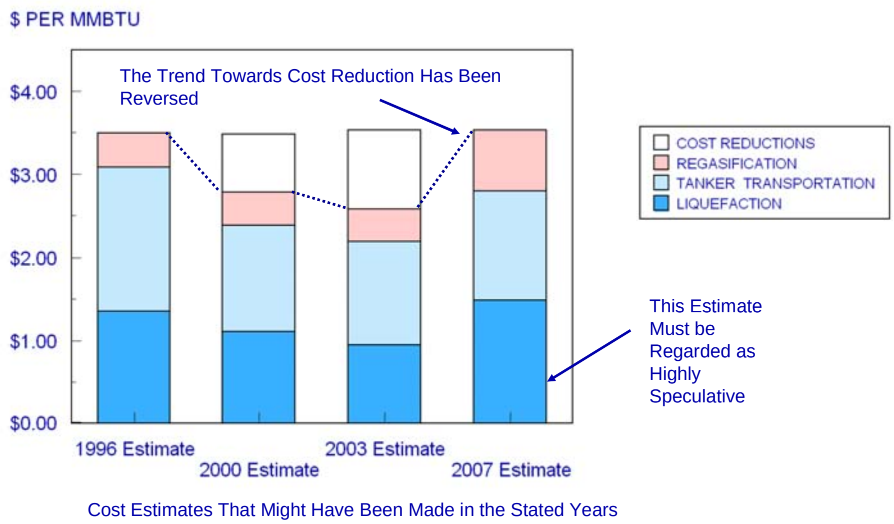
During the period from the mid 1990s to about 2003, costs for both liquefaction plants and tankers were declining. The reasons for the declines were somewhat different. For liquefaction plants, the technological improvements that enabled train sizes to break out of the old two million ton standard size to much larger sizes enabled construction to benefit from economies of scale. Current plants that are going in tend to be in the 4 to 5 million ton size range, and Qatar has a number of super trains sized at 7.8 million tons under construction.

For tankers, however, the scale economies have been less pronounced since size increases until recently have been much less pronounced. The largest single element in declining costs has been the competition which emerged in the 1990s between Korean shipyards and the Japanese yards that had dominated the business for many years.

But size is still a factor. Tankers in the mid 1990s were typically about 120,000 cubic meters in size. Current tankers more commonly are in the 135,000 to 145,000 cubic meter size range. Qatar, which is leading in the design of larger sized equipment, has a series of much larger tankers on order. Its “Q Flex” tankers are 216,000 cubic meters inn size and its “Q Max” tankers are in the 260,000 size range.

Figure 6 is an effort to trace what has happened to LNG transportation costs over time. It uses the cost assumptions of the day to provide an illustration of what the transportation costs (excluding the cost of the feedstock) might be of delivering LNG to the North American Pacific coast from a new six million ton greenfield plant in Australia. In 1996, the plant might have consisted of three 2 million ton trains. In 2000 and 2003, two 3 million ton trains would have provided the same output. Currently the plant might be designed for one 6 million ton train. As **Figure 6** illustrates, the declining cost trend of the late 1990s and early 2000s has been sharply reversed, overriding the scale economy effect operating earlier.

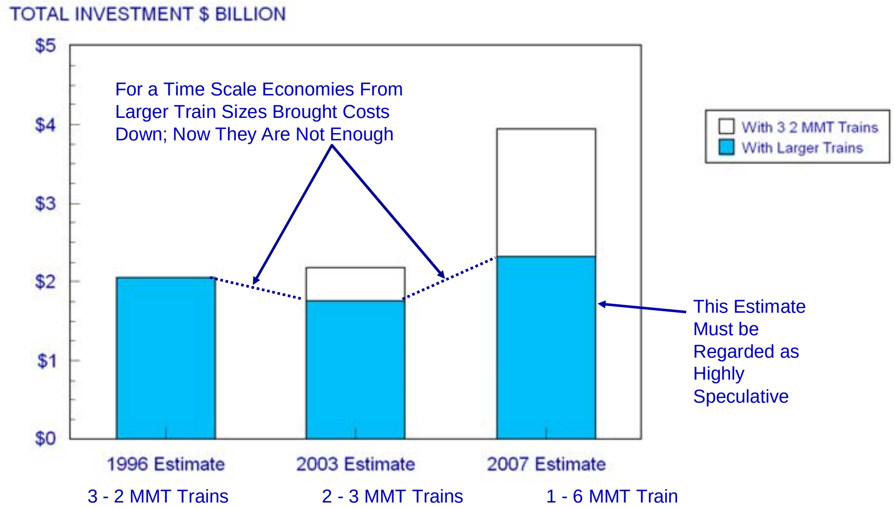
Figure 6.
An Illustration of LNG Transportation Costs over Time for a Hypothetical LNG Trade from Australia to the North American Pacific Coast:
Four Recent Cost Estimates



Source: Jensen Associates

Figure 7 attempts to lay out what might have happened to costs of liquefaction plants if scale economies had not been utilized. It shows what the overall cost of a greenfield 6 million ton plant might have cost if it had still been designed for three 2 million ton trains versus what it would cost with the larger train sizes available at the period. The 2007 estimate is a Jensen Associates estimate and is clearly highly speculative given the great uncertainties in the current cost environment.

Figure 7.
An Illustration of the Costs of a New 6 Million Ton Greenfield LNG Liquefaction Plant Using Costs and Designs of the Day and Using Earlier 2 Million Ton Designs



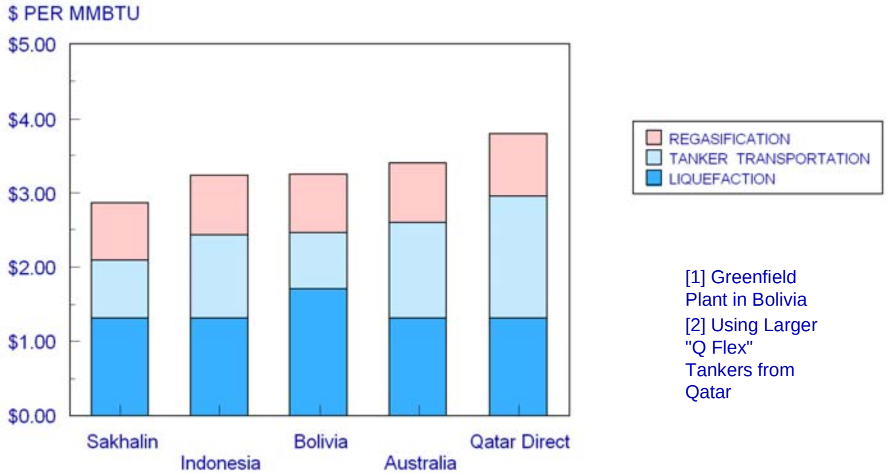
Source: Jensen Associates

The Costs of Serving the North American Pacific Market

The integration of the North American natural gas grid has made it possible to serve the North American Pacific Coast not only from terminals in California, but from Pacific Northwest or British Columbia terminals or, as is the case with the new Costa Azul project in Baja California, through pipeline imports of regasified LNG from Mexico. While some of these LNG delivery options involve added onshore pipelining costs, it has been beyond the scope of this study to examine them.

Figure 8 illustrates hypothetical transportation costs of serving the North American Pacific market from various potential sources of LNG. All except Bolivia have projects in operation or under construction. **Figure 8** assumes a new 4.8 million ton expansion train (except for Bolivia that uses a greenfield installation). It excludes the actual costs of feedstock into the plant, which can vary widely. For example, both Sakhalin and Bolivia require long distance pipelining to reach a coastal plant location (in the case of Sakhalin, an ice-free port).

Figure 8.
Illustrative Costs of Serving North American Pacific Markets from Various Supply Sources: One 4.8 Million Ton Expansion Train [1]; Standard Sized Tankers [2]; Does Not Include Feedstock Cost



Source: Jensen Associates

The use of transportation costs to compare the economics of various supply sources is common in LNG economics. One often sees comparative economics of various sources based on the costs of production plus the costs of transportation to deliver the natural gas. While this may provide some interesting comparisons, it is not the way in which LNG economics are commonly done.

A buildup of costs including production, liquefaction, transportation and regasification provides what is commonly described as a "cost-of-service" value. This is the approach used in utility regulation of natural monopolies where there is no competitive market to determine market values. LNG projects work on a "netback" basis in which a market price or one negotiated with a customer are first determined and transportation costs are deducted to establish a "netback value" at the wellhead. Costs of production are relevant only to the extent that they establish whether or not the netback value gives the producer a high enough return on his investment to decide to proceed.

