



THE JAMES A. BAKER III
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NEW ENERGY TECHNOLOGIES IN THE NATURAL GAS SECTORS:
A POLICY FRAMEWORK FOR JAPAN

DEVELOPMENTS IN ATLANTIC BASIN LNG:
IMPLICATIONS FOR JAPAN

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Introduction

The nature of liquefied natural gas (LNG) trading in the Atlantic Basin has changed dramatically in recent years. Initially begun in 1964 as a small, specialized niche business from Algeria, LNG trade has evolved into a supplementary and often base-load fuel for markets ranging from Asia to Western Europe to the U.S.

From the 1960s through the 1980s, the players in the LNG businesses were limited. Japan was the key buyer in Asia, taking on supplies from Brunei and Indonesia. Shipments in the West were limited to those from Algeria and Libya mainly targeted at Europe. Contract terms were rigid and long in duration (20 years) to cover the risks of building expensive facilities.

Over the past decade, LNG facilities and transport costs have fallen dramatically and technology has improved, allowing LNG to proliferate both East and West. The number of LNG players has grown exponentially, and the rigidity and duration of contracts has loosened considerably. In Asia, suppliers now include Abu Dhabi, Alaska, Qatar, Oman, Australia, Brunei, Indonesia, and Malaysia, and new projects are under discussion from the Russian Far East, Iran, Yemen, Papua New Guinea, and the Middle East. Asian buyers include Japan, Taiwan and South Korea, with China and India among possible future importers. In the Atlantic Basin, Trinidad and Nigeria have joined Algeria and Libya. Also under discussion are new projects in Alaska, Angola, Bolivia, Egypt, Equatorial Guinea, Norway, and Venezuela, among others. Western importers include the U.S., Belgium, France, Spain, Italy, and Turkey, with Portugal, Greece, Brazil and Mexico among possible new entrants.

Whereas traditional LNG businesses required firm, long-term arrangements with volumes, prices and customers fixed for 20 years, Atlantic Basin LNG suppliers and buyers are taking more flexible approaches. Contract terms have become increasingly fluid, with prices more frequently determined by netback calculations from competitive markets and supply sources more interchangeable. Duration is also shifting with buyers now looking for a variety of durations five years or less to complement established 20-year LNG contracts or traditional pipeline supplies. Infrastructure is also being built and acquired on more speculative basis. Terminals and

regasification plant expansions are being built with only part of their capacity locked in to long-term, fixed-volume commitments. In addition, about half of the LNG tankers on order for delivery between 2001 and 2005 are not directly tied to firm LNG transportation contracts. As supply sources proliferated, spot transactions have risen in number, leading to speculation that the structure of LNG markets is entering a period of transition.

Traditionally, LNG markets have been bifurcated between East and West. Orientation of buyers was also different. In the U.S. and Europe, LNG had to compete with readily available pipeline gas, encouraging more flexible and commoditized operations. Buyers in North America and Europe were more concerned with competitive prices than with security of supplies, unlike their Asian counterparts for whom reliability and security of supply were paramount.

Increasingly, the markets, both East and West, may look more similar over time. Already, Japanese customers are asking for increasingly flexible terms in their arrangements with traditional suppliers. At the same time, U.S. gas consumers and marketers are beginning to sign long-term agreements rather than relying solely on spot and short-term arrangements. Eventually, both will likely adopt portfolio strategies, assembling a blend of short-term and long-term supply and transportation arrangements that fit customized needs.

This paper investigates evolution of the Atlantic Basin LNG market and the potential for increased standardization, commoditization and globalization. Discussion will begin with an analysis of U.S. natural gas market trends and whether these trends suggest that LNG will become a permanent fixture in the U.S. energy mix. This section will be followed with an investigation of the factors that have promoted an increase in LNG spot market activity in recent years and how this activity compares to the early development of spot crude oil markets. Existing LNG market developments include several key differences from liquids trade, and those must be taken into account when considering the potential for sustained spot trading and price transparency and convergence. Among the areas to be discussed in relation to the promotion of spot trade are: a) diversity of supply and potential oversupply and competition; b) corporate strategies; c) infrastructure development; d) pricing trends; and e) the role of market makers.

Finally, the paper will cover the implications of a structural change in LNG trade for the Japanese market. Global influences are expected to change the terms of reference for LNG pricing to Japan as well as the nature and duration of Japanese supply contracts. Consideration will be given to whether Japan can expect to find a broad array of supply sources or whether a price premium might be needed to ensure supply security.

U.S. Domestic Gas Demand

The United States is the world's single largest natural gas market, larger than all of Europe. It is a diverse market, with demand originating in many sectors including industrial (14%), power generation (34%), residential/commercial (35%), petrochemical (9%), and other (8%). The U.S. power sector is expected to account for much of the growth to come in domestic natural gas use in the coming decade. The U.S. gas transmission grid is highly sophisticated and interconnected.

Until the early 1980s, the U.S. was relatively self-sufficient in natural gas supplies and even enjoyed a supply overhang. Strong demand growth has given imports added importance in recent years. Canada is by far the largest source for U.S. imported gas. By 1990, imports of mostly Canadian gas accounted for 8% of U.S. demand. The share rose to 13% in 1995 and 16% by 2000, still largely Canadian in origin, but also some LNG. LNG supplies now represent less than 3% of U.S. market supply.

As we will discuss below, this natural gas supply deficit could continue throughout the coming decade, reaching up to 6 to 7 trillion cubic feet (Tcf) in 2010 under high demand growth scenarios. Of this, some 2-2.5 Tcf might have to be supplied by LNG, about 5-10% of demand.

Unless prices support exploitation of high-cost, non-conventional deposits, which in many cases have yet to be delineated and proved, the U.S. will have to turn to more pipeline imports from Canada and LNG from a variety of Atlantic Basin or Pacific Rim producers to meet the projected rise in natural gas demand.

Forecasts show that U.S. natural gas markets are expected to grow at a healthy rate over the coming decade. The U.S. Department of Energy forecasts U.S. natural gas use will rise from 22 Tcf (60 billion cubic feet a day) in 2000 to 28 Tcf (77 Bcf/d) by 2010. Other forecasts show similar growth. Deutsche Bank Alex Brown forecasts U.S. demand will reach 31.96 Tcf by 2010 and 39.85 Tcf by 2020. Private analysts predict natural gas' share in the U.S. power sector could double over the next decade as new generation plants favor natural gas fuel.

Typical Forecast Ranges for U.S. Natural Gas Use by Sector

(Trillion cubic feet/year)

YEAR	2000	2005	2010
Residential/Commercial	8.27	8.1 - 8.6	8.4 - 9.29
Electricity	6.33	6.5 - 12.64	8.3 - 15.54
Industrial	6.29	4.78 - 9.1	5.02 - 9.1
Lease and Plant Use and Pipeline Fuel	1.88	1.94 - 2.2	2.11 - 2.4
Total Demand	22.78	21.32 - 32.54	23.83 - 36.33

Source: Deutsche Bank Alex Brown, Industry, U.S. DOE

The more optimistic forecasts for future U.S. gas demand include projections for a 3-4% per annum increase in natural gas demand by non-utility generators through 2003 and then roughly 5% per annum growth in this sector through the end of the decade. However, last year's sharp rise in U.S. natural gas prices was a warning that such forecasts for the electricity sector may be overly optimistic. Boulder-based RDI NEWgen database reported that 16,422 MW of new generation capacity was cancelled in the first eight months of 2001.¹ Moreover, shortages and high prices over the 2000-2001 winter led many buyers back to fuel oil markets, and some industrial users have shut down permanently or moved offshore rather than foot steep U.S. gas feedstock costs. In the power market, generators are giving more consideration to diversifying their future fuel slates. In the first half of 2001, more than 20,000 MW of new coal-fired capacity had been announced in the U.S., mainly utilizing clean coal technology. The Bush Administration's ruling on the New Source Review standards could encourage this trend back to coal, potentially shaving up to 1.8 Tcf (5 Bcf/d) off natural gas demand growth.

¹ Energy Insight. Resource Data International. September 21, 2001.

Still, by 2010, U.S. demand, at 28 to 32 Tcf, is likely to exceed substantially domestic sources of natural gas of about 20-22 Tcf. Canada's shipments to the U.S. are expected to grow over the decade to 1.6 to 2 Tcf (4.5 to 5 Bcf/d), up from 3.5 Bcf/d currently while Alaska pipelines could provide as much as 1.5 Tcf (4 Bcf/d) and possibly an additional 0.75 Tcf (2 Bcf/d) from the Canadian Northwest. Thus, North American continental supply could be as high as 24.85 Tcf to 26.25 Tcf.

In a low demand growth/high supply scenario where coal shaves close to 2 Tcf from demand growth and pipeline projects from Canada and Alaska proceed as planned, U.S. natural gas demand could almost be met without resorting to LNG supply. However, even in this most pessimistic scenario, it remains to be seen whether LNG would be shunned by U.S. buyers as a marginal supply since several short-haul LNG projects might have competitive costs and economics that beat out certain higher cost domestically drilled gas and/or Canadian supply.

In the more robust U.S. natural gas demand path scenarios, even if North American continental supplies hit the upper ranges of 25 to 26 Tcf, the U.S. market requirement for LNG imports would be great at around 120-140 millions tons a year (6-7 Tcf). At present, the existing American receiving terminal infrastructure can support only around 20 MM tons per year (1 Tcf). Given the industry's historical propensity to overbuild, however, that capacity can be expected to see expansion. Receiving terminal expansions of 20 MM tons a year are already planned (see table below). Moreover, at least four to six new facilities could be built on the East and West coasts, among the many that are under consideration.