A simple example will illustrate the difference in the two approaches to price formation. For example, an LNG project might have a wellhead cost of $1 and transportation costs of $3 to deliver the natural gas to market, but the market price is $5. In cost-of-service pricing the seller would be constrained to sell at $4 despite a market value of $5. In netback pricing, he deducts the $3 from the market realization and nets back $2, or double his actual cost.

Production costs for most of the fields supporting LNG projects are usually very low. They are commonly based on giant natural gas fields with very high well productivities. Qatar's LNG projects and most of the proposed Iranian projects are based on a single field, the world's largest. It is known as the North Field on Qatar's side of the international boundary and South Pars on the Iranian side. Its original combined reserves were in excess of 1,200 Tcf. The Shtokman field in Russia's offshore Barents

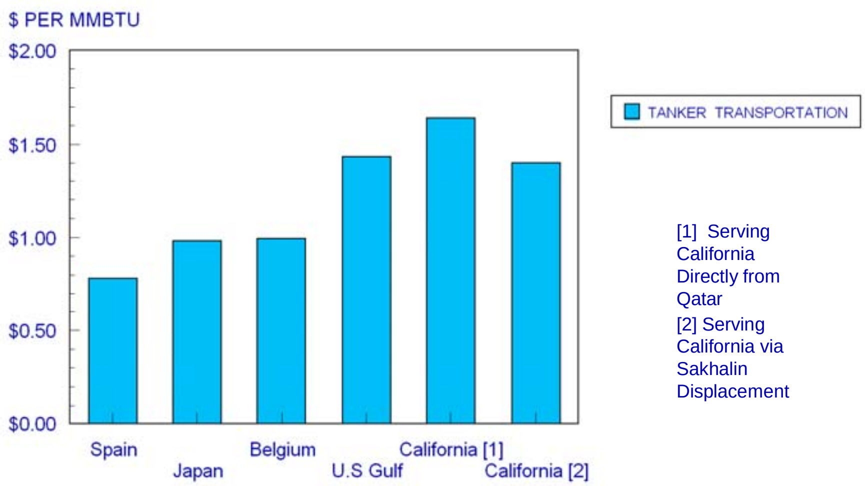
Sea, which Russia has considered for its Atlantic Basin LNG projects, has reserves of 113 Tcf. For comparison to the reserves of these super giant fields, the entire proved reserves of North America — the U.S., Canada and Mexico combined — are only 263 Tcf.

Not only do many of the fields supporting LNG projects have low development and production costs, many of them contain a large quantity of gas liquids (such as condensate, which is a light crude oil). In some of these cases, the liquids content is so high that it would provide the operator with an excellent return on field development even if he had to flare the natural gas. If he is not allowed to do so but must reinject for conservation purposes, he has what we describe as a "negative opportunity cost," equal to the avoided cost of reinjection. Some of Qatar's North Field natural gas contains about 46 barrels of gas liquids per million cubic feet of gas. At current high world oil prices, that represents a co-product credit of over $2.50 per million Btus of gas production.

Figure 8 shows the costs of delivering natural gas from Qatar by direct shipment. It is also possible to consider serving the California market indirectly by the displacement of Northeast Asian deliveries from other sources. For example, a Sakhalin supplier to Japan, having destination flexibility on his contract, might elect to serve a new North American West Coast customer by a new shipment from Qatar to Japan and a diversion of the original Sakhalin/Japanese shipment to the West Coast. This minimizes overall transportation costs. It works best with Sakhalin, but is also possible with other Pacific Basin shippers to Japan.

Figure 9 illustrates the tanker transportation costs of serving Spain, Japan, Belgium, and the U.S. Gulf Coast, as well as California, from Qatar (both direct and via Sakhalin displacement). In the illustration shown, it is $0.22 cheaper to deliver into the Gulf Coast than it is to California directly. A Sakhalin displacement makes the costs almost equivalent.

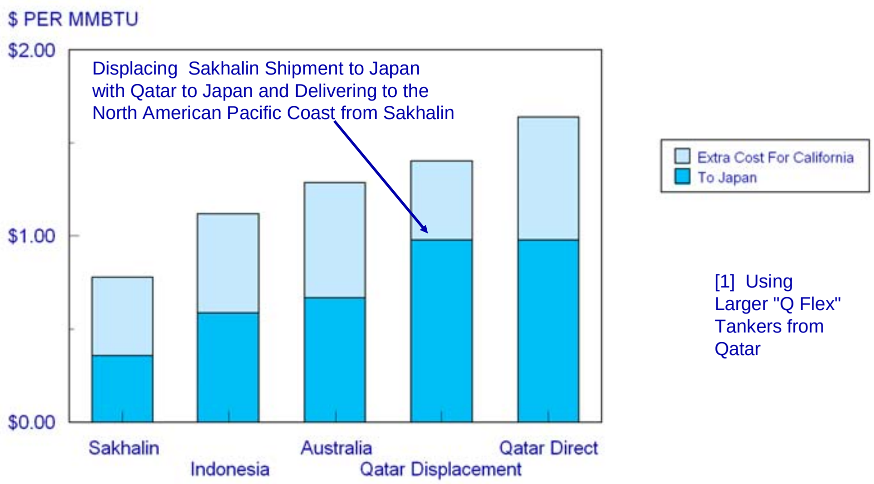
Figure 9.
Illustrative Transportation Costs of Serving Selected Markets from Qatar: "Q-Flex" Sized Tankers



Source: Jensen Associates

Figure 10 illustrates the relative transportation cost differentials for shipments to Japan and to California from various sources. In every case, the Japanese shipment is cheaper and California has a cost disadvantage.

Figure 10.
Representative Transportation Costs to Japan,
Showing the Additional Cost Involved in a North American Pacific Movement:
Standard Sized Tankers [1]



Source: Jensen Associates

Where Will the LNG Come From? — Resources, Technology and Geopolitics

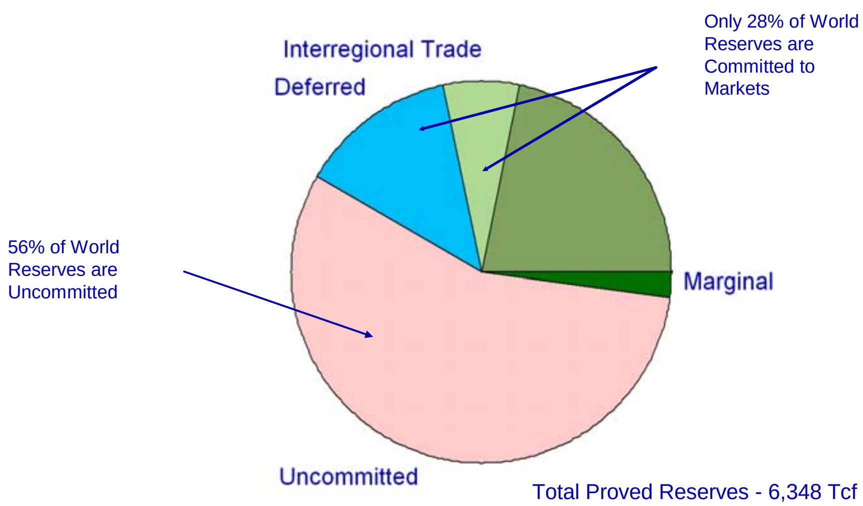
The world's reserves of natural gas are very large and appear more than adequate to support natural gas exports far into the future. But many of those reserves are located in places where economics, technology or geopolitics raise questions about how quickly they will become commercially available.

Jensen Associates maintains a database of world natural gas reserves, classifying them by their current market status. Some portion of the reserves are already committed to markets, either for domestic consumption or contracted for export through pipeline or LNG infrastructure. Other natural gas is "deferred" since it is involved in oil production, either for reinjection, in natural gas caps in producing fields, or "long reserves" (natural gas that is dissolved in the oil and will not be produced until far into the future when the oil is recovered).

It is from the remaining uncommitted natural gas that the reserves necessary to support international natural gas trade will come. Of course, undiscovered resources will also become available at some time in the future, as will the deferred natural gas as its involvement in oil production changes.

Figure 11 shows the market status breakdown of the 6,348 Tcf of world natural gas reserves as of year end 2005. Fully 56 percent of the world's reserves are uncommitted to use. While not all of it is available for current exports, since producers reserve some of it to back up existing pipeline and LNG export contracts, uncommitted natural gas is the major source of new projects.

Figure 11.
The World's Proved Natural Gas Reserves by Market Status
(Focusing on Interregional Trade):
Tcf – Year End 2005
(Source – Jensen Associates Estimates)

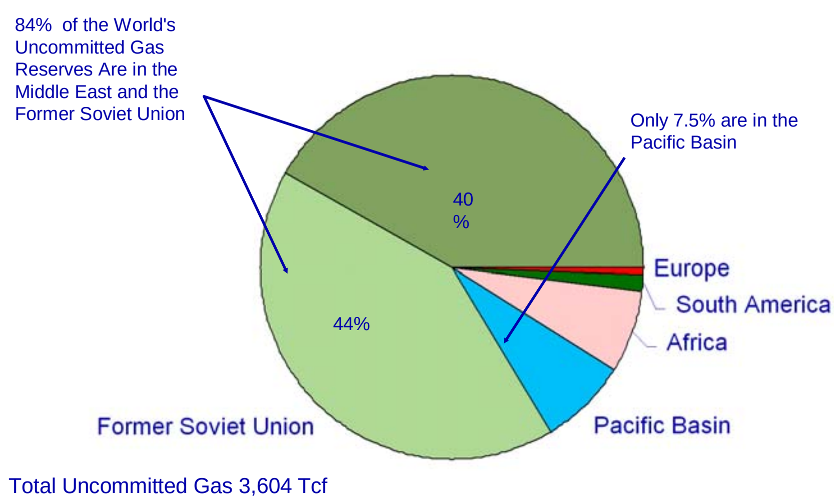


Source: Jensen Associates

However, 84 percent of the world's uncommitted reserves, as well as much of the undiscovered resource base, are in the Middle East and the Former Soviet Union. **Figure 12** shows the regional distribution of the uncommitted natural gas. It is of significance that the Former Soviet Union (FSU) has historically exported entirely by pipeline, while the Middle East has exported nearly all of its volumes as LNG. Russia is about to commence is first LNG exports from Sakhalin Island in Eastern Russia and is considering LNG projects for the Atlantic Basin. In the Middle East, Iran now exports small quantities by pipeline to Turkey and is considering pipeline movements to the Indian Subcontinent and possibly later to Western Europe via the proposed Nabucco Pipeline. But future FSU exports will remain dominantly via pipeline and Middle East exports via LNG.

The importance of these two regions to the future supply of Pacific Basin markets is indicated by their dramatic increase in market share. In 2005 the Middle East accounted for 26 percent of Pacific Basin LNG imports (and there were no receipts from the FSU). But in our base case, by 2020, 44 percent of the region's imports will come from the Middle East and an additional 6 percent from the FSU. The interregional flows in 2005 and 2020 are summarized in the Appendix.

Figure 12.
Regional Share of the World's Uncommitted Natural Gas:
Tcf – Year End 2005
(Source – Jensen Associates Estimates)



Source: Jensen Associates

Despite the growing importance of the Middle East and the FSU, the Pacific Basin will still provide the basis for substantial LNG exports through the period of this forecast. A large portion of the Pacific Basin's near term supply will come from Western Australia, the Timor Sea between Australia and East Timor and Eastern Indonesia, as well as from Sakhalin.

Indonesia has become a source of supply uncertainty after years of enjoying a position as a reliable supplier and the world's largest LNG exporter. Both of the country's LNG export facilities — Arun in Western Sumatra and Bontang in Kalimantan — have experienced supply difficulties and Indonesia has actually been buying in the spot market to purchase LNG cargoes from others in order to honor its contract commitments.

Arun's problems stem from an aging natural gas field (it began producing in 1978) and have been compounded by rebel unrest in Aceh Province where it is located. In addition, the government has elected to divert some natural gas intended for the plant to fertilizer manufacture for farmers in the region. The LNG plant is already partially shut down and is expected to be fully shut down within the next several years.

Bontang in Kalimantan has additional natural gas reserves but the early trains are short of natural gas and it has been difficult to line up surplus reserves elsewhere to keep them operating at capacity. In addition, some natural gas is being diverted for fertilizer there, as well.

Indonesia faces expiration of some of its older LNG contracts between now and 2010 and has indicated that it would not renew its contracts at their original level. However, it is actively developing the Tangguh project in Irian Jaya and has shown interest in going ahead with several smaller projects. In our forecasts of Indonesian supply, we have assumed declining availability of the older supplies as contracts expire, but have assumed that Indonesia's conservative export stance will not negatively affect new projects.

Australia has a large number of potential LNG projects, both in the Browse and Carnavon Basins offshore Western Australia where the Northwest Shelf project has been in operation since 1989, and from the Bonaparte Basin offshore Timor Sea, where the Bayu Undan project recently commenced production. Portions of the Timor Sea area are contained in the jointly-administered Australia/Timor Zone of Cooperation, where political difficulties between the two governments have delayed some projects. In addition to further expansion of Northwest Shelf and Bayu Undan, there is a relatively optimistic outlook for several other Australian projects. These include: Browse, Gorgon, Greater Sunrise, Ichthys, Pluto and Scarborough. There has been some controversy over Western Australia's desire to reserve some project natural gas for domestic use, potentially affecting the economics of some of the projects. But this appears as if it may be resolved and our forecasts anticipate significant expansion from Australia.

Malaysia is a major Pacific Basin exporter and has substantial uncommitted natural gas reserves. We are not aware of any plans for further LNG expansion and have not projected additional LNG from that country.

The startup of the Sakhalin II project LNG exports (currently scheduled for 2008) will represent the first import of FSU natural gas into the region. It also raises the complex issue of Russian geopolitics as a part of regional supply planning.

The island is proving to be hydrocarbon-rich. Six potential Sakhalin blocks have been considered for exploitation, of which two are in advanced stages of development. Sakhalin II, operated by Shell, is an LNG export project, but ExxonMobil, the operator of Sakhalin I, has been trying to put together a natural gas export pipeline system. Determining the future of Sakhalin's potentially large supplies is challenging because of economic and geopolitical uncertainties. The Sakhalin II project, a mixed oil and natural gas project, has experienced huge cost overruns. Originally budgeted at $10 billion, it has now reached the $20 billion level with some reports suggesting that it may ultimately reach $23 billion. It is an Arctic project where the offshore fields are subject to ice conditions and the project uses a 600 mile pipeline to transport the natural gas to an ice-free port for liquefaction and shipment. Since the other Arctic LNG project — Snohvit in Norway — has also been subject to substantial cost overruns, it is not clear how much of this represents a penalty for Arctic environment or if the costs will be susceptible to "learning curve" experience.

But perhaps the greatest uncertainty involves geopolitics — the intentions of the Russian government towards LNG export projects. This uncertainty affects not only Pacific Russian supplies, but also the possible contribution of Western Russian LNG projects as well.

The Russian natural gas projects in Eastern Siberia and Sakhalin have been developed, not exclusively by Gazprom, as in the west, but with the participation of the international oil companies. The problems at Sakhalin II led to very difficult negotiations with the Russian Government in which Shell ultimately relinquished a share of the project to Gazprom. This suggests that Russia wants to reexert control over East Siberian and Sakhalin reserves and make them part of what some observers see as an attempt by the country to use natural gas exports as a political instrument.

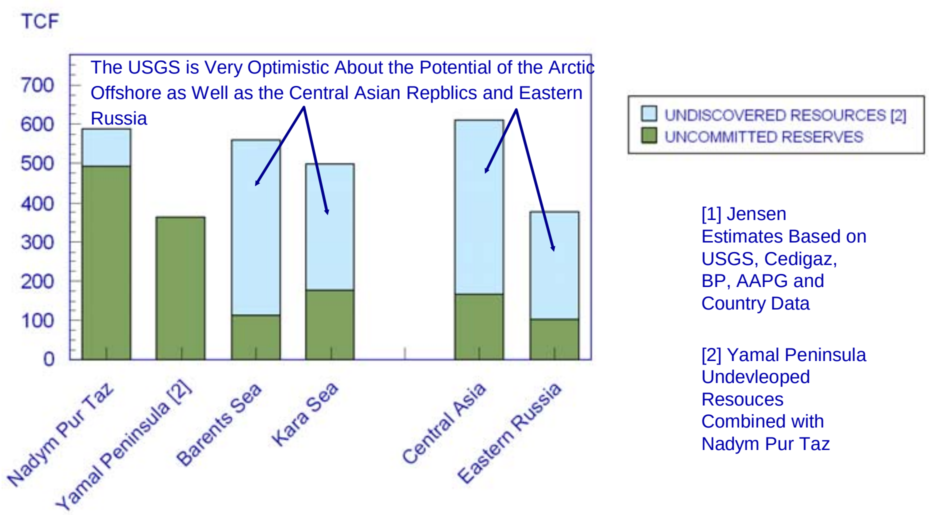
Russia has shown an interest in a pipeline system that would link Sakhalin and East Siberian reserves near Irkutsk with its West Siberian reserves that serve Eastern and Western Europe. The giant Kovytka field near Irkutsk is destined ultimately for pipeline export to China. If a decision is taken to emphasize pipelines, it may well limit the amount of Sakhalin natural gas ultimately available for LNG. **Figure 13** shows the location of some of the major supplies of the Former Soviet Union, including those in the Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan that are also natural gas-prone. **Figure 14** provides a breakdown of uncommitted natural gas in the FSU as well as estimates of undiscovered resources based on U.S. Geological Survey studies.