EXISTING U.S. LNG RECEIVING TERMINALS

Facility	Operator	Peak (Bcf/d)	Throughput (MM tons/year)	Status	Expansion (Bcf/d)	Capacity (MM tons/year)
Everett	Tractebel	0.535	4.1	Open	1.1	8.5
Cove Point	Williams	1.00	7.7	3Q 2001	3.0	23.0
Elba Island	El Paso	0.635	5.0	2Q 2002	0.8	6.1
Lake Charles	CMS	1.00	7.7	Open	1.2	9.2
Total		3.170	24.5		6.1	46.8

U.S. Supply Sources

The U.S. resource base as calculated by the Energy Information Administration of the Energy Dept. is enormous. EIA estimated that total technically recoverable U.S. natural gas reserves as of Jan. 1, 1999, stood at almost 1.3 quadrillion cubic feet, or 1,281 trillion cubic feet.² However, almost a third of that gas is located in unconventional sources such as tight sands reservoirs, shale deposits, and coalbed methane. Another 19% is what EIA called "inferred non-associated." Only 25% of the potential reserves would come from conventional, non-associated gas wells, both onshore and offshore. Proven economically recoverable reserves in the lower-48 states are estimated at around 167 Tcf.

Evidence that the U.S. market will continue to rely on imports seems fairly certain. Barring giant new discoveries, meeting U.S. demand without resorting to rising imports would require a level of drilling activity the industry would have difficulty attaining and costs that far surpass current levels of investment. EIA projects that more than 17,500 wells would have to be drilled in 2010 and 23,500 in 2020 to keep pace with demand, compared to about 10,270 wells drilled in 1999. The industry did approach such drilling rates in the late 1970s, but it is unclear whether the personnel or infrastructure exists to do so again.

² Mary J. Hutzler, Energy Information Agency, presentation, Zeus Development's LNG's Role in North American & Caribbean Gas Supply Conference, Arlington, Virginia, June 28, 2001.

Another question is whether another round of such unprecedented drilling would yield the production results sought. EIA argues that in the 20 years from 1953-1972, the industry added net production on average of 700 Bcf per year, or 13.9 Tcf cumulatively. Attaining the projected total annual production of 24.7 Tcf in 2020 would require additions averaging 510 Bcf annually, or 10.2 Tcf cumulatively, over the next two decades.

Evidence from the drilling upturn of the past two years is not encouraging. In spite of a doubling of the number of drilling rigs searching for natural gas, U.S. production in 2000 was only 2.2% higher than in 1999. Growth for 2001 is estimated at 2.8%, but results from the first half of the year do not support that prediction. Duke Energy Field Services and El Paso Field Services, the two largest natural gas gathering companies, said new well connections to their systems are barely keeping up with the decline in output from existing wells.³

A Deutsche Bank Alex Brown survey of the largest U.S. producers in the first half of 2001 showed only a 1.5% gain overall.⁴ Some of the increase was due to one-time events, including blowing down the gas caps in two large oil fields, ExxonMobil's Friendswood Field in Texas and Occidental Petroleum's Elk Hills Field in California. Both were done to take advantage of high prices, and neither can be sustained. Meanwhile, drilling results from the shallow waters on the Gulf of Mexico shelf provided one-time gains from single-well fields with first-year depletion rates exceeding 50%. Since these wells were drilled mainly because of prices above \$5, this activity may not be repeatable. Absent another sustained price spike, a comparable round of drilling is unlikely.

The supply response from traditional Canadian production areas raises similar questions about the long term. According to the Canadian National Energy Board, drilling there also set a record in number of wells, but the supply response from traditional producing areas in Alberta and surrounding provinces has been minimal.⁵ The Canadian outlook for its frontier regions is brighter, especially in the Northwest Territories and offshore East Coast. Production from the

³ Private interviews.

⁴ Adam Sieminski, Deutsche Bank Alex Brown research report, August 29, 2001.

⁵ Terry Rochefort, Canadian National Energy Board, presentation, Zeus Development's LNG's Role in North American & Caribbean Gas Supply, Arlington, Virginia, June 28, 2001.

Sable Island area off Nova Scotia now exceeds 530 MMcf/d from this new producing basin, and projections for future output are strong enough that pipeline owners are planning expansions. This will be significant for the U.S. New England states that already are tight on gas deliverability.

On average, gas reserves added per well in conventional areas, U.S. and Canada, are declining. In addition, the ongoing decline in U.S. lower-48 onshore and shallow water oil production is similarly negatively impacting gas production rates. Historically, associated gas has accounted for 15% of total gas supply. As oil output in these regions continues to fall, so will associated-gas production.

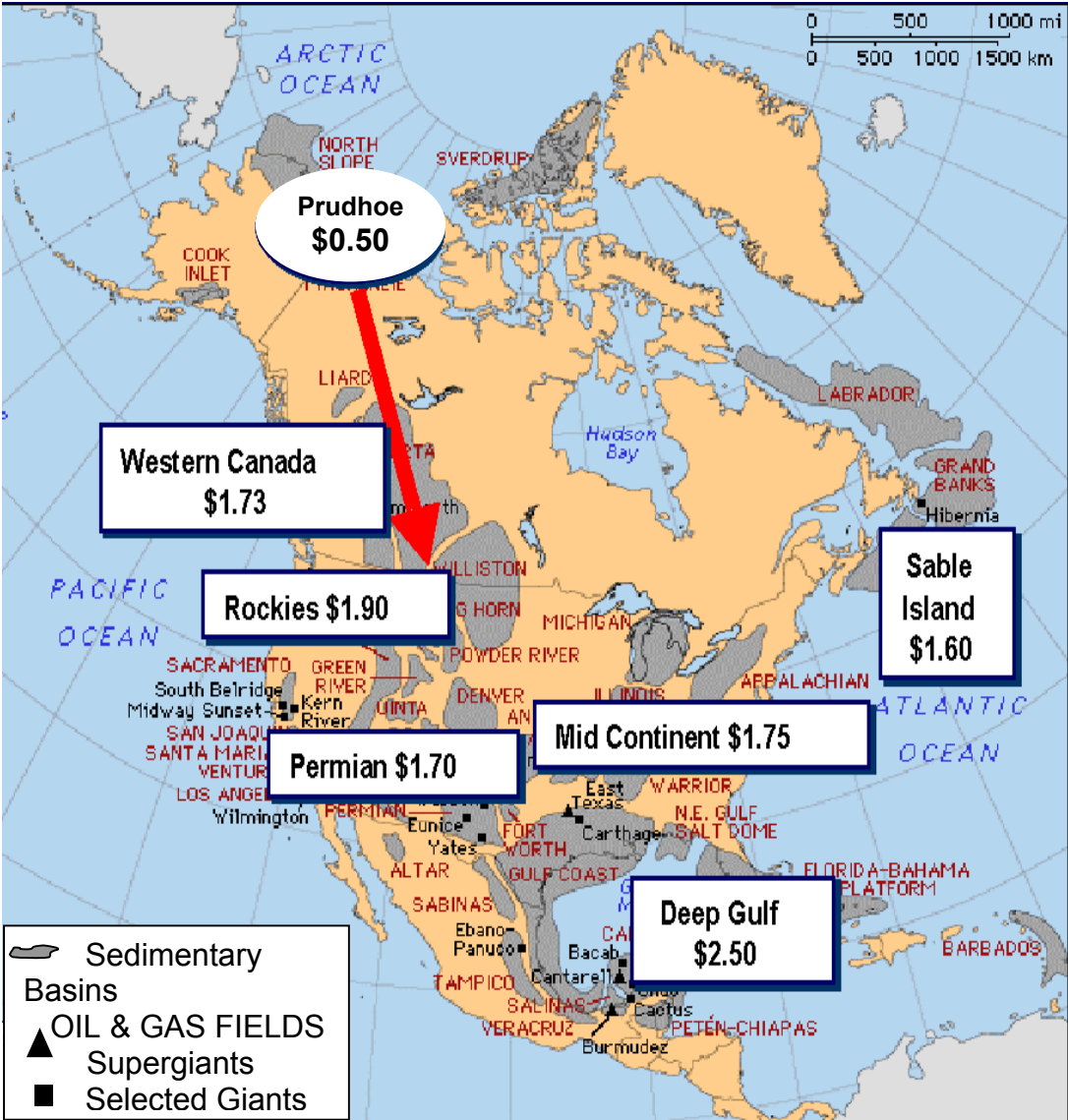
Unfortunately, many of the potential U.S. gas resources that could be profitably exploited are located on lands now off limits to exploration and production, especially in the Rocky Mountains and to a lesser extent in the eastern Gulf of Mexico. Though expanding access to such lands is a major element of the Bush Administration's energy initiative, the proposal faces strong opposition from environmental groups, and prospects for Congressional approval are uncertain. Already, the Bush Administration has caved in to calls for further restrictions on drilling offshore Florida, where a Chevron-led group has a 2 Tcf find in the Destin Dome area that it cannot exploit. The Rocky Mountain outback is another attractive area, estimated to hold up to 300 Tcf of natural gas resources, but permitting in the region is extremely difficult, and many lands are off limits altogether.

The deep waters of the central and western Gulf of Mexico offer the greatest potential for order-of-magnitude gains in both reserves and production capacity. According to Wood Mackenzie, deepwater gas production in 2000 averaged 2.7 Bcf/d and should reach 3.2 Bcf/d in 2001.⁶ Its forecast shows a peak of 4 Bcf/d in 2003, but estimates from major producers are 15-20% higher, with a peak not appearing until later in the decade. More finds are also possible, raising hopes that deep water may be a major contributor to U.S. natural gas supply.

⁶ Wood Mackenzie U.S. Gulf of Mexico (Deepwater) Upstream Report Q1 2001.

**Developments in Atlantic Basin LNG:
Implications for Japan**

As discussed, a reasonable estimate for U.S. lower-48 production, including deep water gas stands at 20 to 22 Tcf over the coming decade, leaving a gap of 6 to 12 Tcf to be covered by imports from Canada, pipeline supplies from Alaska, and LNG imports. Wellhead price estimates for U.S. domestic supplies range from \$0.50 Million Btu to \$2.50 MM Btu, according to Pace Global Consultants. (A million Btu is the standard unit for pricing. On a volumetric basis, it is equivalent to approximately one thousand cubic feet or 1 Mcf.)