Figure 13.
Major Natural Gas Export Basins for the Former Soviet Union

Source: Jensen Associates

It is in the West where some of the Russian policy questions potentially have the greatest impact on world LNG markets. In West Siberia, the Nadym-Pur-Taz region has been the workhorse of the Russian natural gas industry. Russia supplies 26 percent of OECD Europe's natural gas consumption and much of this originates in the region. Russia has three other, as yet undeveloped, major potential producing regions where much of the uncommitted natural gas is located. They are the offshore Barents Sea containing the super giant Shtokman field, the Yamal Peninsula and the offshore Kara Sea.

Figure 14.
Major Uncommitted FSU Natural Gas Resources [1];
Includes Uncommitted Reserves and Undiscovered Resources:
Tcf as of 12/31/2005



Source: Jensen Associates

Nadym-Pur-Taz contains the world's second and third largest natural gas fields — Urengoi and Yamburg. But these two fields, together with another super giant — Medvezhye — are in advanced stages of depletion at a decline rate estimated at 2 Bcfd per year. In 2002 Gazprom brought another super giant — Zapolyarnoye — on line to maintain production rates. While there are still large reserves remaining in Nadym-Pu-Taz, there has been some question as to how much Gazprom wants to increase the commitments on the region before moving on to develop one of the other major regions. These new reserves are likely to be costly, and in the case of the Arctic offshore fields, technically challenging.

For a time, it appeared that Russia favored a pipeline from the Yamal Peninsula to Western Europe as the next step. However, Russia has alienated some of its major European customers, both through supply interruptions to the Ukraine (which were perceived by some as politically motivated) and Russian refusal to allow independent Russian producers access to Gazprom's pipelines, a policy which the European Union strongly advocates. Some of the European interest in LNG is partly motivated by a desire to diversify away from too much dependence on Russian supplies.

The North American "gas shock" of the winter of 2000/2001 and the subsequent interest in LNG appeared to offer Russia a diversification option of its own. By shifting to the Shtokman field in the Barents Sea, Russia contemplated a landing at Murmansk which could supply an LNG export facility for North America as well as European LNG importers who were interested. The pipeline to Murmansk could also be extended south to St. Petersburg, where it could supply not only Russia's new North European Pipeline under the Baltic to serve the German market but also a small proposed LNG facility at Primorsk on the Baltic near St. Petersburg.

More recently, Russia seems to have cooled somewhat on the idea of a Murmansk LNG export facility and now seems to favor the Shtokman pipeline connection to the Baltic. It has not given up on the Yamal option, however.

The development of Shtokman will be a technological challenge because of its Arctic offshore location. A number of international oil companies were attempting to partner with Gazprom to develop Shtokman, but recently the Russian government rejected their overtures, at least for now.

The uncertainties involving Russia's natural gas export plans have a substantial impact on the way in which Atlantic Basin LNG develops. If Russia decides to concentrate on pipeline exports, the technology which it knows best, and if the European customers grow more comfortable with Russian natural gas policies, it would have two effects on future LNG trade. It would reduce Russia's LNG offerings, but it also would reduce European competition for LNG. Europe has the pipeline as well as the LNG option. North America and most of the Pacific Basin must rely on LNG for interregional trade. In our low case scenario, where we assume future LNG supply limitations, Europe shifts to a much greater reliance on pipeline imports to accommodate the supply limitations

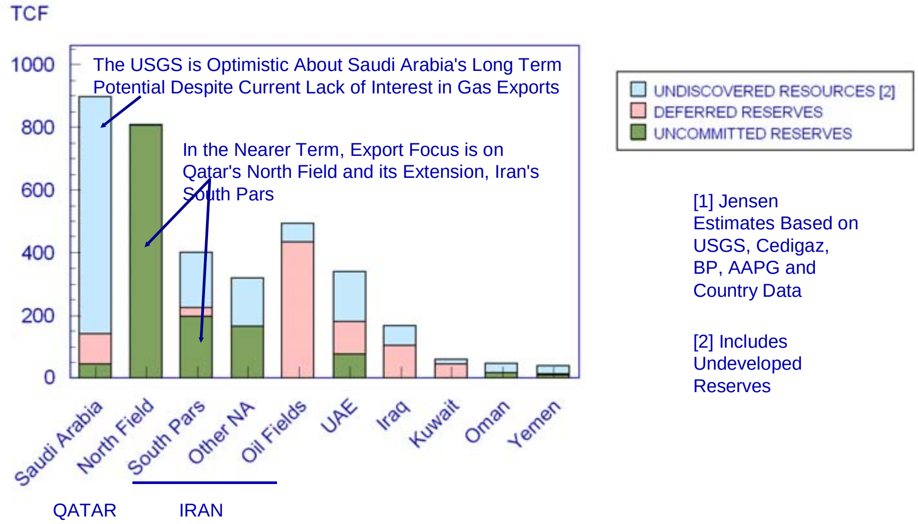
The Middle East accounts for 40 percent of both the world's total proved reserves and its uncommitted reserves. But 61percent of the region's uncommitted natural gas is in a single natural gas field shared between Qatar and Iran. In Qatar it is known as the North Field; in Iran it is called South Pars. If one were to add in the uncommitted natural gas elsewhere in Iran, those two countries would account for nearly 90 percent of the Middle East's uncommitted natural gas. Obviously, the LNG export policies of those two countries will have a powerful influence on the way in which future Middle East LNG trade develops. **Figure 15** is a map of the Middle East, showing where the natural gas is located and **Figure 16** summarizes the status of potential resources for export (including undiscovered natural gas).

Qatar began its first LNG exports in 1997 and has elected an aggressive policy of LNG expansion since that time. If its current plans for 2011 are realized (and most of its new capacity is in operation or under construction), it will account for nearly 40 percent of the entire world's increase in capacity between 1996 and 2011.

Figure 15.
Major Natural Gas Export Sources for the Middle East

Source: Jensen Associates

Figure 16.
Uncommitted Middle East Natural Gas Resources [1];
Includes Uncommitted Reserves, Deferred Reserves and Undiscovered Resources:
Tcf as of 12/31/2005



Source: Jensen Associates

However, Qatar has adopted a "wait and see" policy for further LNG expansion beyond that point, both to digest the consequences of its rapid growth and to better understand how the natural gas field behaves. Thus what has been the engine of recent Middle East LNG supply growth will be switched off, for how long it is difficult to tell. The U.A.E. (Abu Dhabi) and Oman are also LNG exporters, and Yemen has an active project under way. But the early outlook for expansion from these sources over the forecast period is limited. The United States Geological Survey Service (USGS) is very optimistic about undiscovered natural gas resources in Saudi Arabia, but that country has not yet found that natural gas nor shown any interest in natural gas exports. As long as Qatar maintains its decision against expansion beyond 2011, further Middle East LNG growth between 2011 and 2020 will have to come largely from Iran.

In determining how much natural gas it may want to export, Iran faces two issues that do not apply to Qatar — it has a very rapidly growing domestic market (fueled in part by subsidized pricing policies) and it needs natural gas for reinjection into its complex oil fields. It has a planned development of South Pars well under way. Its development is based on 20 (perhaps as much as 23 if the natural gas proves to be there) production blocks of about one Bcfd each. Five of the first eight blocks (which should all be in place by next year) are designated for domestic markets and three for oil field injection. Exports will not be implemented until Blocks 9 and 10 come on stream at some point in the future. There are currently five LNG projects that have been proposed for subsequent North Field blocks, as well as two that would utilize other Iranian natural gas fields.

The issue of whether or not to export LNG is of itself controversial within Iran, but the largest barrier to Iran's development of LNG is the international political climate. The imposition of sanctions on Iran, which have recently become more binding with the standoff over nuclear enrichment, denies Iran access to technology and most international markets. While the current geopolitical standoff will presumably not last forever, it is very difficult to put any realistic time line on when Iranian projects are likely to be commercialized.

Geopolitical issues that inhibit LNG development are not unique to Russia and the Middle East. Bolivia, Libya, Nigeria and Venezuela have substantial natural gas reserves and have potential LNG projects that are under consideration. But each of them faces geopolitical problems in developing new LNG projects.

In 2005, Nigeria exported 6 percent of the world's LNG from its Bonny project, which first commenced operation in 1999. It flares more natural gas than any other country in the world and the international oil companies are under pressure to stop flaring. Nigeria has the largest uncommitted natural gas reserves outside of Russia, Iran and Qatar and at least five additional proposed LNG projects. By all indications, Nigeria should be one of the most important future LNG suppliers.

But there has been substantial civil unrest in the country. Rebels have at times raided production facilities and taken workers hostage. Shell, which operates in one of the difficult regions, was forced to shut in nearly half its Nigerian oil production for many months because of the unrest. It is not a political climate that lends itself to large international investments with long payout times.

Nonetheless, Jensen Associates — like most observers — expect Nigeria to become a very important LNG supplier going forward. The major question is how rapidly will the expected growth take place?

Libya has finally gained acceptance of the international community and is no longer exposed to sanctions. It has one small LNG export plant that has been unable to operate at design capacity for many years. There are proposals to revamp the existing plant as well as to consider LNG from exploration in one of its natural gas-prone Basins. But when and how this will take place remains uncertain.

Both Bolivia and Venezuela have large natural gas reserves and have considered LNG projects. But current political policies might not be conducive to international investment in LNG facilities.

Bolivia was under active consideration as an LNG supplier for the Costa Azul terminal in Baja California. But Bolivia's politics are complex. Since Bolivia has no Pacific coastline, the liquefaction plant was to be located in Chile. But the proposal was unpopular in Bolivia because of the historic tensions between Bolivia and Chile as a result of the nineteenth century war which lost Bolivia its coastline. Then the election of the current administration, which favored nationalization of some international oil operations, further diminished the prospects for the LNG export project.

Our base case assumes that some of these geopolitical problems will be resolved and some of the potential supply described in this section will be realized. But the bulk of the supply limitations that define our low case come from projects that have been proposed for these regions.

Should We Worry About a Natural Gas OPEC?

The fact that many of the potential LNG suppliers are OPEC members and that there have been proposals for cooperation among supplying countries has raised the specter of a “Gas OPEC.” In our view, the kind of cooperation that would be required to influence the supply/demand balance and thus prices is highly unlikely because the two markets are so different.

OPEC was set up to prevent very low cost marginal producing capacity from causing a collapse of oil prices in surplus markets. It has not proved to be very effective in influencing prices during tight markets when the surplus capacity is largely gone.

Oil demand has grown 1.7 percent per year over the past decade and year-on-year declines in demand — and the resulting surpluses — have been common. Over the same period, LNG demand has grown at a rate of 7.4 percent per year and has not seen a year-on-year decline in demand in 27 years, when Algeria’s pricing policies effectively drove the U.S. out of the LNG import business for a period. And that was a supply-induced shortage, not a demand one.

LNG requires decisions about very large capital investments that, because of the long lead times between project initiation and final startup, will not affect the LNG supply/demand balance for four years or more. If the LNG producers could devise an organization that could correctly foresee natural gas supply/demand balances four years into the future and then allocate the new project construction schedules among members, a Gas OPEC might work. Jensen Associates, however, doubt that it will happen.

LNG Demand Uncertainties and Their Influence on Forecasts

The balance between pipeline and LNG trade will strongly affect the future of LNG. To date both North America and Northeast Asian markets are LNG markets, but pipeline options exist for China and India. It is also possible that pipelines will be extended to Korea as a part of the Russia/China options. That would provide at least part of Northeast Asia’s supply via pipeline.

Because OECD Europe is by far the largest interregional natural gas importer and because pipeline imports from Russia and North Africa account for 80 percent of its interregional natural gas trade, world LNG trade levels are very sensitive to how much of future European imports are destined to come via pipeline. Algeria and Libya export both by pipeline and LNG, while Egypt’s emerging exports are still in the form of LNG.

While there has been a proposal for a pipeline across North Africa originating in Nigeria, we have not included it in our estimates of pipeline trade with Europe.

The Nabucco proposal for a pipeline that would originate in the Caspian and deliver to Western Europe via Turkey and the Balkans is under active consideration. It would also potentially serve Iranian exports at some future time, and Iran is more comfortable with pipelining than it appears to be with LNG.

There are also significant differences in LNG estimates for North America. We have tended to rely on EIA LNG import estimates for the U.S. (adjusted for pipeline imports of regasified LNG from Mexico) and trade press information for Mexico. The EIA has a broad range of import estimates in its various scenarios, and we have used these to help construct our cases.

In projecting Pacific Basin demand, some of the largest uncertainties involve the demand in China and on the North American Pacific region. It is interesting that individual country estimates of future natural gas imports are commonly higher than those of the governmental organizations providing world forecasts. This may be because governments without experience in world natural gas trade do not see the difficulties of project development that the international organizations see.

This is particularly true of China. China has ambitious plans for natural gas utilization in power generation. But Chinese coal is very low in cost. The IEA, for example, does not see how high priced natural gas can compete with low cost coal and has a relatively conservative forecast for China. In addition, Russia has been attempting to sell pipeline natural gas to China in competition with LNG.

Some of the Chinese LNG import plans were formulated before the rise in oil and other energy prices during the early 2000s. Faced with currently high natural gas prices, Chinese buyers have been trying to change the pricing system from one linked to oil to one linked to coal. In our base case forecast we have assumed the more conservative approach favored by the IEA, but we have included higher Chinese estimates in our high case.

We have utilized the EIA's adjusted Pacific Census region LNG demand estimates to construct our base case. We have also considered them in the development of our alternate scenarios. The EIA's base case scenario for the Pacific Census region shows only modest growth and suggests a lower import level than might have been common in the early post "gas shock" period.

Liquefaction and Terminal Capacities

The usual expectation is that liquefaction plants will operate at a 90 percent capacity factor. The traditional long term contract utilized a take-or-pay clause, and the most common level was 90 percent. However, while the traditional contract also usually specified a “plateau level” of deliveries, it also gave the buyer a ramp up period for his market to grow into his commitment level. And since the Jensen Associates capacity database maintains its estimates on an end of year basis, plants starting up during the year will not be able to attain their annual design capacity levels in their first year of operation. This suggests that countries which are actively adding new capacity may appear to operate at low capacity factors. **Table 2** shows the national 2005 capacity factors for LNG exporters. Both Egypt and Qatar appear to have lower than average capacity factor operation, largely for the above reasons.

Table 2.
Liquefaction Plant Capacity Factors – 2005.

	CAPACITY FACTOR %	CAPACITY MMCFD	EXPORTS MMCFD
Algeria	96.3%	2,579	2,484
Australia	90.5%	1,587	1,436
Brunei	92.1%	960	885
Egypt	41.2%	1,627	670
Indonesia	83.2%	3,655	3,043
Libya	63.1%	133	84
Malaysia	91.1%	3,028	2,758
Nigeria	98.6%	1,181	1,164
Oman	95.5%	934	892
Qatar	76.4%	3,428	2,621
Trinidad	97.7%	1,387	1,355
U.A.E.	92.4%	747	691
U.S. (Alaska)	98.1%	181	178

Source: Jensen Associates

Capacity is a more complex concept for a receipt and regasification terminal. Three different elements in the design affect the operating capacity — the capacity of the terminal’s regasification unit, the holding capacity of the storage tanks, and the tanker handling capability of the pier. Since the regasification unit itself is a relatively small part of the terminal capital cost, the economic penalty for oversizing regasification capacity is small. And particularly for terminals serving power generation loads that may only operate for a portion of the day, the extra capacity provides the sendout flexibility to handle these intermittent loads. The capacity of the regas unit is usually described as “peak” capacity.

But the storage capacity and the tanker unloading capability are commonly unable to accommodate peak sendout for any period of time, raising the concept of “annual” or “sustainable” capacity. Thus in working with terminal capacity numbers, it is very important to understand how capacity is being defined. The use of peak capacity figures for judging yearly performance will usually lead to abnormally low percentage utilization figures.

The problem is compounded by the fact that different groups report on different bases. The Federal Energy Regulatory Commission (FERC), in its website listing of import (regasification) terminals, uses the peak capacity numbers. Japanese capacities (where power generation intraday load factors are low) also report on a peak basis. In our database we prefer to use annual capacity figures where they are available. **Table 3** lists importing country terminal capacity figures for 2005. Note, however, that liquefaction and import terminal capacity factors should not be totaled, for the reasons noted above.