Source: Pace Global Consultants

BP, ExxonMobil, and Phillips Petroleum control more than 95% of the 36 Tcf of known natural gas deposits on Alaska's North Slope. They are currently evaluating the options for development and export. The most likely choice will be construction of a pipeline to the lower-48 states that would move about 3-4 Bcf/d of gas, equal to about 7% of current U.S. consumption of just over 60 Bcf/d feet per day. North Slope gas production now is more than 8 Bcf/d, almost all of which is re-injected into the Prudhoe Bay oil field for pressure maintenance. The remainder is used to fuel operations and for local Alaskan native consumption.

When and how the North Slope gas will be exploited is as much a function of operational requirements as economics. Oil production is declining across the region, and the percentage of natural gas recovered from the Prudhoe Bay field increases as oil output drops. By 2007, the rising percentage of natural gas production from the Prudhoe Bay field will exceed the 10 Bcf/d gas-handling facility's capacity. The Prudhoe Bay producers could mitigate the decline rate for oil production later in the decade by identifying alternative outlets for associated gas such as an export project. Limiting gas production to the capacity of the gas-handling facilities is a less attractive option, as it would restrict oil production from North Slope, putting additional strain on the region's operating economics. The Alaska gas pipeline project would alleviate this problem, allowing the companies to maximize oil production while still having enough gas for other applications -- LNG, natural gas-to-middle distillates or gas-to-liquids (GTL), and pressure maintenance. Producers can also utilize an existing salt-water injection facility to free up more gas to move to the lower-48.⁷

Both BP and ExxonMobil have said they believe the pipeline option is viable as long as gas prices are around \$3.50 per MM Btu delivered to Chicago, which has a modest premium to the Henry Hub, Louisiana, delivery point for the New York Mercantile Exchange. They estimate the transportation tariff from the North Slope to Chicago at about \$2.00-\$2.50 per Mcf.⁸

A final processing at a plant built on the North Slope would add another \$0.25-\$0.50 per Mcf, but a portion of that cost would be offset by the value of the natural gas liquids extracted as well

⁷ Authors' Private Interviews.

⁸ Energy Intelligence Briefing, March 3, 2001.

as the carbon dioxide removed. Carbon dioxide already is used in Prudhoe Bay's enhanced oil recovery efforts, thereby disposing of a greenhouse gas/global-warming problem.

Transportation costs may seem low by historical standards, but BP and ExxonMobil cite the development of new pipe manufacturing and line construction technologies, some of them proprietary. For example, ExxonMobil and a Japanese partner have developed a thin-wall, high-pressure line pipe that requires less steel and thus costs less than traditional pipe. However, this technology has yet to be tested in the field so final costs remain open to revision.

The Alaska producers expect to determine their preferred route by early 2002. They are examining two options. One is essentially an update of the 1970s Alaska Natural Gas Transportation System, also called the Alaska Highway route, and is preferred by Alaskan state and civic leaders as well as many Canadian interests. It would run from the North Slope, paralleling the existing oil pipeline to Fairbanks before turning east into Canada. The other, the so-called "over-the-top" route, would run offshore from Prudhoe Bay through the Beaufort Sea and coming south along the Mackenzie River and then into Alberta. This route would be shorter and could carry both North Slope and Mackenzie Delta gas in a single line. Producers prefer this route, claiming its costs would be as much as 20% lower than the Alaska Highway option. Alaskan political interests, however, oppose the "over-the-top" route because it would not provide natural gas deliveries to Alaska's interior.

Canada's northern frontiers in the Mackenzie Delta-Mackenzie Valley region of the North West Territories provide another potential source of up to 2 Bcf/d (0.75 Tcf). A consortium of ExxonMobil's Imperial Oil, Chevron, Gulf Canada Resources (now Conoco Canada), and Royal Dutch/Shell Group is evaluating pipeline options. Gas could flow out through either the "over-the-top" Alaska route from the Beaufort Sea or through a lateral constructed off the Alaska Highway system. In either case, gas could be flowing to Canada's border provinces or the U.S. lower-48 by 2007-2010.

New production from Alaska, Canada's Mackenzie Delta and offshore eastern Canada could total as much as 3.85 Tcf to 4.25 Tcf by 2010 in best-case scenarios. Assuming some success

fighting the decline curve for production from traditional U.S. areas, total North American supply could reach 24.85 Tcf to 26.25 Tcf, leaving room for significant LNG imports under all but the most pessimistic natural gas demand scenarios. The authors' own forecasts are that U.S. LNG demand in 2010 could total as much 60 MM tons per year, requiring construction of new receiving terminal capacity of up to 40 MM tons a year capacity (2.2 Tcf or 6 Bcf/d).

LNG Demand: Filling the U.S. Supply Gap

If Alaska producers hold their investment at a single 4 Bcf/d natural gas pipeline and no "elephant" domestic gas discoveries are made, then the primary means to fill any gaps in market supply will be to increase U.S. imports of LNG. Based on the above calculations, then, by 2010, under high growth scenarios, the United States could represent an LNG market of more than 4 Tcf, or, in the measure of the LNG producer, 80 MM tons per year.

Financially, the economics of LNG are improving with every project. The Atlantic LNG project in Trinidad is more than profitable at a delivered price of \$2.75 per MM Btu at the Tractebel North America terminal in Everett, Massachusetts, near Boston.⁹ Subsequent trains, which can derive synergies from existing infrastructure, will have even better returns. The cost of service to deliver LNG to Cove Point from the second and third trains at the Atlantic LNG project in Trinidad could be as low as \$1.50 per MMBtu, equivalent to approximately one thousand cubic feet of natural gas. The first trains in both Trinidad and Nigeria covered their costs at \$2.50 per MMBtu. Egyptian, Norwegian and Qatari LNG could be delivered at \$3.25 per MMBtu or less.¹⁰

As mentioned above, only three LNG plants serve the U.S. market currently in the Atlantic Basin: Algeria, Nigeria, and Trinidad. Most of current LNG export capacity is concentrated in Algeria, which can produce 23 MM tons/year, much of which goes to Europe. Nigeria can supply 6 MM tons/year, with much of it also committed to European buyers. So far, Trinidad

⁹ Gordon Shearer, Cabot LNG, presentation, Zeus Developments; LNG in the Atlantic Basin Conference, April 26, 2000, Savannah, Georgia.

¹⁰ Gabriel F. Avgerinos, Poten & Partners, presentation, Zeus Development's LNG's Role in North American & Caribbean Gas Supply Conference, Arlington, Virginia, June 28, 2001.

provides 3 MM tons/year, with the majority coming to the United States. Libya has a small LNG export project, but none of its output could come to the U.S. because of sanctions.

While the volumes from these facilities are currently limited, by the end of this decade the Atlantic Basin could be awash in LNG. Expansions and new projects are in the works from a wide variety of players. Trinidad project sponsors alone are planning on as many as six trains over the next decade. That will give the Trinidad project a capacity of up to 23 MM tons a year.

It is hard to predict how many additional projects might be built that could service U.S. demand. LNG shipping specialists Poten & Partners estimates that expanded and new-build projects could boost the current Atlantic Basin capacity of 32 MM tons/year to 110 MM tons annually. The figures could be much higher if drawing board projects in Latin America, the Middle East, Africa and the Pacific Basin get off the ground. In Latin America, Argentina, Bolivia, and Peru have intentions to become major LNG suppliers to North America. Middle East LNG producers Abu Dhabi, Oman, and Qatar are midway between the Asian and North Atlantic consuming markets, and their volumes can go to the highest-price buyers. Both expansion and new-build liquefaction facilities are in the works in Australia, Indonesia, and Malaysia, and LNG may yet happen in Alaska, where the unexploited gas supplies are ample enough to support a number of applications.

PIRA Energy Group of New York projects in a new study on Atlantic Basin LNG markets that expanding LNG supplies to the Atlantic Basin could reach 90 MM tons/year in 2005, of which almost 80 MM tons/year is fairly committed under contract and 5 MM tons/year of capacity (about 6%) remains unsold. This compares with 60 MM tons/year in 2000 from Algeria, Libya, Trinidad, Nigeria, Abu Dhabi, Qatar, and Oman, of which 44 MM tons/year was committed under contract and 15 MM tons/year of export capacity unsold. By 2010, PIRA projects supply will expand to 132 MM tons/year with 20 MM tons/year still to be sold, or roughly 17%. PIRA estimates that 32 MM tons/year are still searching for buyers past 2015 or about 25% of potential supplies to the Atlantic Basin.

The Evolution of the Spot LNG Market

Until about 1999, spot LNG cargoes were an aberration in a business where every step from wellhead to burnertip was defined in detailed contractual terms. The number of spot cargoes traded in an average year could be counted on one hand, and some years on a single finger.

This situation changed dramatically in 1998-1999 as the Asian economic crisis depressed LNG demand in Japan, South Korea, and Taiwan just as new and expanded liquefaction projects were coming on line across the Middle East, Australia, Nigeria, and Trinidad. Simultaneously, Europe and the U.S. were demanding more natural gas, giving the suddenly surplus LNG a home. Spot markets were also given a push when CMS Energy began aggressively marketing capacity at its vastly underused LNG receiving terminal at Lake Charles, Louisiana. It had acquired the facility in early 1999 as part of the \$2.2 billion purchase of the Panhandle Eastern and Trunkline Gas pipeline systems from Duke Energy.¹¹ Besides the terminal, CMS had the pipelines to move regasified LNG to markets and a trading company to find buyers.

To create a market to utilize their facilities, CMS had to prove that it could handle shipments from sources around the world with variable qualities energy contents on different sizes of tankers. The CMS terminal demonstrated quickly that it could receive a wide variety of tanker sizes, taking deliveries from ships with capacities less than 60,000 cubic meters up to 138,000 cubic meters. To deal with the quality issue, CMS installed a liquids extraction plant to bring “rich” LNG down to U.S. pipeline quality.

Through CMS’ ambitious efforts, global LNG suppliers began thinking of the U.S. market in different terms. At first, LNG marketers saw the U.S. as a great option of last resort. But by 2000, it became a destination of choice, initially for only spot and short-term arrangements. Now, however, with several transactions underway and demand seeming to be reliable, the U.S. is being viewed as a preferred, long-term buyer.

¹¹ Natural Gas Week, November 9, 1998.