Table 3.
Import Terminal Capacity Factors – 2005

	CAPACITY FACTOR %	CAPACITY MMCFD	IMPORTS MMCFD
U.S.	52.5%	3,291	1,728
Puerto Rico	95.3%	68	65
Dominican Republic [1]	25.2%	96	24
Belgium	64.5%	447	288
France	63.3%	1,961	1,241
Greece [1]	23.0%	193	44
Italy [1]	21.2%	1,141	242
Portugal [1]	30.4%	503	153
Spain	72.1%	2,930	2,113
Turkey	93.8%	503	472
U.K. [2]	11.6%	435	50
India [1]	29.2%	2,001	584
Japan [1]	30.8%	23,974	7,381
Korea	62.0%	4,750	2,945
Taiwan	88.5%	1,050	929

[1] Based on peak capacity
[2] Start up year

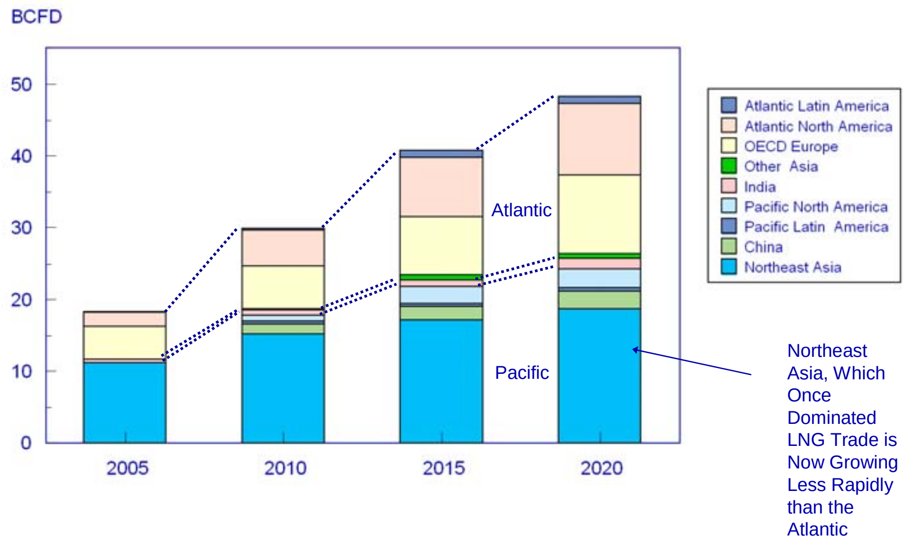
Source: Jensen Associates

The Forecast Results

LNG Demand

The base case envisions a world LNG demand growing from 18.26 Bcfd in 2005 to 48.29 Bcfd by 2020. While Atlantic Basin markets will grow much more rapidly over the period than the Pacific Basin markets, which historically have dominated world trade, they still will not surpass the Pacific over the forecast time period. The base case projections, broken down by major importing regions are illustrated in **Figure 17**.

Figure 17.
Base Case Projections of World LNG Demand by Region:
BCFD



Source: Jensen Associates

The three biggest importing regions — Northeast Asia, OECD Europe and the Atlantic Coast of the U.S. and Canada (combined since their markets are so closely integrated) among them — account for more than 80 percent of world LNG trade. Despite the potential importance of China and India, they account for only 5 percent and 3 percent respectively. **Table 4** provides detailed demand by region for the base case.

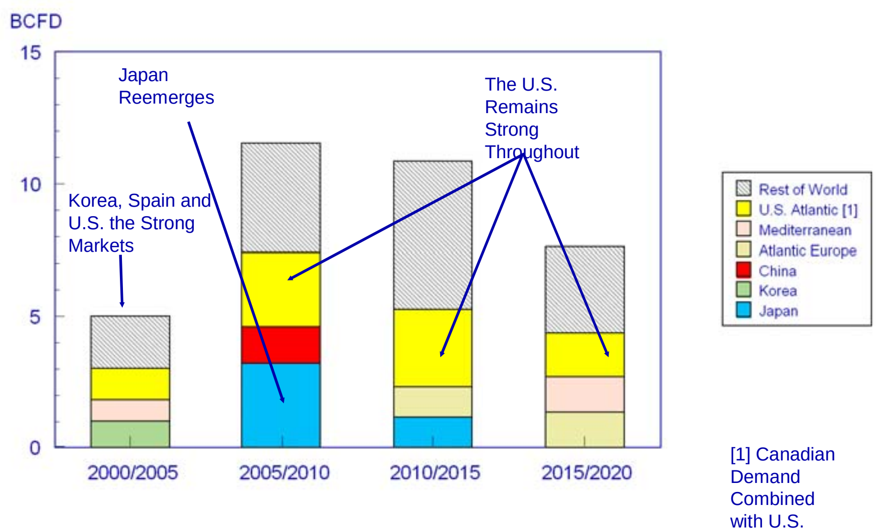
Table 4.
Summary of Base Case Demand Estimates

Bcfd	Actual 2005	Base Case 2010	Base Case 2015	Base Case 2020
Northeast Asia	11.26	15.35	17.28	18.86
China	0.00	1.38	1.89	2.43
India	0.58	0.79	1.02	1.43
Other Asia	0.00	0.12	0.16	0.20
North America Pacific	0.00	0.83	2.34	2.59
Latin America Pacific	0.00	0.32	0.41	0.51
Total Pacific Basin	11.84	18.79	23.61	26.51
OECD Europe	4.60	5.93	8.10	10.79
North America Atlantic	1.79	4.96	8.19	10.13
Latin America Atlantic	0.02	0.13	0.78	0.86
Total Atlantic Basin	6.42	11.01	17.07	21.78
Total World	18.26	29.80	40.68	48.29

Source: Jensen Associates

Figure 18 highlights the regional markets that are responsible for the greatest growth. It shows the three largest incremental increases in LNG demand by five year periods going forward. Totaling all columns will provide overall growth for the 20-year period. The U.S. and Canadian Atlantic coastal region is in the top three for all forecast periods, indicating strong growth in comparison to other countries. Japan shows substantial LNG demand growth between 2005 and 2015 but does not increase demand as much as other countries between 2015 and 2020. **Figure 18** breaks down the European imports into Atlantic Europe and Mediterranean Europe. In 2005, the Mediterranean was a larger market than Atlantic Europe. Atlantic Europe's demand for LNG increases in the out years and between 2015 and 2020, its demand growth is similar to Mediterranean Europe.

Figure 18.
The Three Largest Contributors to Incremental Natural Gas Demand Over Five Year Periods – Base Case: BCFD



Source: Jensen Associates

From **Figure 18**, it is apparent that the incremental growth in LNG demand for the five year period 2005/2010 is much larger than that shown for the succeeding two five year periods. The large increment is a direct outgrowth of the LNG plant construction that is already under way and, barring slippage in plant completion dates, should result in additional production by 2010. The demand forecast assumes that there is pent-up demand to absorb the new supply. The LNG market has recently been very tight as customers have been forced to compete for cargoes, and the new capacity available particularly from Qatar should alleviate the shortage.

The surge in **Figure 18** also illustrates an issue underlying the forecast approach. Since supply additions have been made using actual projects, the additions to capacity are inherently "lumpy", occasionally creating short term surpluses. In balancing demand with supply, the study has at times selectively absorbed temporary surpluses by slightly reducing capacity factors for suppliers that are deemed to play a “swing” role in the market.

Table 5 summarizes the demand by region in the two alternate scenarios — the high case and the low case. In the high case, the total demand growth between 2005 and 2020 is the largest for OECD Europe (split almost equally between Atlantic Europe and the Mediterranean) with Atlantic U.S. and Canada a close second. In the high case, Chinese and Indian demands are both substantially greater than in the base case. The high case also foresees growth in the Pacific North American market. World natural gas reserves are sufficient to meet the high case demand.

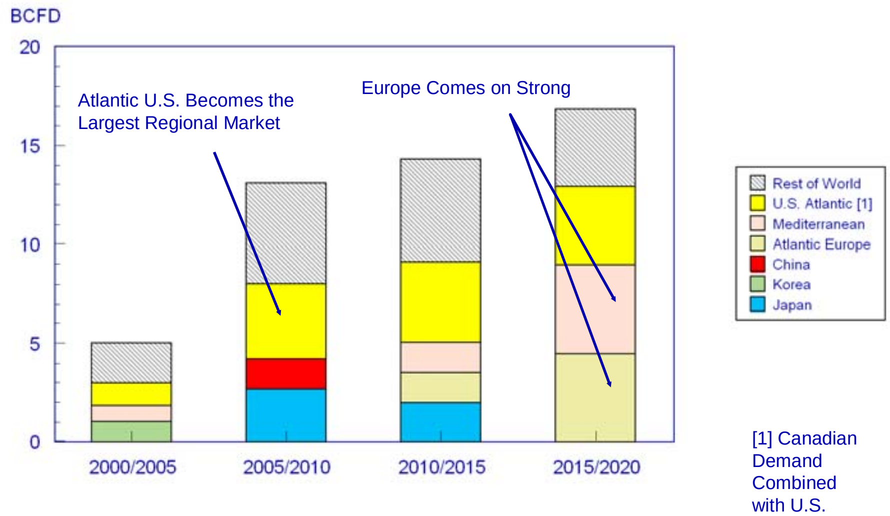
Table 5.
Summary of Alternate Scenario Demand Estimates

Bcfd	Actual 2005	High Case 2010	High Case 2015	High Case 2020	Low Case 2010	Low Case 2015	Low Case 2020
Northeast Asia	11.26	15.35	17.43	19.42	15.35	16.94	18.30
China	0.00	1.55	2.85	3.49	1.38	1.76	2.21
India	0.58	1.36	1.59	1.65	0.79	0.92	1.27
Other Asia	0.00	0.12	0.66	0.70	0.12	0.01	0.70
North America Pacific	0.00	1.08	2.86	3.57	0.83	2.11	2.33
Latin America Pacific	0.00	0.32	0.41	0.51	0.32	0.41	0.51
Total Pacific Basin	11.84	19.78	25.80	29.34	18.79	22.80	25.32
OECD Europe	4.60	5.46	8.50	17.50	4.65	3.82	4.96
North America Atlantic	1.79	5.94	10.52	14.73	5.23	8.04	9.81
Latin America Atlantic	0.02	0.13	0.78	0.86	0.13	0.78	0.78
Total Atlantic Basin	6.42	11.53	19.80	33.09	10.00	12.64	15.55
Total World	18.26	31.31	45.60	62.43	28.79	35.44	40.87

Source: Jensen Associates

Figure 19 again highlights the three largest incremental contributors to demand over each five year period. The U.S. and Canadian Atlantic coast remains a strong market throughout, although it is eclipsed by both Atlantic Europe and the Mediterranean in the 2015/2020 time frame.

Figure 19.
The Three Largest Contributors to Incremental Natural Gas Demand Over Five Year Periods – High Case:
BCFD

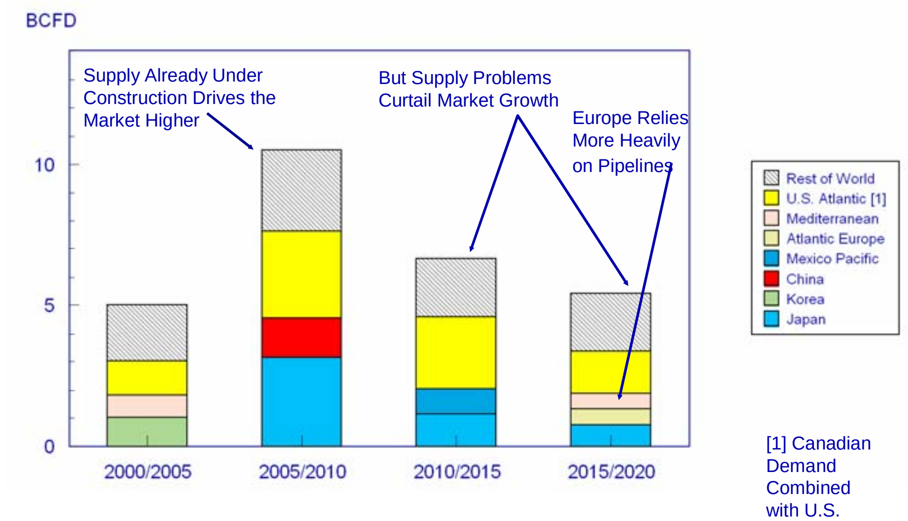


Source: Jensen Associates

The basic assumption behind the low case demand for LNG is that supply becomes the limiting factor in restricting the growth in demand. It also assumes that Russia elects to de-emphasize the LNG option in favor of pipeline exports, limiting its LNG trade to that from the Sakhalin II project that has already been committed. Assuming that the supply restraints imply higher world prices for traded natural gas, a number of markets utilize somewhat less than in the base case. The greatest shift in LNG occurs in Europe, where presumably the region would shift largely to pipeline imports from the Former Soviet Union. North America lacks that option and thus takes a significantly larger share of LNG trade relative to Europe than in the base case.

Figure 20 shows the three largest importing regions under the low scenario. By 2020, Atlantic Europe and the Mediterranean are both in the top five, but at sharply reduced levels from the base case. Because North America relies heavily on natural gas produced within the region, LNG imports are only a supplemental supply. Therefore, in the low case, demand in North America drops much more relative to the base case than it does in Northeast Asia where all natural gas is imported as LNG.

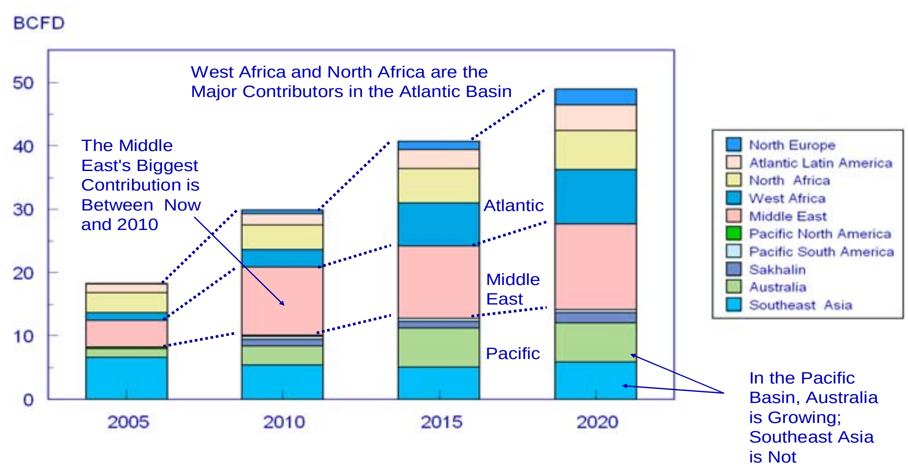
Figure 20.
The Three Largest Contributors to Incremental Natural Gas Demand Over Five Year Periods – Low Case: BCFD



Source: Jensen Associates

Qatar dominates LNG supply additions out to the year 2011. But the country has adopted a "wait and see" policy for further expansion beyond that point. While it is likely that Qatar will at some point revisit that conservative policy, it is difficult to include further Qatar supply beyond 2011. **Figure 21** shows the regional contributions to supply by five year periods out to 2020. In the period beyond 2010, the greatest contributions to base case supply come from North Africa, West Africa and Australia. Southeast Asia, given some of the problems in Indonesia, does not show significant growth.

Figure 21.
Base Case Projections of World LNG Supply by Region: BCFD



Source: Jensen Associates

LNG Supply

Table 6 details the supply contributions by region over the forecast period. Southeast Asia including Indonesia, which was the world's largest LNG supplier as recently as 2005 (it is being passed by the Middle East led by Qatar), shows virtually no growth in the forecast. The country is grappling with the desire to use more of its natural gas domestically, and we expect LNG export growth to be limited to new projects versus existing projects.

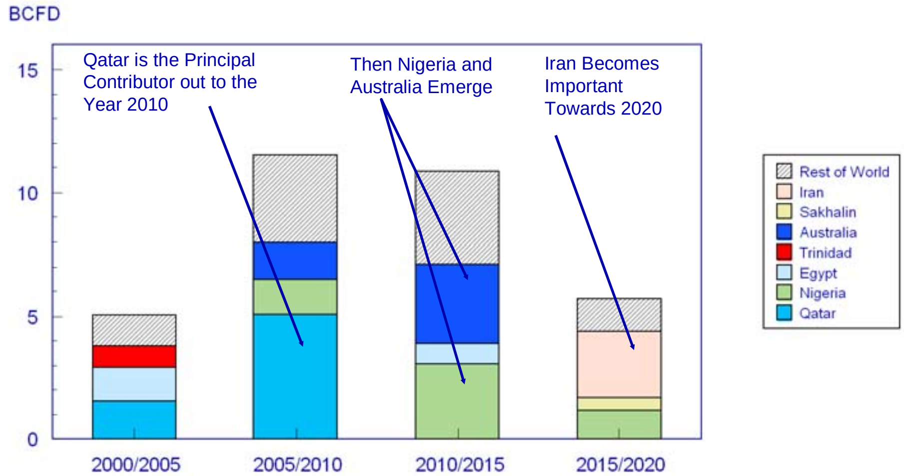
Table 6.
Summary of Base Case Supply Estimates

Bcfd	Actual 2000	Actual 2005	Base Case 2010	Base Case 2015	Base Case 2020
Australia	0.98	1.36	2.87	6.08	6.20
Southeast Asia	6.34	6.49	5.57	5.25	5.33
Russian Far East	0.00	0.00	1.11	1.03	1.54
Pacific North America	0.16	0.15	0.16	0.00	0.00
Pacific Latin America	0.00	0.00	0.58	0.54	0.53
Total Pacific Basin	7.47	8.00	10.28	12.91	13.60
Total Middle East	2.27	4.36	10.68	12.91	13.60
North Africa	2.62	3.71	3.76	5.38	6.09
West Africa	0.54	1.01	2.81	6.94	8.66
Northern Europe	0.00	0.00	0.47	1.20	2.39
Atlantic Latin America	0.34	1.18	1.80	2.97	4.10
Total Atlantic Basin	3.50	5.90	8.85	16.49	21.24
Total World	13.25	18.26	29.80	40.68	48.27

Source: Jensen Associates

Figure 22 indicates the top three regional suppliers for each of the forward five year periods. The base case estimate assumes that the current geopolitical issues that inhibit near term LNG projects in Iran will have been resolved in the 2015/2020 time frame and it emerges as the largest incremental supplier during that period.