Several events that coalesced during the first week of July 1999 have been taken as a turning point for the LNG business.¹² The first came from Royal Dutch/Shell, which announced it was sending a cargo of Malaysian LNG to its U.S. gas and power marketing affiliate, Coral Energy, via the CMS terminal on a tanker it was redeploying from the Pacific to the Atlantic Basin for use in the Nigerian trade. It might have been only a single cargo, but Shell indicated that the shipment represented the initial step in a strategy shift, from point-to-point LNG sales to an integrated value chain approach. In this new paradigm, a deal's worth would be measured by its total return to the consolidated bottom line, not its margin at any single link.

Next, Sonat, now part of El Paso, said it would reopen its Elba Island, Georgia receiving/regasification terminal, which had been out of service for almost two decades. The terminal also had a firm customer for more than half of its 440 MMcf/d of baseload capacity: the BG Group, which intends to deliver LNG from the second and third trains at Trinidad to the U.S. El Paso Merchant Energy is the initial buyer, but BG aims to develop its own marketing program, accessing markets directly.

El Paso disclosed that it would supply a new electricity generating plant near Boston with LNG rather than traditional pipeline gas. The LNG would enter through the then-Cabot LNG, now Tractabel North America, terminal at Everett, Massachusetts. This deal represents the first U.S. power plant that would be fueled with imported LNG.

Finally, CMS confirmed it had received 10 spot cargoes at the Lake Charles terminal during the first six months of 1999, changing perceptions about the scale of LNG trade into the U.S. Through the first half of 2001, 27 cargoes have been received, many of which are from Nigeria, Qatar and Trinidad, with occasional shipments from Australia, Indonesia and Oman.

Differences in the Atlantic and Pacific Basin LNG businesses, especially in the U.S., quickly emerged. Pricing terms in the U.S. are now generally not tied to oil, but to the New York Mercantile Exchange natural gas futures prices, usually some percentage of the 12-month strip of

¹² Energy Intelligence Briefing, July 7, 1999.

forward contracts. Some contracts are also linked to electricity price netbacks or other market-oriented markers.

Debate remains whether the development of credible spot market for LNG was a function of the Asian recession or a long-term shift related to the evolution of the LNG business. Several factors seem to point to the latter. To begin, as already discussed, the U.S. market looks to be a sustainable off-taker of LNG for the foreseeable future. The existence of an already thriving spot U.S. natural gas market would seem to imply continued opportunity for trading in LNG to the U.S.

Also, the players in LNG markets are becoming more diverse, creating greater opportunities for location and timing swaps, backhaul trades and other optimization activities that will feed spot market activity and enhance liquidity. Tanker usage, for example can become more efficient if customers could swap cargoes rather than have them pass in the night somewhere in the North Atlantic. By cutting sailing distance and time, such trades could effectively increase the amount of shipping capacity available without having to build new vessels. Over time, the fleet of uncommitted ships is expected to grow, leaving more capacity for spot trading. Many LNG facilities have the ability to produce some volume above contracted levels, creating possible spot supplies during times of temporary rises in market demand.

In addition, Atlantic Basin LNG markets are likely to be oversupplied and competitive, similarly promoting liquidity and ensuring that the move to flexible pricing will not be short-lived. LNG suppliers are also moving to create the kind of standardized contracts that can facilitate short term trading.

Finally, as more companies move to reduce costs by building larger facilities, in some cases with LNG trains as large as 5 MTA, a buildup of spare, uncommitted export capacity is emerging. Price deregulation in many countries and other factors have contributed to a fall in the typical size of new individual LNG sales deals, which are more frequently running between 0.5 to 2 MTA. This trend is leading to increased mismatching between sales contract sizes and plant construction size goals. Rather than hold up projects, however, increasingly, LNG producers are

employing more creative financing arrangements that allow projects to proceed without the traditional 100% of capacity locked up in long-term sales contracts. This trend will also provide more volume that can be sold under spot market arrangements.

The analogies to the early development of spot crude oil markets are striking and lend more credence to the idea that LNG spot trade could become global over time. The early spot market for crude oil developed in the 1970s to service marginal markets and niche opportunities. Players were limited, and pricing terms not fully transparent. As late as the early 1980s, crude oil was still being sold under long term, multi-year fixed price contracts. But as an overhang of supplies developed toward the early 1980s and a new batch of non-OPEC producers entered the crude oil business, the liquidity of spot crude oil markets increased.

The opening of a crude oil futures contract in 1984 on the New York Mercantile Exchange gave the spot crude market more prominence and raised the visibility of the U.S. futures price as a marker of market direction and a potential pricing basis for transactions. Over time, market pressures -- created by excess supplies and visible spot market prices that were cheaper than long-term supplies -- convinced buyers by late 1985 to abandon altogether long term fixed price contracts for crude oil supply in favor of more flexible annual contracts at prices linked to spot crude market indicators. Spot market transactions became a major component of worldwide trading, and a global price developed despite the wide variation in relative qualities for crude oil produced from different oil fields.

Increasingly, crude oil trade has become more closely related to shipping economics, with sellers looking to move barrels to the closest end-user markets as possible. Some exceptions remain, however, and crude oil trade, though driven by regional arbitrage, still faces some politically driven and other inefficiencies.

The development of a transparent, highly liquid, global spot market for crude oil took less than a decade. It can be reasonably argued that LNG now faces the same kind of structural changes as seen in oil markets in the late 1970s and early 1980s. If a supply overhang of LNG develops as it did in crude oil markets in the early 1980s, the potential for LNG markets to follow the path of

crude oil seems strong. LNG is even more fungible in quality terms than crude oil. The U.S. and U.K. already have liquid futures and forward markets for natural gas. Some LNG players are using these forward markets to hedge prices. The number of players in the LNG game also is increasing, and several market makers have emerged. LNG developers, most of whom include major crude oil producers and marketers, have the benefit of knowing the history and trading experience of crude oil markets and do not, therefore, have to learn new methods as was the case in the early days of spot crude oil marketing. And, shipping economics and market arbitrage encouraging time trades and location swaps in the LNG business, opening the way for greater trading.

However, key differences exist that could hold back LNG spot-market development, especially at the global level. The most powerful argument against the development of a global, spot market for LNG is the structural limitation on shipping and receiving infrastructure. Almost every country in the world had crude oil tanker receiving terminals and export facilities at the time the spot market was emerging. The crude oil tanker fleet was overbuilt, leaving dozens of spare vessels available for spot trade. In addition, companies can use portable single buoy mooring systems to unload tankers at locations that lack port facilities.

Only a few locations have the specialized facilities needed to receive and regasify LNG. Though almost 20 receiving terminals and regasification plants proposed for North America are in some stage of development, perhaps only six or seven will come to fruition. Cost is one limiting factor, but siting and permitting are greater impediments. Despite natural gas' "clean fuel" image, which extends to LNG, local opposition to new installations is a major problem. Such regulatory and social issues will mitigate the industry's well-demonstrated tendency to overbuild, especially in the U.S. Difficulties in building any industrial facilities in some U.S. regions, particularly California, have prompted several terminal developers to look to Mexico as for preferred locations.

Today, the Lake Charles terminal is doing more business than ever before, and the long-mothballed facility at Elba Island, Georgia is gearing up. Another mothballed facility at Cove Point, Maryland will reopen within the year. The Everett, Massachusetts facility, while seeing a

huge surge in business, may be affected by the September 11 terrorist attacks on the World Trade Center and experienced security related shipment delays in September and October 2001.

All of the U.S. receiving facilities have new, more market-focused owners with capacity expansions planned. Effective Jan. 1, 2002, none of them has any spare firm capacity available, which has led to a spate of new terminal proposals and the expected birth of a secondary market at the existing facilities.¹³

Finally, while the number of available LNG tankers that are not tied to direct contract point to point sales is growing, the available fleet is still quite limited when compared to the more liquid, crude oil tanker markets and could remain an obstacle to the growth of global LNG spot trade.

Several major LNG producers are developing new technologies that might overcome some of these structural limitations down the road. The development of mobile, floating receiving terminals might help increase the number of countries that can off-take LNG. This technology could be operable in the next five years or so. Longer term, developers are working on ship-based technology that would allow LNG vessels to liquefy and regasify directly on board, obviating the need for specialized infrastructure and opening up LNG trade to any country that has a coastal connection to its natural gas grid. However, such a development, while clearly promoting spot LNG trade, is likely to be a decade or more away.

Corporate Strategies

A key factor in the speed and nature of the evolution of LNG markets will be the corporate strategies taken by major players. As the U.S. and Europe look for cleaner fuels to reduce pollution and developing countries such as Brazil, China, India, and Mexico look to diversify energy supply in the face of growing demand, the market for LNG could expand dramatically.

¹³ Energy Intelligence Briefing, May 17, 2001.

A host of players have emerged to take a share of the North American LNG sector. Some, notably the Royal Dutch/Shell Group, have been in the industry for years. A few, such as El Paso, tried their hands at LNG 25 years ago, only to be burned badly. A good many are new to the business and have some innovative ideas to make LNG more flexible and market responsive than the traditional single-source-to-a-single-market, long-term arrangements.

These companies also believe the spot market is here to stay and will grow significantly once deliveries of tankers under construction begin. Though spot LNG trades accounted for only about 5% of internationally sold volumes in 2000, some predict it eventually could account for as much as 25% of the global LNG business. North America should remain a strong market for LNG, assuming long-range U.S. prices is in the range of \$2.50-\$3/Mcf.

Following are the major players and their strategies.

AES

Integrated utility and power-generator AES held its plans very close until it had three combined LNG-power generation projects well into development, which collectively will cost \$1.5 billion.¹⁴

The largest will be on Ocean Cay, near Bimini Island in the Bahamas. The \$750 million complex will include an LNG receiving/regasification terminal with a capacity of 550 MMcf/d or 4 MM tons/year, 7.6 Bcf of storage, and a 70-mile pipeline that could deliver up to 800 MMcf/d to Florida. The company also plans a 1,000 MW power plant.

In addition, AES is developing two Caribbean Basin LNG terminal-power plant projects, one in the Dominican Republic and the other in Honduras. The LNG portion of the projects in the Dominican Republic and Honduras will be half the size of the Bahamas facilities, though all will be combined LNG-power ventures. Each will have a receiving/regasification capacity of 270 MMcf/d or 2 million tons/year of LNG, with 3.8 Bcf of storage.

¹⁴ Oil Daily, September 25, 2001

AES is constructing a 330 MW power plant in the Dominican Republic and will add a pipeline to deliver gas to an existing 167 MW plant. Construction already has begun, and the first LNG cargo is due there in September 2002. In Honduras, the company will build a 750 MW electricity generation plant. Startup is due in early 2004.

AES is negotiating with BP and Royal Dutch/Shell for LNG supplies.

BG Group

BG, the former British Gas, grabbed the attention of the LNG world earlier this year when it acquired all of the available capacity of the CMS Energy Lake Charles, Louisiana, terminal in a 22-year deal.¹⁵ BG beat out five other bidders to get 510 MMcf/d of capacity at the terminal. Its volume will rise to 630 MMcf/d when a contract with another party expires in August 2005.

BG has a 26% stake in the Atlantic LNG project in Trinidad and plans to build an LNG plant in Egypt. Two years ago, it booked 59% of the 675 MMcf/d of capacity in El Paso's Elba Island, Georgia, terminal. More recently, it has been assembling a tanker fleet, with two on order and options for another six.

BG Chief Executive Frank Chapman described the company as an "integrated gas major," with holdings now in gas production, liquefaction, shipping, and terminal capacity. Details of its broader strategy still haven't been revealed, but Chapman indicated BG has "downstream" plans in the U.S., suggesting that the company will develop an aggressive natural gas marketing program to extend its links in the value chain all the way to the final customer. Until its own LNG volumes ramp up to match its terminal capacity, BG is expected to create an active secondary market for other LNG importers that want to use the facility on a spot or short-term basis.¹⁶

¹⁵ Energy Intelligence Briefing, May 17, 2001.

¹⁶ Private interview.

BP

BP, like most other major oil companies, has taken an integrated value chain approach to the LNG business.¹⁷ It wants a part of every link in the chain from the wellhead to the liquefaction plant to the tankers to the receiving terminal and maybe all the way to the ultimate customer. The company has ownership positions in two major LNG projects, Atlantic LNG in Trinidad and North West Shelf in Australia. It also is active in the spot trade, with four vessels now assigned to the short-term and single-cargo business. The company has committed to 250 MMcf/d of capacity at the Cove Point, Maryland, receiving terminal when it reopens next year.

Yet, all this is not enough for a company that already is a major natural gas and electricity trader in the United States. BP is considering development of as many as three LNG receiving terminals in North America, including one in Baja California, Mexico, and another at Tampa, Florida. The third would likely be on either the Gulf or East Coast. The company could deliver LNG to electric power generators in Florida from Atlantic LNG in Trinidad or from the North West Shelf to Baja California for consumption in either northern Mexico or California.¹⁸

Later in the decade, after 2005, BP could move LNG from the proposed Texaco-operated Angolan LNG project to the U.S., as well as volumes from a planned venture in Egypt. Both of these fit perfectly into BP's goal of expanding the LNG trade in the Atlantic Basin. Further out, Alaskan LNG could become part of the West Coast mix, but BP doesn't see that happening until 2010 or later, following completion of the proposed gas pipeline from the North Slope to the lower-48 states.

Cheniere Energy

Cheniere Energy, a tiny exploration and production company, whose 2000 revenues were a miniscule \$5.3 million and whose total reserves are less than half of what ExxonMobil produces

¹⁷ Tony Fountain, president, BP Gas and Power, presentation, Ziff Energy Conference, Houston, Texas, April 2, 2001.

¹⁸ Philip Bainbridge, regional LNG manager, BP, Zeus Development's LNG's Role in North American & Caribbean Gas Supply, Arlington, Virginia, June 28, 2001.

in a day, has said it plans to develop three LNG receiving and regasification terminals along the Texas Gulf Coast over the next five years.¹⁹ At a cost of \$300 million or more for each 600 MMcf/d facility, Cheniere would be committing at least \$1 billion.

Chevron

Chevron announced last spring that it was considering construction of an LNG receiving terminal on the California or Baja California, Mexico, coast, but only recently has the company begun to fill in the details: it plans to construct a value chain that links the undeveloped Gorgon Field offshore northwestern Australia to the U.S. West Coast.²⁰

Chevron consumes enormous quantities of natural gas in its operations in California. It burns gas to fuel operations at two refineries, including their cogeneration power plants, and it consumes natural gas to operate its steam-flood enhanced oil recovery operations. Companies including ExxonMobil, Royal Dutch/Shell, and Texaco (also Gorgon Field partners), also have operations in California that rely on natural gas. Collectively, they consume 750 MMcf/d of natural gas in the state, enough to support a 6 MM tons/year by themselves.

Natural gas supplies in North America are tight, and California is at the far end of the supply pipelines. Those lines have been running a maximum capacity for more than a year as demand from the state's power plants consume gas at record rates. Even additional pipelines will not bring in new sources of supply; they will merely tap existing basins. For security of supply, Chevron is turning to LNG.

California's well known environmental zealots assuredly will prevent construction of an onshore terminal anywhere on the California coast, but Chevron believes an offshore structure, where it would not pollute the vision of even the most ardent opponent, could be built. If not, an onshore terminal in Baja California with a pipeline across the Mexican border into the state would work equally well.

¹⁹ Oil Daily, June 13, 2001.

²⁰ Steven R. Schneider, manager, business development, Chevron, presentation, Zeus Development's LNG's Role in North American & Caribbean Gas Supply, Arlington, Virginia, June 28, 2001.

CMS

Few looking at CMS Energy as recently as three years ago would have guessed that it was destined soon to become the most aggressive player on the world LNG stage. CMS was a good-sized but apparently unexceptional Michigan-based electricity and natural gas utility holding company with a small exploration and production unit. Its midwestern base, far from oil-patch central in Houston, allowed the company to operate somewhat stealthily.

In November 1998, CMS made its big move: It bought the Panhandle Eastern Pipe Line and Trunkline Gas systems and related assets from Duke Energy for \$2.2 billion.²¹ Duke had acquired the properties in its 1996 purchase of PanEnergy, but the midcontinent pipelines didn't fit its strategy. Thrown in with the pipelines was a little-used LNG receiving terminal at Lake Charles, Louisiana. Built in the late 1970s, the terminal never handled more than a handful of Algerian cargoes a year. For much of the 1980s, it was totally empty.

Ironically, CMS really didn't originally want the LNG terminal, but neither did Duke, which made taking the Lake Charles facility a condition for CMS's purchase of its pipeline assets.

The change in ownership coincided with the major shakeup in the global LNG business after the Asian economic upset of 1997-98. Traditional LNG buyers in Asia reduced their purchases to contractual minimums, just as new and expanded liquefaction projects were coming on line across the Middle East, Australia, Nigeria, and Trinidad. Suddenly, LNG was a surplus commodity, and CMS had a terminal available in the world's biggest gas market.

Its aggressive marketing efforts paid off handsomely. Traffic at the terminal has moved up steadily: 12 cargoes in 1997, 17 in 1998, 27 in 1999, and 55 in 2000. More than 60 are expected this year. Financially, this "throw-in asset" is expected to generate \$29 million in after-tax income in 2001 and \$50 million in 2002. CMS recently completed an expansion of the send-out

²¹ Natural Gas Week, November 9, 1998.

capacity to 1 Bcf/d from 700 MMcf/d. A second expansion to 1.2 Bcf/d, involving more extensive upgrading and an additional storage tank, is due to come on in late 2004.²²

The company now has more projects in development. One would be an offshore terminal in the Gulf of Mexico, connected to one of CMS' natural gas pipelines. The other would be in Mexico. A motivating factor is the need to provide capacity for its U.S. natural gas and power marketing affiliate. The unit has been the largest user of the Lake Charles terminal, but it loses that right on Jan. 1, 2002, when BG gains 510 MMcf/d of the facility's capacity. Duke Energy Trading has the remainder until August 2005, when its contract expires.

Conoco

While most other big oil companies are focusing on mega-projects and global ventures, Conoco is looking at smaller-scale, niche opportunities.²³ Its plan is to develop and build about four small terminals in different regions of the U.S. Ideally, one would be on the West Coast, another in South Texas or northern Mexico, and the others in the Southeast and Mid-Atlantic. These would be 2 million tons/year facilities, with a send-out capacity of about 275 MMcf/d.

Most would be greenfield projects, but not all. One potential site is its Chesapeake liquefied petroleum gases (LPG) import terminal near Norfolk, Virginia. Using an existing facility would ease the permitting process and reduce costs, to possibly as low as \$100 million. The goal would be accessing the natural gas pipeline grid at locations near large markets that are far downstream from traditional supply sources or where excess pipeline capacity exists, such as South Texas. This strategy would give LNG suppliers more options as they could sell on both a small-and large-volume basis with multiple delivery options.

Conoco would use smaller tankers than the current standard. Most new LNG tankers are in the range of 135,000-138,000 cubic meters of capacity, or about 2.5-2.7 Bcf. Conoco envisions vessels of 65,000-70,000 cubic meters. These would allow deliveries to smaller ports with

²² World Gas Intelligence, May 17, 2001.

²³ Natural Gas Week, July 16, 2001.

shallow drafts. The tankers also could take LNG from larger vessels at offshore transfer facilities or could transport product directly from short-haul sources such as Trinidad, Nigeria, and future Caribbean and West African projects. The half-size tankers would cost around \$100 million, compared to \$165 million or higher for a conventional vessel.

Entry into the LNG business would be phased over three or four years as the spot market in particular develops, but the first project could start as early as 2002. Conoco already has begun the process to arrange for supply by obtaining a license from the U.S. Energy Department to import up to 50 Bcf of LNG.

One other difference in Conoco's strategy is its more selective approach. For example, the company does not plan to invest in upstream liquefaction plants. Most of its international gas reserves are located in Southeast Asia and the North Sea and are dedicated to regional markets served by pipelines. That could change if a second Nigerian project proceeds. Chevron is leading the study, but Conoco, ExxonMobil, and Texaco would be partners in the venture.