Figure 22.
The Three Largest Contributors to Incremental Natural Gas Supply Over Five Year Periods – Base Case: BCFD



Source: Jensen Associates

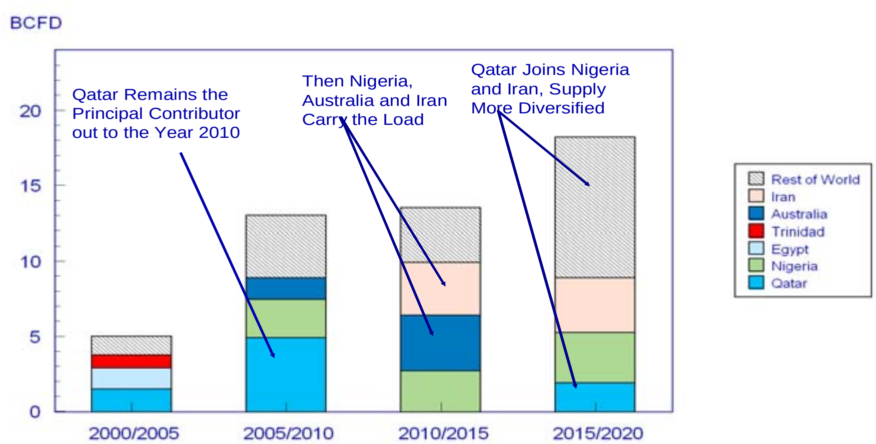
Table 7 details the LNG supplies by country in the two alternate scenarios. To achieve the high case supply scenarios it is necessary to assume that some of the suppliers whose near term contributions are questionable will rise to the occasion in the out years. For example, in the Middle East, Iran is expected to provide the largest increment to supply in the last five year period of the forecast. We also assume that Qatar will revisit its "wait and see" decision and again expand capacity. **Figure 23** shows the top three incremental contributors in the high case. Nigeria, Australia and Iran carry much of the incremental load.

Table 7.
Summary of Alternate Scenario Supply Estimates

Bcfd	Actual 2005	High Case 2010	High Case 2015	High Case 2020	Low Case 2010	Low Case 2015	Low Case 2020
Australia	1.36	2.83	6.53	7.37	2.32	4.10	5.81
Southeast Asia	6.49	5.70	5.76	6.47	5.78	5.45	4.96
Russian Far East	0.00	1.09	1.62	2.31	1.15	1.15	1.15
Pacific North America	0.15	0.16	0.00	0.00	0.16	0.00	0.00
Pacific Latin America	0.00	0.01	0.56	1.79	0.00	0.45	0.45
Total Pacific Basin	8.00	10.34	14.47	17.94	9.42	11.15	12.37
Total Middle East	4.36	10.53	14.03	18.08	10.19	11.77	12.76
North Africa	3.71	4.28	5.61	8.48	3.91	5.12	6.62
West Africa	1.01	3.91	7.72	10.87	2.92	5.02	5.69
Northern Europe	0.00	0.47	1.25	3.07	0.49	0.49	0.85
Atlantic Latin America	1.18	1.78	2.52	3.99	1.87	1.87	2.57
Total Atlantic Basin	5.90	10.43	17.10	26.42	9.19	12.51	15.73
Total World	18.26	31.31	45.59	62.44	28.80	35.44	40.86

Source: Jensen Associates

Figure 23.
The Three Largest Contributors to Incremental Natural Gas Supply Over Five Year Periods – High Case: BCFD

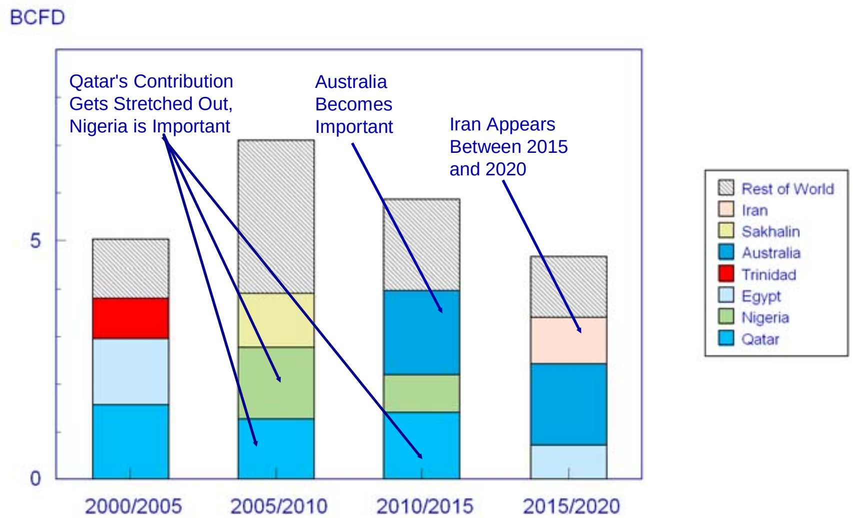


Source: Jensen Associates

Figure 24 shows the same information for the low case. Since the case is based on supply limitations, countries whose near term expansions have not been included in the base case are pushed even further into the future or not included altogether. One interesting outcome of the low case is the shift in destinations for Middle East supplies. In the low case, Atlantic Basin supply growth is expected to continue at the same time that Europe is switching more of its demand to pipeline delivery. The effect is to back

Middle East natural gas out of Atlantic Basin markets, diverting them largely to the Pacific Basin.

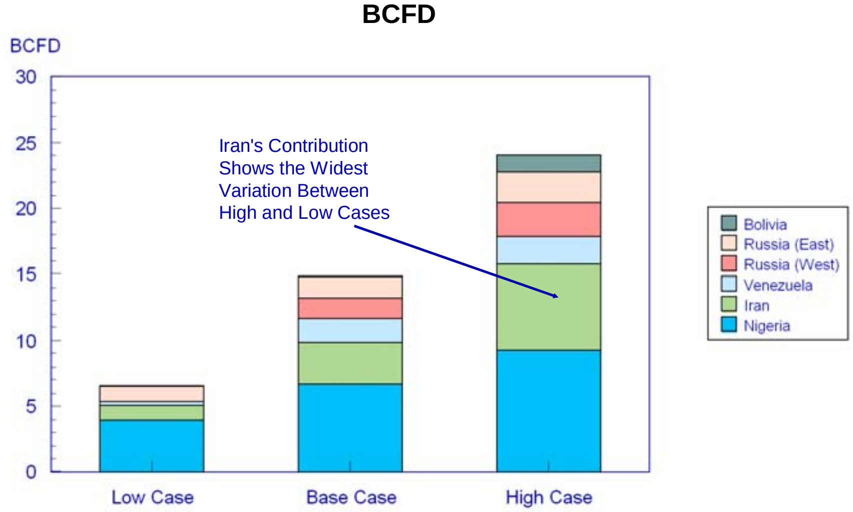
Figure 24.
The Three Largest Contributors to Incremental Natural Gas Supply Over Five Year Periods – Low Case: BCFD



Source: Jensen Associates

Several countries, for which the near term LNG supply outlook is clouded by geopolitics, technology or economics, will probably show the greatest variation in future LNG supply among the three cases. **Figure 25** highlights the differences in LNG supply for selected countries.

Figure 25.
Variation in LNG Exports in 2020 for the Three Scenarios for Selected Suppliers: BCFD



Source; Jensen Associates

APPENDIX A

REGIONAL PATTERNS OF WORLD LNG TRADE
2005 AND 2020 (BCFD)

Demand Regions	Atlantic Basin Supply		Middle East Supply	
	2005	2020	2005	2020
Atlantic North America	1.8	9.7	Small	0.4
Atlantic Latin America		0.9		
OECD Europe	3.9	10.6	0.6	0.2
India			0.6	1.4
China				0.4
Northeast Asia			3.0	10.5
Other Asia				0.5
Pacific North America				
Pacific Latin America				
World	5.7	21.2	4.2	13.4

Demand Regions	Pacific Basin Supply		World	
	2005	2020	2005	2020
Atlantic North America	Small		1.8	10.1
Atlantic Latin America				0.9
OECD Europe			4.6	10.8
India			0.6	1.4
China		2.0		2.4
Northeast Asia	8.2	8.4	11.2	18.9
Other Asia		0.2		0.7
Pacific North America		2.6		2.6
Pacific Latin America		0.5		0.5
World	8.3	13.6	18.2	48.3