Dynegy

Energy trading and services giant Dynegy believes it can get into the LNG business faster and cheaper than the competition by converting an under-used liquefied petroleum gases (LPG) import terminal at Hackberry, Louisiana, to handle LNG.²⁴ The LNG terminal would have an initial send-out of 750 MMcf/d, expandable up to 1.5 Bcf/d, with commercial operations starting by the end of 2003 and full capacity by 2004. This would be 18-24 months sooner than a greenfield project and quicker even than expansions of some of the existing facilities. The cost would be about \$250 million, compared to \$350 million-\$400 million for a new-build facility.

Like Conoco, Dynegy sees expansion of an existing complex to be environmentally preferred to a new-build project, which should ease the permitting process. In fact, Dynegy sees the regulatory process for a new facility so onerous that it does not expect any greenfield terminals to be constructed in the United States.

²⁴ Natural Gas Week, July 16, 2001.

Dynegy will operate the terminal as a peaking facility, handling no more than six to eight cargoes per month. On-site storage would be only 2.7 Bcf, or about a third of the capacity of the nearby CMS Trunkline LNG terminal at Lake Charles, Louisiana. That is enough to hold the contents of a single LNG tanker. The lack of storage suggests that Dynegy's take-away pipeline connections will be able to handle more than 1 Bcf/d, so that the storage tank could be emptied every three days to receive the contents of the next tanker. It also would demand incredibly tight scheduling and vessel turnaround.

The company sees the LNG business as an expansion of its established LPG trading and marketing operations, which will serve as the business model. In addition, Dynegy already has relationships with many of the world's LNG producers, such as Nigeria and Qatar, through its LPG purchases. Chevron, which owns more than 25% of Dynegy's stock, has its own strategy, and will not be a direct partner in the Hackberry venture.

The jurisdiction of the Hackberry project is still to be determined. The Federal Energy Regulatory Commission (FERC) has authority over four existing import terminals, and all but the Tractebel facility at Everett, Massachusetts, are open-access service providers. An open-access terminal is (theoretically) available on an equal basis to any customer that has contracted for capacity in an open auction. The highest bidder could take all the capacity, leaving the terminal owner's marketing affiliate with no direct access as happened at Lake Charles when the UK's BG Group took all the capacity through a 22-year contract. Dynegy, however, appears to want to operate this facility for the benefit of its own gas marketing subsidiary. As an LPG terminal, Hackberry does not come under FERC jurisdiction. If the LNG facilities are considered just an expansion of an existing plant, not a new project, then it might escape FERC's oversight and allow Dynegy to control access to the facility.

El Paso

Earlier this year, El Paso disclosed an ambitious, \$1.5 billion investment program for the LNG business, and it has not backed off from those plans.²⁵ The company is actively developing four receiving/regasification terminals in North America, has at least two more under consideration, and so far has chartered four tankers to use in its global trading program. Its strategy is the portfolio approach with a mix of terminal sizes and configurations and a variety of shipping and supply arrangements.

For example, the planned Bahamas facility could be a traditional project, with a regasification plant, storage tanks, and a pipeline connection to the U.S. However, the company has not ruled out a novel arrangement that would include only an offshore, off-loading facility that would transfer LNG to shuttle tankers or barges for delivery to conventional LNG terminals on shore. The company also has a planned joint venture with Royal Dutch/Shell at Altamira, Tamaulipas, Mexico. The two plan a facility that would provide up to 1.3 Bcf/d of regasified LNG (10 MM tons/year) to the Mexican market.²⁶

While Phillips and El Paso signed a letter of intent to develop a 650 MMcf/d West Coast LNG receiving facility that would be supplied by a Phillips-operated LNG plant near Darwin, Australia earlier this year, the deal has been called into question more recently.²⁷

The Bahamas, Altamira, and West Coast terminals would be large-capacity facilities, while a proposed terminal along the North Carolina coast would be a niche project for regulatory reasons. The Federal Energy Regulatory Commission has regulatory authority over most U.S. LNG projects because of their connections to interstate natural gas pipelines. The North Carolina complex might come under the jurisdiction of state agencies by serving only customers in that state.

²⁵ Natural Gas Week, February 12, 2001.

²⁶ Natural Gas Week, July 16, 2001.

²⁷ Natural Gas Week, March 12, 2001.

Besides the proposed new terminals, El Paso owns the Elba Island, Georgia, receiving and regasification facility, which will reopen in October 2001. El Paso gained the facility through its acquisition of gas-pipeline company Sonat in 1999. Elba Island can deliver up to 675 MMcf/d (5 MM tons/year) of regasified LNG into the pipeline grid and expects to handle about 65 cargoes a year. BG Group has booked 59% of the available capacity under a long-term agreement, and Enron has an option on the remaining capacity. El Paso's trading unit will have access to the terminal for its own account as available. The company also has 250 MMcf/d of capacity in the Cove Point, Maryland, plant owned by Williams Cos.

The portfolio approach also holds for supplies. El Paso has firm commitments of varying lengths with Phillips for Timor Sea gas and Atlantic LNG in Trinidad. It is negotiating other arrangements with additional suppliers, including Indonesia's Pertamina for output from the BP-led Tangguh project.

Enron

Enron is convinced it can apply its long-held strategy of minimizing hard assets to the capital- and asset-intensive LNG business.²⁸ Detractors have described that model, based on contractual arrangements with a smattering of physical facilities, as "asset-light," but Enron's Global Markets group prefers to call it "asset-smart." The company maintains it will invest in assets, but only where absolutely necessary. So far, Enron's involvement in LNG has consisted largely of trading and marketing spot cargoes of Middle East and West African supplies, but it plans much more.

For example, Enron claims to be prepared to commit hundreds of millions of dollars to an LNG receiving and regasification terminal in the Bahamas to deliver gas into Florida via an undersea pipeline. The Bahamas terminal would have an initial capacity of 300 MMcf/d of regasified LNG, expandable to 800-900 MMcf/, at prices competitive with pipeline-delivered volumes.

²⁸ Natural Gas Week, August 20, 2001.

Enron also will take capacity in import terminals owned by others where that makes sense. It has call on up to 160 MMcf/d at El Paso's Elba Island, Georgia, facility. It also expects to have access to the Lake Charles, Louisiana, terminal through the secondary market BG Group is developing. Finally, Enron and El Paso, through their Citrus Trading joint venture, buy LNG that Duke Energy imports from Algeria. The regasified LNG is sold to a Florida electric utility under a contract that expires in 2005.

Currently, the only firm supply arrangement the company has is a memorandum of understanding for 1 MM tons/year (130 MMcf/d) of Nigerian LNG, starting in 2005. An earlier deal with Cabot LNG, now Tractebel North America, for supplies from the Atlantic LNG plant in Trinidad was assigned to Mirant, the buyer of the EcoElectrica terminal and adjacent power plant in Puerto Rico.²⁹

Enron hopes to have an interest in a liquefaction facility planned for Venezuela through a partnership with Venezuela's energy ministry and located at the Jose industrial zone along the country's central coast. The project has been pending for several years, but the company hopes for final approval soon. Aside from Venezuela, however, Enron has no investment plans in liquefaction facilities. A portfolio of contractual arrangements will guarantee the supplies and the markets. Nor will the company be building any tankers. It has two vessels on long-term charter, and any future commitments would be charters.

Enron's LNG activities have focused on the Atlantic Basin, but it has dabbled in several Middle East and Asian ventures that so far have come to naught. In 1999, Enron signed a confirmation of intent (COI) with the Malaysian LNG company for a large volume of product that would have gone to India to supply the now-suspended MetGas Pipeline project. Though Malaysian state Petronas used the preliminary pact to underpin financing of its MLNG Tiga expansion, Enron allowed the COI to lapse earlier this year because of the loss of intended market.

The troubled 65% Enron-owned Dabhol Power project in India also has an LNG component that has become uncertain with the suspension of operations there. Dahl had contracted with Oman

²⁹ Natural Gas Week, August 13, 2001.

LNG and Abu Dhabi's Adgas to purchase a combined 2.1 million tons/year (about 275 MMcf/d) for 20 years. Those contracts are between Dabhol and the sellers, and Enron has no firm obligation to take LNG. It may, however, offer some participation but only after the other issues surrounding Dabhol are resolved. Enron also has an office in Tokyo, where it expects to build an LNG supply and services business.

ExxonMobil

Before its acquisition of Mobil Oil, Exxon did not maintain a large business presence in LNG trade. Exxon had looked seriously at a several LNG opportunities, one in Alaska, another that would have used gas from the undeveloped Natuna Field offshore Indonesia, and the defunct Cristobal Colon project in Venezuela, but its preferred delivery system was and is the traditional pipeline. Mobil, however, was a major player prior to the merger with Exxon, and the combined ExxonMobil continues to be a significant force in LNG markets. ExxonMobil has interests in Qatar's two LNG projects, QatarGas and Ras Laffan (RasGas), as well as the giant Arun project in Indonesia. The company is actively pursuing bringing on two new LNG trains at RasGas and is looking to debottleneck at Qatargas and has a Memorandum of Understanding for a fourth train. The company is involved in efforts to create LNG businesses in Yemen, Angola and possibly a combined pipeline/LNG project from Bolivia and is taking the lead on the West Niger Delta LNG study.

Still, the ExxonMobil philosophy favors pipeline gas. ExxonMobil continues to support pipelines as the best options for moving the 36 Tcf of stranded gas on Alaska's North Slope to the lower-48 states and for delivery of Sakhalin gas to Japan over an LNG venture.

ExxonMobil does have a stake in the revamped Venezuelan LNG project, now called Paria, but whether that plant is ever built may depend more on the Venezuelan political situation than any technical or economic factors. Venezuela has been trying to develop an LNG industry for almost a quarter of a century with no success.

Irving Oil

Canadian Irving Oil thinks it can entice LNG producers to deliver their product to a terminal in New Brunswick to serve markets in eastern Canada and the U.S. Northeast.³⁰ The company proposes to add LNG receiving and regasification capabilities to its existing deepwater oil terminal, Irving Canaport, located near St. John, New Brunswick. The company said that its ice-free terminal is open year-round and that it is the nearest such facility to U.S. markets that is able to handle supertankers.

This is the first LNG receiving terminal proposed in Canada since the resurgence of the North American LNG sector began about two years ago. No such facility now exists in Canada. Irving estimated the cost at about C\$500 million (US\$330 million). Irving is planning a facility that could send out up to 500 MMcf/d regasified LNG with three storage tanks, each capable of holding approximately 3 Bcf. The capacity of each tank is about the same as the largest LNG tankers now operating.

Chevron Canada has joined Irving in the feasibility study. The company indicated that its need to find markets for future LNG projects in Angola and Nigeria is driving its interest in a receiving terminal.

Mirant

Mirant's purchase of the EcoElectrica LNG terminal and associated power plant in Puerto Rico from Enron and Edison Mission Energy is the latest in a series of moves that has transformed the U.S. gas and power company formerly known as Southern Energy from a non-player to a significant Atlantic Basin LNG operator in just six months.³¹ It represents another step by Enron out of the asset end of the gas business. Mirant paid Enron and Edison Mission \$586 million and assumed \$600 million in debt.

³⁰ Oil Daily, July 27, 2001.

³¹ Natural Gas Week, August 13, 2001.

The acquisition is in keeping with Mirant's overall strategy of making money through assets and trading capabilities. EcoElectrica has a firm agreement to buy nine 125,000 cubic meter cargoes annually from Tractebel, equivalent to about 110 MMcf/d or less than 1 MM tons/year. Tractebel uses its tanker LNG Matthew to make the deliveries from nearby Trinidad. The nearness to not only Trinidad but also Nigeria and the power plant's ability to burn other fuels offer Mirant significant marketing flexibility. If gas oil or propane is less expensive, Mirant can trade the LNG into more profitable markets.

The company has not declared its long-range intentions, but other terminals in the Caribbean and elsewhere are possible. Mirant believes the terminal-power plant combination could be a good model for other ventures. It is working to get into electricity generation in Italy, which several companies have identified as a potential base for trans-Atlantic LNG arbitrage trading. Mirant is also building a power plant in Norway.

Mirant has no plans to go into LNG shipping as not all of the tankers on order have specific markets, so an ample amount of capacity should be available for both spot and short-term charters. Nor does it see much opportunity on the liquefaction side, which generally is the purview of the majors and host-country national oil companies.

Phillips Petroleum

Phillips Petroleum has been in the LNG business longer than almost anyone else. It operates the western hemisphere's first LNG export project at Nikiski on Alaska's Kenai Peninsula, owned jointly with Marathon Oil, delivering about 2 million tons of LNG per year to Japan for some three decades. So far, that has been the company's only direct participation in LNG, but the situation appears to be changing.

First, Phillips developed the "optimized cascade" liquefaction process, which has lowered costs dramatically at the Atlantic LNG project in Trinidad. Now the company is not only trying to license the technology to others, it is developing its own projects.³² The most advanced is a plan

³² Natural Gas Week, March 12, 2001.

to develop the Bayu-Undan Field in the Timor Sea, but tax problems with the East Timor government have put that venture on hold. In addition, Shell has proposed a joint development plan including the Greater Sunrise Field using a newly designed floating liquefaction facility Shell has developed. Phillips had planned to use the Bayu-Undan LNG to supply its joint venture with El Paso for a Baja California terminal and West Coast marketing program.

Phillips recently signed a letter of intent to participate in a third Nigerian project, a 5-million tons/year facility that could be operating by 2008.

Royal Dutch/Shell Group

Unquestionably, Shell is the world's leading LNG company. Shell has been in LNG since the early 1970s in Brunei and now operates in almost every country that has any LNG production or trading. Shell has made no secret of its strategy: integrate fully from the wellhead to the liquefaction plant to the tanker fleet to the receiving terminal, and if at all possible to the ultimate customer.³³ For example, Shell can take equity production from Nigeria, convert it into LNG at a plant in which it is 26% owner, transport it in a Shell tanker for delivery to a Shell affiliate that markets the regasified product to U.S. customers, possibly delivering the gas in a Shell-owned pipeline. Once the Cove Point, Maryland, terminal reopens, Shell will use its leased capacity there.

In the Atlantic Basin, Shell's only LNG venture now is Nigeria. It has plans for another LNG complex in Egypt as part of an integrated manufacturing center that also would convert natural gas into middle distillates, or "gas-to-liquids" (GTL). Either could be a supply source for the receiving and liquefaction facilities it plans to develop jointly with El Paso at Altamira, Mexico.

The Middle East is a core area for Shell, where it has a large stake in Oman LNG, which can go to either Asia or the Atlantic markets. Shell also is viewed as a possible candidate to develop Iran's first LNG plant. Nor would the company have a problem moving Australian LNG to

³³ Energy Intelligence Briefing, July 7, 2001.

markets on the North American West Coast. Shell recently placed orders for four LNG tankers to be used in its merchant trading business, with the supplies likely coming from the next phase of Australia's North West Shelf project.

Texaco

The need to access markets is driving Texaco's North American LNG strategy which will be highly complimentary to pending merger partner Chevron.³⁴ The company already has ample supply commitments from proposed equity projects in Angola and Nigeria. Texaco is the lead along with state-owned Sonangol in Angola to develop a 4 MM tons/year (550 MMcf/d) liquefaction plant, and a partner with ExxonMobil, pending merger-partner Chevron, and Conoco for a second Nigerian project of probably 8 MM tons/year (1.1 billion cubic feet per day). Both projects would come on production in about 2005.

To bring the LNG to market, Texaco said it would develop an offshore receiving terminal in the Gulf of Mexico offshore south-central Louisiana that could handle 1 billion cubic feet per day initially and eventually up to 2 billion cubic feet per day. The offshore LNG terminal would be a first anywhere in the world, though several others are under consideration. Texaco did not identify the specific location for the facility, but it most likely will be in the South Marsh area, where the company has existing infrastructure, including a 30-inch Texaco-owned gas pipeline that is connected to the Henry Hub trading center.

Texaco cited the lack of capacity available at existing U.S. terminals as the reason for doing its own project. The proposed offshore LNG receiving terminal also may not be subject to FERC jurisdiction if regulators deem that it is an extension of gas-producing infrastructure already at the designated location.

³⁴ Mark Weller, project manager, Texaco, presentation, Zeus Development's LNG's Role in North American and Caribbean Gas Supply, Arlington, Virginia, June 28, 2001.

Tractebel

Tractebel Group, the energy arm of French Suez Lyonnaise de Eaux, had little visibility in North America until a year ago, when it purchased Cabot LNG and gained ownership of the Everett, Massachusetts, import terminal for \$680 million.³⁵ The company already was in the LNG business in Europe where it operates an import terminal at Zeebrugge in Belgium.

The Everett terminal has been the most active of the U.S. facilities, handling at least one cargo a year for two decades, mostly from Algeria. The past several years have been increasingly busy following the startup of the Atlantic LNG project in Trinidad. Some 60% of the Atlantic LNG volumes come to Everett. The terminal can send out 435 MMcf/d through pipelines connected to the plant, plus deliver another 100 MMcf/d by truck to customers throughout New England.³⁶

The company has since renamed its new U.S. unit Tractebel LNG North America. It is planning to add 600 MMcf/d of send-out capacity, bringing the total to more than 1.1 Bcf/d. As the only owner of terminals on both sides of the Atlantic Ocean, Tractebel expects to exploit arbitrage opportunities between the two markets. The company also plans to boost its trading and marketing activities with two new LNG carriers that will begin service in 2003. The former Cabot assets included one tanker that is used for Trinidad deliveries.

Williams Cos.

Williams is another new entrant into the LNG business. It bought the mothballed Cove Point, Maryland, from Columbia Energy and initiated plans to reopen the facility. The restart is scheduled for the second quarter of 2002, with an initial capacity of 750 MMcf/d. Three companies -- BP, El Paso, and Shell -- have each committed to 250 MMcf/d. Expansion to the original capacity of 1 Bcf/d already is planned, and Williams is looking at boosting the volume to as much as 3 Bcf/d.³⁷

³⁵ Natural Gas Week, July 17, 2000.

³⁶ Frank Katulak, Tractebel LNG North America, presentation, Zeus Development's LNG's Role in North American & Caribbean Gas Supply, Arlington, Virginia, June 28, 2001.

³⁷ Natural Gas Week, May 28, 2001.

LNG Market Development: Implications for Japan

The increasingly commercial approach of Atlantic Basin LNG is a major difference between the Atlantic and Pacific Basin LNG businesses. Asian customers in particular have been more oriented toward the security of their supplies, while buyers in North America and Europe are more concerned with competitive prices. Such perspectives also reflect the degree of liberalization in the two regions. By comparison, North American gas consumers are accustomed to the market's allocating price to the highest value uses. Those Western gas users that have alternatives typically will switch to either gas oil or fuel oil when the price of gas exceeds their limits. Conversely, this market allocation mechanism helps to mitigate prices at the high end by creating competition and thereby reducing demand. This tendency has forced LNG marketers to offer more flexible, market-linked pricing.

The markets in the two regions, East and West, should look more and more alike over time. Already, Japanese customers are asking for more flexible terms in their arrangements with traditional supplies. U.S. gas consumers and marketers are beginning to sign long-term agreements rather than relying solely on spot and short-term arrangements. Eventually, both will likely adopt portfolio strategies, assembling a blend of supply and transportation arrangements that fit each individual need.

In recent years, Asian buyers of LNG have requested more flexibility in their contracts. Korea Gas (Kogas) gained some substantial concessions in term contracts signed with Oman LNG and Ras Laffan, Qatar LNG including loosening floor-price arrangements and other off-lift flexibilities. Kogas would like to renegotiate LNG contracts to allow for more seasonal variation in volumes as well as greater cargo volume tolerances. In particular, the company would like to see a relaxation of take-or-pay clauses in view of the possible return of recession in Asia. Deregulation in South Korea, Japan and Taiwan will make inflexible take-or-pay clauses increasingly hard to enforce since importers will have more difficulty guaranteeing sales volumes to end-users. During the slow down in 1998, South Korea had to dispose of several cargoes in the short-term market and is seeking a 15-20% downward lifting tolerance. Japanese

buyers Tepco and Tohoku similarly sought a lower floor price for sales from Indonesia, down 30 cents per MM Btu from previous levels. Other Japanese buyers are seeking similar concessions and are also seeking contract flexibility. Take-or-pay clauses are likely to be eased and buyers will be seeking more liberal force majeure terms, greater lifting tolerance and some reduction of restrictions on third party sales. Durations of far less than 20 years are also considered desirable and will likely be necessary in contract renewals after 2007 expirations.

Increasingly in Japan, gas companies are preparing for more cargo swaps and backhaul trades. For example, Osaka Gas publicly stated its interest in renting spare capacity on LNG backhauls. Taiwan's recent problems in meeting its LNG lifting obligations opened the door to cargo swaps. In mid-2000, Chubu Electric took a 240,000-ton cargo of LNG originating at Pertamina's Bontang complex that was committed to Taiwan's China Petroleum Corp., which could not absorb the cargo given a delay in completion of a new gas pipeline. Chubu used the cargo to meet a weather related surge in power demand and will give a cargo back to CPC at a later date. Such transactions point the way to trading at times when market fundamentals bring differing short term buying trends in Asia.

In addition, another unexpected event has demonstrated the benefit to spot, versus term, contracts. The shutdown of the Arun LNG complex in Indonesia due to political unrest demonstrated that even the most secure term supply contract could be disrupted, arguing for flexibility in acquisition patterns to include both spot and long-term contracts. When the Arun cargoes were taken off the market, buyers were able to replace the supplies on a short-term basis from substantial uncommitted working capacity at a number of other LNG export projects.

As LNG markets in Japan grow, smaller, less regular buyer demand is likely to emerge, forcing sellers to offer more flexible terms in order to build markets. Although Japanese buyers may not require the current Atlantic Basin model for future LNG commitments, new entry level buyers will be unlikely to provide considerable financial backing for greenfield projects as was customary in the 1970s and 1980s. More flexible delivery and pricing terms will also be sought. Much will depend, like in the Atlantic Basin, on the supply-demand balance in Asia.

Forecasts indicate that like the Atlantic Basin, a wealth of projects could prompt an oversupply of LNG in Asian markets. Japan's IEEJ projects that LNG demand for Asia will rise by about 4 to 5% per annum to 105 to 112 MM tons/year by 2010 (see table). Industry estimates are higher at 108 to 138 MM tons/year.

Asia Pacific LNG Demand in 2010
(MM tons/year)

Country	1999 (actual)	2010	Average Growth
Japan	51.30	64.00	2.0%
South Korea	12.97	22.00	4.9%
Taiwan	4.16	11.00	9.2%
India	0	5.00-10.00	
China	0	3.00-5.00	
Total	68.43	105.00-112.00	4.0-4.6%

Source: IEEJ

Japan's demand for natural gas for the power generation sector may rise if the country cannot mobilize public support for the construction of 13 new nuclear energy plants. Growth in town gas sales should also not be underestimated. The Japanese Gas Association notes that in 1999 while Japanese GNP rose only 0.5%, town gas rose 5.6% to 14 MM tons/year. The JGA projects that demand for town gas might rise to 22 to 24 MM tons/year by 2010.

A number of projects being discussed could easily supply the expected rise in demand in Asia Pacific as well as meet incremental demand from the U.S. market. They include several major Middle East projects as well as regional facilities that can target either Asia or the U.S. West Coast (see appendix). In fact, the potential surplus of possible projects means that a supply overhang could remain a typical feature of LNG markets in the coming years. Japan is unlikely to have to compete with U.S. buyers for limited LNG supplies. Rather, buyers could have a wide variety of alternative exporters to choose from and will be able to maintain a diversified slate of suppliers. Only in the case of prolonged depressed prices might a widespread cancellation of projects limit new supply.

Interestingly, the possibility of a surplus of LNG in Asia as well as in the Atlantic Basin could leave Middle East producers to serve in a swing role, delivering to East or West as demand trends require (see appendix for list of projects). CMS Energy, for example, has purchased short-term cargoes from Abu Dhabi, Oman, and Qatar for delivery to the U.S. market. Also, at the end of 2000, Enron signed a short-term contract with Oman LNG for 6 cargoes of 40,000 MTA each for 2001, most of which is expected to come to the Lake Charles, Louisiana, terminal. Some Pacific supplies could also serve to balance regional demand swings as several LNG projects are targeting both Asian buyers and the U.S. West coast. Shell, for example, is expected to market its contracted volumes from Australia's North West Shelf to the U.S. West Coast. Enron also asked for flexible terms in its now terminated contract with Malaysia LNG Tiga that would allow it to resell cargoes under special circumstances.

Sample of LNG Spot Transactions to the U.S. from Asia and Middle East 1Q 2001

Importer	LNG Supplier	Volume (Bcf)	Average Price (MM btu)
CMS	Australia	5.94	\$2.81
CMS	Indonesia	2.76	\$3.57
CMS	Oman	2.33	\$2.93
CMS	Qatar	46.05	\$3.05
CMS	Abu Dhabi	2.73	\$3.16
Coral	Oman	4.92	\$2.44
Enron	Oman	2.74	N/A

The greater the interaction of these swing suppliers with both markets, the more likely prices will converge over time. This could be good news for Asian buyers who paid roughly between \$4.50 to \$5.00 per million Btu in July 2001 for LNG supplies from the Middle East, Malaysia, Indonesia and Australia compared to a U.S. Gulf coast natural gas price of \$3.06 million Btu in July and \$2.97 in August and a U.S. West Coast price of \$4.61 in July and \$3.26 in August.

Comparative LNG Prices (July 2001)

Buyer	Seller	Price
Japan	Abu Dhabi	\$2.50
Japan	Australia	\$4.51
Japan	Indonesia	\$5.05
Japan	Malaysia	\$4.45
Japan	Oman	\$4.57
Japan	Qatar	\$4.52
Japan	Average	\$4.66
South Korea	Various	\$4.81 (June)
U.S. Spot Market	Various	\$3.06
Trunkline Louisiana California	Pipeline	\$4.61

Source: EIG's World Gas Intelligence

Gordon Shearer, then president of Cabot LNG and now an associate at Poten & Partners, captured the shift tides of the LNG business at a speech at Zeus Development's LNG in the Atlantic Basin Conference in Savannah, Georgia, in April 2000.³⁹ Shearer noted that the geography of LNG was changing. "With the rapidly growing LNG production in the Middle East and the Atlantic, the center of gravity of the world's LNG industry is moving eastward (from Asia)," Shearer stated. "As LNG moves eastward, the United States looms large, as the largest gas market on earth, and one with a large over-hanging capacity of cheap LNG import capacity."

Shearer notes that this shift will create an opportunity for greater flexibility in pricing. A global LNG market could use the New York Mercantile Exchange (NYMEX) as its primary pricing point, with other trading centers emerging at Zeebrugge in Belgium, Tokyo, and other locations, all indexed off New York. This would operate in much the same way as oil markets, with West Texas Intermediate, Brent Blend, and Dubai serving as benchmarks. A linked price relationship with U.S. spot natural gas prices on the NYMEX would afford even small Japanese buyers a

³⁹ Gordon Shearer, Cabot LNG, presentation, Zeus Development's LNG in the Atlantic Basin Conference, Savannah, Georgia, April 26, 2000.

greater opportunity to hedge transactions through futures and derivatives markets, potentially promoting a wider deployment of natural gas use as deregulation progresses.

Other pricing mechanisms are sure to emerge as the industry matures. For LNG used as feedstock for chemical manufacturing, the price could be indexed off product prices. In power generation, electricity prices or competing fuels would be the logical basis. Some LNG sales in the Atlantic Basin are already including such linkages.

A stronger link to U.S. natural gas prices could be favorable for Asian LNG buyers. The U.S. DOE's Energy Information Agency's current long-range price forecast still shows a relatively flat line for the future in a base case around \$3 per MM Btu in 1999 dollars through 2020. Recent public comments by EIA officials note that a permanent return to gas prices of \$2-\$2.25 is not likely, but then neither is a rise above about \$3.50. Technology improvements could hold the average price through 2020 to as low as \$2.75, according to EIA. Only slow implementation of advanced drilling and production technology would push to \$4 by 2020. Other U.S. forecasters predict similarly moderate price trends of prices between \$3 and \$3.50 over the coming decade.

APPENDIX

New LNG Trains

Project	Size (MM tons/year)	Startup
Abu Dhabi	2.0-3.8	2010 or beyond
Alaska LNG	7.7	2010
Angola	4.3	2005-06
Australia - Gorgon	8.0	2005-06
Australia - Greater Sunrise	4.8	2005-06
Australian – North West Shelf	4.2	2004-2005
Bolivia	7.7	2006
Brunei	3.0-4.0	2008
Egypt – BG	3.0	2004
Egypt - BP	7.7	2005
Egypt – Shell	4.0	2004
Egypt - Union Fenosa	3.0	2005
Equatorial Guinea	4.0	2008
Indonesia Tangguh	8.0	2005-2006
Iran (BP)	10.0	2008-2009
Iran (Shell)	7.0-8.0	Under study
Iran (TotalFinaElf)	7.0-8.0	Under study
Nigeria - Bonny 3	3.0	2005
Nigeria - Bonny 4&5	8.5	2007-08
Nigeria II	4.7	2007-08
Nigeria III	5.0	2008
Norway - Snohvit	4.0	2006
Oman	3.3	2004-2005
Peru - Camisea	4.3	2005-06
Qatar –Qatargas	3.1-4.0	2004
Qatar. - RasGas	5	2004
Sakhalin II	9.6	2006
Timor Sea – Bayu Undan	5.8	2005-06
Trinidad 2&3	6.0	2004-05
Trinidad 4	5.5	2006-07
Venezuela Jose	2.0	2005
Venezuela Paria	4.3	2006
Yemen	6.2	2004-2005
TOTAL	175.7-181.4	

(Source: Industry, EIG World Gas Intelligence, Asia Pacific Consulting)